Agenda
Operating Committee
March 4, 2014 | 1:00–5:00 p.m. (CST)
March 5, 2014 | 8:00 a.m.–Noon (CST)

Hyatt Regency St. Louis at the Arch
315 Chestnut Street
St. Louis, Missouri

Introductions and Chair’s Opening Remarks

Trustees Douglas Jaeger and Paul Barber Opening Remarks

NERC Antitrust Compliance Guidelines and Public Announcement

Agenda

1. Administrative - Secretary
   a. Arrangements
      i. Safety Briefing and Identification of Exits
   b. Announcement of Quorum
   c. Background Information*
      i. Operating Committee (OC) Membership
      ii. OC Roster
      iii. OC Organizational Chart
      iv. OC Charter
   v. Parliamentary Procedures
   vi. Participant Conduct Policy
   d. Future Meetings

<table>
<thead>
<tr>
<th>2014 Meeting Dates</th>
<th>Time</th>
<th>Location</th>
<th>Hotel</th>
</tr>
</thead>
<tbody>
<tr>
<td>June 10, 2014</td>
<td>1:00 to 5:00 p.m.</td>
<td>Orlando, FL</td>
<td>Hyatt Regency Orlando International Airport</td>
</tr>
<tr>
<td>June 11, 2014</td>
<td>8:00 a.m. to Noon</td>
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<tr>
<td>September 16, 2014</td>
<td>1:00 to 5:00 p.m.</td>
<td>Vancouver BC</td>
<td>TBD</td>
</tr>
<tr>
<td>September 17, 2014</td>
<td>8:00 a.m. to Noon</td>
<td></td>
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</tr>
<tr>
<td>December 9, 2014</td>
<td>1:00 to 5:00 p.m.</td>
<td>Atlanta, GA</td>
<td>Westin Buckhead Atlanta</td>
</tr>
<tr>
<td>December 10, 2014</td>
<td>8:00 a.m. to Noon</td>
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</tr>
</tbody>
</table>
2. **Consent Agenda – Chair Castle**
   a. December 10–11, 2013 Draft OC Meeting Minutes*

<table>
<thead>
<tr>
<th>Action</th>
<th>Objective</th>
</tr>
</thead>
<tbody>
<tr>
<td>Approve</td>
<td>Approve consent agenda as a block.</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Presentation</th>
<th>Duration</th>
<th>Background Items</th>
</tr>
</thead>
<tbody>
<tr>
<td>No</td>
<td>10 minutes</td>
<td>December 10-11, 2013 OC Meeting Minutes</td>
</tr>
</tbody>
</table>

3. **Chair’s Remarks**
   a. Report on February 5, 2014 Member Representatives Committee Meeting and the February 6, 2014 Board of Trustees Meeting*

4. **OC Action Items Review* – Chair Castle**

<table>
<thead>
<tr>
<th>Action</th>
<th>Objective</th>
</tr>
</thead>
<tbody>
<tr>
<td>None</td>
<td>Streamline the Action Item Process to improve its usefulness.</td>
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</tbody>
</table>

<table>
<thead>
<tr>
<th>OC Strategic Plan Goal:</th>
<th>None, this is an administrative item.</th>
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</thead>
</table>

<table>
<thead>
<tr>
<th>Background:</th>
<th>The OC Action Item list will be reviewed near the beginning of each OC meeting, with the intent to effectively work through action items, reaching prompt resolution.</th>
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<table>
<thead>
<tr>
<th>Presentation</th>
<th>Duration</th>
<th>Background Items</th>
</tr>
</thead>
<tbody>
<tr>
<td>No</td>
<td>15 minutes</td>
<td>Revised OC Action Item List</td>
</tr>
</tbody>
</table>

5. **Subgroup Status Reports**
   a. Operating Reliability Subcommittee* – Chair Joel Wise
   b. Resources Subcommittee* – Chair Gerry Beckerle
      i. **Endorse** – Eastern Interconnection Frequency Initiative Whitepaper* – Vice Chair Blalock
   c. Event Analysis Subcommittee* – Chair Sam Holeman
   d. Personnel Subcommittee* – Neil Lindgren

6. **Reliability Issues Steering Committee Status Report – Vice Chair Case**

   a. ERO Top Priority Reliability Risks*
   b. ERO Priorities – RISC Updates and Recommendations*

8. **Committee Matters**
   a. Operating Reliability Coordination Agreement (ORCA) Implementation – David Zwergel

<table>
<thead>
<tr>
<th>Action</th>
<th>Objective</th>
</tr>
</thead>
<tbody>
<tr>
<td>None</td>
<td>Review a status report related to the implementation of the ORCA.</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>OC Strategic Plan Goal:</th>
<th>To investigate emergent issues that impact the reliability of the BES.</th>
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</table>

<table>
<thead>
<tr>
<th>Action Item Number:</th>
<th>None</th>
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<table>
<thead>
<tr>
<th>Background:</th>
<th>At its June 20, 2013 webinar meeting, the Parties (MISO, SPP, TVA, Southern, AECI, PowerSouth, Louisville Gas and Electric, and Kentucky Utilities) informed the OC that they had entered into an Operating Reliability Coordination Agreement (ORCA). The ORCA provides a long term road map for achieving reliability goals.</th>
</tr>
</thead>
</table>
for coordination and study between the Parties to ensure reliability in the consolidated MISO BA that stretches from the gulf coast through middle America to the US Canadian border. The Operating Committee approved the MISO Reliability Plan given the executed ORCA. MISO agreed to keep the OC informed of the progress on items outlined within the ORCA.

| Presentation: Yes | Duration: 15 minutes | Background Items: None |

Notes:

b. Essential Reliability Services Task Force* – John Moura

**Action:** Endorse

**Objective:** Review, discuss and endorse the Essential Reliability Services Task Force scope, which notes that beyond capacity and energy characteristics, essential reliability services (ERS), such as inertia, frequency response, and voltage control, must be maintained across a given system to ensure reliable operation. There may be other characteristics or functions that make up the suite of ERS.

**OC Strategic Plan Goal:** To investigate emergent issues that impact the reliability of the BES.

**Action Item Number:** 1312-08

**Background:** The amount of variable renewable generation is expected to grow considerably as federal policies and regulations are developed and implemented by individual states and provinces throughout North America. The proposed levels of commitment to renewable variable generation is one component of an ongoing resource mix shift. It is imperative that power system planners and operators understand the potential and cumulative reliability impacts associated with large scale integration of variable generation, an overall capacity reduction in larger base-load generation, increased participation from demand resources and distributed generation, and a more prominent reliance on natural gas-fired generation. Variable generation, in particular, has different characteristics and respond differently on the system. As larger amounts of variable generation are added to the system, they will displace the traditional large, rotating machines and the operating characteristics those machines provided.

The ERSTF has a multi-faceted purpose that includes a technical foundation of ERS, educate and inform industry, regulators, and the public about ERS, develop an approach for tracking and trending ERS, and formulate recommendations to ensure the complete suite of ERS are provided and available. More specifically, the task force will reconcile a collection of analytical approaches for understanding potential reliability impacts as a result of increasing variable resources and how those impacts can affect system configuration, composition, and ERS.

| Presentation: Yes | Duration: 15 minutes | Background Item: |
| **i.** ERSTF Scope |
| **ii.** ERSTF Work Plan |

Notes:

**Agenda**

– Operating Committee Meeting
– March 4-5, 2014

<table>
<thead>
<tr>
<th><strong>Action:</strong> None</th>
<th><strong>Objective:</strong> Review and discuss the development status of COM-002-4 (Operating Personnel Communications Protocols)</th>
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</table>

**OC Strategic Plan Goal:** To investigate emergent issues that impact the reliability of the BES.

<table>
<thead>
<tr>
<th><strong>Action Item Number:</strong> None</th>
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**Background:** The purpose of the proposed COM-002-4 Reliability Standard is to improve communications for the issuance of Operating Instructions with predefined communications protocols to reduce the possibility of miscommunication that could lead to action or inaction harmful to the reliability of the Bulk Electric System (BES). The proposed Reliability Standard, similar to posting 7, combines COM-002-3 and former draft COM-003-1 into one standard that addresses communications protocols for operating personnel in Emergency, and non-emergency conditions. The Operating Personnel Communications Protocols Standard Drafting Draft (OPCP SDT) continues to believe that one communications protocols standard that addresses emergency and non-emergency situations will improve communications because operating personnel will not need to refer to a different set of protocols during the different operating conditions.

In preparing Posting 8, the OPCP SDT revised the first draft of COM-002-4 in Posting 7 to develop a single communications standard that addresses protocols for operating personnel in Emergency and non-emergency conditions. The OPCP SDT considered the comments provided on Posting 7 and also drew from a variety of other resources including:

1. The NERC Board of Trustees’ November 7, 2013 Resolution for Operating Personnel Communication Protocols.
2. A survey distributed to a sample of industry experts by the Director of Standards Development and the Standards Committee Chair requesting feedback on the draft standard in Posting 8; and

<table>
<thead>
<tr>
<th><strong>Presentation:</strong> Yes</th>
<th><strong>Duration:</strong> 20 minutes</th>
<th><strong>Background Items:</strong> COM-002-4 (Operating Personnel Communications Protocols)</th>
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**Notes:**

d. Geomagnetic Disturbance Planning Guide* – Frank Koza

<table>
<thead>
<tr>
<th><strong>Action:</strong> None</th>
<th><strong>Objective:</strong> Review and discuss the Planning Committee’s Geomagnetic Disturbance (GMD) Planning Guide and its companion work product the Application Guide: Computing Geomagnetically-Induced Current in the bulk power system (BPS) and to review and discuss the current activities of the GMD Task Force.</th>
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<tr>
<th><strong>OC Strategic Plan Goal:</strong> Improve the depth of NERC reports to include operations perspectives.</th>
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<tr>
<th><strong>Action Item Number:</strong> 1312-01</th>
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**Background:** At its December 2013 meeting, the Planning Committee approved the GMD Planning Guide and the Application Guide: Computing Geomagnetically-Induced Current in the BPS that was developed...
by the GMD Task Force. The OC will review the Planning and Application guides and provide feedback to the Planning Committee.

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<tr>
<th>Presentation:</th>
<th>Duration: 15 minutes</th>
<th>Background Items:</th>
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<tbody>
<tr>
<td>Yes</td>
<td></td>
<td>i. GMD Planning Guide</td>
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<tr>
<td></td>
<td></td>
<td>ii. Application Guide: Computing Geomagnetically-Induced Current in the BPS</td>
</tr>
</tbody>
</table>

**Notes:**

e. Event Analysis Subcommittee – Cold Weather Events – **Sam Holeman**
   
i. Opening Remarks – **Mike Moon, Senior Director, Reliability Risk Management, NERC**
   
ii. MISO – **David Zwergel, Senior Director, Regional Operations**
   
iii. South Carolina Electric and Gas – **Tom Hanzlik, Manager, System Control**
   
iv. Tennessee Valley Authority – **Joel Wise, Manager, Reliability Operations**
   
v. ERCOT – **Ken McIntyre, VP, Grid Planning and Operations**
   
vi. FirstEnergy – **Shawn Gehring, Senior Advisor, Transmission and Substation Services**

<table>
<thead>
<tr>
<th>Action:</th>
<th>Objective: Review and discuss the January 2014 cold weather events.</th>
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**OC Strategic Plan Goal:** Utilize the results of the Event Analysis Process to improve the reliable operation of the BES.

**Action Item Number:** None

**Background:**

In early January 2014 a Polar Vortex impacted the ERCOT and Eastern Interconnections. The OC will hear lessons learned from impacted reliability coordinators, balancing authorities, transmission operators and NERC staff.

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<thead>
<tr>
<th>Presentation:</th>
<th>Duration: 60 minutes</th>
<th>Background Items:</th>
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<tr>
<td>Yes</td>
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<td>None</td>
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| Notes: |


<table>
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<tr>
<th>Action:</th>
<th>Objective: Review and discuss an overview of the formation of the Eastern Interconnection Data Sharing Network, which will assume ownership of NERCnet.</th>
</tr>
</thead>
</table>

**OC Strategic Plan Goal:** To investigate emergent issues that impact the reliability of the Bulk Electric System.

**Action Item Number:** None

**Background:** At its September 2013 meeting the OC discussed NERC’s initiative to transition the ISN (NERCnet) to industry in a manner that will result in a reduced level of redundancy and potential reliability and compliance implications as detailed in a letter, dated September 12, 2013, from PJM, Southern Company, Duke Energy, IESO, and NYISO to Chair Castle. The September letter noted that a key deliverable identified within sections 3.1 and 5.1 of the ISN request for proposal (RFP) focused on redundancy, specifically: the selection of a vendor who would serve as a Network Administrator that
would “Negotiate with carriers for redundant networks on separate carriers; two diverse providers.”
The letter discussed the concern regarding the potential impact to reliability tools (e.g., state estimator)
if the ISN network is out-of-service.

The OC discussed the possibility of drafting a response to NERC management regarding the concerns
raised in the letter and seeking assurances that NERCnet would undergo a smooth transition to industry.
Following the OC’s discussion, it approved a motion that the OC strongly recommends that NERC
coordinate with Eastern Interconnection Reliability Coordinators to develop a coordinated action plan
that ensures a smooth transition of the ISN to the industry. The coordinated action plan shall meet all
the requirements, including redundancy, as identified by the technical expertise of the Data Exchange
and Telecommunications Working Groups and documented within the ISN RFP.

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<thead>
<tr>
<th>Presentation:</th>
<th>Duration: 25 minutes</th>
<th>Background Items:</th>
<th>None</th>
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<td>Notes:</td>
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**g. OC Organization – Chair Castle**

1. Minimum Subcommittee Scope Outline*
2. Event Analysis Subcommittee Scope*

**Objective:** The OC will discuss the organization and scope documents of its subcommittees following a meeting of the OC Executive Committee and its subcommittee leadership, which preceded this OC meeting.

**OC Strategic Plan Goal:** None, this is an administrative item.

**Action Item Number:** 1309-04

**Background:** The task force assigned to revise the OC strategic plan recognized the need to review the scopes of its subcommittees. For example the Interchange Subcommittee has not met for approximately 2-years. The OC will consider whether to keep the IS in an inactive state or to assign its responsibilities to other subcommittees. In addition, the OC expects each of its subcommittees to align its workplan with the goals identified in the OC revised strategic plan and its scope with the Minimum Subcommittee Scope Outline.

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<thead>
<tr>
<th>Presentation:</th>
<th>Duration: 20 minutes</th>
<th>Background Items:</th>
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<tbody>
<tr>
<td>i. Minimum Subcommittee Scope Outline</td>
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<tr>
<td>ii. Event Analysis Subcommittee Scope</td>
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**Notes:**

**h. NERC Monthly Newsletter* – Chair Castle**

**Objective:** Review OC’s item in the NERC January 2014 Monthly Newsletter for potential improvement.

**OC Strategic Plan Goal:** None, this is an administrative item.

**Action Item Number:** None

**Background:** A summary of OC activities was submitted for inclusion in NERC’s January newsletter. Can the quality of this submission be improved, and what should be included in future submissions?
### Planning Committee’s Performance Analysis Subcommittee* – Melinda Montgomery, Chair

#### Performance Analysis Subcommittee

**Objective:** Review, discuss, and endorse the draft Severity Risk Index whitepaper, and review and discuss draft metric ALR 1-4, and review the timeline for development of the 2014 State of Reliability report.

**Action:** Endorse

**Background:** At its December 2013 meeting, the PAS requested OC comment on a draft revision to the Severity Risk Index whitepaper. The PAS will seek endorsement of its final draft. In addition, the PAS will review the timeline for development of the 2014 State of Reliability Report. The OC will schedule a webinar to further consider the report. Finally at the OC’s December 2013 meeting, the PAS conceptually discussed implementation of a revised metric, ALR 1-4. The OC tasked its EAS with further review of ALR 1-4. The PAS will update the OC on its continued efforts to revise this metric.

**Presentation:** Yes  
**Duration:** 15 minutes  
**Background Items:**

1. Draft of the Severity Risk Index whitepaper
2. Draft ALR 1-4 (BPS Transmission Related Events Resulting in Loss of Load) (Clean)

**OC Strategic Plan Goal:** Improve the depth of NERC reports to include operations perspectives.  
**Action Item Number:** 1312-06

### BPS Element Outage Coordination and Governor Frequency Response* – Chair Castle

**Objective:** Review and discuss Appendix F – BPS Risks Not Adequately Mitigated (Gaps) identified in the Standards Independent Experts Review Project – An Independent Review by Industry Experts report, focusing on BPS element outage coordination and governor frequency response.

**Action:** None

**Background:** The Standards Committee is seeking OC input on two BPS risks not adequately mitigated identified by a panel of independent experts during a review of NERC reliability standards.

**Presentation:** No  
**Duration:** 30 minutes  
**Background Items:**

2. Independent Experts Proposed Authority Standard
3. RISC Triage of IEPR Appendix F

**Notes:**

*Background materials included.*
NERC Antitrust Compliance Guidelines

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

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

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

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

- Discussions involving pricing information, especially margin (profit) and internal cost information and participants’ expectations as to their future prices or internal costs.
- Discussions of a participant’s marketing strategies.
- Discussions regarding how customers and geographical areas are to be divided among competitors.
- Discussions concerning the exclusion of competitors from markets.
- Discussions concerning boycotting or group refusals to deal with competitors, vendors or suppliers.
- Any other matters that do not clearly fall within these guidelines should be reviewed with NERC’s General Counsel before being discussed.

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

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

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

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

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

- Reliability matters relating to the bulk power system, including operation and planning matters such as establishing or revising reliability standards, special operating procedures, operating transfer capabilities, and plans for new facilities.
- Matters relating to the impact of reliability standards for the bulk power system on electricity markets, and the impact of electricity market operations on the reliability of the bulk power system.
- Proposed filings or other communications with state or federal regulatory authorities or other governmental entities.
- Matters relating to the internal governance, management and operation of NERC, such as nominations for vacant committee positions, budgeting and assessments, and employment matters; and procedural matters such as planning and scheduling meetings.
## Operating Committee Membership 2013-2015

<table>
<thead>
<tr>
<th>Name</th>
<th>Member (Term)</th>
</tr>
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<tbody>
<tr>
<td>1. Investor-owned utility</td>
<td>Gerry Beckerle, Ameren (15)</td>
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<tr>
<td></td>
<td>Paul Johnson, American Electric Power (14)</td>
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<tr>
<td>2. State/municipal utility</td>
<td>Doug Peterchuck, Omaha Public Power District (15)</td>
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<td></td>
<td>Richard Kinas (Orlando Utilities Commission (14)</td>
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<tr>
<td>3. Cooperative utility</td>
<td>Keith Carman, Tri-State G&amp;T Association (15)</td>
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<td></td>
<td>Chris Bolick, Associated Electric Cooperative, Inc. (14)</td>
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<tr>
<td>4. Federal or provincial utility/Federal Power Marketing Administration</td>
<td>Tom Irvine, Hydro One Networks (15)</td>
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<td></td>
<td>Don Watkins, Bonneville Power Authority (15)</td>
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<td></td>
<td>Martin Huang, BC Hydro (14)</td>
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<td></td>
<td>Pierre Paquet, Hydro Québec TransÉnergie (15)</td>
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<td>5. Transmission-dependent utility</td>
<td>Dennis Florom, Lincoln Electric System (15)</td>
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<td></td>
<td>Ray Phillips, Alabama Municipal Electric Authority (14)</td>
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<tr>
<td>6. Merchant electricity generator</td>
<td>J.T. Thompson, Constellation Energy (15)</td>
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<tr>
<td></td>
<td>Open</td>
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<tr>
<td>7. Electricity marketer</td>
<td>Open</td>
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<tr>
<td>8. Large end-use electricity customer</td>
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<tr>
<td>9. Small end-use electricity customer</td>
<td>Open</td>
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<td></td>
<td>Kevin Conway, Intellibind (14)</td>
</tr>
<tr>
<td>10. Independent system operator/</td>
<td>Kenneth McIntyre, ERCOT (15)</td>
</tr>
<tr>
<td>regional transmission organization</td>
<td>David Zwergel, Midwest ISO (14)</td>
</tr>
<tr>
<td>11. Regional reliability organization¹</td>
<td>ERCOT Alan Bern, Oncor Energy Delivery</td>
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<td></td>
<td>FRCC Ron Donahey, Tampa Electric Company</td>
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<td></td>
<td>MRO Lloyd Linke, Western Area Power Administration</td>
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<td></td>
<td>NPCC John G. Mosier, Jr., Northeast Power Coordinating Council</td>
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<td></td>
<td>RFC Jacqueline Smith, ReliabilityFirst Corporation</td>
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<td></td>
<td>SERC Stuart Goza, Tennessee Valley Authority</td>
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<td></td>
<td>SPP Jim Useldinger, Kansas City Power and Light Company</td>
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<tr>
<td></td>
<td>WECC Jerry D. Rust, Northwest Power Pool Company</td>
</tr>
<tr>
<td></td>
<td>William Chambless, Virginia State Corporation Commission (14)</td>
</tr>
<tr>
<td>Officers</td>
<td>Chairman: Jim Castle, New York ISO</td>
</tr>
<tr>
<td></td>
<td>Vice Chairman: Jim Case, Entergy</td>
</tr>
<tr>
<td>Government representatives¹:</td>
<td>David Andrejčák, Federal Energy Regulatory Commission</td>
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<tr>
<td></td>
<td>U.S. Federal Government</td>
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<td></td>
<td>Canadian federal government</td>
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<td>Provincial government</td>
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<td>Open (1)</td>
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<td>Open (1)</td>
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<td></td>
<td>Daniel Soulier, Régie de l’énergie</td>
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¹ Appointed
## Operating Committee

<table>
<thead>
<tr>
<th>Role</th>
<th>Name</th>
<th>Organization</th>
<th>Address</th>
<th>Phone</th>
<th>Fax</th>
<th>Email</th>
</tr>
</thead>
<tbody>
<tr>
<td>Chairman</td>
<td>James D. Castle</td>
<td>New York Independent System Operator</td>
<td>10 Krey Blvd, Rensselaer, New York 12114</td>
<td>(518) 356-6244</td>
<td><a href="mailto:jcastle@nyiso.com">jcastle@nyiso.com</a></td>
<td></td>
</tr>
<tr>
<td>Vice Chairman</td>
<td>James S Case</td>
<td>Entergy Services, Inc.</td>
<td>6540 Watkins Drive, M-THQ-3B, Jackson, Miss.</td>
<td>601-985-2345</td>
<td>(601)-985-2238 Fx</td>
<td><a href="mailto:jcase@entergy.com">jcase@entergy.com</a></td>
</tr>
<tr>
<td>Secretary</td>
<td>Larry J. Kezele</td>
<td>North American Electric Reliability Corporation</td>
<td>3353 Peachtree Road, N.E., Suite 600, North Tower, Atlanta, Georgia 30326</td>
<td>(609) 273-0839</td>
<td>(404) 446-2595 Fx</td>
<td><a href="mailto:larry.kezele@nerc.net">larry.kezele@nerc.net</a></td>
</tr>
<tr>
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<tr>
<td>Cooperative</td>
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<td>Manager, System Operations</td>
<td>Associated Electric Cooperative, Inc.</td>
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<td>(417) 885-9229</td>
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<tr>
<td>Electricity Marketer</td>
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<tr>
<td>Federal/Provincial</td>
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<td>(514)-879-4689</td>
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<td>Role</td>
<td>Name</td>
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<td>Merchant Electricity Generator</td>
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<tr>
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Section 1. Purpose

The purpose of the Operating Committee (OC) is to promote continent wide Bulk-Power System operational reliability excellence.
Section 2. General Overview and Functions

1. General forum.

Provides a general forum for aggregating ideas and interests regarding the operations of the interconnected Bulk-Power Systems in North America.

2. Advice and recommendations.

Provides the electric reliability organization (ERO) (stakeholders, Board of Trustees, and staff) with advice, recommendations, and the collective and diverse opinions on matters related to interconnected operations to help the industry arrive at informed decisions.

3. Support for other NERC programs.

Provide technical advice and subject matter expert support to each of the NERC program areas, and serve as a forum to integrate the outputs of each ERO program area, including:

a. Reliability Assessments – Review reliability assessments, assure technical accuracy and completeness of results, and endorse approval of assessments to NERC’s Board of Trustees (Board).

b. Emerging Issues and Reliability Concerns – Identify emerging issues within the electric industry, address issues in reliability assessments, and address other issues as assigned by the Board.

c. Operational Analyses – Develop operational analyses, model validation, and key reliability areas, resulting in technically accurate and comprehensive reports addressing these areas (i.e., frequency response, intermittent generation, smart grid, etc.). Provide recommendations that facilitate addressing the reliability risks identified. Provide oversight, guidance, and direction to address key planning related issues.

d. Standards Input – Provide technical expertise and feedback to Standard Authorization Requests (SARs) that have reliability-related impacts, provide foundational technical efforts that support the key reliability operational related standards development, coordinate effectively with the Standards Committee to maintain alignment on priorities of related OC efforts, develop and vet operational guidelines with industry stakeholders, and provide reliability risk information for prioritization of SARs and new Reliability Standards.

e. Metrics – Provide direction, technical oversight, and feedback on the NERC Adequate Level of Reliability (ALR) metrics.

f. Event Analysis – Review all event reports to determine lessons learned and good industry practices and promote the dissemination of information to the industry to enhance reliability.

g. NERC Alerts – Participate in the review and development of requests for industry actions and informational responses.

h. Guidelines and Technical Reports – Develop guidelines, white papers, technical reports and reference documents to address emerging issues and industry concerns related to system operations.

4. Review and approval of Reliability Coordinator Plans.

Comply with existing requirements for review and approval of Reliability Coordinator plans.
5. **Review of foundational changes to interconnected operations.**

Review and provide constructive feedback regarding foundational changes to interconnected operations, such as changes to the footprints of reliability coordinators, balancing authorities, transmission operators, Interconnections, field tests and HVDC ties, etc.

6. **Review, manage and coordinate the following documents.**

   a. The technical content of the NERC Reliability Functional Model.
   b. Reliability Guidelines (See Appendix 3).

7. **Opinions and interpretations.**

   Provide technical opinions at the industry stakeholders’ request on operating reliability concepts, philosophies, and standards.
Section 3. Membership

1. Goals.

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

2. Expectations.

OC voting members are expected to:

a. Bring subject matter expertise to the OC
b. Be knowledgeable in reliable operations within their organization
c. Attend and participate in all OC meetings
d. Express their own opinions, as well as the opinions of the sector they represent, at committee meetings
e. Complete committee assignments
f. Inform the secretary of any changes in their status that may affect their eligibility for committee membership. Failure to do so in a timely manner may result in the member’s dismissal by the chair.

3. Representation.

See Appendix 1, “Committee Members”

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

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

4. Selection.

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

a. Un-nominated voting member positions will remain vacant until the next annual or special election. If a vacancy in an elected sector is created by a resignation or other cause, a special election will be held unless it would coincide with the annual election process. Special elections shall follow the same procedure as the annual election.

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

c. A particular organization, including its affiliates, may not have more than one member on the committee.
Section 3. Membership

Section 3. Membership

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

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

f. After the secretary announces the election results, the newly elected members will serve on the committee pending approval by the Board. The secretary will submit the newly elected members’ names to the Board for approval at the Board’s next regular meeting.

5. Terms.

Members’ terms are staggered, with one-half of the members’ terms expiring each year. Except for the cases described below, a member’s term is two years. Members may be re-elected for subsequent terms. Shorter terms may be required for several reasons:

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

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

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

6. Resignations, Vacancies, and Nonparticipation.

a. Members who resign will be replaced for the time remaining in the member’s term. Members will be replaced pursuant to Section 3.4, officers will be replaced pursuant to Section 5, and executive committee members will be replaced pursuant to Section 7.

b. Newly elected or appointed members will serve on the committee pending approval by the Board. The secretary will submit new members’ names to the Board for approval at the Board’s next regular meeting.

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

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

7. Proxies.

A member of the committee may give a proxy only to a person who:

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

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

To permit time to determine a proxy’s eligibility, proxies must be submitted to the secretary in writing at least one week prior to the meeting (electronic transmittal is acceptable). Any proxy submitted after that time will be accepted at the chair’s discretion, provided that the chair believes the proxy meets the eligibility requirements.
Section 4. Meetings

See Appendix 2, “Meeting Procedures.” In the absence of specific provisions in the Charter document, the OC will follow Roberts Rules of Order, Newly Revised.

1. Quorum.

   A quorum requires two-thirds of the voting members.

2. Voting.

   Except for sector 11, each voting member of the committee shall have one vote on any matter coming before the committee that requires a vote. Sector 11 voting is specified in Appendix 1. Actions by members of the committee shall be approved upon receipt of the affirmative vote of two-thirds of the voting members of the committee present and voting, in person or by proxy, at any meeting at which a quorum is present. The chair and vice chair may vote. Additional voting guidelines are in Appendix 2. Voting may take place during regularly scheduled in-person meetings or may take place via electronic mail, facsimile or conference call.

3. Antitrust Guidelines.

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

4. Open Meetings.

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

5. Confidential Sessions.

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

1. Terms and conditions.

At its first June meeting and every two years thereafter, the committee shall select a chair and vice chair from among its voting members by majority vote of the members of the committee to serve as chair and vice chair of the committee from the end of that June meeting until the end of the June meeting two years later. The newly selected chair and vice chair shall not be representatives of the same sector.

a. Pending approval by the Board, the newly elected officers will assume their duties as stated above. The secretary will submit the names of the elected officers to the chair of the Board for approval at the Board’s next regular meeting.

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

2. Selection.

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

a. The nominating subcommittee will present its recommended candidate.

b. The chair opens the floor for nominations.

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

d. The committee will then vote on the candidate recommended by the nominating subcommittee, followed by the candidates nominated from the floor in the order in which they were nominated. The first candidate to garner the majority of the committee’s votes will be selected.

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

f. If the committee nominates two or more persons, and none receive a majority of the committee’s votes, then the secretary will distribute paper ballots for the members to mark their preference.

g. The secretary will collect the ballots. If the committee nominates three or more candidates, then the winner will be selected using the Instant Runoff Process. (Explained in Roberts Rules of Order)
Section 6. Subcommittees

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

2. Nominating subcommittee.
   
   At the first regular meeting following the selection of a new committee chair, the chair will nominate, for the committee’s approval, a slate of five committee members from different sectors to serve as a nominating subcommittee. The subcommittee will:
   
   a. Recommend candidates for the committee’s chair and vice chair, and
   b. Recommend candidates for the executive committee’s four “at large” members.
Section 7. Executive Committee

1. Authorization.

The executive committee of the OC is authorized by the OC to act on its behalf between regular meetings on matters where urgent actions are crucial and full committee discussions are not practical. Ultimate OC responsibility resides with its full membership whose decisions cannot be overturned by the executive committee, but retains the authority to ratify, modify, or annul executive committee actions.

2. Membership.

The committee will elect an executive committee of six members, all from different sectors, as follows:

   a. Chair
   b. Vice-chair
   c. Four at-large members from different sectors nominated by the nominating subcommittee.

3. Election Process. The nominating subcommittee will present its slate of candidates for the four “at large” members.

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

4. Terms.

The executive committee will be replaced every two years, with the chair and vice chair replaced at a June meeting and the at-large members replaced at a September meeting.
Section 8. Action Without A Meeting

The OC may act by mail or electronic (facsimile or e-mail) ballot without a regularly scheduled meeting. Two-thirds of the members present and voting is required to approve any action. A quorum for actions without a meeting is two-thirds of the OC members. The OC chair or four members (each from different industry segments) may initiate the request for such action without a meeting. The secretary shall post a notice on the NERC website and shall provide OC members with a written notice (letter, facsimile, or e-mail) of the subject matter for action not less than five business days prior to the date on which the action is to be voted. The secretary shall distribute a written notice to the OC (letter, facsimile, or e-mail) of the results of such action within five business days following the vote and also post the notice on the NERC website. The secretary shall keep a record of all responses (e-mail, facsimiles, etc.) from the OC members with the OC minutes.
## Appendix 1 – Committee Members

<table>
<thead>
<tr>
<th>Name</th>
<th>Definition</th>
<th>Members</th>
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<tbody>
<tr>
<td><strong>Voting Members</strong></td>
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<tr>
<td>1. Investor-owned utility</td>
<td>This sector includes any investor-owned entity with substantial business interest in ownership and/or operation in any of the asset categories of generation, transmission, or distribution. This sector also includes organizations that represent the interests of such entities.</td>
<td>2</td>
</tr>
<tr>
<td>2. State/municipal utility</td>
<td>This sector includes any entity owned by or subject to the governmental authority of a state or municipality, that is engaged in the generation, delivery, and/or sale of electric power to end-use customers primarily within the political boundaries of the state or municipality; and any entity, whose members are municipalities, formed under state law for the purpose of generating, transmitting, or purchasing electricity for sale at wholesale to their members. This sector also includes organizations that represent the interests of such entities.</td>
<td>2</td>
</tr>
<tr>
<td>3. Cooperative utility</td>
<td>This sector includes any non-governmental entity that is incorporated under the laws of the state in which it operates, is owned by and provides electric service to end-use customers at cost, and is governed by a board of directors that is elected by the membership of the entity; and any non-governmental entity owned by and which provides generation and/or transmission service to such entities. This sector also includes organizations that represent the interests of such entities.</td>
<td>2</td>
</tr>
<tr>
<td>4. Federal or provincial utility/Federal Power Marketing Administration</td>
<td>This sector includes any U.S. federal, Canadian provincial, or Mexican entity that owns and/or operates electric facilities in any of the asset categories of generation, transmission, or distribution; or that functions as a power marketer or power marketing administrator. This sector also includes organizations that represent the interests of such entities. One member will be a U.S. federal entity and one will be a Canadian provincial entity.</td>
<td>2</td>
</tr>
<tr>
<td>5. Transmission dependent utility</td>
<td>This sector includes any entity with a regulatory, contractual, or other legal obligation to serve wholesale aggregators or customers or end-use customers and that depends primarily on the transmission systems of third parties to provide this service. This sector also includes organizations that represent the interests of such entities.</td>
<td>2</td>
</tr>
<tr>
<td>Name</td>
<td>Definition</td>
<td>Members</td>
</tr>
<tr>
<td>-----------------------------------------------------------</td>
<td>-----------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------</td>
<td>---------</td>
</tr>
<tr>
<td>6. Merchant electricity generator</td>
<td>This sector includes any entity that owns or operates an electricity generating facility that is not included in an investor-owned utility’s rate base and that does not otherwise fall within any of sectors (i) through (v). This sector includes but is not limited to cogenerators, small power producers, and all other non-utility electricity producers such as exempt wholesale generators who sell electricity at wholesale. This sector also includes organizations that represent the interests of such entities.</td>
<td>2</td>
</tr>
<tr>
<td>7. Electricity marketer</td>
<td>This sector includes any entity that is engaged in the activity of buying and selling of wholesale electric power in North America on a physical or financial basis. This sector also includes organizations that represent the interests of such entities.</td>
<td>2</td>
</tr>
<tr>
<td>8. Large end-use electricity customer</td>
<td>This sector includes any entity in North America with at least one service delivery taken at 50 kV or higher (radial supply or facilities dedicated to serve customers) that is not purchased for resale; and any single end-use customer with an average aggregated service load (not purchased for resale) of at least 50,000 MWh annually, excluding cogeneration or other back feed to the serving utility. This sector also includes organizations that represent the interests of such entities.</td>
<td>2</td>
</tr>
<tr>
<td>9. Small end-use electricity customer</td>
<td>This sector includes any person or entity within North America that takes service below 50 kV; and any single end-use customer with an average aggregated service load (not purchased for resale) of less than 50,000 MWh annually, excluding cogeneration or other back feed to the serving utility. This sector also includes organizations (including state consumer advocates) that represent the interests of such entities.</td>
<td>2</td>
</tr>
<tr>
<td>10. Independent system operator/Regional transmission organization</td>
<td>This sector includes any entity authorized by the Commission to function as an independent transmission system operator, a Regional transmission organization, or a similar organization; comparable entities in Canada and Mexico; and the Electric Reliability Council of Texas or its successor. This sector also includes organizations that represent the interests of such entities.</td>
<td>2</td>
</tr>
<tr>
<td>11. Regional Entity</td>
<td>This sector includes any Regional Entity as defined in Article I, Section 1, of the Bylaws of the corporation. In aggregate, this sector will have voting strength equivalent to two members. The voting weight of each Regional member’s vote will be set such that the sum of the weight of all available Regional Entity members’ votes is two votes.</td>
<td>2</td>
</tr>
</tbody>
</table>
### Appendix 1 – Committee Members

<table>
<thead>
<tr>
<th>Name</th>
<th>Definition</th>
<th>Members</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Voting Members</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>RE</td>
<td>Number of Members</td>
<td>Proportional Voting</td>
</tr>
<tr>
<td>FRCC</td>
<td>1</td>
<td>X</td>
</tr>
<tr>
<td>RFC</td>
<td>1</td>
<td>X</td>
</tr>
<tr>
<td>TRE</td>
<td>1</td>
<td>X</td>
</tr>
<tr>
<td>MRO</td>
<td>1</td>
<td>X</td>
</tr>
<tr>
<td>NPCC</td>
<td>1</td>
<td>X</td>
</tr>
<tr>
<td>SERC</td>
<td>1</td>
<td>X</td>
</tr>
<tr>
<td>SPP</td>
<td>1</td>
<td>X</td>
</tr>
<tr>
<td>WECC</td>
<td>1</td>
<td>X</td>
</tr>
<tr>
<td>12. State government</td>
<td>(See Government representatives below)</td>
<td>2</td>
</tr>
<tr>
<td>Officers</td>
<td>Chair and Vice Chair</td>
<td>2</td>
</tr>
<tr>
<td></td>
<td><strong>Total Voting Members</strong></td>
<td><strong>26</strong></td>
</tr>
<tr>
<td><strong>Non-Voting Members</strong>&lt;sup&gt;1&lt;/sup&gt;</td>
<td>This sector includes any federal, state, or provincial government department or agency in North America having a regulatory and/or policy interest in wholesale electricity. Entities with regulatory oversight over the Corporation or any Regional Entity, including U.S., Canadian, and Mexican federal agencies and any provincial entity in Canada having statutory oversight over the Corporation or a Regional Entity with respect to the approval and/or enforcement of Reliability Standards, may be non-voting members of this sector.</td>
<td></td>
</tr>
<tr>
<td>Government representatives</td>
<td>United States federal government</td>
<td>2</td>
</tr>
<tr>
<td></td>
<td>Canadian federal government</td>
<td>1</td>
</tr>
<tr>
<td></td>
<td>Provincial government</td>
<td>1</td>
</tr>
<tr>
<td>Secretary</td>
<td>The committee secretary will be seated at the committee table.</td>
<td>1</td>
</tr>
<tr>
<td>Subcommittee Chairs</td>
<td>The chairs of the subcommittees will be seated at the committee table.</td>
<td></td>
</tr>
</tbody>
</table>

<sup>1</sup> Industry associations and organizations and other government agencies in the U.S. and Canada may attend meetings as non-voting observers.
Appendix 2 – Meeting Procedures

   a. The default procedure is a voice vote.
   b. If the chair believes the voice vote is not conclusive, he/she may call for a show of hands.
   c. The chair will not specifically ask those who are abstaining to identify themselves when voting by voice or a show of hands.
   d. The committee may conduct a roll-call vote in those situations that need a record of each member’s vote.
      i. The committee must approve conducting a roll call vote for the motion.
      ii. The secretary will call each member’s name.
      iii. Members answer “yes,” “no,” or “present” if they wish to abstain from voting.

2. Minutes.
   a. Meeting minutes are a record of what the committee did, not what its members said.
   b. Minutes should list discussion points where appropriate, but should usually not attribute comments to individuals. It is acceptable to cite the chair’s directions, summaries, and assignments.
   c. Do not list the person who seconds a motion.
   d. Do not record (or even ask for) abstentions.

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

4. Personal Statements.
   The minutes will also provide an exhibit to record personal statements.
Appendix 3 – Reliability Guidelines Approval Process

1. Reliability Guidelines.

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

2. Approval of Reliability Guidelines.

Because reliability guidelines contain suggestions that may result in actions by responsible entities, those suggestions must be thoroughly vetted before a new or updated guideline receives approval by the OC. The process described below will be followed by the OC:

a. New/updated draft guideline approved for industry posting. The OC approves for posting for industry comment the release of a new or updated draft guideline developed by one of its subgroups or the committee as a whole.

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

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

d. New/updated guideline approval and posting. A new or updated guideline which considers the comments received, is approved by the OC and posted as “Approved” on the NERC website. Updates must include a revision history and a redline version against the previous version.

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

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

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


Approved reliability guidelines shall be reviewed for continued applicability by the OC at a minimum of every third year since the last revision.

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

**Based on Robert’s Rules of Order, Newly Revised, 1990 Edition**

## Motions

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

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

### Notes on Motions

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

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

**Revisions.** Technically, revisions to the main motion are accomplished by the Amend procedure. However, immediately after making the motion, and before it is announced by the Chair, another member may ask that the motion be revised. If the original “motion -maker” agrees to the revision, then the revised motion will be the one debated. The original “seconder” need not be consulted, because the original “motion-maker” plus the “reviser” constitute a motion and a second.
Participant Conduct Policy
Applicable to NERC Operating Committee and its Subgroups

I. General
To ensure that the Operating Committee, including that of the OC’s subgroups, process, hereafter referred to as the stakeholder committee process, is conducted in a responsible, timely and efficient manner, it is essential to maintain a professional and constructive work environment for all participants. Participants include, but are not limited to, members of the committees, media, stakeholders, observers, and NERC staff. In order to ensure the stakeholder committee process remains open and facilitates the goals of the NERC stakeholder committees in a timely manner, NERC has adopted the following Participant Conduct Policy for all participants in the stakeholder committee process.

II. Participant Conduct Policy
All participants in the stakeholder committee process must conduct themselves in a professional manner at all times. This policy includes in-person conduct and any communication, electronic or otherwise, made as a participant in the stakeholder committee process. Examples of unprofessional conduct include, but are not limited to, verbal altercations, use of abusive language, personal attacks or derogatory statements made against or directed at another participant, and frequent or patterned interruptions that disrupt the efficient conduct of a meeting or teleconference.

III. Reasonable Restrictions in Participation
If a participant does not comply with the Participant Conduct Policy, certain reasonable restrictions on participation in the stakeholder committee process may be imposed as described below. If the Chair, Vice Chair, or a designee of a NERC stakeholder committee determines, by his or her own observation or by complaint of another participant, that a participant’s behavior is disruptive to the orderly conduct of a meeting in progress, the Chair, Vice Chair, or a designee may remove the participant from a meeting. Removal by the Chair, Vice Chair, or a designee is limited solely to the meeting in progress and does not extend to any future meeting. Before a participant may be asked to leave the meeting, the Chair, Vice Chair, or a designee must first remind the participant of the obligation to conduct himself or herself in a professional manner and provide an opportunity for the participant to comply. If a participant is requested to leave a meeting by the stakeholder committee Chair, Vice Chair, or a designee, the participant must cooperate fully with the request.

Similarly, if a stakeholder committee Chair, Vice Chair, or designee determines, by his or her own observation or by complaint of another participant, that a participant’s behavior is disruptive to the orderly conduct of a teleconference in progress, the Chair, Vice Chair, or a designee may request the participant to leave the teleconference. Removal by the Chair, Vice Chair, or a designee is limited solely to the teleconference in progress and does not extend to any future teleconference. Before a participant may be asked to leave the teleconference, the Chair, Vice Chair, or a designee must first remind the participant of the obligation to conduct himself or herself in a professional manner and provide an opportunity for the participant to comply. If a participant is requested to leave a teleconference by a stakeholder committee Chair, Vice Chair, or designee, the participant must cooperate fully with the request. Alternatively, the Chair, Vice Chair, or a designee may choose to terminate the teleconference.
At any time, the Chair, Vice Chair, or a designee, may impose a restriction on a participant from one or more future meetings or teleconferences, a restriction on the use of any NERC-administered list serve or other communication list, or such other restriction as may be reasonably necessary to maintain the orderly conduct of the stakeholder committee process. Restrictions imposed by the stakeholder committee Chair, Vice Chair, or a designee, must be approved by the NERC General Counsel, or a designee, prior to implementation to ensure that the restriction is not unreasonable. Once approved, the restriction is binding on the participant. A restricted participant may request removal of the restriction by submitting a request in writing to the stakeholder committee Chair or Vice Chair. The restriction will be removed at the reasonable discretion of the stakeholder committee Chair, Vice Chair or a designee.

IV. Guidelines for use of NERC Email Lists
NERC provides email lists, or “listservs,” to NERC stakeholder committees to facilitate sharing information about NERC activities; including balloting and committee work with interested parties. It is the policy of NERC that all emails sent to NERC listserv addresses be limited to topics that are directly relevant to the listserv stakeholder committee’s assigned scope of work. NERC reserves the right to apply administrative restrictions to any listserv or its participants, without advance notice, to ensure that the resource is used in accordance with this and other NERC policies.

Prohibited activities include using NERC-provided listservs for any price-fixing, division of markets, and/or other anti-competitive behavior. Recipients and participants on NERC listservs may not utilize NERC listservs for their own private purposes. This may include lobbying for or against pending balloted standards, announcements of a personal nature, sharing of files or attachments not directly relevant to the listserv group’s scope of responsibilities, and/or communication of personal views or opinions, unless those views are provided to advance the work of the listserv’s group. Any offensive, abusive, or obscene language or material shall not be sent across the NERC listservs.

Any participant who has concerns about NERC’s Participant Conduct Policy may contact the NERC’s General Counsel.
A regular meeting of the NERC Operating Committee (OC) was held on December 10–11, 2013, in Atlanta, Georgia. The meeting agenda and the attendance list are affixed as Exhibits A and B, respectively; and individual statements and minority opinions as Exhibits C and D, respectively. The meeting presentations are posted in a separate file at OC Presentations.

OC Chair Jim Castle convened the meeting at 1:00 p.m. EST. Secretary Larry Kezele announced that a quorum was present, read the Notice of Public Meeting and referred the committee to the NERC Antitrust Compliance Guidelines.

Chair’s Opening Remarks
Chair Castle stated that the OC’s Executive Committee identified the following agenda priorities and keys to success for this meeting:

1. 2014 – 2017 ERO Enterprise Strategic Plan Recommendations
2. Draft Reliability Guideline: Generating Unit Operation during Complete Loss of Communications
3. Peak Reliability’s Reliability Plan
4. Involvement of the OC in the NERC Alerts Process

Consent Agenda
By consent, the committee approved the minutes of the September 17–18, 2013 and the October 11, 2013 webinar meetings.

Chair’s Remarks
Chair Castle summarized his verbal report of OC activities to the NERC Board of Trustees (Board) at its November 6, 2013 meeting. He highlighted 1) the work of the OC in developing a revised Strategic Plan and Charter, 2) the committee’s approval of the Reliability Guideline: Operating Reserves Management and 3) its work on the development of comments in response to the Board’s Resolution on COM-003.
Operating Reliability Subcommittee (ORS)
ORS Chair Colleen Frosch reported that at its November 2013 meeting the subcommittee 1) endorsed the revised SPP and FRCC reliability plans, 2) approved a revised subcommittee scope, 3) endorsed the Planning Committee’s Performance Analysis Subcommittee’s revised ALR metrics and endorsed new officers for the ORS (Presentation 1). Jerry Rust moved to approve the revised ORS scope. The committee approved the motion. Chair Castle appointed Joel Wise as ORS chair and Eric Senkowicz as ORS vice chair.

Subsequent to the November 2013 ORS meeting, the ORS Executive Committee endorsed a revised MISO reliability plan and approved recommending to the OC approval of Peak Reliability’s reliability plan.

Resources Subcommittee (RS)
RS Chair Don Badley reported that the RS is continuing to update the master list of frequency events that will be used in the determination of frequency bias settings. Frequency bias setting data has been requested for use in 2014. In anticipation that FERC will approve BAL-003-1, and under the field trial, the RS will ask BAs to follow the requirements of BAL-003-1 by using the forms and frequency event list to calculate frequency bias settings.

Event Analysis Subcommittee (EAS)
EAS Vice Chair Hassan Hamdar provided an overview of subcommittee activities (Presentation 2). Paul Johnson, chair of the EAS’s EMS Task Force, also provided a brief summary of the NERC hosted conference titled “Improving EMS Reliability.” Topics addressed included EMS outage analysis, event response strategies and management of EMS systems (Presentation 3). In addition, Mr. Hamdar provided an overview of three lessons learned: 1) Loss of Authentication, 2) SCADA Failure and 3) EMS Failure.

Personnel Subcommittee (PS)
Laura Hennebury, chair of the PS, provided an overview of recent subcommittee activities.

Reliability Issues Steering Committee Status Report (RISC)
Chair Castle reported that the Board appointed OC Vice Chair Jim Case as the OC’s representative to the RISC. The RISC chair is now Robert Schaffeld, Southern.

2014–2017 ERO Enterprise Strategic Plan Recommendations
Andy Rodriguez, Director of Reliability Risk Analysis and Control, provided an overview of the draft ERO Enterprise Reliability Risk Management Projects and Reliability Risk Profiles – 2014-2017 document. The concepts presented in the paper may be categorized into six priority areas. Standing committees and other sources of information are used to initially identify risks and priorities for consideration by RISC. NERC staff will likely develop a similar report on an annual basis in the future.

Participant Conduct Policy Applicable to the NERC Operating Committee and its Subgroups
Chair Castle explained that the Standards Committee and NERC Legal developed the initial participant conduct policy. While problems areas identified in the policy have not been prevalent within the OC’s organization, this would be a good policy for the OC to adopt. He suggested that if the OC adopted the
policy that it be posted to the OC website. Following a brief discussion, Jerry Rust moved to adopt the Participant Conduct Policy. The committee approved the motion.

Draft Reliability Guideline: Generating Unit Operations during Complete Loss of Communications

Don Badley, chair of the RS, provided a brief overview of the draft reliability guideline and stated that the guideline is designed to handle generator operations with complete loss of communications. The guideline may not be applicable to some plants. Mr. Badley emphasized that the only source of outside information available to the generator owner/operator is the frequency meter. The OC debated the purpose and intended applicability of the guideline. In other words, should the guideline be applicable to system operators (TOPs or RCs or BAs) or to GOPs? How should remotely monitored generating units be handled in the guideline? Expectations for coordination with TOPs? Does the guideline raise questions about GOP certification?

Following the OC’s discussion, Kevin Conway moved to approve posting the reliability guideline for a 45-day comment period. The committee approved the motion.

Peak Reliability’s Reliability Plan

Michelle Mizumori briefed the OC on the formation of Peak Reliability as a result of the bifurcation of WECC. Peak Reliability has received conditional FERC approval; however, until final FERC approval is received, Peak Reliability will continue to operate under WECC. Ms. Mizumori reported that Peak Reliability drafted its Reliability Plan and that plan was approved by the WECC Board of Directors and endorsed by the OC’s Operating Reliability Subcommittee. The reliability plan does exclude Alberta. Effective January 1, 2014, Alberta will be withdrawing from Peak Reliability. Alberta already operates as a reliability coordinator and has agreements in place with neighboring BAs and TOPs. Peak Reliability is also working to develop a coordination agreement with Alberta.

Jerry Rust moved to approve Peak Reliability’s Reliability Plan. The committee approved the motion.

MISO Balancing Authority Area Expansion Update and Operating Reliability Coordination Agreement Implementation

Dave Zwergel briefed the OC on the status of implementation activities related to MISO’s reliability plan and the Operating Reliability Coordination Agreement (Presentation 4). NERC certification of the MISO BA was completed in September and finalized in November. Transition is expected to occur on December 19, 2013. Implementation tasks, such as MISO Midwest-South Region Dispatch Flow Calculation, that needed to be completed prior to the December 19 transition have been completed.

Event Analysis Subcommittee – Cold Weather Trends

EAS Vice Chair Hamdar summarized the report titled “Assessment of Previous Severe Winter Weather Reports 1983-2011,” which is posted on the NERC website. Common issues identified in previous cold weather events include 1) natural gas supply and interdependence and 2) equipment freezing.

Florida Power and Light’s Transmission Performance Diagnostic Center
EAS Vice Chair Hamdar introduced William Pflug, Florida Power and Light, who briefed the committee on FPL’s Transmission Performance and Diagnostic Center (Presentation 5). FPL’s TPDC began operations in 2009, with its primary focus being on restoration of distribution substations. The focus has evolved since 2009 into predictive applications for both transmission and distribution. These applications are designed to predict and thereby prevent T&D problems and include such applications as transformer and breaker monitoring. The monitoring applications and associated activities identify and prescribe actions before they require immediate response. TPDC staff also provide restoration support to first responders by interpreting findings and indications from monitoring sources.

Geomagnetic Disturbance Task Force Status Report
Ken Donohoo, chair of the GMDTF, summarized task force activities. He noted that a Reliability Standard has already been developed and submitted to FERC that requires the development of operating procedures to mitigate a space weather event. Currently the standard drafting team is attempting to define the size of the space weather event to plan for through the development of a planning guideline.

Involvement of Operating Committee in NERC Alerts Process
Mike Moon, Senior Director of Reliability Risk Management, provided an overview of the NERC Alerts Process (Presentation 6). The OC commented that NERC needs to be sure that the right message is being communicated, while not bogging down the process such that alerts are not issued in a timely manner. The OC also asked why alerts are typically issued to compliance representatives and not to operations management. It was reported that registered entities can have several representatives who receive the initial alert.

Adjourn and Reconvene
The committee adjourned at 5:10 p.m. EST and reconvened the following morning at 8:00 a.m. EST.

Gerry Cauley, NERC President and CEO, Opening Remarks
Gerry Cauley welcomed the OC to the Atlanta area and expressed his appreciation to the OC for its increased focus on reliability. The OC’s work is also appreciated by the Board and the Board trusts the input received from the OC. He requested further assistance from the OC as the Board and other industry stakeholders wrestle with significant operating issues. Mr. Cauley specifically highlighted 1) communications standard development, 2) FERC Order on TOP and IRO standards, 3) CAISO and NERC report of variable energy resources, 4) changing reliability coordinator footprints and 5) NERC’s evolving role in situation awareness and event analysis.

Future of the North American SynchroPhasor Initiative
Alison Silverstein briefed the OC on the history and current status of the North American SynchroPhasor Initiative (Presentation 7). In 2014, the U.S. Department of Energy will begin funding NASPI and the Electric Power Research Institute will begin hosting NASPI meetings. There are currently approximately 1,700 production grade, networked phasor measurement units on the grid. Ms. Silverstein reviewed several examples of synchrophasor on-line uses (e.g., wide-area visualization and oscillation detection). She also reviewed several examples of off-line uses (e.g., model validation and frequency analysis).
John Breckenridge summarized the preamble, introduction, purpose and goals sections of the Security Guideline for the Electricity Sub-sector: Physical Security Response (Presentation 8). Mr. Breckenridge summarized the Baseline, Elevated Risk and Imminent Risk threat levels and the associated recommended actual response guidelines.

NERC Monthly Newsletter
Chair Castle asked the OC to consider drafting news articles for publishing in the NERC Monthly Newsletter on a periodic basis. The OC fully supported this activity and asked the leadership team to consider posting a year-in-review article in one of the upcoming monthly newsletters.

August 14, 2003 Blackout in the U.S. and Canada – 10 Years Later
Mike Moon reported that the 2003 Northeast Blackout resulted in several significant landmark actions by federal and provincial regulators and legislators and electric industry stakeholders, including NERC. For example, U.S. legislation resulted in the passage of Section 215 of the Federal Power Act, which led to the creation of the electric reliability organization, while the former NERC Operating Guides became the Version 0 Reliability Standards, and NERC (as the ERO) launched programs related to compliance with and enforcement of those reliability standards. NERC placed a higher emphasis on such programs as situation awareness, vegetation management, operation of protective relays and operator training. Mr. Cauley’s opening remarks emphasized system operator communications, development of interconnected operation services and the remand by FERC of the TOP and IRO Reliability Standards as areas of future engagement by the OC.

Special Protection Systems and Remedial Action Schemes: Assessment of Definition, Regional Practices and Application of Related Standards
Phil Tatro, Senior Performance and Analysis Engineer, provided an overview of the report titled “Special Protection Systems (SPS) and Remedial Action Schemes (RAS): Assessment of Definition, Regional Practices, and Application of Related Standards,” dated April 2013 (Presentation 9). The special RAS/SPS Assessment was the result of a Standards Committee Request for Research and will likely support the Reliability Standards Project 2010-05.2 drafting team, which is scheduled to begin work in Q1 of 2014.

Planning Committee’s Performance Analysis Subcommittee
Melinda Montgomery, chair of the Performance Analysis Subcommittee, reviewed proposed revisions to five Adequate Level of Reliability metrics. Following Ms. Montgomery’s review, Kevin Conway moved to endorse the revised ALR metrics, with the exception of ALR1-4 (BPS Transmission Related Events Resulting in Loss of Load). The committee approved the motion. Chair Castle tasked the EAS with reviewing ALR1-4 prior to further committee action.

Ms. Montgomery also reviewed a Severity Risk Index whitepaper and requested OC comments by January 17, 2014. Chair Castle tasked Vice Chair Case and Alan Bern with developing draft comments.
Ms. Montgomery reviewed ALR-C1 which is a compliance space metric developed by the PAS at the request of the Certification and Compliance Committee. Mr. Moon suggested that use of this metric could have serious unintended consequences and noted that NERC’s compliance enforcement staff already develops and tracks metrics. Mr. Moon further recommended a broader joint ERO and industry focus group to review the KCMI and ensure the method is sound and can also be adjusted over time. Vice Chair Case moved to retire the Key Compliance Monitoring Index current used in the Annual State of Reliability report. The committee approved the motion.

2013 Special Reliability Assessment: Maintaining Bulk Power System Reliability While Integrating Variable Energy Resources to Meet Renewable Portfolio Standards

John Moura, Director Reliability Assessment, briefed the committee on the preliminary findings and recommendations presented in the 2013 Special Reliability Assessment: Maintaining Bulk Power System Reliability While Integrating Variable Energy Resources to Meet Renewable Portfolio Standards (Presentation 10). Mr. Moura reported that the integration of large quantities of variable energy resources (VERs) is changing electric system planning and operations and that the variability of these resources requires new approaches to planning and operating methods to ensure the reliability of the bulk power system. The special reliability assessment provides an explanation of the current efforts of the California Independent System Operator to integrate VERs, as well as some of the current and proposed solutions to maintain resource adequacy and reliable operations in anticipation of a significantly changing resource mix.

The solutions being implemented by the California ISO support the recommendations of the IVGTF. In many ways, concerns in the CAISO are a test bed to develop effective ways to plan and operate a transformed electric grid. The report highlights the steps CAISO has taken based on the IVGTF’s guidance, describes the unique challenges in California’s electric grid, and proposes recommendations to address residual gaps for consideration by the CAISO system as well as by others. Consequently, other parts of the North America can learn from the challenges and enhancements occurring and apply them to meet their own future needs.

Incident Command Center

Vice Chair Case stated that the Severe Impact Resilience Task Force report at page 80 states: “Entities need to be familiar with government emergency management structures. For example, entities in the U.S. should be familiar with the government’s Incident Command System (ICS)/National Incident Management System (NIMS) principles.” He provided an overview of Entergy’s use of the ICC (Presentation 11). As reflected in the National Response Framework: “Private-sector organizations play an essential role in protecting critical infrastructure systems and implementing plans for the rapid restoration of normal commercial activities and critical infrastructure operations in the event of disruption.” He highlighted the on-line training that is available from the Emergency Management Institute.

GridEx II

Matt Blizard summarized the objectives and timeline of the GridEx II exercise (Presentation 12). The simplified objectives of the November 14, 2013 GridEx II Executive Tabletop discussion are to 1) communicate with each other, 2) walk through crisis response and 3) gather lessons learned. Mr. Blizard
reported that approximately 200 organizations participated in the exercise or approximately 1900 registered participants. That compares with 76 participating organizations and 420 registered participants for GridEx 2011.

**OC Organization**
Chair Castle reported that he conducted an analysis of all OC subcommittee scopes to identify similarities and good practices (*Exhibit E*). His analysis resulted in minimum criteria of elements that should be contained in all OC subcommittee scopes (*Exhibit F*). Chair Castle will distribute Exhibit F to all subcommittee officers with a request to redesign their own scope. In addition, he is asking each subcommittee to review the responsibilities assigned to the Interchange Subcommittee, with the initial thought to retire the IS at some point in the future.

**OC Action Items Review**
Chair Castle stated that the OC’s Action Item list has become cluttered and cumbersome to use. The OC leadership met with the intent to streamline the OC’s Action Item list and proposes that as items are completed, they be archived following the next NERC Board meeting. This process will help keep the list crisp and focused on current issues. The revised Action Item list is attached as *Exhibit G*.

**Next Meeting**
The next meeting of the Operating Committee will be on March 4–5, 2014 in St. Louis, Missouri.

**Adjourn**
There being no further business before the Operating Committee, Chair Castle adjourned the meeting on Wednesday, December 11, 2013 at 12:02 p.m. EST.

**Larry Kezele**
Larry Kezele
Secretary
I want to recognize Board of Trustee member Janice Case for taking the time out of her busy schedule to spend with the Operating Committee. Janice made sure that she was in the room when the OC debated a new draft reliability guideline addressing “Generating Unit Operations during Complete Loss of Communications”. While many pro and con issues surfaced during the debate, the OC ultimately approved the draft guideline for a 45 day public posting to receive industry comment. Thank you for witnessing the OC in action.

I also want to recognize Gerry Cauley for taking the time to address the OC and share some of his thoughts on concepts for improving BES reliability as the industry supply side landscape continues to evolve. The Operating Committee heard you. In fact we are already working with NERC staff and the PC to develop the plan for moving forward. The OC Looks forward to our participation on this project.

Operating Committee highlights and accomplishments since the last Board meeting include:

Generator Loss of Communications Guideline:
As discussed earlier, this draft reliability guideline has been posted for industry comment. The comment period closes on February 28. This draft guideline addresses a recommendation in the Severe Impact Resilience Report. In that light, I encourage interested parties (Generators, Transmission Providers, Grid-Operators) to review it, give it some deep thought, and provide constructive comment.

Peak Reliability Plan:
With the Reliability Coordinator function transition from the WECC to Peak Reliability that included the carve-out of Alberta, the OC devoted significant time to discuss and understand the reliability plan. With the understanding that operating agreements are in place around the Peak – Alberta border, the Operating Committee concluded that Peak Reliability’s Reliability Plan was sound for the footprint described within the plan. The plan was approved.

NERC Monthly Newsletter:
The OC discussed how the activities and achievements of the OC can become more visible to the industry stakeholders. Overwhelmingly, the OC agreed that it would be a good practice to provide OC meeting highlights in the NERC Newsletter. Although comprehensive meeting notes are available on the NERC Website, the NERC News highlights delivered by email would provide information to those that might not otherwise search through meeting notes. It was encouraging to us that NERC published the year in review of all the standing committees. We hope to keep that momentum through the year.

Operating Committee Organization:
The Operating Committee is working with its subordinate groups to update all of the work scopes with the intent to streamline the OC Structure and more efficiently utilize the scarce resources of the stakeholders that volunteer their service.
## September 2012 Meeting Action Items

<table>
<thead>
<tr>
<th>OC meeting and item number</th>
<th>Assignment</th>
<th>Description</th>
<th>Due Date</th>
<th>Progress</th>
<th>Status</th>
</tr>
</thead>
<tbody>
<tr>
<td>1209-16</td>
<td>HILF - AGENDA Item – Incident CMD Structure – impact so the language on this</td>
<td>Jun 2013</td>
<td>Jim Case to present in September 2013 meeting. Will include on the OC’s December 2013 Meeting agenda.</td>
<td>Complete</td>
<td></td>
</tr>
<tr>
<td>1209-19</td>
<td>RS</td>
<td>HILF – RS to continue to work on re-tuning the Y2K Frequency Guideline</td>
<td></td>
<td>In Progress</td>
<td></td>
</tr>
<tr>
<td>OC meeting and item number</td>
<td>Assignment</td>
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</tr>
<tr>
<td>1212-02</td>
<td>OC</td>
<td>Strategic Plan Review</td>
<td>Mar 13</td>
<td>Maybe Sooner before FEB - Work with OCEC and later OC. Waiting for the NERC goals Brainstorming complete in March. Small team to edit plan for June meeting discussion and possible approval. Revised plan expected to be presented to the Board at its November 2013 meeting.</td>
<td>Complete</td>
</tr>
<tr>
<td>1212-05</td>
<td>OC - EAS</td>
<td>EAS to review – the 1989 Cold Weather Report to establish trends</td>
<td>Dec 13</td>
<td>Larry to review with Jule Tate, Sam Holeman and Hassan Hamdar.</td>
<td>Complete</td>
</tr>
<tr>
<td>1212-06</td>
<td>OC - EAS</td>
<td>EAS to work with the Forums on sharing lessons learned</td>
<td>Dec 2013</td>
<td>Larry to review with Mike Moon.</td>
<td>In Progress</td>
</tr>
<tr>
<td>1212-07</td>
<td>OC</td>
<td>Approve EAS Process Document</td>
<td>June 13</td>
<td>Highlight on BANNER/TAB of OC Web-Page</td>
<td>Complete</td>
</tr>
</tbody>
</table>
| 1212-09                    | OC         | • Posting the ACE Diversity Guideline  
• Communicate Same to Industry | | Late Waiting on NERC | |
| 1212-12                    | OC         | Cold Weather Update Each Year – ANNUAL AWARENESS– RISC Tasking – how will we do this. | December 2013 | Need in the strategic plan. Request EAS to track and report to OC at next regularly scheduled meeting. | Complete |
| 1212-13                    | OC         | OC Guidelines Initiatives (Should share with PC)  
• TEMPLATE - Guideline Template or Style Guide – Checklist (review Policy 2 for tone) –  
  • Do we address the authoritative nature of the OC’s expertise.  
  • Do we add a RISK ASSESSMENT to each guideline?  
  • Should Guidelines have links to Standards?  
  • REVIEW Cadence  
  • LESSONS LEARNED - How do we connect Lessons Learned to updating impacted | June 2013 | Mike Moon’s team to draft a possible template.  
Template developed by ERO staff, reviewed by the OC leadership, and shared with the OC – but the OC was not able to discuss in March | Late |
guidelines – how do we boil the wisdom out of the lessons – does the OC have a
  • AWARENESS to Broader Industry Base – how do we do a better job - Highlight on BANNER/TAB of OC Web-Page

<table>
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</thead>
<tbody>
<tr>
<td>1212-16</td>
<td>Mike Moon</td>
<td>Further engagement with future ALERTS</td>
<td>Dec 13</td>
<td>Need to review NERC’s Alerts Procedure</td>
</tr>
<tr>
<td>1212-21</td>
<td>BARC SDT (Jerry Rust and Gerry Beckerle)</td>
<td>BARC Final Report of Field Trail – lay out the analysis – lessons learned from field trial structure and testing</td>
<td>Dec 2013</td>
<td>Need information from Drafting Team Facilitator.</td>
</tr>
<tr>
<td>1212-22</td>
<td>OC</td>
<td>NERC OC Chair sends a note to the SC Chair – about transitioning from a field trial to what we might do next.</td>
<td></td>
<td>OC Chair is working with SC Chair. See 1309-01</td>
</tr>
<tr>
<td>1212-24</td>
<td>OC</td>
<td>What should the OC do with the NASPI effort in the future as this organization winds down</td>
<td>December 2013</td>
<td>Need to consider this question at the June 2013 meeting. Current understanding is that this activity will be funded by EPRI beginning in 2014. Invite EPRI to December 2013 Meeting.</td>
</tr>
</tbody>
</table>

### March 2013 Meeting Action Items

<table>
<thead>
<tr>
<th>OC meeting and item number</th>
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</tr>
</thead>
<tbody>
<tr>
<td>1303-20</td>
<td>Larry Kezele</td>
<td>Need to review the DRAFT PC Guideline for SPS and RAS Schemes</td>
<td>December 2013</td>
<td>Place this topic on the OC’s December 2013 agenda.</td>
<td>Complete</td>
</tr>
<tr>
<td>OC meeting and item number</td>
<td>Assignment</td>
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<td>Progress</td>
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</tr>
<tr>
<td>1309-01</td>
<td>Castle</td>
<td>Chair Castle will work with the other Standing Committee chairs and the chair of the Standards Committee to return approval of a Standards field test to the appropriate Standing Committee.</td>
<td>December 2013</td>
<td>Chair Castle working with the SC chair and the OC EC. An SC charter amendment is currently under consideration by the SC.</td>
<td>In Progress</td>
</tr>
<tr>
<td>1309-03</td>
<td>Castle</td>
<td>Chair Castle will work with the OC Subcommittee chairs to meet with the EC to address alignment of their goal and objectives with the strategic plan.</td>
<td>December OC meeting</td>
<td>New charge. The OC’s Charter states: The Subcommittee Chair is considered a non-voting member of the Operating Committee. The Chair of the subcommittees will be seated at the committee table. Therefore, the subcommittee chairs are expected to attend regularly scheduled Operating Committee meetings to deliver verbal reports, engage in Committee discussions, and advise the Committee on important topics.</td>
<td>In Progress</td>
</tr>
<tr>
<td>1309-04</td>
<td>Castle</td>
<td>Mr. Castle will invite the current chair of the Interchange Subcommittee to attend a future meeting of the OC to discuss the future role of the IS.</td>
<td>December OC meeting</td>
<td>New charge. Chair Castle contact IS Chair Joe Gardner. He is amenable to disbanding the IS, if its responsibilities as identified in its scope are transitioned to another subcommittee.</td>
<td>In Progress</td>
</tr>
</tbody>
</table>
# December 2013 Meeting Action Items

<table>
<thead>
<tr>
<th>OC meeting and item number</th>
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<th>Progress</th>
<th>Status</th>
</tr>
</thead>
<tbody>
<tr>
<td>1312-01</td>
<td>GMD</td>
<td>Feedback to the P.C.</td>
<td></td>
<td>OC Chair sent letter to PC Chair requesting a copy of the draft guideline for inclusion into the March OC Packet.</td>
<td>In Progress</td>
</tr>
<tr>
<td>1312-03</td>
<td>Bob</td>
<td>Cummings Frequency Response</td>
<td></td>
<td>OC approved the revised Frequency Response Annual Analysis report by conference call on December 20, 2013.</td>
<td>Complete</td>
</tr>
<tr>
<td></td>
<td>Castle</td>
<td>Annual Analysis</td>
<td></td>
<td>Chair Castle sent an email to the leadership of each of the OC’s subcommittees outlining his request.</td>
<td>Complete</td>
</tr>
<tr>
<td>1312-04</td>
<td>Chair Castle</td>
<td>Letter to the Subcommittees charging them to review their scopes.</td>
<td></td>
<td>Chair Castle sent an email to the leadership of each of the OC’s subcommittees outlining his request.</td>
<td>Complete</td>
</tr>
<tr>
<td>1312-05</td>
<td>EAS</td>
<td>EAS to review ALR 1-4 and provide recommendations back to the OC</td>
<td></td>
<td>EAS reviewing</td>
<td>In Progress</td>
</tr>
<tr>
<td>1312-06</td>
<td>ALR-C1</td>
<td>Support NERC staff on working through this</td>
<td></td>
<td>Waiting on NERC</td>
<td>In Progress</td>
</tr>
<tr>
<td>1312-07</td>
<td>GridEx II</td>
<td>Lessons Learned</td>
<td></td>
<td>Waiting on NERC</td>
<td>In Progress</td>
</tr>
<tr>
<td>1312-08</td>
<td>Gerry</td>
<td>Cauley Policy 10 work</td>
<td></td>
<td>Waiting on NERC</td>
<td>In Progress</td>
</tr>
<tr>
<td>1312-09</td>
<td>Vice Chair Case and Alan Bern</td>
<td>SRI Document review for Melinda Montgomery, chair of the PAS</td>
<td>Jan 2014</td>
<td>Vice Chair Case transmitted their comments to the Ms. Montgomery on January 9, 2014.</td>
<td>Complete</td>
</tr>
</tbody>
</table>
NERC Operating Committee  
Sub-group Status Report

**Group:** Operating Reliability Subcommittee  
**Purpose:** Assist the Operating Committee in enhancing Bulk Electric System reliability by providing operational guidance to the industry; by providing oversight to the management of the suite of information technology tools and services which support operational coordination and facilitate standards compliance; and by providing technical support and advice as requested.

**Last Meeting:** February 11, 2014  
**Location:** Tampa, FL  
**Duration:** 1 Day

**Next Meeting:** May 6–7, 2014  
**Location:** Toronto, ON  
**Duration:** 1½ Days

**Chair:** Joel Wise – TVA  
**Vice-Chair:** Eric Senkowicz – FRCC

**Pending OC Approval Items:**
- Draft Reliability Guideline: Reliability Coordinator – BA/TO/TOP Communication: Real-Time Reliability Tools Degradation  
- The ORS began its review of the Interchange Subcommittee scope to determine if there are tasks or responsibilities that could be assigned to the ORS.

**Key issues for OC Resolution:**
- None

**Key Issues for OC Information:**
- Briefed on the Eastern Interconnection Data Sharing Network’s business plans related to the current NERCnet.  
- Began discussions related to the need for further revision of the ORS scope.  
- Engaged in a lengthy discussion of the lessons learned from the January 2014 Cold Weather events (e.g., the polar vortex).  
- Endorsed revised ERCOT and SPP reliability plans  
- While Alberta does not intend to register with NERC as a reliability coordinator, it does intend to submit a reliability plan to the ORS for its review at the September 2014 meeting.  
- NERC Reliability Coordinator Hotline – NERC staff is implementing a project to replace the NERC RC hotline with newer technology, which will provide for greater flexibility in conducting hotline calls.
• Net Actual and Net Scheduled Interchange – In accordance with the OC’s motion at its March 2013 meeting, Peak Reliability RC and MISO RC will further study the implementation of a project to share net scheduled and net actual interchange to improve system operations resiliency. The Resources Subcommittee will support the ORS as this project moves forward.

Current Initiatives/ Deliverables:
• Parallel Visualization Flow visualization project and coordination with the NAESB Business Practices Subcommittee.

Future Initiatives/ Deliverables:
• None

External requests to group:
• None

Internal requests to group:
• None

Group’s recurring deliverables: ORS continues to review Reliability Coordinator reliability plans

Any NERC Programs Oversight Responsibility for the ORS: No

Any NERC Document (non-Reliability Standard) Responsibility for the ORS:
• The ORS oversee several technical reference documents (e.g., Geomagnetic Disturbance Reference Document) in the Operating Manual.
Group: Resources Subcommittee
Purpose: Status Update

Last Meeting: January 22-23, 2014 Location: Houston, TX
Duration: 1½ days

Next Meeting: April 23-24, 2014 Location: Charlotte, NC
Duration: 1½ days

Chair: Gerry Beckerle, Ameren Vice-Chair: Troy Blalock, SCE&G

Pending OC Approval Items:

• The RS Scope is being updated, with the goal of presenting it to the NERC OC for approval at the June meeting.

• Reliability Guideline: Generating Unit Operations during Complete Loss of Communications – The OC approved posting this reliability guideline for a 45-day industry comment period. Comments were due February 28, 2014. The RS will consider comments at its next meeting with the goal of bringing it to the NERC OC during the June meeting for approval.

• Interconnection Frequency Response Obligation – NERC staff, with the support of the RS’s Frequency Working Group and the RS, updated the supporting data for the calculation of each Interconnection’s Frequency Response Obligation. The final results of this annual review were endorsed by the OC Executive Committee on December 20, 2013.

• Eastern Interconnection Frequency Response Initiative – A voluntary generator survey was issued to Eastern Interconnection regional entity contacts for submission to their balancing authorities. Vice Chair Blalock will provide an initial overview of the survey results and request endorsement of the Initiative from the NERC OC.

Key issues for OC Resolution:
• None

Key Issues for OC Information
• Frequency Events – The RS’s Frequency Working Group continues to review, on a quarterly basis, frequency events that occur on each of the four Interconnections. The selected
frequency events will be used by balancing authorities to determine the 2014 frequency bias or by NERC staff to support the calculations of the frequency response ALR metric.

**Current Initiatives/ Deliverables:**
- Inadvertent Interchange Working Group – The IIWG is working with the Eastern Interconnection Regional Entities to identify and resolve possible errors with Eastern Interconnection inadvertent interchange accumulations.

**Future Initiatives/ Deliverables:**
- **Inadvertent Interchange Accounting Training Document.** The current reference document in the Operating Manual will be updated to conform to the current on-line application.
- **Area Interchange Error Survey Training Document.** The RS is developing a revision to the AIE Survey Training Document.
- **Frequency Response Characteristic Survey Training Document.** The RS will likely seek OC approval to retire this training document following completion of the work of the Frequency Response Standard Drafting Team.

**External requests to Subcommittee:**
- Support NERC’s frequency response initiative
- Support Planning Committee’s Performance Analysis Subcommittee

**Subcommittee’s recurring deliverables:**
- Quarterly review of balancing authority performance.
- Annual bias calculation and CPS Limits.
- ALR1-12 (Interconnection Frequency Response) – Assemble frequency event data for use by the Performance Analysis Subcommittee related to the Interconnection Frequency Response metric and for use by the Frequency Response Standard Drafting Team’s frequency response field trial.
- RS Frequency Working Group – Creates and updates a master frequency event list for each of the four Interconnections. All frequency event data is posted on the NERC RS website.
- Update bubble map and corresponding tool changes based on certification, retirement, or reconfiguration of balancing authorities.

**Any NERC Document (non-Reliability Standard) Responsibility for the Subcommittee:**
- NERC Operating Manual Items
  - Control Area Criteria
  - Performance Standards Reference Guidelines
  - Area Interchange Error Survey Training Document
  - Frequency Response Characteristic Survey Training Document
- Inadvertent Interchange Accounting Training Document
- Time Monitor Reference Document (jointly with ORS)
Eastern Interconnection Frequency Initiative Whitepaper
Date: October 28, 2013

Prepared by Members of the NERC Resource Subcommittee

Preface:

Members of the NERC Resource Subcommittee, who are representatives of the Eastern Interconnection, are working with Balancing Authorities within the same interconnection on a voluntary basis to support a pilot program in an effort to improve frequency response. Frequency Response is defined as automatic and sustained change in the power consumption or output of a device such as generator that occurs within 5-20 seconds of and is in a direction to oppose a change in the Interconnection Frequency. While it has been determined that the Eastern Interconnection has generally sufficient frequency response as a whole, there are clues that point to issues with generator governor settings. The sponsors of this initiative believe that proper and consistent governor settings are the low hanging fruit to allay concerns raised by the Federal Energy Regulatory Commission (FERC) as to past trends in frequency response and the differing appearance of frequency in the East, compared to other Interconnections.

Prior to 2010, frequency response has been declining in the East when it should have been increasing with increasing customer demand and the addition of complimentary generation. Additionally, post-event frequency typically exhibits a “lazy L” shape likely caused by set point control overriding the initial response provided by governors.

Figure 9: Updated Eastern Interconnection Mean Primary Frequency Response (May 2012)


Example of “lazy L” a common frequency response characteristic of Eastern Interconnection
Source “CERTS NERC Interconnection Frequency Events May 2013”, October 30, 2012

Agenda Item 5.b.i
OC Meeting
March 4-5, 2014
The initiative focus is on the existing generator fleet with respect to 1) the completeness and accuracy of the data provided in the 2010 NERC Generator Survey 2) improving their frequency response capabilities, and 3) for Balancing Authorities and/or Reliability Coordinators to install tool(s) to monitor individual generator performance within their authority of control and communicate performance results to the individual generators.

Introduction:

Frequency Response has been the focus of increased attention, analysis, development of standards, and deliberation by stakeholders. The foundation of this complex issue is the performance of governors. The starting point to address the issue is to have a firm understanding of current governor settings. The Resources Subcommittee believes the logical place to begin is to confirm generator data, make changes to settings where feasible and to share tools that can measure governor response.

Frequency Control

To understand the role Frequency Response plays in system reliability, it is important to understand the different components of frequency control and the individual components of Primary Frequency Control, also known as Frequency Response. It is also important to understand how those individual components relate to each other.

Frequency control can be divided into four overlapping windows of time:

**Primary Frequency Control (Frequency Response)** – Actions provided by the Interconnection to arrest and stabilize frequency in response to frequency deviations. Primary Control comes from automatic generator governor response, load response (typically from motors), and other devices that provide an immediate response based on local (device-level) control systems.

**Secondary Frequency Control** – Actions provided by an individual Balancing Authority or its Reserve Sharing Group to correct the resource – load unbalance that created the original frequency deviation, which will restore both Scheduled Frequency and Primary Frequency Response. Secondary Control comes from either manual or automated dispatch from a centralized control system.

**Tertiary Frequency Control** – Actions provided by Balancing Authorities on a balanced basis that are coordinated so there is a net zero effect on Area Control Error (ACE). Examples of Tertiary Control include dispatching generation to serve native load; economic dispatch; dispatching generation to affect Interchange; and re-dispatching generation. Tertiary Control actions are intended to replace Secondary Control Response by reconfiguring reserves.
Time Control – This includes small offsets to scheduled frequency to keep long term average frequency at 60 Hz.

Primary Frequency Control - Frequency Response

Primary Frequency Control, also known generally as Frequency Response, is the first stage of overall frequency control and is the response of resources and load to arrest that locally sensed changes in frequency. Primary Frequency Response is automatic, is not driven by any centralized system, and begins within seconds after the frequency changes rather than minutes. Different resources, loads, and systems provide Primary Frequency Response with different response times, based on current system conditions such as total resource/load mix and characteristics.

The NERC Glossary of Terms defines Frequency Response in two parts as:

- (Equipment) The ability of a system or elements of the system to react or respond to a change in system frequency.

- (System) The sum of the change in demand, plus the change in generation, divided by the change in frequency, expressed in megawatts per 0.1 Hertz (MW/0.1 Hz).

As noted above, Frequency Response is the characteristic of load and generation within Balancing Authorities and Interconnections that reacts or responds with changes in power to variations in the load-resource balance that appear as changes to system frequency. Because the loss of a large generator is much more likely than a sudden loss of an equivalent amount of load, Frequency Response is typically discussed in the context of a loss of generation.

2010 NERC Generator Survey

Of those that responded to the 2010 NERC Generator survey data in the Eastern Interconnection, only approximately 57% (Figure 1) provided a generator dead band setting. The remaining 43% provided no responses or responses that did not provide the governor settings (e.g. “Looking into” or “Researching this”). Additionally of those that did respond with a dead band value, the majority of those responses reported values close to or equal to zero or exceeded the historical NERC Policy 1 value of 36 mHz. (Figure 2)
The first goal of this voluntary initiative is to have Eastern Interconnection Balancing Authorities provide an updated Generator Survey Form from their existing generator fleet with confirmed generator data. The data will then be transferred to central repository to be used by Modeling Working Groups. The second goal is to target dates for resetting dead bands to a common target range:

- dead band of +/- 36 mHz,
- droop settings of 3%-5% depending on turbine type,
- continuous, proportional (non-step) implementation of the response
- appropriate operating modes to provide frequency response, and
- appropriate outer-loop controls (distributed controls) settings to avoid primary frequency response withdrawal

The third goal is to develop and share tools to measure individual generator performance on multiple frequency events and provide performance metrics results to their generation fleet in an effort to continue to improve Frequency Response.

**Current Activities:**

Several entities have agreed to support this initiative, including MISO, PJM, Duke Energy, TVA, FPL, SCE&G, and SPP. The current plan is:

- All individual generators (including nuclear) 400 MW or larger, BAs will request generators to provide a completed generator survey of governor settings and related data by January 1, 2014. The 400 MW threshold limits this to roughly 7% of all generators in the East.
- All individual generators (excluding nuclear and combined cycle steam turbines) 400 MW or larger, BA’s will request generators to modify all dead bands greater than 0.036 Hz to at most 0.036 Hz and install proportional response if feasible by June 1, 2014. If a generator is unable to meet this timing, the generator is asked to provide reasonable target date to complete this task.
• All individual generators 100 MW to 400 MW, BA’s will request generators to provide a completed generator survey of current governor settings and related data by July 1, 2014.

• All individual generators 100 MW to 400 MW, BA’s will request generators to modify all dead bands greater than 0.036 Hz to at most 0.036 Hz and install proportional response by November 1, 2014. If a generator is unable to meet this timing, the generator is asked to provide reasonable target date to complete this task.
Related Documents and Links:
“Frequency Response Initiative Report” October 30, 2012
2010 NERC Generator Data Survey
Revision History:

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<thead>
<tr>
<th>Date</th>
<th>Version Number</th>
<th>Reason/Comments</th>
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</table>
NERC Operating Committee
Sub-group Status Report

Group: Event Analysis Subcommittee (EAS)

Purpose: The Event Analysis Subcommittee is a cross-functional group of industry experts that will support and maintain a cohesive and coordinated event analysis (EA) process across North America with industry stakeholders. EAS will support development of lessons learned, promote industry-wide sharing of event causal factors and assist NERC in implementation of related initiatives to lessen reliability risks to the Bulk Electric System.

Last Face-to-Face Meeting: December 09, 2013 Location: Atlanta, GA

Duration: 1 Day

Next Meeting: March 02, 2014 Location: St Louis

Duration: 1 Day

Bi-Weekly Conference Calls on Wednesdays from 1100 to 1300 (EDT)

Chair: Sam Holeman – Duke Energy
Vice-Chair: Hassan Hamdar – FRCC

Pending OC Approval Items:

• Revised EAS Scope
  o Approval of the EAS Scope was deferred at the December 2014 OC meeting to ensure the scope met the OC Minimum Subcommittee Scope criteria. The EAS scope was previously revised to align with the revised OC Strategic Plan and more recently revised to meet the criteria set forth by the OC. EAS has agreed to the changes and the scope is awaiting OC approval.

Key issues for OC Resolution:

• None at this time

Key Issues for OC Information:

• Polar Vortex Review – Multiple Presenters
• Trending Working Group (TWG) has developed a scope to align with the EAS scope and the OC Strategic Plan
• Energy Management System (EMS) Task Force has developed a scope document to transition to a Working Group of the EAS. The scope will align with the EAS scope and the OC Strategic Plan
Current Initiatives/ Deliverables:
- Energy Management System (EMS) event review/summary

Future Initiatives/ Deliverables:
- EMS Event Task Force – periodic reports
- Lesson Learned accountability model
- EAS will continue to review and address reliability issues that pose a threat and risk to the reliability of the BPS. Information obtained from the review will be shared with the OC and industry.

External requests to group:
- The potential for conducting collaboration meetings with North American Transmission Forum and North American Generator Forum is being discussed.
- The EAS is working towards coordination with the Personnel Subcommittee (PS).
  - 2 leadership calls have taken place
  - Liaisons have been established between the two sub-committees
  - Leadership calls are set up prior to OC meetings
- The EAS worked with the Performance Analysis Subcommittee (PAS) to review ALR1-4 as directed by the OC.
  - EAS and PAS worked together to develop a draft solution to the questions on ALR1-4
  - On-going coordination calls will be schedule prior to OC meetings

Internal requests to group:
- None

Group’s recurring deliverables:
- EAS continues to manage the ERO Event Analysis Process Document update process
- Action oriented Lessons Learned posted on NERC website

Any NERC Programs Oversight Responsibility for the Group:
- No

Any NERC Document (non-Reliability Standard) Responsibility for the Group:
- ERO Event Analysis Process Document
NERC Operating Committee
Personnel Subcommittee Status Report
March 4-5, 2014

Group: Personnel Subcommittee
Purpose: Oversight of the Continuing Education Program

Last Meeting
Date: 2/4-5/2014
Location: Phoenix, AR (joint PCGC)
Duration: 2 days

Next Meeting
Date: 6/11-12/2014
Location: Orlando, FL
Duration: 1.5 days

Chair
Laurel Hennebury
Vice-Chair
Lauri Jones
NERC Staff
Brenda Boline

Pending OC Approval Items: Revised PS Scope Document

Key Issues for OC Resolution: None

Key Issues for OC Information: Scope document under revision; version 4.3 of CE Manual at NERC for change mapping and Technical Publications review.

Current Initiatives/Deliverables
• CE Program 2013 audits completed

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<th>4Q</th>
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<td>Level 1 Audits</td>
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<td>117</td>
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<td>Level 2 Audits</td>
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<td>33</td>
<td>33</td>
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<tr>
<td>Total Courses Audited</td>
<td>269</td>
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CE 2013 Program Statistics

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<tr>
<td>Total CEH Processed</td>
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<td>2624</td>
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<td>Active Provider Accounts</td>
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<td>Active System Operators</td>
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<td>6647</td>
<td>6791</td>
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</table>

• Identified an error in the SOCCED report for Total CEH Processed. Values shown here have been corrected.
**Future Initiatives/ Deliverables**

- Undertaking a review of key continuing education processes (Courses; Providers; and, Audits) to identify and address areas for improvement.
- Developing record retention, data storage and transmittal guidelines.
- External Requests to Group:
  - Chair and vice chairs of the PS and EAS working to develop a process to identify training needs and support
  - Requested NERC repost on the Website the PS consultation request form
- Internal Requests to Group:
  - SOCCED phase 2 advisory group formed in conjunction with the PCGC
  - SOCCED phase 2 testing support

**Recurring Deliverables of Group**

- The review and approval of CE courses.
- The review and approval of NERC Approved CE Providers.
- Audits of CE courses for a selected quarter (CERP and PS members perform audits each quarter)

**NERC Program’s Oversight Responsibility for the Group**

- Oversight of the Continuing Education Program

**NERC Document (Non-Reliability Standard) Responsibility for the Group**

- CE Program Administrative Manual
- CE Program Provider's Guide
- CE Program Audit Guide
- Guide to Bulk Upload of Transcripts into SOCCED
- Quarterly CE Program Report to PCGC and OC
- Guide to Writing Learning Objectives
- Guide to Selecting and Developing Learning Assessments
- Individual Learning Activity (ILA) Guide
Executive Summary
NERC staff has collected input from the Reliability Issues Steering Committee (RISC), the leadership of the Standing Committees, and other stakeholders and NERC staff to develop a set of ten top priority reliability risks for consideration in the development of the 2014-2017 ERO Enterprise Strategic Plan. These risks warrant additional focus. In rank order, the top priority reliability risks are: Changing Resource Mix, Resource Planning, Protection System Reliability, Uncoordinated Protection Systems, Extreme Physical Events, Availability of Real-Time Tools and Monitoring, Protection System Misoperations, Cold Weather Preparedness, Right-of-Way Clearances and 345-kV Breaker Failures. Recommendations for action and measures of success are included.

Summary of Top Priority Reliability Risks
NERC reviewed and assembled information from various committee reports and stakeholder inputs to develop a set of ten top priority reliability risks for use in the development of the 2014-2017 ERO Enterprise Strategic Plan. Starting with the RISC’s gap analyses1 presented to the Board of Trustees in August, 2013, staff undertook further review and analysis to identify any additional reliability risk areas of strategic importance for the ERO. Next, qualitative estimates of probability, consequence, and current level of risk management were prepared for each of the identified reliability risks within the chosen areas. These were used to identify ten top priority reliability risks requiring increased attention or additional activity. Following this analysis, recommendations were developed based on previous committee discussions; industry dialogue at the Reliability Leadership Summit; and past committee work products, such as the Long Term Reliability Assessment, the State of Reliability Report, and various special reports and assessments. These recommendations include a number of different approaches based on the various tools NERC has available to influence reliability (such as Guidelines, Information Requests, Training, Standards, and others).

Listed below are the ten high priority reliability risks intended to focus ERO enterprise program areas, including training and education, standards setting, and compliance. Some of these priorities represent conclusions based on experience from reviewing actual system events (topics 3, 4, 6, 7, 8, 9 and 10) while others are more forward looking based on analysis, assessments, and forecasts (topics 1, 2, and 5). These priority risks will be considered in the development of the 2014-2017 ERO Enterprise Strategic Plan, which will in turn lead into the development of the business plan and budget, ultimately aligning resources across the ERO enterprise and program areas to help ensure the most efficient and effective approaches are undertaken to improve or maintain reliability.

The list is in rank order. Detailed profiles for each reliability risk are provided after the list.

1. **Changing Resource Mix.** As the generation and load on the power system changes (e.g. integrated variable resources, increased dependence on natural gas, increased demand-side management, new technologies deployed), the system is being brought into states that are significantly different than those considered when the system was designed and planned, exposing new vulnerabilities not previously considered. Fundamental operating characteristics and behaviors are no longer a certainty. Absent focused action to respond, this risk will increase.

2. **Resource Planning.** Plant retirements (largely due to implemented environmental regulations; increased uncertainty in future resources due to other potential environmental regulations; and lower natural gas prices, which significantly affect power plant economics) are leading to cases where resources may be inadequate to ensure firm demand is served at all times. As the system continues to change, some regional assessments identify concerns with insufficient reserve margins as early as 2014 and 2015 in the ERCOT and Midcontinent ISOs.

3. **Protection System Reliability.** A fault accompanied by a failure of any Protection System component could in some cases result in instability, violation of applicable thermal or voltage ratings, unplanned or uncontrolled loss of demand or curtailment of firm transfers, or cascading outages. Such cases should be identified and addressed.

4. **Uncoordinated Protection Systems.** A lack of protection system coordination has the potential to increase the size and magnitude of events due to unnecessary trips. Uncoordinated protection systems were identified as contributing to the September 8, 2011 and August 14, 2003 events. Ensuring protection system coordination should be a priority for the ERO.

5. **Extreme Physical Events.** While the probability of physical events (such as physical attack, geomagnetic disturbance, or severe weather) that lead to extensive damage is low, the potential consequences are high enough that risk avoidance (reducing the probability) is insufficient as a sole risk management strategy. Risk mitigation efforts (reducing the potential consequence) are also underway, but additional focus is needed to address this risk and minimize both the magnitude and duration of the consequences of an extreme physical event.

6. **Availability of Real-Time Tools and Monitoring.** Not having the right tools and monitoring available to manage reliability in real time is a latent problem waiting for the right combination of events. Such events occurred August 14, 2003, and September 8, 2011, resulting in significant blackouts. Reducing the probability of entities not having key capabilities is essential.

7. **Protection System Misoperations.** NERC’s 2012 and 2013 State of Reliability Reports identified protection system misoperations as a significant threat to BPS reliability. Additional activities are needed to ensure this risk is managed adequately.

8. **Cold Weather Preparedness.** Lack of generator preparedness for cold weather extremes may result in forced outages, de-ratings, and failures to start. Insufficient availability of intra-regional generation and limits on import transfer capability may result in insufficient generation to serve forecasted load, resulting in load shedding.

9. **Right-of-Way Clearances.** Transmission Owners and applicable Generation Owners may have established incorrect ratings based on design documents, rather than on the actual facilities built. Managing to stay within SOL and IROL limits that are based on incorrect ratings may be inadequate to prevent equipment damage and/or cascading, instability, or separation.

10. **345-kV Breaker Failures.** NERC has identified a potential trend of 345 kV SF6 puffer type breakers failing. Circuit breaker failures, in conjunction with another fault, may lead to more BES Facilities removed from service than required to clear the original fault. This poses a risk to the reliability of the BES.

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**Alignment with RISC Priority Recommendations**

The matrix below illustrates the alignment of these ten priority reliability risks with the broader risk areas recommended by the RISC. As reported by the RISC at the November 2013 Board Meeting, many of the risk areas
they identified are in the process of being addressed and are on track for being well managed (see FOOTNOTE 1 and FOOTNOTE 2). However, a key priority area identified in the RISC report, emphasized at the 2013 Reliability Leadership Summit, and reported verbally at the November Board of Trustees meeting was the need to adapt and plan for change. Accordingly, this is reflected in the top two priority risks (nos. 1 and 2) identified in this document. While protection systems continue to be a focus area for the ERO (and several aspects have been addressed), NERC can use additional tools to improve performance in this area. As such, three of the ten top priority projects (nos. 3, 4, and 7) address protection system performance. One top priority (no. 6) deals with availability of real-time tools and monitoring, which was highlighted at the Leadership Summit as well. While activities are ongoing in this area, NERC can do more to address this risk. The four remaining top priority risks (nos. 5, 8, 9, and 10) are ones that NERC has concluded deserve additional attention, as explained in NOTE 3, NOTE 4, NOTE 5, and NOTE 6.

### Alignment between ERO Top Priority Reliability Risks and RISC Priority Reliability Risk Areas

<table>
<thead>
<tr>
<th>High-Priority Areas from the July 26, 2013 RISC Report “ERO Priorities: RISC Updates and Recommendations”</th>
<th>Adaptation and Planning for Change</th>
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<tr>
<td>Cyber Attack SEE NOTE 1</td>
<td>Long Term Planning and System Analysis</td>
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<tr>
<td>Workforce Capability and Human Error SEE NOTE 2</td>
<td>Resource and Transmission Adequacy</td>
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<td>Protection Systems</td>
<td>Integration of New Technologies and Operations</td>
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<td>Monitoring and Situational Awareness</td>
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<tbody>
<tr>
<td>Changing Resource Mix</td>
<td>Blue shading indicates alignment between an ERO Top Priority and a RISC High Priority Area</td>
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<tr>
<td>Resource Planning</td>
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**NOTE 1** – Current activities related to Cyber Attack are appropriately scoped and moving forward, and do not require additional ERO focus at this time.

**NOTE 2** – Current activities related to Workforce Capability and Human Error are appropriately scoped and moving forward, and do not require additional ERO focus at this time.

**NOTE 3** - The RISC recommended that Coordinated Attack on Multiple Facilities be treated as a medium priority, and that other risks involving physical damage (Geomagnetic Disturbance, Extreme Weather/Acts of Nature, Localized Physical Attack, and Electromagnetic Pulse) be treated as low priority. Their priority decisions were based in part on the “all-hazards planning” approach used by utilities when planning systems. However, this issue was discussed at some length at the 2013 Reliability Leadership Summit, and NERC management has concluded it deserves additional attention.

**NOTE 4** - The RISC recommended that Generator Availability and Equipment Maintenance and Management be treated as medium priority. NERC management has concluded that Cold Weather Preparedness is still a risk that needs further attention before it can be considered adequately managed, especially given the recent challenges experienced in January 2014.
NOTE 5 - The RISC recommended that and Equipment Maintenance and Management be treated as medium priority, and that Transmission Right-of-Way be treated as a low priority. Until such time as the Facility Ratings Alert tasks are completed and the data indicates the risk has been adequate managed, NERC management has concluded this risk should continue to be a top priority.

NOTE 6 - The RISC recommended that and Equipment Maintenance and Management be treated as medium priority. However, because of the potentially wide-ranging consequences of this issue and the relative ease of correcting the problem, NERC management has concluded this risk should continue to be a top priority.

Cyber Attack, Workforce Capability and Human Error, and Other Considerations

Both Cyber Attack and Workforce Capability and Human Error were identified by the Reliability Issues Steering Committee as high-priority areas of reliability risk. However, they have not been highlighted in this report as priorities, as the current activities related to each area are appropriately scoped and moving forward.

Cyber Attack is a threat that is constantly evolving. As such, the ERO has made it a priority to build a framework that can be responsive to various attacks. This includes the establishment of the ES-ISAC, ongoing efforts to improve information sharing and analytic capabilities, and the use of various approaches to aid entities in preparation for Cyber Attack (such as the development of the CIP standards, creation and sharing of the Cyber-security Capability Maturity Model, and the biennial Grid Exercise). While work in this area remains important and will continue, it represents and ongoing need for focus, rather than an exception.

Similarly, Workforce Capability and Human Error is important, but represents a continuing need for attention. NERC has enhanced its voluntary event analysis process, and both NERC and the industry are learning a great deal through this collaborative process. However, this is an area where focus is constantly changing, and what is needed is an ongoing operational capability, rather than a specific effort. Work in this area remains important and will continue as part of the ERO’s regular activities.

Additional areas for work was have been identified as well. AC Substation Equipment Failure was noted in the 2013 State of Reliability report as an area of concern; however, sufficient information has not been gathered to support its inclusion in this document. As more is learned and actionable plans are developed, this area will be considered for inclusion as a top priority for the ERO. Other areas that have been identified but require additional analysis include outage coordination and the broad topic of infrastructure maintenance.

The Reliability Risk Management Process (RRMP)

The process used to develop this list is an interim approach as NERC transitions to a broader planning effort titled the Reliability Risk Management Process (RRMP). NERC staff worked with the RISC to develop this process to ensure the consideration of reliability risk and the development of associated reliability risk management projects are reflected in ERO business planning activities. Under the RRMP, the RISC will collect information to identify and prioritize broad areas of reliability risk. These areas then undergo a deeper analysis to identify specific reliability risks, how they can be measured, and what are the most critical risks within those broad areas that should be considered for further risk management activity. Following this analysis, strategies for managing these reliability risks are developed. Such strategies may include the use of Guidelines, Information Requests, Training, NERC Alerts, Technical Conferences, Research, Standards, and other tools. Strategies will be weighed for overall effectiveness and efficiency, and a plan will be developed that addresses each identified reliability risk with a set of approaches commensurate in scope to the level of risk being managed. Ultimately, these projects will be reflected in key ERO activities and the overall ERO planning process. The transition to the RRMP will be implemented and continuously improved over the next several years.
Risk Profile #1: Changing Resource Mix

Associated Reliability Risk Areas: Long Term Planning and System Analysis, Resource and Transmission Adequacy, Integration of New Technologies and Operations

As the generation and load on the power system changes (e.g. from integrated variable resources, increased dependence on natural gas, increased demand-side management, new technologies deployed), the system is being brought into states that are significantly different than those considered when the system was designed and planned, exposing new vulnerabilities not previously considered. Fundamental operating characteristics and behaviors are no longer a certainty. Absent focused action to respond, this risk will increase.

Detailed Problem Description

The energy currently produced by large rotating machines is being replaced with energy produced by variable resources, demand response programs, and other new types of resources, which exhibit different characteristics with respect to some of the less obvious fundamental components of reliable operation (e.g., inertia, frequency response, maneuverability). At the same time, continuing improvements in energy efficiency and other changes in load composition impact characteristics and behavior of load, reactive power needs, and how the system operates and behaves during disturbances (e.g. fault-induced delayed voltage recovery). Finally, the ongoing shift in fuel from coal to natural gas brings its own sets of challenges, such as critical dependence on the just-in-time fuel supply chain of the natural gas infrastructure. All of these changes move the system toward different behaviors, operating characteristics, and levels of reliability risk.

Current Risk Management Activities

- **Ongoing problem evaluation.** Research and analysis by NERC’s technical committees to address specific issues related to this risk, such as the work being done by the Integrating Variable Generation Task Force and their reports and recommendations.
- **Raising awareness.** Annually publishing Long-Term Reliability and Seasonal Assessments, and NERC special assessments (such as Maintaining Bulk Power System Reliability While Integrating Variable Energy Resources — CAISO Approach (2013); Accommodating an Increased Dependence on Natural Gas for Electric Power (2013), A Primer of the Natural Gas and Electric Power Interdependency in the United States (2011), Accommodating High Levels of Variable Generation (2009)).

Recommendations

Current activities provide information, but do not actively drive change. To directly respond to this risk, NERC should focus on these additional activities:

- **Execute previously proposed plans.** Implement the recommendations that have been made in the assessments and reports described above, such as:
  - Develop a standardized model of variable generation for stability and power-flow studies.
  - Develop guidelines for performing load composition modeling analysis; operations and emergency coordination with gas suppliers and transporters; planning considerations for variable energy resources, performance and monitoring requirements for variable energy resources.
  - Incorporate fuel risk and capacity impacts into long-term reliably assessments and planning activities.
  - Consider standards modifications to ensure appropriate applicability and alignment with reliability goals.

- **Define essential reliability services by the end of 2014.** Identify the fundamental components of reliable operation, and determine how to best ensure the need for those components is well understood and met (currently underway at the Planning Committee).

Measures of Success

- Stable and reliable levels for essential reliability services.
- Accurate forecasts of system performance that account for characteristics of the changes to the resource mix.
Risk Profile #2: Resource Planning
Associated Reliability Risk Areas: Resource and Transmission Adequacy

Plant retirements (largely due to implemented environmental regulations; increased uncertainty in future resources due to other potential environmental regulations; and lower natural gas prices, which significantly affect power plant economics) are leading to cases where resources may be inadequate to ensure firm demand is served at all times. As the system continues to change, some regional assessments identify concerns with insufficient reserve margins as early as 2014 and 2015 in the ERCOT and Midcontinent ISOs.

Detailed Problem Description

Environmental regulations, low natural gas prices, load forecasting uncertainty, and economic factors all contribute to an increased rate of plant retirements and a lack of construction. While demand response and energy efficiency may offset some of these losses, performance of those technologies can be uncertain, and each brings unique challenges. Long-term outages of multiple units to employ environmental retrofits also may have impacts. This all contributes to a lack of certainty regarding resource adequacy in North America over the next several years. Forecasts show potential deficiencies in reserve margins as early as 2014 and 2015 in the ERCOT and Midcontinent ISOs.

Current Risk Management Activities

- **Ongoing problem evaluation.** Research and analysis by NERC’s technical committees to address specific issues related to this risk, such as the work being done by the Reliability Assessments Subcommittee.

Recommendations

While entities are aware of this issue and taking action, the amount of time required to implement solutions may be too long to provide relief in the near term, making a reactive approach inadequate. In order to be more proactive and provide assurance that issues are being addressed, NERC should undertake the following additional activities. Dependent on the results of these activities, NERC may need to consider whether its current body of Reliability Standards is sufficient to ensure this risk is appropriately managed.

- **Request information.** Ask entities experiencing problems with resource planning to provide explanations of the activities taken to manage this issue, as well as present regular progress updates.
- **Raise awareness.** Continue emphasis on sharing information through assessments. Meet with regulators to discuss the issue and explain the potential consequences. Issue press releases. Host technical conferences.
- **Promote Best Practices and Guidelines.** Collaborate with entities that have experienced challenges in maintaining sufficient reserve margins to develop best practices and guidelines to help other entities that may experience these challenges in the future manage the issue proactively.

Measures of Success

- Resource adequacy in all North American regions should reverse declining trends and approach target reserve margin levels by the end of the 2014-2017 period. Reserve margins forecasts should not fall below targets within the future three-year horizon.
### Risk Profile #3: Protection System Reliability

**Associated Reliability Risk Areas:** Protection Systems

*A fault accompanied by a failure of any Protection System component could in some cases result in instability, violations of applicable thermal or voltage ratings, unplanned or uncontrolled loss of demand or curtailment of firm transfers, or cascading outages. Such cases should be identified and addressed.*

### Detailed Problem Description

Protection Systems serve a vital role in defense against system disturbance events. However, there are cases where design of a protection system design may be insufficient - where a fault accompanied by a failure of any single Protection System component could result in outage significant event on the BES. One example is the June 24, 2004 Westwing outage event, which resulted in the loss of approximately 5,000 MW of generation and the potential for collapse of the Western Interconnection. NERC identified five events between 2004 and 2010 where a single point of failure on a protection system caused, in whole or in part, an event on the Bulk-Power System.

### Current Risk Management Activities

- **Ongoing problem evaluation.** Research and analysis by NERC’s technical committees to address specific issues related to this risk, such as the work being done by System Protection and Control Subcommittee.
- **Promote Best Practices and Guidelines.** System Protection and Control Subcommittee (SPCS) publication of a document explaining the need for and design of redundancy in protection systems.
- **Section 1600 Data Request.** NERC’s ongoing data request and analysis to determine the risks to the Bulk Power System (“BPS”) posed by potential single point of failure events.

### Recommendations

Current activities provide information, but do not actively drive toward change. Because of the number of events in which this risk has been implicated, NERC must take a more active role in addressing the problem by focusing on these additional activities:

- **Continued data collection and analysis.** NERC’s should continue its ongoing data request and associated analysis to determine the risks to the Bulk Power System (“BPS”) posed by potential single point of failure events.
- **Mandatory Standards.** Upon the completion of the data request described above and dependent on the associated findings from that analysis, develop a standard that requires entities identify and address on an ongoing basis those cases in which a fault accompanied by a failure of any single Protection System component could result in instability, violations of applicable thermal or voltage ratings, unplanned or uncontrolled loss of demand or curtailment of firm transfers, or cascading outages.

### Measures of Success

- Zero instances in which a single point of failure on a protection system causes or contributes to an event on the Bulk Power System.
Risk Profile #4: Uncoordinated Protection Systems
Associated Reliability Risk Areas: Protection Systems

A lack of protection system coordination has the potential to increase the size and magnitude of events due to unnecessary trips. Uncoordinated protection systems were identified as contributing to the September 8, 2011 and August 14, 2003 events. Ensuring protection system coordination occurs should be a priority for the ERO.

**Detailed Problem Description**

Protection systems that trip unnecessarily can contribute significantly to the size of an event. When protection systems are not coordinated properly, the order of execution can result in either incorrect elements being removed from service or more elements being removed than necessary. This can also occur with special protection systems, remedial action schemes, and under-frequency and under-voltage load shedding schemes. Such coordination errors occurred in the September 8, 2011 event (see Recommendation 19) and the August 14, 2003 event (see recommendation 21).

**Current Risk Management Activities**

- **Promote Best Practices and Guidelines.** SCPS publication of a document explaining the need for power plant and transmission system protection coordination, as well as associated training materials and webinars.
- **Mandatory Standards.** Development of requirements for sharing information and protection system coordination studies for interconnecting elements between functional model entities when certain system conditions change (Standards Project 2007-06 System Protection Coordination).

**Recommendations**

NERC already has requirements (and associated enforcement capability) to address this area of concern, and additional improvements are being developed. However, an increased focus on prevention in addition to accountability, education and coaching techniques will help produce positive results, especially given the complex nature of the subject. To this end, NERC should undertake the following additional activity.

- **Mandatory Standards.** Complete the standards project described above.
- **Develop Strategies for Coordination of Protection Systems and Other Devices.** Develop a best practices document on coordinating the design and operation of transmission system protection, generator protection and control, special protection systems, and UFLS and UVLS programs; include modeling considerations necessary for assessing coordination through planning and operating assessments of system performance. The issue of coordinating protection systems and controls that respond to different quantities such as voltage, frequency, apparent impedance, and excitation, is not traditional relay-to-relay coordination. Coordination must be addressed in assessments of system performance to compare the response of protection and controls responding to different quantities, and to account for time-based and location-based variations in these quantities.
- **Promote Best Practices and Guidelines.** Continue to promote best practices and guidelines to aid in protection system design and coordination, such as developed by the SCPS as described above. Collaborate with industry, as well as other entities, to develop additional training programs and educational opportunities for protection engineers to share knowledge and learn about best practices and guideline associated with protection system coordination. Consider working with other bodies (e.g., Energy Providers Coalition for Education) to provide continuing education credits and improve certifications related to protection system education programs.

**Measures of Success**

- Downward trend in the frequency of unnecessary protection system trips caused by lack of coordination.
Risk Profile #5: Extreme Physical Events


While the probability of physical events (such as physical attack, geomagnetic disturbance, or severe weather) that lead to extensive damage is low, the potential consequences are high enough that risk avoidance is insufficient as a sole risk management strategy. Risk mitigation is also underway, but additional focus is needed to address this risk and minimize both the magnitude and duration of the consequences of an extreme physical event.

Detailed Problem Description

Coordinated sabotage attacks, severe weather events, and geomagnetic disturbances are physical events that, at the extreme, can cause extensive equipment damage. Because of the long time involved in manufacturing and replacing some BES assets, an extreme physical event that causes extensive damage to equipment would result in degraded reliability for an extended period of time. While these events of this magnitude have a low probability of occurrence, the potential consequences of such an event are high enough that additional focus is needed to properly address this risk and minimize the consequences of an extreme physical event to acceptable levels.

Current Risk Management Activities

- **Ongoing problem evaluation.** Research and analysis by NERC’s technical committees to address specific issues related to this risk, such as the work being done by the Geomagnetic Disturbance Task Force, Severe Impact Resiliency Task Force and the Critical Infrastructure Protection Committee.
- **Simulation and training.** The biennial Grid Exercise, which identifies strengths and weaknesses by providing entities the opportunity to respond to simulated malicious attacks against the electricity subsector.
- **Mandatory standards.** Requirements related to GMD (Standards Project 2013-03 GMD Mitigation).
- **Develop coordination programs.** Establishment of NERC’s Spare Equipment Database, which facilitates sharing of equipment in times of need. This is complementary to EEI’s Spare Transformer Equipment Program.

Recommendations

While risk avoidance strategies can help prevent manifestation of this risk, a number of events are outside of human control, and avoidance strategies are ineffective. Mitigation efforts to reduce the magnitude of the consequence will address both malicious physical attack and those events which we have little or no ability to prevent.

- **Mandatory Standards.** Complete the standards projects described above.
- **Promote and support coordination programs.** Emphasize the need for industry to participate in coordination support programs, such as the Spare Equipment Database and the Spare Transformer Equipment Program.
- **Encourage resiliency.** Promote the sharing of resiliency best practices within NERC, as well as through collaborative activities with the North American Transmission Forum, the North American Generation Forum, and the North American Energy Standards Board. By leveraging best practices, the magnitude and duration of any significant event would be reduced. Additionally, support entities in pursuing and recovering the costs of implementing resilience strategies, such as the Recovery Transformer Program consortium’s efforts to design and test a universal mobile spare transformer that could be deployed to respond to emergency needs quickly.

Measures of Success

- Increased participation in the Spare Equipment Database and Spare Transformer Equipment Program.
- Strategic deployment of recovery transformers across North America.
- Reduced durations of customer outages caused by extreme physical BPS events.
- Positive trending in other measures of system resilience and restoration performance.
Risk Profile #6: Availability of Real-Time Tools and Monitoring
Associated Reliability Risk Areas: Monitoring and Situational Awareness

Not having the right tools and monitoring available to manage reliability in real time is a latent problem waiting for the right combination of events. Such events occurred August 14, 2003, and September 8, 2011, resulting in significant blackouts. Reducing the probability of entities not having key capabilities is essential.

Detailed Problem Description

Less than adequate situational awareness has the potential for significant negative reliability consequences, and is often a precursor event or contributing cause to events. Experience has shown that not having the right tools and data available can play a critical role in reduced situational awareness, contributing to events such as those seen September 8, 2011 (see Recommendation 12) and August 14, 2003 (see Recommendation 22). NERC has analyzed data and identified that outages of tools and monitoring systems are fairly common occurrences, with approximately an 89% chance of a tool or monitoring system outage occurring within a given month. Each time one of these outages occurs, it creates a potential lack of situational awareness, resulting in a latent risk that could combine with other risks to produce a large event. In addition to outages, simply not having the correct tools or data provided to operators is also a key concern.

Current Risk Management Activities

- **Ongoing problem evaluation.** Research and analysis by NERC’s technical committees to address specific issues related to this risk, such as the work being done by the Real-time Tools Best Practices Task Force.
- **Raising awareness.** Issuing Alerts, publishing Lessons Learned, presenting data and case studies to appropriate technical committees, and NERC’s Monitoring and Situational Awareness Technical Conference, which provided a forum for vendors and users to share information and exchange knowledge about increasing EMS availability.

Recommendations

Current activities provide information, but do not actively drive toward change. Additional emphasis on education and coaching techniques will help produce positive results, especially given the complex nature of the subject. Because of the number of events in which this risk has been a factor, NERC must take an active role in addressing the problem. To more directly respond to this risk, NERC should focus on the following additional activities:

- **Raise awareness.** Continue emphasis on analyzing and addressing unplanned full and partial EMS outages, including activities such as issuing Alerts, publishing Lessons Learned, presenting data and case studies to appropriate technical committees, and hosting additional vendor/stakeholder conferences to discuss issues and strategies for minimizing unplanned full and partial EMS outages.
- **Develop Best Practices and Guidelines.** Collaborate with industry and vendors to develop best practices for system design and maintenance that minimize the probability of downtime, and a guideline to describe approaches for continued reliable operation following the loss of critical tools, such as reliable Real Time Contingency Analysis (RTCA) and Automatic Generation Control (AGC).
- **Mandatory Standards.** Develop a reliability standard to mandate minimum real-time monitoring and analysis capabilities (Standards Project 2009-02 Real Time Reliability Monitoring and Analysis Capabilities).

Measures of Success

- No event where a root, initiating, or contributing cause is identified as a Reliability Coordinator, Transmission Operator, or Balancing Authority not having the real-time tools and monitoring they need to maintain reliability.
- Downward trend in frequency and duration of unplanned full and partial EMS outages.
Risk Profile #7: Protection System Misoperations
Associated Reliability Risk Areas: Protection Systems

NERC’s 2012 and 2013 State of Reliability Reports identified protection system misoperations as a significant threat to BPS reliability. Additional activities are needed to ensure this risk is managed adequately.

Detailed Problem Description

Protection System Misoperations represent a double threat. Unnecessary trips can result in making a bad event worse, and even start cascading failures as each successive trip can cause another protection system to trip. However, failures to trip and slow trips can result in damaged equipment, which may result in degraded reliability for an extended period of time. Key Finding 4 from NERC’s 2012 State of Reliability Report concluded protection system misoperations are a significant contributor to disturbance events and automatic transmission outage severity.

Current Risk Management Activities

- **Ongoing problem evaluation.** Research and analysis by NERC’s technical committees to address specific issues related to this risk, such as the work done by the Protection System Misoperations Task Force.
- **Promote Best Practices and Guidelines.** The Protection System Misoperations Task Force development of a set of suggestions for addressing commonly seen problems and improving protection system performance through the development of guidelines. Ongoing development of training modules to further educate the industry in this area.
- **Raise awareness.** Publication of misoperations statistics in the State of Reliability Report, highlighting this risk. Quarterly updates and outreach to the Regional Protection Committees.
- **Information Requests.** Data collection and analysis regarding protection system misoperations, as well as additional activities to improve processes for collecting data and ensuring data quality and collaborating with other organizations for more focused analysis.
- **Mandatory Standards.** Development of requirements for analysis and corrective action for all protection system misoperations (Standards Project 2010-05.1 Phase 1 of Protection Systems: Misoperations), as well as a standard requiring appropriate disturbance monitoring equipment (Standards Project 2007-11 Disturbance Monitoring).

Recommendations

Increased focus on prevention through education, awareness, and coaching techniques are also expected to produce positive results, especially given the complex nature of the subject. To this end, NERC should undertake the following additional activities.

- **Mandatory Standards.** Complete the standards projects described above.
- **Promote Best Practices and Guidelines.** Develop best practices and guidelines to aid in the proper application of relay elements, minimizing setting errors, maintaining microprocessor-based relay firmware, and the application of power line carrier communication aided protection. Collaborate with industry, as well as other entities, to develop training programs and educational opportunities for protection engineers. Consider working with other bodies to provide continuing education credits and improve certifications related to protection system education programs.
- **Raise Awareness.** Develop a better understanding of regional differences in protection system misoperation rates to support actions to reduce variability, where appropriate. Actively engage the industry through different forums (conferences, regional committee meetings, etc.) to promote awareness and foster mitigation measure development.

Measures of Success

- Variability of regional and registered entity misoperation performance is reduced.
- Overall median misoperation performance rate improves.
### Risk Profile #8: Cold Weather Preparedness
Associated Reliability Risk Areas: Extreme Weather/Acts of Nature, Generator Availability

*Lack of generator preparedness for cold weather extremes may result in forced outages, de-ratings, and failures to start. Insufficient availability of intra-regional generation and limits on import transfer capability may result in insufficient generation to serve forecasted load, resulting in load shedding.*

### Detailed Problem Description

Lack of generator preparedness for cold weather extremes may result in forced outages, de-ratings, and failures to start. During wide-area extreme weather events, unexpectedly large amounts of generation may be unavailable within a region or sub-region. Failure to communicate changes in operating status of generation during next-day and real time operations time periods may result in inaccurate Balancing Authority generation/load forecasts. Insufficient availability of intra-regional generation and limits on import transfer capability may result in inadequate generation to serve forecasted load, resulting in load shedding.

### Current Risk Management Activities

- **Promote Best Practices and Guidelines.** NERC Operating Committee development of a guideline for generator unit winter weather readiness. Ongoing training offerings to further educate the industry in this area.
- **Raise awareness.** Annual notifications, reminding entities to prepare for cold weather.

### Recommendations

The industry experiences in January 2014 were less severe that those from the 1994 and 2011 cold weather events. Despite this, more work remains to be done. NERC should undertake the following additional activities. Dependent on the results of these activities, NERC may need to consider whether its current body of Reliability Standards is sufficient to ensure this risk is appropriately managed.

- **Promote Best Practices and Guidelines.** Collaborate with industry, as well as other entities, to develop a voluntary review process through which entities can verify their preparedness. Consider working with other bodies to provide continuing education credits and improve certifications related to cold weather preparation.

### Measures of Success

- Decreasing values in the following areas:
  - Frequency of unexpected loss of generation during cold weather events
  - Percentage of Generation de-rates due to cold weather events
  - Frequency of generator failures during cold weather events
  - Frequency and magnitude of load shedding during cold weather events
### Risk Profile #9: Right-of-Way Clearances
Associated Reliability Risk Areas: Transmission Right of Way, Equipment Maintenance and Management

*Transmission Owners and applicable Generation Owners may have established incorrect ratings based on design documents, rather than on the actual facilities built. Managing to stay within SOL and IROL limits that are based on incorrect ratings may be inadequate to prevent equipment damage and/or cascading, instability, or separation.*

#### Detailed Problem Description
Reports from various entities have indicated that in a number of cases, actual conductor-to-ground clearances seen in the field have been inconsistent with those assumed during the design of the facility. Examples of inaccurate historical information that leads to these inconsistencies include, but are not limited to, misplaced structures or supports, inadequate tower height, and ground profile inaccuracies. While an entity may address this concern by changing the facility ratings, modifying the transmission line configuration, or changing the topography, such cases must be identified before they can be addressed. Failure to address these misalignments could lead to incorrect ratings that are be inadequate to prevent equipment damage and/or cascading, instability, or separation.

#### Current Risk Management Activities
- **Information Requests.** Data collection and analysis regarding field conditions and alignment with design assumptions, and when misalignment is identified, how that will be corrected.

#### Recommendations
While this risk is in the process of being evaluated and managed, further activity may be needed.

- **Information Requests.** Monitoring and analysis of the data collection described above should continue. Dependent on the results of these activities, NERC may need to consider whether additional information requests are warranted, as well as whether its current body of Reliability Standards and associated compliance enforcement activities are sufficient to ensure this risk is appropriately managed.

#### Measures of Success
- 95% of entities either have verified facility design, installation, and field conditions are within design tolerances when the facilities are loaded at their rating or have taken remediation steps such that facility design, installation, and field conditions are within design tolerances when the facilities are loaded at their rating.
### Risk Profile #10: 345-kV Breaker Failures

Associated Reliability Risk Areas: Equipment Maintenance and Management

NERC has identified a trend of 345 kV SF6 puffer type breakers failing. Circuit breaker failures, in conjunction with another fault, may lead to more BES facilities removed from service than required to clear the original fault. This poses a risk to the reliability of the BES.

### Detailed Problem Description

NERC has reviewed nine 345 kV breaker failures affecting both generation and transmission facilities. Six of these failures have occurred within the past year. From these reviews, NERC has identified a trend of 345 kV sulfur hexafluoride (SF6) puffer type breakers failing. A SF6 puffer type breaker compresses a bellows when opening, directing SF6 gas across the parting contacts to extinguish the arc. The SF6 gas is directed across the contacts via a nozzle. The reports indicate a trend with respect to a separation of the nozzle from its point of attachment. In most cases, the nozzle has been found lying on the tank floor. The manufacturer, Hitachi HVB, Inc (formerly HVB AE Power Systems, Inc.) issued a Maintenance Advisory on the affected model of breaker in 2010. The manufacturer has indicated that approximately 1,000 of these breakers were delivered to customers. Based on Transmission Availability Data System data, it is estimated that this type of breaker could comprise 10% to 16% of the 345 kV breakers in service.

### Current Risk Management Activities

- **Raise awareness.** NERC published an Industry Advisory alert on August 27, 2013. This alert was accompanied by the Manufacturer’s Maintenance Advisory.
- **Information Requests.** NERC requested the North American Transmission Forum, the North American Generator Forum, and other trade associations work with their members to collect and report aggregate information related to this concern (such as the number of these breakers believed to be in operation and whether maintenance has been conducted to address this risk in accordance with the manufacturer’s maintenance advisory).

### Recommendations

While this risk is in the process of being evaluated and managed, further activity may be needed.

- **Information Requests.** Monitoring and analysis of the data described above should continue. Depending on the results of these activities, NERC may need to consider whether additional information requests are warranted, as well as whether its current body of Reliability Standards and associated compliance enforcement activities are sufficient to ensure this risk is appropriately managed.

### Measures of Success

- Reduction in the frequency of 345 KV SF6 puffer type breaker failures.
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Introduction

Summary of Recommendations
Following additional analysis since the presentation of its February 2013 report to the Board of Trustees (Board), the Reliability Issues Steering Committee (RISC) makes the additional following recommendations:

1. Continue collaboration between NERC, the RISC, and Standing Committee leadership to develop a data-driven reliability risk strategy development process that integrates with overall electric reliability organization (ERO) planning (currently being developed as the “Reliability Risk Control Process”).

2. Continue existing NERC efforts to control the risk associated with the high- and medium-priority issues, as the efforts are well aligned and appropriately scoped relative to the priorities assigned.

3. Continue collaboration between NERC and the Technical Committees to develop measures for use in determining the success and ongoing performance of those existing risk control efforts.

4. A new high-priority issue based on consolidating several other related issues (entitled “Adaptation and Planning for Change”) should be processed through the post-prioritization steps of the “Reliability Risk Control Process.”

5. Additionally, the set of issues contained in “Operational Modeling and Model Inputs” should also be processed through the post-prioritization steps of the “Reliability Risk Control Process.”

Background
The RISC is an advisory committee that reports directly to the Board and triages and provides front-end, high-level leadership and accountability for issues of strategic importance to Bulk-Power System (BPS) reliability. The RISC assists the Board, NERC standing committees, NERC staff, regulators, Regional Entities, and industry stakeholders in establishing a common understanding of the scope, priority, and goals to develop solutions to address these issues. In doing so, the RISC provides a framework for steering, developing, formalizing, and organizing recommendations to help NERC and the industry effectively focus their resources on the critical issues needed to best improve the reliability of the BPS. Benefits of the RISC include improved efficiency of the NERC standards program. In some cases, that includes recommending reliability solutions other than the development of new or revised standards and offering high-level stakeholder leadership engagement and input on issues that enter the standards process.

To carry out its responsibility to help NERC and the industry focus resources on the most critical issues, the RISC completed an initial assessment of all ongoing efforts at NERC and made a set of recommendation to the Board in February 2013. In that recommendation, the RISC identified for further study four high-priority areas and five medium-priority areas.

After review and discussion of the initial RISC report, the Board adopted the following resolutions:

**RESOLVED**, that the Board hereby accepts the report of the Reliability Issues Steering Committee (RISC), expresses its appreciation to the RISC for the excellent report, and endorses continued work by the RISC on a gap analysis on the high-priority and then the medium-priority issues and requests continued reports to the Board.

**FURTHER RESOLVED**, that the Board hereby directs NERC management to continue to work with the RISC to consider how the priority rankings should be reflected in the development of the ERO’s business plan and in the work plans of NERC committees.

**FURTHER RESOLVED**, the Board hereby directs NERC management to work with the RISC and, as appropriate, NERC committee leadership to consider how NERC should utilize a data-driven reliability strategy development process that integrates with budget development and overall ERO planning (e.g., Standing Committee planning, department, and employee goal-setting).

The following is an update on the progress made with respect to these resolutions. Similar to its February 2013 report to the Board, the RISC has based these estimates of risk primarily on the expert judgment of its members and that of NERC’s staff and stakeholder subject matter experts. This is based on the maturity of the ERO’s process for analyzing and developing interventions related to reliability risk, as shown in Figure 1. While “expert judgment” is invaluable, as the
process matures, the RISC continues to recommend that NERC focus on data collection and clear problem definition, as well as defining success and developing metrics for all projects going forward. With mature data collection and management for decision support, as well as formal decision-making processes, expert judgment can more effectively be used in the analysis of performance and project effectiveness.

Figure 1: ERO Analysis and Intervention Maturity

**Gap Analysis Activities**

Following the February Board meeting, the RISC immediately began working with NERC staff to perform a gap analysis on each of the high- and medium-priority issues. The gap analyses included the following considerations:

- Are the existing efforts in this area sufficient?
- Are all of the existing efforts needed? If not, what can be eliminated?
- Are any of the existing efforts duplicative of what other organizations are doing?
- Are any of the existing efforts done in concert with the work of other organizations?
- If the existing efforts are not sufficient, what gaps do you see and how do you propose to solve them?
- If new efforts are needed:
  - Is the new effort within NERC’s scope, or should it be directed to another organization?
  - What gap in existing efforts was identified that this new effort was meant to address?
  - What data is available to scope the new activity?
  - How will we measure performance? What metrics will define and track success?

Working collaboratively with stakeholders, NERC staff collected and consolidated information to be used in the gap analyses. This effort included reviews by the leadership of the technical committees as well as representatives from the North American Transmission Forum and North American Generator Forum (see Appendix 1 for complete details of the gap analyses). Following this effort, the information was reviewed over the course of two days in an open RISC meeting held in Washington, D.C., during which input both from RISC members and observers was solicited. The results of these efforts were used to develop this update. The RISC commends NERC staff and the many stakeholders who participated in the preparation and discussion of these gap analyses.
After the review of these gap analyses, it became clear that the earlier prioritization exercise conducted by the RISC did not indicate that issues were not well controlled. In the majority of cases, the high-priority and medium-priority areas are either well controlled or in the process of becoming well controlled. Placement on the high-priority list generally indicates that the scope of a given issue is ERO-wide and deserves increased focus from the ERO and industry. To a large extent, this is already occurring through previously initiated activities (e.g., the System Protection Initiative) or new activities already in development (e.g., NERC’s efforts to improve analysis of events through the use of cause-coding and root-cause techniques).

It was also noted during the gap analyses that no individual problem is likely to result in a negative reliability outcome. The power system was designed so that no single error or contingency should be capable of impacting reliability to a point at which service is interrupted. This inherent resilience presents a challenge when trying to analyze risk to reliability, as it is rare that any one thing can directly lead to an observable degradation in reliability.

**Key Prioritization Determinations**

This update reflects the RISC’s additional analyses completed since its February report. In that report, the RISC identified several high-priority issues. During the development of this update, one new issue was added to the high-priority list: Adaptation and Planning for Change. This issue was added to recognize the importance the industry and the ERO place on constantly assessing the reliability risks of the power system and doing the necessary planning to be ready for any change so it does not manifest as an operational risk. Absent the rapid pace of certain elements of change driven by economics, policy, regulatory, and legislative activities, a number of the issues associated with change that were considered in the February 2013 report are medium- or low-priority issues. However, NERC’s *Long-Term Reliability Assessment* properly notes that the pace of change, and the interaction of these factors with one another, introduces a new level of uncertainty that could affect the assumptions and models that underlie long-range planning. Accordingly, several issues that were previously given medium- and low-priority will be looked at through the lens of this new issue to determine what specific items in those broad categories should receive priority attention.

The Adaptation and Planning for Change issue also presents an opportunity to ensure closer alignment between the priorities of the RISC and areas of concern identified in NERC’s *Long-Term Reliability Assessment*. Identifying these items and giving them separate treatment within this special category of risk ensures that the broader issues considered in long-term planning are handled differently. This will eliminate the somewhat difficult question of trying to compare and prioritize unlike things (e.g., “Monitoring and Situational Awareness” and “Increased Dependence on Natural Gas Generation” are both concerns worth of study, but in different ways, and for different reasons).

Adding this new issue and consolidating several other issues within this new area changed the total counts in each of the priority groups. The five high-priority issues are as follows:

- **Cyber Attack** – NERC is undertaking a number of activities in this important area. The RISC recommends that NERC continue its work in this area and continue to actively seek strong industry support in the areas of information sharing and efficient threat analysis. Improved sharing of information requires a structure in which open, timely and secure information can be shared without the threat of enforcement action and penalties, and the RISC encourages NERC to consider implementing approaches that minimize or eliminate any potential disincentives to information sharing.

- **Workforce Capability and Human Error** – NERC’s Event Analysis program has identified a key problem that spans a number of potential issues: organizational culture’s and management decision making’s contribution to operational error. Specifically, stronger management and organizational support for enhanced robustness of entity event evaluation would be expected not only to reduce operational error, but to ensure such errors are not repeated. NERC staff is aggressively working to improve industry performance in this area through training and communication initiatives, and the RISC recommends continued allocation of resources to support these activities. However, the RISC notes that best-practice groups (such as the North American Transmission Forum and North American Generation Forum) are developing, and the RISC urges NERC to continue to work with those forums and other stakeholder and best-practices groups in the industry to ensure that lessons learned are developed and shared as quickly as possible, and that industry resources are used most efficiently.
- **Protection Systems** – NERC has identified a number of potential problems within this area, and has either completed or is in the process of completing efforts to reduce risks associated with Protection Systems. The RISC recommends that NERC continue its efforts in this area, such as the further analysis ongoing within NERC’s Event Analysis and Performance Analysis programs.

- **Monitoring and Situational Awareness** – NERC’s Event Analysis program reviews have shown a number of cases in which tools for monitoring system conditions are partially or totally unavailable, reducing the capability of operators to make informed decisions. While such conditions rarely produce negative reliability outcomes by themselves, they can serve as latent risks through which an otherwise small problem can expand unnoticed into one of greater magnitude and severity. NERC has begun undertaking efforts to make both industry and vendors more aware of the manner in which such systems fail, so that further analysis to develop corrective or mitigating strategies can be undertaken. The RISC recommends NERC continue its efforts in this area.

- **Adaptation and Planning for Change.** As technologies, policies, and the operating environment change, the industry faces significant changes in the way the power system operates. These issues all require careful consideration, preparation, and planning before they manifest, as interventions may not be immediately available or apparent.

There are also four areas of medium priority, and six of low priority. Figure 2 shows the updated list of issues the RISC considered during its analysis, grouped by priority.

![Figure 2 - Reliability Issues and Priorities](image)

**All-Hazards Planning**

During the RISC’s discussions regarding the gap analyses and the risks represented by various issues, one item that became clear was that no individual problem is likely to result in a negative reliability outcome. This is largely because of the conservative planning and design approaches utilized within the electricity industry. The power system has been designed so that no single error or contingency should be capable of impacting reliability to a point where service is interrupted. Service interruptions are most often related to distribution-level failures. In those cases where events occur at the bulk level, typically multiple barriers to failure have been breached such that the industry’s inherent defense-in-depth approach to risk control has been rendered ineffective.
Introduction

The industry does not know which of the many risks to bulk power reliability will actually occur. For this reason, the industry and the ERO properly focus on “all-hazards” planning. The focus is and should be on the resiliency of the system to operate reliably, regardless of which of the risks actually occur. While large investments could be made in an effort to prevent each specific risk, a more cost-effective approach is to focus on mitigating the impact on reliability - regardless of which risk actually occurs.

This approach to defense in depth and design underscores the importance of continued industry and ERO focus on the items that could affect the reliability of the power system. It is with this focus that the RISC prioritized the issues in the report. As such, it is critical that the issues identified in NERC’s Long-Term Reliability Assessment are given appropriate attention, as they represent the constant and recurring analysis required to ensure the power system continues to meet the performance for which it was designed. The decision to create a new issue for Adaptation and Planning for Change, as described above, is intended to further emphasize the need for this consideration.

**Collaboration Opportunities**

In addition, the electricity industry is very focused on learning from experience. When events do occur, there is a significant amount of self-directed effort from industry to determine root causes of the event and develop reasonable plans to either address those causes (such that events are less likely to repeat), or better position the system (so that future events are less impactful and the system can be more efficiently returned to a reliable state).

Another significant discussion item during the development of the gap analyses was the increasing efforts being undertaken at the North American Transmission Forum and the North American Generator Forum. Further, additional collaborative groups are being formed that plan to focus their efforts on voluntary activities and sharing of best practices. By reaching out to collaborate with these and similar organizations, NERC can enhance its ability to address issues of concern through targeted interventions that may be just as effective as using its authority to develop reliability standards, but more efficiently or quickly, ensuring that lessons learned are developed and shared as soon as possible and industry resources are used most effectively. The RISC encourages NERC to continue its efforts to work collaboratively with these groups and to develop formal relationships when appropriate (such as the recent memorandum of understanding executed between NERC and the North American Transmission Forum).

**ERO Planning Integration - The Reliability Risk Control Process**

In addition to these prioritizations, working with the RISC, NERC staff is developing a process through which flagship NERC reports, such as the State of Reliability Report and the Long-Term Reliability Assessment, are used in concert with input from industry leaders to develop an overall set of priority recommendations for the ERO. Once accepted by the Board, those priorities will be provided to the technical committees for further analysis, refinement, and ultimately development of strategic interventions that can be included in NERC’s activities consistent with its existing planning processes. The RISC believes this approach has the potential to ensure that ERO activities are aligned with the problems that matter most to reliability. Provided that the Board concurs with the prioritization recommended in this report, the RISC would expect those priorities to be reflected in the NERC business plan and in the ongoing work of the NERC committees and staff.

This process, tentatively referred to as the “Reliability Risk Control Process,” will be initiated in October 2013 at a Leadership Summit through which industry leadership representing stakeholders, regulators, trade organizations, subject matter experts, and other interested parties will be asked to discuss their priorities and concerns in a collaborative environment. This discussion will serve as initial input into the development of the 2014 RISC Update and Recommendations.
Chapter 1 - High Priority Issues

Overview
As discussed in the Introduction, the four high-priority problem areas identified in the February report to the Board of Trustees remain, with the addition of a fifth high-priority area entitled “Adaptation and Planning for Change.” Further detail regarding each of these areas is provided below. However, in general, NERC’s activities in these areas are adequate and appropriate at this time.

Cyber Attack
Cyber Attack generally refers to malicious activities on the behalf of hackers, disgruntled employees, terrorists, unfriendly nation-states and non-governmental organizations, and other similar parties that occur through the use of computer-based attacks or exploits. Cyber Attack is an area of increased focus due to the potential for harm it represents.

The RISC’s gap analysis in this area was conducted with input from NERC staff, the chair of the Critical Infrastructure Protection Committee (CIPC), the RISC representative from the CIPC, the North American Transmission Forum CEO, and the North American Generator Forum chair. A large number of threats and concerns were identified and discussed. In general, industry activities regarding Cyber Attack are in progress and only require time to be completed. However, there were two areas where the correct activities are being undertaken, but further efforts to accelerate progress would be beneficial. Those areas were sharing of information (or the failure to do so) and limited analytic capability at the ES-ISAC. Both of these areas are critical and foundational to the industry’s ability to prevent or respond to a cyber attack.

NERC is already moving forward in these areas, but success is largely dependent on continued industry support. There are a number of areas, such as improving and automating the exchange of “indicators of compromise” and similar threat information, that could improve efficiency and timeliness of response. To this end, the RISC encourages NERC to continue reaching out to entities to seek their support for these activities. Expanded participation at the ES-ISAC, as well as improving industry and NERC staff capabilities for supporting analytics efforts, are also encouraged. The RISC notes that improved sharing of information requires a structure in which open, timely and secure information can be shared without the threat of enforcement action and penalties, and encourages NERC to consider implementing approaches that minimize or eliminate any potential disincentives to information sharing.

Additionally, the industry and the ERO rely on and cooperate with federal intelligence agencies and law enforcement to mitigate this risk. Accordingly, outreach to these groups should also continue.

Workforce Capability and Human Error
Workforce Capability and Human Error is an issue that spans multiple potential problem areas and generally refers to those situations in which a human being makes a decision, as well as the elements that influence that decision making.

NERC staff, the chair and vice chair of the Operating Committee, the RISC representative from the CIPC, the North American Transmission Forum CEO, and the North American Generator Forum chair provided input into this gap analysis. While there is a tendency to focus on individual errors, NERC’s Event Analysis efforts have identified that current challenges within this area are more organizationally focused. Of the 273 reports reviewed and cause-coded in the Event Analysis database, 20 percent of those with identified root causes point to issues at the management or organizational level. When contributing causes are also considered, over half of the event reports to date indicate some management or organizational challenge that led or contributed to the event. Further, when both root cause and contributing cause are considered, a large number of events are associated with relatively similar causes. A large number of those causes are related to not fully understanding or addressing the cause of previous events.

As such, the RISC encourages and supports the activities NERC is currently undertaking to inform the industry regarding best practices for event analysis and cause coding. These activities aid in ensuring that when events occur, their causes are found and addressed in a timely manner, reducing the potential for repeat events under more adverse circumstances.

Both the North American Transmission Forum and the North American Generator Forum are actively undertaking efforts in this area as well, and the RISC encourages NERC to continue collaboration with those organizations. In so doing, NERC can
continue to encourage and promote voluntary participation in the sharing of event analysis information, while at the same time reducing the burden on registered entities by sharing scarce human resources more efficiently and streamlining information processing.

**Protection Systems**

Protection Systems are designed to remove equipment from service to avoid its being damaged when a fault occurs. Protection Systems are made up of a number of components, such as relays, associated communication systems, and voltage and current sensing devices. Protection System misoperations often contribute to the severity of an event. A failed protection system that does not trip or is slow to trip may lead to the damage of equipment (removing it from service for some period of time), while a failed protection system that trips when it should not can remove important elements of the power system from service at times when they are needed most.

The gap analysis for this area included input from NERC staff, the Planning Committee chair and advisors, the Standards Committee chair, and the North American Transmission Forum CEO. As System Protection has been an important initiative at NERC for some time, a number of activities to address concerns in this area are already well underway. At this time, these activities are progressing well and should be sufficient to address this area of risk.

During the gap analysis, it was proposed to remove one specific area (Special Protection Schemes (SPS) and Remedial Action Schemes (RAS)) from this category and place it into a new category. NERC already has plans to address this issue, and the RISC believes those plans should continue. At this time, further discussion should occur to determine the appropriate treatment of this area with regard to its categorization. Determination of whether SPS and RAS should be considered within the discussion of Protection Systems will be reconsidered at a future date.

**Monitoring and Situational Awareness**

Much like human error, monitoring and situational awareness is frequently identified as an issue that is central to failures. This functional area includes having the appropriate tools available, perceiving and comprehending the information those tools provide, sharing information, and coordinating mental models.

The RISC’s gap analysis for monitoring and situational awareness was developed through collaboration of NERC staff, the Operating Committee chair and vice chair, the North American Transmission Forum CEO, and the North American Generator Forum chair. In general, given existing standards as well as the efforts planned and ongoing at NERC, the data at this time does not seem to indicate significant need for additional work in this area. Of special note is the failure of decision-support tools. This an occurrence that is frequent enough to merit further attention, and NERC efforts are underway to better understand and manage this risk. Failure of a decision-support tool is rarely the cause of an event. Instead, such failures manifest as latent risk that further hinders the decision-making capabilities of the operator. As such, addressing these failures reduces the chances that a poor decision will be made, indirectly reducing the likelihood that human error will cause an event. Educational conferences and information-sharing activities are currently in development at NERC to ensure this potential problem is monitored and controlled.

**Adaptation and Planning for Change**

During its gap analysis of the high- and medium-priority issues, members of the RISC began further consideration of some of the low-priority areas as well and determined that several of them may have an effect on long term planning. Therefore, a more optimal way of considering several of them would be to incorporate them into a broader category of concern for further analysis. Included in the consolidation were the following items:

- Increased Dependence on Natural Gas Generation (previously identified as medium-priority)
- Generation Resource Adequacy (previously identified as low-priority)
- Long-Term Planning and Modeling (previously identified as low-priority)

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1 These issues were previously ranked as described. However, further analysis of this area is needed to identify and prioritize specific initiatives that could include consideration of some or all of the elements described. This may result in different priorities and a different or restructured set of issues.
• Climate Change, Environmental Regulations, Changing Resource Mix due to Environmental or Other Market Conditions, Integration of Variable Generation (previously identified as low-priority)
• Integration of New Technologies (previously identified as low-priority)
• Demand Response (previously identified as low-priority)
• Smart Grid (previously identified as low-priority)
• Post-Recession Demand Growth (previously identified as low-priority)

Absent the rapid pace of certain elements of change driven by economics, policy, regulatory, and legislative activities, a number of the issues associated with change that were considered in the February 2013 report are medium- or low-priority issues. However, NERC’s Long-Term Reliability Assessment properly notes that the pace of change, and the interaction of these factors with one another, introduces a new level of uncertainty that could affect the assumptions and models that underlie long-range planning. At this time, further analysis of this area is needed to identify and prioritize specific initiatives that could include some or all of the elements described above. The RISC believes the Planning Committee (or its subcommittees) should work collaboratively with the members of NERC staff who are responsible for the development of the Long-Term Reliability Assessment and special assessments to perform this analysis.

Using the Reliability Risk Control Process that NERC is currently developing as the way to analyze and consider this area of concern would be a good transition into the more formal use of that new process. Additionally, it would offer NERC an opportunity to improve that process based on its experience with a smaller set of issues. Accordingly, the RISC recommends NERC take this approach.
Chapter 2 - Medium-Priority Issues

Overview
Similar to the high-priority items, the medium-priority items are largely consistent with those presented in the February 2013 report. NERC’s activities in these areas are adequate and appropriately scaled at this time.

Operational Modeling and Model Inputs
This issue refers to lack of data or accurate models in Real time, such that correct decisions are difficult to make. NERC staff, the Planning Committee chair, and the North American Transmission Forum CEO contributed to this gap analysis.

The analysis identified a number of potential problems, all of which NERC or other organizations are addressing with one or more efforts. The RISC encourages NERC to continue analyzing and resolving these areas of concern collaboratively with stakeholders. Further analysis of this area is needed. The RISC believes the Planning Committee (or its subcommittees) should work collaboratively with NERC staff from the Reliability Initiatives and System Analysis team to perform this analysis.

As discussed earlier, using the “Reliability Risk Control Process” to evaluate this area would be a good transition into the more formal use of that new process and would offer NERC a hands-on opportunity to gain experience in its implementation. Accordingly, the RISC recommends NERC take this approach.

Equipment Maintenance and Management
This issue refers to transmission or resources not being available due to equipment being poorly managed or maintained, resulting in physical failure. Additionally, this area includes coordination problems in maintenance schedules and increasing complexity within generation plants as environmental regulations become more stringent. The gap analysis was performed by NERC staff and the Planning Committee chair.

NERC is addressing these threats through a variety of activities. The RISC encourages NERC to continue analyzing and resolving these areas of concern collaboratively with stakeholders.

Coordinated Attack on Multiple Facilities
This issue refers to a physical attack on a number of facilities simultaneously in a coordinated fashion. NERC staff, the Critical Infrastructure Protection Committee chair, the CIPEC RISC representative, the North American Transmission Forum CEO, and the North American Generator Forum chair participated in the development of the gap analysis.

This area has a number of threats, all of which can be challenging to manage. In general, industry takes an all-hazards approach to planning, for which a number of potential failures, regardless of cause, have been planned. When events occur on the power system, usually, more than one layer in the “defense in depth” approach to reliability risk management employed by the industry has broken down. As such, physical attacks generally require some level of knowledge and sophistication in order to be effective.

However, the level of industry expertise and maturity in this area is diverse, and a coordinated attack that targets less-sophisticated participants with significant vulnerabilities could lead to a negative reliability outcome. Current industry activities are moving toward developing collaborative processes for sharing lessons learned and for peers assisting each other in assessments and preparation. NERC should stay engaged with these activities by collaborating with industry and the forums to increase information sharing and lessons learned.

Generator Availability
This issue refers to generators not being able to provide energy or related services in Real time. The gap analysis was performed by NERC staff and the Planning Committee chair.

Similar to other issues, NERC is already addressing this area via a number of activities. The RISC encourages NERC to continue analyzing and resolving these areas of concern collaboratively with stakeholders.
Chapter 3 - Low-Priority Issues

Overview
The following areas are considered to be of lower priority and do not to require any special attention from a RISC perspective because they are well controlled or covered by the industry’s all-hazards planning. These issues should continue to be monitored, but additional resources should not be directed toward these issues.

Geomagnetic Disturbance (GMD)
Geomagnetic disturbance is a unique problem that is being handled separately based on a FERC initiative. NERC is taking an active role in this area based on FERC guidance. At this time, this risk is being adequately addressed.

Transmission Right-of-Way
The FAC-003 Vegetation Management standard, combined with the FAC-008 data request, has led to an increased awareness and industry focus on maintaining transmission rights-of-way, and performance in this area has improved greatly over the past several years. At this time, this risk is being adequately addressed.

Extreme Weather/Acts of Nature
This is always a concern for utilities, and the concern is being addressed through an ongoing effort of planning for all hazards. To the extent weather trends are changing, ongoing processes for all-hazards planning will include updated preparations that consider such changes. Additionally, the majority of problems related to extreme weather or acts of nature occur on the distribution system, rather than the bulk power system. At this time, this risk is being adequately addressed.

Localized Physical Attack
Similar to extreme weather, this is always a concern for utilities, and the concern is being addressed through an ongoing effort of planning for all hazards. To the extent physical security trends are changing, ongoing processes for all-hazards planning will include updated preparations that consider such changes. At this time, this risk is being adequately addressed.

Electromagnetic Pulse (EMP)
Unlike GMD, an electromagnetic pulse is based on a deliberate action, such as a low atmosphere detonation or a specifically designed weapon. Existing programs within the federal government, such as the FBI, the CIA, and the Department of Homeland Security, are relied on for management of this threat.

Pandemic
Industry has in the past prepared plans for responding to a pandemic. At this time, this risk is adequately addressed through the existence of those plans.
Chapter 4 - Moving Forward

NERC’s Reliability Risk Control Process
In February 2013, the NERC Board passed a resolution stating:

The Board hereby directs NERC management to work with the RISC and, as appropriate, NERC committee leadership to consider how NERC should utilize a data-driven reliability strategy development process that integrates with budget development and overall ERO planning (e.g., Standing Committee planning, department, and employee goal setting).

Based on RISC input, NERC staff has been developing a more formal approach for the identification and resolution of reliability problems that can be used as described in the Board’s resolution. Key foundational concepts for this effort include the belief that the process should be open and transparent and encourage stakeholder participation. It should ensure close strategic alignment between and across the RISC, the Operating Committee, the Planning Committee, the Critical Infrastructure Protection Committee, the Compliance and Certification Committee, and the Standards Committee. Further, it should acknowledge that in addition to mandatory reliability standards, NERC has a wide array of tools to address reliability concerns and promote the most effective and appropriate tools for each concern determined to require intervention.

The diagram below illustrates the process that is in development:

This process begins with a Leadership Summit. At the summit, industry leadership, trade association representation, regulators, and others are brought together to share their thoughts regarding what they perceive to be the greatest threats to reliability. This dialogue with the RISC becomes the first input into the development of the RISC’s priority recommendations. Documents and conclusions from various NERC programs (e.g., the Long Term Reliability Assessment and the State of Reliability report) are considered as well. Together with input from other areas, this comprises the foundation upon which the RISC’s priority recommendations are built.
Following the collection of this information, the RISC drafts its recommendations and presents them to the Board. If the Board approves the recommended priorities, they then proceed to the Technical Committees for further refinement and analysis, essentially performing the gap analyses that were undertaken in the development of this report. For those areas where gaps are identified and additional controls are needed, the Technical Committees, working with NERC staff, the Compliance and Certification Committee, and the Standards Committee, would meet together in a workshop setting to develop proposals for targeted interventions to address those gaps. Once developed, those proposals would either be included in the process for the development of the NERC business plan or, if urgent, be considered for inclusion within the current year’s activities.

NERC staff continues to develop the details for implementing this process, with execution commencing this year with the Leadership Summit, planned for October 24–25, 2013, in Washington, D.C.

**Activities for the Remainder of 2013**

Although NERC is in the development and documentation stages of its Reliability Risk Control Process and expects to implement the process soon, there are near-term efforts that can and should be undertaken to ensure progress is made now.

**Continued Support for Existing Efforts**

As discussed above, NERC has a number of activities underway to address the high and medium risks that were identified in the February 2013 report. Further analysis reaffirms much of that report’s conclusions and therefore indicates that those activities are appropriate. The information learned during the performance of the gap analyses shows adequate scoping of those activities as well. The RISC recommends that NERC complete these efforts.

**Development of Key Metrics**

As discussed, NERC has a number of activities underway to address key risks. However, because these projects were in already in existence, a number of them do not have clear and specific measures that can be tracked to monitor industry performance.

The RISC believes that having metrics through which performance can be measured is essential. Developing such metrics provides several functions to the organization:

1. It ensures a thorough understanding of the problem being solved.
2. It allows the development of a baseline against which changes in performance can be measured.
3. It provides a way to continually monitor the problem for future changes.

For this reason, the RISC recommends that NERC work with its technical committees to develop metrics for use in determining the success and ongoing performance of existing ERO activities. For example, there are a number of standards development projects related to Protection Systems, each addressing a different specific issue. It does not seem that there are published metrics that can indicate if performance in those specific areas is improving, staying the same, or declining. The RISC notes that NERC may already have the data it needs to calculate many of these metrics, and this may be a simple matter of developing more granular reports to focus on performance in more specific areas. However, visibility of these metrics is an essential part of moving NERC toward a data-driven process for reliability strategy development and execution.

**Development of New Project Proposals**

As presented earlier in this document, a new high-priority issue has been identified for which additional analysis is needed: that of “Adaptation and Planning for Change.” Similarly, the area of “Operational Modeling and Model Inputs” is in need of further analysis. The RISC recommends that these issues be processed through the post-prioritization steps of the new “Reliability Risk Control Process” described previously; that is:

- Ask the Planning Committee to explore these issues further in the form of a gap analysis or similar activity, and identify the specific threats to reliability associated with each area.
• Ask the Planning Committee to select one or more of these threats for further refinement, through which the problem would be specified exactly, measures for use in analyzing performance would be developed, and appropriate goals and objectives would be identified.

• Ask the PC, OC, CIPC, CCC, and SC (or a subset of their members) to meet and collaboratively develop proposed interventions that would meet the goals and objectives identified.

• Provide those proposals to NERC in January of 2014 for consideration in the development of the 2015 business plan.

The RISC believes that this approach will allow NERC to work through the process it is developing on a smaller scale and identify any areas for improvement prior to moving into full-scale implementation in 2014.
Appendix 1 - Gap Analyses

The RISC has included for reference the results of the gap analyses undertaken for the high- and medium-priority problem areas. These documents were developed for discussion purposes only, and as such are not official statements of NERC, its Board, its committees, or its stakeholders.
Cyber Attack

**DISCUSSION**

An event occurs due to a cyber attack on BES cyber assets.

<table>
<thead>
<tr>
<th>Related NERC Standards</th>
<th>NERC Standards Development Projects</th>
<th>Other NERC and Industry Activities</th>
<th>Non-NERC Activities</th>
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</thead>
<tbody>
<tr>
<td>CIP-002 through -009 version 3</td>
<td>None</td>
<td>ES-ISAC</td>
<td>Entities: Internal and independent programs, monitoring, and testing</td>
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<tr>
<td>EOP-001, -005, -006, -008, -009 address generically</td>
<td></td>
<td>Industry/Government Information Sharing via the Public/Private Model Cyber Risk Preparedness Assessments (CRPA)</td>
<td>Department of Homeland Security: Cyber-Dependent Infrastructure Identification (CDI)</td>
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<td></td>
<td></td>
<td>Grid Security Conferences</td>
<td>Department of Energy/Department of Homeland Security: Information sharing and security clearances; Sector Incident Response Survey; sector response plan development; event lessons learned understanding</td>
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<td>Implementation of DOE/DHS/White House Electricity Subsector Cybersecurity Capability Maturity Model (ES-C2M2 Model)</td>
<td>Major Trade Organizations: collaborative staffing development support to Industry Incident Response Plan creation aligned to NERC Crisis Action Plan and public sector plans</td>
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<td></td>
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<td>HIF Efforts/Coordinated Action Plan</td>
<td>DHS, FBI, and OTHER GOVT AGENCIES: Participation in joint threat and vulnerability community briefings to analysts and sector participants</td>
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<td>CIPC Security Training WG to develop workshop on operator training scenarios including cyber-attack components</td>
<td>DHS, DoD, DOE and ESCC, creation and participation in Energy Security Public Private Partnership (ES3P), a CIPAC Working Group</td>
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<td></td>
<td></td>
<td>Electricity Sub-sector Coordinating Council (ESCC)</td>
<td>Industrial Control Systems Joint Working Group (ICS WG): SME sharing on contemporary security issues involving control systems</td>
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<tr>
<td></td>
<td></td>
<td>Electricity Sub-sector Information Sharing TF Report (CIPC approved, being submitted for BOT approval in August)</td>
<td>CYBERCOM: understanding of institutional role definition, authorities and capabilities pertinent to mission assurance, asset protection and response issues</td>
</tr>
<tr>
<td></td>
<td></td>
<td>New NERC Guidelines</td>
<td>Energy and Interdependent Cross Sector Industry venues: various to address interdependency understanding</td>
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<td>Vendor and Service Provider venues: staying up to date on latest classes of technologies, services and the security practices and technologies which support them</td>
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<td>National Council of ISACs and various other ISAC events; cross sector information sharing, collaborative threat assessment, and interdependency planning considerations</td>
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<td>DHS NCCIC: floor watch participation and integration planning activity</td>
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<td>Software and Supply Chain Assurance Working Group; addressing supply chain, hardware, and software development assurance issues</td>
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<td>Multi-State Commissioners and Regional Resiliency Group Meetings; support for regional catastrophe planning and readiness</td>
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<td>Office of Assistance Secretary of Defense for Homeland Defense and America’s Security Affairs; Mission Assurance matters</td>
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<td>Black Hat and similar security and technical conferences; maintenance of technical acumen commensurate with ISAC analytic role</td>
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Based on the existing efforts described above:

- Are the existing efforts in this area sufficient?
1. Failure to share Security Information: Critical information regarding an actual or potential attack is not shared, leading to increased vulnerability or risk of harm.

Background: In GRIDEX 2011, when exercise injects occurred, bi-directional information sharing between entities and the ES-ISAC did not occur as effectively as it should. The ES-ISAC needs a free, uninhibited exchange of information to enable it to respond effectively to a cyber event. There is reluctance to share security information due to compliance concerns.

Response: CID and CIPC have assigned top priority to improving information sharing. Key initiatives are summarized in the CIPC Information Sharing Task Force (ISTSF) and ES-ISAC Strategy, and include further developing the capability for cross sector information sharing and secure bi-directional communication. At this time, current activities are moving toward addressing this risk adequately; however, stronger industry support is needed to ensure short term objectives are met expeditiously – specifically, industry must be able to share (through automation and common protocols) and use information (i.e., indicators of compromise, or IOCs) in real-time. This concern will be reviewed again during GRIDEX II in 2013.

2. Limited Analytic Capability at the ES-ISAC: Evidence found during the progression of an attack is unable to be processed accurately in a timely fashion, limiting the ability to respond to an attack in progress on a proactive basis.

Background: Analyzed cyber attack timelines require some time to identify an adversary to take action in a series of steps which result in observable IOCs. By carefully collecting, organizing and analyzing the IOCs, patterns can be discerned to inform defensive actions which can reduce or eliminate the impacts of an attack in progress. Currently, many of the technical tasks associated with this work are manual and need to be automated or technology enabled for faster, more actionable analytic results. Advanced analytic capability is needed to fully leverage information sharing such that it delivers enhanced rapid mitigation and improved sector coordination.

Response: There are two main aspects of analytic improvement – one is the ES-ISAC staff analytic capability. The other is providing self service analytic capability to our entities. As detailed in the ES-ISAC strategy, answers both of these through initiatives aimed at rapid response and campaign analysis, such as an analyst workbench and cyber awareness monitoring tools. At this time, current activities are moving toward addressing this risk adequately; however, stronger industry support is needed to ensure short term objectives are met expeditiously. Although a number of entities have a wide variety of Security Information and Event Management (SIEM) capabilities, various proprietary products make automated translation and scripting of IOCs from ES-ISAC difficult – this will have to be addressed going forward.

3. Spearphishing: A spearphishing attack leads to penetration or the creation or disclosure of vulnerabilities that are then exploited.

Background: Spearphishing is an email spoofing attempt to target an organization or individual to conduct unauthorized collection of confidential information. This may be a general target on all users or advanced variants for specific targets. It offers the adversary opportunities to identify system topology and vulnerability, or to insert malicious content. Large numbers of spearphishing attacks have been noted in the media and other channels.

Response: Indications of Compromise (IOCs) are being identified, analyzed and shared both within sector and across critical infrastructure sectors by ES-ISAC using portal, email, and government threat community networks. Common sharing formats and processes are being implemented. Watch lists are being employed. Additional information sharing and analytic capability is being proposed and implemented at ES-ISAC according to its strategic plan. Utilities are implementing defense in depth capabilities, which can be a good way to defend against this. User training and awareness must be significantly increased to address the Spearphishing threat. At this time, current activities are moving toward addressing this risk adequately.

4. DOS/DDOS: Access to functions or critical information is blocked by coordinated efforts to overload networks and/or servers.

Background: Denial of service attacks are efforts to make one or more systems or devices unavailable. A distributed denial of service attack coordinates many computers in an attack where all coordinated systems send a stream of requests simultaneously towards targeted victim systems all at once. DOS/DDOS can restrict information flows relating to ICS or commercial and enterprise systems functionality. Large numbers of DOS/DDOS attacks have been noted in the media and other channels.

Response: Indications of Compromise (IOCs) are being identified, analyzed and shared both within sector and across critical infrastructure sectors by ES-ISAC using portal, email, and government threat community networks. Common sharing formats and processes are being implemented. Watch lists are being employed. Additional information sharing and analytic capability is being proposed and implemented at ES-ISAC according to its strategic plan. Some Registered Entities are working with their Internet Service Providers to address these concerns. At this time, current activities are moving toward addressing this risk adequately.

5. Malware and Virus Injection: A virus or malware attack degrades or debilitates hardware or software.

Background: Malware and virus injection or code injection is the act of placing computer programming code into a computer program to change the course of processing or execution instructions. It may result in degraded performance or adversary transparency and communications and control capability within the target victim network, computer or device. Multiple vectors for injection are possible. Techniques, tactics and procedures may be hybrid and advanced. A related sub-issue is data diode applicability to this threat, and the treatment of data diodes under applicable CIP-007-OS Requirements R1 and R2. This opportunity is listed separately below. Many well known peer incidents, including Stuxnet, relied on the injection of malicious code, and these codes can cause computer worms to propagate across machines and networks.

Response: Indications of Compromise (IOCs) are being identified, analyzed and shared both within sector and across critical infrastructure sectors by ES-ISAC using portal, email, and government threat community networks. Common sharing formats and processes are being implemented. Watch lists are being employed. Additional information sharing and analytic capability is being proposed and implemented at ES-ISAC according to its strategic plan. Additionally, a number of utilities are using various technologies (e.g., “White listing,” Intrusion Prevention Systems, USB controls, and additional Distributed Control Systems segmentation) to defend against these kinds of attacks. At this time, current activities are moving toward addressing this risk adequately.

6. Industrial Control Systems (ICS) Compromise: A mission critical control system is corrupted or disabled.

Background: Industrial Control Systems can be compromised in many ways. Because there are many types of ICS devices and so many ways to access them, an asset protected by authentication could be compromised if a vulnerability that bypasses authentication is exploited, a non-authenticated trusted connection is utilized (SQL injection or similar) or a DOS attack is placed against open ports (baarded with hyper text transfer protocol [HTTP] or secure shell [SSH] requests that overwhelm the device and result in non-availability). There are many network examples, and recent attacks on ICS have occurred in some sectors and locations; hardware examples also exist, such as smart grid blue tooth enabled devices, and remote access port and point accessibility of both control devices, but also devices used to secure physical security perimeters around sensitive cyber assets, such as gate entry systems [access control]. Compromised holds, sensitive data is compromised and operational control at key times or locations, either causing a BPS risk events or reducing the capability of dynamic operator response during a risk event.

Response: Indications of Compromise (IOCs) are being identified, analyzed and shared both within sector and across critical infrastructure sectors by ES-ISAC using portal, email, and government threat community networks. Common sharing formats and processes are being implemented. Watch lists are being employed. Authoritative Alert guidance products are being developed and disseminated as appropriate. ES-ISAC subject matter experts participate in expert venues, such as the Industrial Control Systems Joint Working Group. Additional information sharing and analytic capability is being proposed and implemented its ES-ISAC according to its strategic plan. Utilities are deploying defense in depth capabilities, such as enhanced multi-level segregation; “White listing,” Intrusion Prevention Systems, and limited communication across security zones. At this time, current activities are moving toward addressing this risk adequately.

7. Software Supply Chain Integrity Compromise: Software with a legitimate purpose is co-opted by an attacker for malicious purposes prior to or during installation.

Background: Supply chain integrity refers to integrity throughout the full life cycle creation and use of software. For example, was the software designed and delivered in a form that fulfills what it is known and designed to do, with additional (perhaps malicious) execution or processing steps, or steps that increase malicious observation of the software while it is performing its primary functions. This threat offers potential for adversary compromise of key software or management with products with possible increase to BPS risk. Observed examples include cases where software was designed with embedded “bugs” or, during installation (often performed by third party contractors) was known to have taken on additional information that caused it to depart from desired installation and performance specifications.

Response: ES-ISAC subject matter experts participate in technical venues, such as collaborative Software Assurance events. Planned ES-ISAC capability maturity includes tools supportive of sharing and analysis related to this issue. Alert products and processes can be utilized to address these issues. After
ES-ISAC capability maturation is achieved, we may be able to more rapidly and fully learn more regarding this threat due to automated and cross sector information sharing using these capabilities, which are outlined in the ES-ISAC Strategy. At this time, current activities are moving toward addressing this risk adequately.

8. Hardware Supply Chain Integrity Compromise: Hardware is modified or replaced such that vulnerabilities are embedded prior to its installation. Background: If the hardware was not created within a trusted foundry environment, it may be subject to intentional (or unintentional due to false packaging or poor development quality controls) tampering or delivery out of specification for its intended use. This threat offers potential for adversary compromise of key hardware control, reporting or management products with possible increase to BPS risk. Numerous examples exist where counterfeit or out of specification products were shipped for use by Original Equipment Manufacturers or final product users. The result can be performance that is out of design specification.
Response: ES-ISAC subject matter experts participate in technical venues, such as collaborative vendor and threat community events. Planned ES-ISAC capability maturation includes tools supportive of sharing and analysis related to this issue. Alert products and processes can be utilized to address these issues. At this time, current activities are moving toward addressing this risk adequately.

9. Design and Build Life Cycle Quality Assurance (QA) Compromise: A manufacturer inadvertently introduces a vulnerability in their product through a lack of design robustness or quality assurance. Background: If QA is compromised, the risk is that performance may be out of specification for the immediate device or product, and systems within which it operates, or which depend on its operation within specification. This threat offers potential for adversary compromise of key technologies with possible increase to BPS risk.
Response: ES-ISAC subject matter experts participate in technical venues, such as collaborative vendor and threat community events. Planned ES-ISAC capability maturation includes tools supportive of sharing and analysis related to this issue. At this time, current activities are moving toward addressing this risk adequately.

10. Social Engineering: An attacker obtains information by gaining a target’s confidence, resulting in inappropriate information disclosure.
Background: Social engineering broadly includes the non-technical and human interaction aspects of intelligence gathering, including by adversary threat actors. This threat can result in preparing the attack space for further adversary reconnaissance of target victim systems, or subsequent advanced threats. For example, social media can be used to obtain personal information on targets, which can then be applied to broader efforts designed to obtain systems or data control, or to manipulate/work processes in malicious ways.
Response: Alert products and process are utilized to address these issues. ES-ISAC subject matter experts routinely participate in relevant threat and vulnerability collaborative events. Readiness assessment activities in the field are underway and help address this issue. Cyber hygiene is encouraged through outreach activities. Subject matter expert support and staff training are provided for various exercises. Cross sector sharing through the National Council of ISACs, DHS and other threat community channels is employed for early notification and mitigation advice development. At this time, current activities are moving toward addressing this risk adequately.

11. Long term Exfiltration: Information is taken for the purpose of preparing for future attacks.
Background: Results in unauthorized collection of data from devices, systems and networks. This threat can result in preparing the attack space for further adversary reconnaissance of target victim systems, or subsequent advanced threats. Examples include instances where adversaries gained access to commercial networks electronically, then lurked for long periods of time to extract data regarding routine operating patterns of use for devices on network or port status, to potentially leverage later in development of attacks.
Response: Alert products and process are utilized to address these issues. ES-ISAC subject matter experts routinely participate in relevant threat and vulnerability collaborative events. Readiness assessment activities in the field are underway and help address this issue. Cyber hygiene is encouraged through outreach activities. Subject matter expert support and staff training are provided for various exercises. Cross sector sharing through the National Council of ISACs, DHS and other threat community channels is employed for early notification, entity education, and mitigation advice development. At this time, current activities are moving toward addressing this risk adequately.

12. Remote Access Vulnerabilities/Capabilities: An attacker uses vulnerabilities in remote access capabilities to collect or corrupt information or take control of equipment.
Background: While many networks and devices allow remote access, which results in substantial benefits and efficiencies to organizations, remote access routes and the business practices and policies dependent on them also can cause a proliferation of potential attack surfaces for an adversary. This type of threat can allow contractor engineering service providers (OSP) channel or direct channel for threat actor to gain visibility or control of grid related operational systems. Consolidated remote access capability to sufficient grid operational assets or infrastructure in order to potentially cause grid risk events is the issue. For example, if a large organization or entity relies on remote access using third party services, what level of control does it have on security exposure of affected networks and devices?
Response: Alert products and processes are utilized to address these issues. ES-ISAC subject matter experts routinely participate in relevant threat and vulnerability collaborative events. Readiness assessment activities in the field are underway and help address this issue. Cyber hygiene is encouraged through outreach activities. Subject matter expert support and staff training are provided for various exercises. Cross sector sharing through the National Council of ISACs, DHS and other threat community channels is employed for early notification, entity education, and mitigation advice development. The ES-ISAC Strategy document calls for collaborative information sharing and analytic capabilities which will be of primary importance in addressing this issue. With the addition of these capabilities, we hope to explore this threat more fully, and better understand its scale and complexity. Additionally, data diode technology is being discussed through webinars and portal content to help educate entities about this broad class of technologies, its potential applicability related to its employments. Utilities are implementing multiple levels of segregation, jump hosts, multiple separate untrusted forest credentials and dual factor authentication to reduce this risk in accordance with NERC guidance. At this time, current activities are moving toward addressing this risk adequately.

13. Identification/Authentication Compromise: An attacker impersonates a legitimate user through presentation of the credential used to identify the user or authenticate their access.
Background: Identity Management (IDM), Access Control (AC) and Identity and Access Management (IAM) are important enterprise services, particularly in environments where commercial networks may be in contract with control networks. By properly establishing a trusted connection for communications, these functions enable enterprises to know that authorized direction is given to their important control systems and personnel functions. These compromises come in several forms, but may include token integrity, secret or infrastructure compromises, or faulty authentication rules and systems. If authentication is not properly accomplished with integrity, many of the other lists in this document can become more easily accomplished and more likely. These threats can result in malicious actor presence on target victim networks or access to grid control, coordination and reporting systems.
Response: Alert products and process are utilized to address these issues. ES-ISAC subject matter experts routinely participate in relevant threat and vulnerability collaborative events. Readiness assessment activities in the field are underway and help address this issue. Cyber hygiene is encouraged through outreach activities. Subject matter expert support and staff training are provided for various exercises. Cross sector sharing through the National Council of ISACs, DHS and other threat community channels is employed for early notification, entity education, and mitigation advice development. Utilities are implementing multiple separate untrusted forest credentials, dual factor authentication, and segmentation such that no single compromise should cause significant impact to the BES. At this time, current activities are moving toward addressing this risk adequately.

14. Entity Level Network Awareness: An entity’s system has been compromised without their knowledge.
Background: In an environment where sophisticated cyber attacks and intrusions occur with greater frequency, an entity could easily have new additional malicious actors or malware resident within its networks and devices without its own knowledge. To the extent entities can monitor their own systems and networks more effectively, more adverse events are identified and addressed.
Response: Some ES-ISAC capabilities currently provide IS-ISAC staff with additional visibility regarding malware travelling through domains so that this information might be supplied to affected or potentially affected entities. New planned capability may make some of this transparency available through self-service tools that the entity can access at ES-ISAC portal. ES-ISAC also routinely participates in expert and operator oriented venues designed to improve Network Awareness. Additional industry efforts are needed to standardize a method for exchanging IOCs with minimal effort. At this time, current
activities are moving toward addressing this risk adequately.

15. Individual Security Errors: A failure in good security practices by individuals ("cyber-hygiene") results in a system compromise.

   Background: The vast majority of cyber intrusions and attacks are nuisance attacks that can be nearly or completely avoided through good forceful adoption of cyber hygiene. Many attacks of lesser importance might precede or support larger or more sophisticated attack efforts which could be reduced substantially if excellent cyber hygiene implementation is in effect. Stronger cyber hygiene may also increase the chance that a prospective adversary might be deterred from selection of a particular target organization, in favor of one where the cost benefit appears to be higher due to lax cyber hygiene. In that way, sector security might be strengthened. Studies and casual expert observation indicate that substantial entity level and BPS risk reduction could result from improved applied cyber-hygiene in the workplace. This concern includes both cyber and physical aspects, including steps such as increased awareness regarding social media use risks, reduction of tailgating through controlled physical security perimeters, careful construction and protection of strong passwords, etc...

   Response: ES-ISAC routinely participates in expert and operator oriented venues designed to improve cyber hygiene and is taking steps to consider facilitation of cyber hygiene self education services to entities through its portal. At this time, current activities are moving toward addressing this risk adequately.

16. Hybrid and Coordinated Attack: A threat actor employs advanced techniques which straddle cyber and physical domains, as well as exploits cross sector interdependencies.

   Background: Advanced threats may leverage coincident cyber and physical attack vectors or vulnerabilities (such as a cyber attack on a hot day with low reserve margins). They might also leverage interdependencies between critical sectors (for example, eliminating fiber connections relevant to systems control and coordination before impacting control systems for direct impacts). Recent events have confirmed that impacts to one critical sector may be part of a coordinated or sophisticated threat against other sectors, and that physical security threats may exist due to threat actor intent to achieve cyber impacts or effects. We understand that prospective threats and contingencies may be novel. These may include cyber-physical hybrid elements or substantial cross sector interdependency issues. For example, “no fiber, no cyber” two step threat techniques. We acknowledge the requirement to better understand these for reliability performance and resilience.

   Response: NERC is collecting data, reviewing authoritative blue ribbon findings from NIAC, CIPC SIRT/HILF, and others. NERC participates in a variety of exercises and expert collaborative events focused on this issue. NERC is pursuing increased information sharing and analysis capabilities, which will aid immensely in better understanding and managing mitigation development and delivery, as well as sector coordination, for these types of events. At this time, current activities are moving toward addressing this risk adequately.

- Are all of the existing efforts needed? If not, what can be eliminated?
  Yes. The above are needed for improved BPS reliability going forward.

- Are any of the existing efforts duplicative of what other organizations are doing?
  No. While within our sector there are some additional operations centers that perform some similar functions, they are mutually supportive of the ES-ISAC efforts and are valued partners. The authoritative nexus for the sector to the government threat and vulnerability community is the ES-ISAC, leaving it uniquely positioned to address these issues at lowest cost to the sector and its entities. In addition to providing centralized information sharing and analytic capabilities, ES-ISAC offers the potential to provide self-service capabilities and shared resource capabilities for entities at lower cost than they might otherwise have available organically with reduced duplication of effort.

- Are any of the existing efforts done in concert with the work of other organizations?
  Yes. All of the efforts above are accomplished or planned to be accomplished in close coordination with other public and private sector organizations due to their importance, scope and complexity. Capabilities and technologies to address these challenges is presently in the late stages of being documented at high level in both security unclassified and classified venues. Specifically, CID and ES-ISAC both work extensively with other organizations, such as Hydra Subject Matter Experts, Federal Technical Partners, Trades, Technology Vendors, other ERO participants, Registered Entities, National Council of ISACs and all National Infrastructure Protection Plan (NIPP), National Response Framework (NRF) and Unified Coordination Group (UCG) Partners.

- If the existing efforts are not sufficient – what gaps do you see and how do you propose to solve them?
  Current efforts are sufficient; however, filling gaps will require the steady execution of efforts such that current efforts continue and deliver expected results. CIP v5 has set a foundation in standards that is sufficient at this time; additional steps regarding automated information sharing and increasing participation in industry efforts are critical to further developing that foundation such that threats can be identified more readily and acted on in a timely manner. Present gap filling activity focuses on evaluation of pending CIPC Information Sharing Task Force (ISTF) findings for prospective implementation, ES-ISAC technology and business process development, and support to Trades for creation of an industry response plan.

If new efforts are needed: (No)

- Is the new effort within NERC’s scope or should it be directed to another organization?
- What gap in existing efforts was identified that this new effort was meant to address?
- What data is available to scope the new activity?
- How will we measure performance? What metrics will define and track success?
Based on the existing efforts described above:

- Are the existing efforts in this area sufficient?
  No. NERC has identified six sub-areas for this issue, one of which is not being addressed adequately at this time.
  1. Individual Skill Based Errors: Inattention or over-attention to work led to or contributed to an event. Response: At this time, data does not show a need for additional work in this area. Existing entity efforts appear to be sufficient to address this concern. NERC Staff continues to work with industry to collect and analyze data looking for these trends.
  2. Individual Rule Based Errors: A misapplication of a good rule or application of a bad rule during the work process led to or contributed to an event. Response: At this time, data does not show a need for additional work in this area. Existing entity efforts appear to be sufficient to address this concern. NERC Staff continues to work with industry to collect and analyze data looking for these trends.
  3. Individual Knowledge Based Errors: A lack of knowledge during the work process led to or contributed to an event. Response: At this time, data does not show a need for additional work in this area. Existing entity efforts appear to be sufficient to address this concern. NERC Staff continues to work with industry to collect and analyze data looking for these trends.
  4. Organizational Challenges: A lack of support for good practices through adequate processes, controls, or procedures led to or contributed to an event. Response: NERC's event analysis database shows this to be an area of concern. Of the 273 reports reviewed and cause coded in the EA database, 20% of those with identified root causes point to issues at the management or organizational level. When contributing causes are also considered, over half of the event reports to date indicate some management or organizational challenge that led or contributed to the event. Further, when both root cause and contributing cause are considered, a large number of events are associated with relatively similar causes. When analyzing event analysis data, processes, and causes AAB1C05, AAB1C08, and AAB1C09 may make up 38 of the 163 cause codes represented (approximately 23%). These three causes are each associated with either not understanding root cause or not taking action to address root cause. Root causes most prevalent in the A4 area, Management and Organizational category include: 1) B3C08 - job scoping did not identify special circumstances or conditions, 2) B5C04 - risks/consequences associated with change not adequately reviewed, 3) B1C03 - direction created insufficient awareness of impact on operations and safety/reliability, 4) B1C04 - follow-up did not identify problems and 5) B1C05 - assessment did not determine cause of previously event or known problem. When considering the contributing contributing causes in this area the top seven causes are: 1) B1C05 - assessment did not determine cause of previously event or known problem, 2) B3C08 - job scoping did not identify special circumstances or conditions, 3) B3C03 - inadequate vendor support of change, 4) B5C04 - risks/consequences associated with change not adequately reviewed, 5) B1C08 - corrective action responses to a known or repetitive problem was untimely, 6) B5C05 - system interactions not considered and 7) B1C04 - follow-up did not identify problems. Accordingly, NERC believes an appropriate intervention to address this area of concern is to encourage more in-depth root cause analysis that goes beyond identification of apparent cause, and aids in more timely resolution of root causes when they are determined. In addition to the internal benefits expected, this will also ensure NERC is more rapidly able to develop responsive interventions to issues rapidly, such as Lesson’s learned reports, Alerts, and similar work products.
  5. Communication Errors: A message between operators is misunderstood, leading to incorrect decisions. Response: The OC has developed a guideline describing current industry practices, in order to educate the industry on common communications strategies. Additionally, Standards Project 2007-02 Operating Personnel Communications Protocols is intended to put in place rules regarding appropriate communications protocols to minimize communication errors. These activities, once completed, should be sufficient to address this concern.
  6. Design Errors: A poor design leads to a latent error in the system, which later manifests and contributes to an event. Response: At this time, data does not show a general need for additional work in this area; however, Protection Systems seems to require additional work. See Protection Systems Gap Analysis.

- Are all of the existing efforts needed? If not, what can be eliminated?
  Yes, all are needed.

- Are any of the existing efforts duplicative of what other organizations are doing?
  No.

- Are any of the existing efforts done in concert with the work of other organizations?
  Yes. The North American Transmission Forum (NATF) is developing a voluntary companion process to NERC's Events Analysis process that should improve the overall quality of event analyses. The North American Generator Forum is considering activities in this area as well. In both cases, slow coordination between NERC and these forums will help encourage and promote voluntary participation in the sharing of event analysis information, while at the same time reducing the burden on registered entities by sharing scarce human resources more efficiently and streamlining information processing.

- If the existing efforts are not sufficient — what gaps do you see and how do you propose to solve them? As discussed above, organizational challenges are an area which NERC believes additional work is merited. We believe one way to address organization challenges is to educate industry regarding proper root cause analysis techniques. NERC can also further enhance NERC's Events Analysis process and Code Analysis Process (already in progress), and continue to hold conferences and provide education opportunities regarding root cause analysis and NERC's CCAP, including the use of "train the trainer" sessions. NERC can also use alerts to make entities aware of common problems (for example, Configuration Control Events Alert - November 08, 2011).

  Additionally, NERC can encourage and promote voluntary participation in the sharing of event analysis information through continued outreach efforts with entities and organizations.

Related NERC Standards
PER-001 through -002
COM-001 through -002

NERC Standards Development Projects
2007-02 Operating Personnel Communications Protocols IN PROGRESS ETC Q3 2013
2010-01 Support Personnel Training IN PROGRESS ETC Q4 2013

Other NERC and Industry Activities
Events Analysis Program
Lessons learned
Event Analysis Subcommittee
Trend Working Group
System Operator Certification
Training

Non-NERC Activities
North American Generator Forum: Efforts related to Human Performance and Events Analysis, Lessons learned
Entities: Simulations, management oversight, procedures and practices, human performance and operator training, human error prevention tools
Vendors: Improvements to Human/Machine Interfaces i.e., Man-Machine Interfaces
If new efforts are needed:

- Is the new effort within NERC's scope or should it be directed to another organization?
  
  Yes, this is within NERC's scope.

- What gap in existing efforts was identified that this new effort was meant to address?
  
  Based on analysis of past events, it appears there are organizational challenges that could be addressed and would aid in reducing the probability of mistakes and errors that can lead to events.

- What data is available to scope the new activity?
  
  NERC's Events Analysis database and associated reports provide data that can be used to analyze performance and guide interventions.

- How will we measure performance? What metrics will define and track success?
  
  Initial measures will be broad. Although the focus will be on reducing the occurrence of event cause codes associated with A4B1C05 (assessment did not determine cause of previously event or known problem), A4B1C08 (corrective action responses to a known or repetitive problem was untimely), and A4B1C04 (follow-up did not identify problems), focusing on only these codes may not identify additional changes that may be seen in other areas. As such, we recommend that the effectiveness of these interventions be measured based on higher-level code metrics.

  In the subsequent three years following initiation of interventions described above, success will be defined as,

  - Metric 1: A reduction in the annual percentage of events that have been coded as “AZ,” or “Information to determine cause less than adequate.”
    
    - Number of AZ events divided by the number of total events
    
    \[
    M_1 = \frac{AZ}{E} \]

  - Metric 2: A reduction in the annual percentage of events not coded as “AZ” that are coded as “A4,” or “management/Organization.”
    
    - Number of A4 events divided by the number of total events less the events coded as AZ
    
    \[
    M_2 = \frac{A4}{E - AZ} \]
Protection Systems

**DISCUSSION**

An event becomes worse due to a protection system failing to operate correctly.

**DRAFT**

Contributors:
- NERC Staff
- Planning Committee Chair and advisors
- Standards Committee Chair
- North American Transmission Forum CEO

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**Related NERC Standards**
- PRC-001, PRC-003 through -005, PRC-012 through -017, -023
- TPL-003 and -004

**NERC Standards Development Projects**
- Project 2007-09 Generator Verification
- Project 2010-05.2 SPS and RAS (Recommended for transfer; see below)
- Project 2010-13.2 Stable Power Swings

**Other NERC and Industry Activities**
- Protection System Misoperation Task Force
- System Protection and Control Subcommittee
- Regional Criteria
- Operating Committee
- Event Analysis Subcommittee
- Trend Working Group
- Event Analysis Program
- Lessons Learned
- State of Reliability Report

**Non-NERC Activities**
- IEEE: Research and development efforts
- Entities: Internal company procedures
- North American Transmission Forum: Peer reviews of company Protection System methods and processes
- North American Transmission Forum: Regional pilot of best practice approaches for addressing Protection System Misoperations
- North American Transmission Forum: Evaluating the offering of System Protection expertise as part of member assistance function

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Based on the existing efforts described above:

- Are the existing efforts in this area sufficient? Yes.

  Analysis has identified eight ways in which threats within this general risk area may manifest. These are summarized below, along with a brief description of how the risk is being controlled.

  1. Field Personnel Errors: Settings specified in the protection system design are correct, but personnel in the field applied them incorrectly.
     - Response: Analysis of misoperation data does not support this as a major cause of misoperations or events involving protection systems. No interventions are suggested beyond regular internal company procedures.

  2. Relay Loadability: Part of the BES trips due to protection system settings being overly conservative, such that necessary equipment does not "ride through" an event and is subsequently unavailable to respond to or support the event.
     - Response: NERC has already completed Project 2010-13.1, which addressed the loadability of transmission protection system relays Project 2010-13.2, which will similarly address the loadability of generator protection system relays, is in progress. A potential third project to address the loadability of protection system relays during stable power swings through standards development is being evaluated. These activities are sufficient to address this concern.

  3. Lack of Redundant Protection for Critical Facilities: A protection system critical to the stability of the BES fails, leaving the system in essentially an N-0 state.
     - Response: NERC’s SPCS has developed a document explaining Redundancy of Protection Systems and its application. At this time, these activities are sufficient to address this concern.

  4. Single Points of Failure in Protection Systems: A single component integral to a number of protection systems fails, resulting in several protection systems not functioning.
     - Response: A NERC Rules of Procedure, Section 1600 data request to the industry is underway to determine the extent to which such scenarios exist. This work is also in part to address the single point of failure issue raised in FERC Order 754. Following that analysis, a new standards development effort may commence if warranted.

  5. Coordination of Protection Systems: Two or more protection systems have setting or design conflicts (for example, such that the protective action of one system negates or overrides the intended operation of the other).
     - Response: Entities are already required to coordinate protection system settings. Project 2007-06 System Protection Coordination is intended improve existing standards, and require coordination activities when certain facility changes to the system are made, which will help reduce the potential for conflicts. This activity is sufficient to address this concern.

  6. Generator Frequency and Voltage Protective Relay Coordination: Generators without adequate coordination between generator protective relays and generator voltage regulator controls and limit functions may trip off-line during voltage and frequency excursions.
     - Response: Project 2007-09 Generator Verification, recently completed and awaiting Board adoption, includes Standard PRC-024-1 — Generator Frequency and Voltage Protective Relay Settings, which requires Generator Owners set their generator protective relays such that generating units remain connected during
defined frequency and voltage excursions. This activity is sufficient to address this concern.

7. Reduction of common mode failures and repeat misoperations: The lessons learned from a single misoperation are not applied, resulting in an identical misoperation of the same equipment or a functionally identical misoperation on other equipment.

Response: Project 2010-05.1 Protection Systems Misoperations is intended to require analysis and corrective action plans to address misoperations, and will help reduce common mode failures and repeat misoperations. NERC and Standards Committee representation will be meeting with the Project 2010-05.1 standards drafting team to ensure the team’s approach is correctly aligned with the conclusions identified in the recently published State of Reliability Report. Additionally, Project 2007-11: Disturbance Monitoring Equipment Standard will assist in the analysis of misoperations, further enhancing the ability of entities to discover root causes and take appropriate remediation steps. Outside the realm of mandatory reliability standards, the Protection System Misoperation Task Force has been investigating this area and recently developed a set of suggestions for addressing commonly seen problems and improving protection system performance through the development of guidelines. NERC’s State of Reliability Report also identified areas for improvement and made recommendations in this area. NERC has begun disseminating more information regarding these commonly seen problems, and is developing training modules to further educate the industry in this area. These activities are sufficient to address this concern.

8. Protection Equipment Failure: Protection system components fail to operate as expected. It is assumed that periodic maintenance and regular testing would catch these failures in a safe environment, rather than a live environment where their failure can adversely impact reliability.

Response: Project 2007-17 (Protection System Maintenance and Testing; completed), developed standards that specify how and when to maintain certain key protection system equipment. There is additional work regarding Reclosing Relays and Sudden Pressure Relays in progress. NERC’s State of Reliability Report also identified areas for improvement and made recommendations in this area. These activities are sufficient to address this concern.

- Are all of the existing efforts needed? If not, what can be eliminated?
  No. The PC has reviewed the need for a standard related to “Protection System Commissioning Testing,” and found that a standard is not necessary at this time. Additionally, NERC, under a Section 1600 data request, is collecting data for analysis (described above as “Single Point of Failure (Order 754) Data Request”) to determine if a new standard is needed to address “Reliability of Protection Systems”, if a modification of existing TPL standards would adequately cover the Single Point of Failure (SPOF) concern, or if existing TPL standards adequately cover the SPOF concern. Under the NERC PC, the SPCS and SAMS will review the Order 754 data and recommend if additional actions are required. Other NERC efforts to address Single Point of Failure include the NERC Board approved interpretation INT-2012-02 of TPL-003 and -004 and the new TPL-001-2, which is currently NERC Board approved and awaiting FERC approval.

- Are any of the existing efforts done in concert with the work of other organizations?
  No.

- If the existing efforts are not sufficient – what gaps do you see and how do you propose to solve them?
  We do not see any gaps. However, we make the following suggestions:
    o Remove SPS and RAS from this risk discussion, and create a new priority area specifically for SPS and RAS. The technologies, goals, and functions are sufficiently different to merit a separate treatment.
    o Review the PSMTF Report on protection system misoperations to determine if there are next steps that the RISC should undertake.
  Also, there may be additional value in NERC undertaking the following activities:
    o Consider collecting data to determine if aging protection system equipment is an area of concern to be addressed
    o Coordinating more closely with the NATF and NAGF on their efforts related to protection systems
    o Evaluating the effectiveness of mandatory NERC requirements associated with protection systems

If new efforts are needed: (No)

- Is the new effort within NERC’s scope or should it be directed to another organization?

- What gap in existing efforts was identified that this new effort was meant to address?

- What data is available to scope the new activity?

- How will we measure performance? What metrics will define and track success?
DISCUSSION

Situational Monitoring

An event occurs due to a control center or similar facility either not receiving, understanding, or acting on information related to system conditions.

Related NERC Standards

- BAL-005
- COM-001 through -002
- FAC-001
- IRO-001 through -005
- IRO-008, -010, -014 through -016
- NUC-001
- PER-001 through -005
- TOP-001, -003 through -006
- VAR-001

NERC Standards Development Projects

- 2007-02 Operating Personnel Communications Protocols IN PROGRESS ETC Q3 2013
- 2009-02 Real-time Reliability Monitoring and Analysis Capabilities IN PROGRESS ETC Q1 2014

NERC Standards

- Entity Certification and Registration
- RCS
- Events Analysis Program
- Lessons Learned
- NERC Alerts
- SAFARI II NERC Bulk Power System Awareness
- NERC Functional Model
- Operating Committee
- Event Analysis Subcommittee
- EMS Task Force
- System Operator Certification
- September Vendor Conference
- OC-directed Tool Status Communication Practices research; assigned to the ORS, with the goal of guideline development
- Tools developed through NERC facilitated efforts (e.g., The Reliability Coordination Information System (RCIS), the System Data Exchange (SDX) program).

Non-NERC Activities

- Vendors: Alarms, Disturbance Monitoring Equipment
- Entities: Implementation of Teams (shared SA)

Based on the existing efforts described above:

- Are the existing efforts in this area sufficient? Generally, yes, although one area can use some additional improvement. Seven ways in which errors associated with Monitoring and Situational Awareness can manifest are shown below, along with associated responses.

  1. Appropriate Decision Support Systems do not exist: The tools needed to monitor or comprehend BES conditions have not been provided, leading the operator to make incorrect decisions. Response: Standards Project 2009-02 Real-time Reliability Monitoring and Analysis Capabilities will list required capabilities for system operators. This activity is sufficient to address this concern.

  2. Decision Support System Failure: Tools used by the operator to monitor or comprehend BES condition fail, leading the operator to make incorrect decisions. Response: Data has shown this to be a significant threat to situational awareness. NERC recommends activities be undertaken to increase awareness of this problem, such that industry will implement creative, situation-specific solutions to increase availability. Additionally, NERC should educate the industry on good practices for mitigating the risk of problems should a failure occur. See additional details below.

  3. Communication Error: A message between operators is misunderstood, leading to incorrect decisions. Response: The OC has developed a guideline describing current industry practices, in order to educate the industry on common effective communications strategies. Additionally, Standards Project 2007-02 Operating Personnel Communications Protocols is intended to establish rules regarding appropriate communications protocols, thus minimizing communication errors. These activities, once completed, should be sufficient to address this concern.

  4. Individual Perception Failure: An individual operator is unaware of a communicated condition, leading him or her to make incorrect decisions. Response: At this time, data does not indicate this to be a problem within the industry. NERC will continue to monitor this area for any change in performance.

  5. Individual Comprehension Failure: An individual operator does not understand the impact of a communicated condition, leading him or her to make incorrect decisions. Response: At this time, data does not indicate this to be a problem within the industry. NERC will continue to monitor this area for any change in performance.

  6. Intra-Entity Team Disagreement: Individual operators within the same entity disagree about system conditions, resulting in incorrect or postponed decisions. Response: At this time, data does not indicate this to be a problem within the industry. NERC will continue to monitor this area for any change in performance.

  7. Inter-Entity Team Disagreement: Operators from different entities disagree about system conditions, resulting in incorrect or postponed decisions. Response: A number of NERC standards, programs, and guidelines address this concern. Coordination obligations, such as those defined in the TOP and PRC standards, help ensure agreement and consistency ahead of time. Tools developed through NERC facilitated efforts, such as RCS and SDX, help ensure information is shared between entities. In a real-time, IRO-014-2 requires that in situations in which Reliability Coordinators are in disagreement regarding system conditions, the Reliability Coordinator that identified the condition shall be given deference regarding how to mitigate the condition. At this time, it is believed this is sufficient to address this concern.

- Are all of the existing efforts needed? If not, what can be eliminated?
  Yes.

- Are any of the existing efforts duplicative of what other organizations are doing?
  No.

- Are any of the existing efforts done in concert with the work of other organizations?
  No.

- If the existing efforts are not sufficient — what gaps do you see and how do you propose to solve them?
  Regarding Decision Support System Failure, NERC recommends activities be undertaken to increase awareness of this problem, such that industry will implement creative, situation-specific solutions to increase availability. Additionally, NERC should educate the industry on good practices for mitigating the risk of problems should a failure occur. Approaches for accomplishing this could include:
    o Using Alerts to make entities aware of common problems (for example, Preventable EMS and SCADA Events Alert – April 10, 2012)
    o Publishing Lessons Learned that provide insight into this problem (four Lessons Learned published in February 2013, two more in development).
Appendix 1 – Gap Analyses

- Presenting discussions of the concern and various mitigation strategies in public forums (e.g., meetings of the Event Analysis Subcommittee and Operating Committee).
- Holding a stakeholder/vendor conference where issues can be discussed and strategies for minimizing failures developed (Targeted for Sept 2013 Denver, CO).

If new efforts are needed:

- Is the new effort within NERC’s scope or should it be directed to another organization?
  Yes, although the assistance of other organizations would be beneficial.

- What gap in existing efforts was identified that this new effort was meant to address?
  Decision Support System Failures create latent risk that, when combined with other real-time events or conditions, can lead to significant failures.

- What data is available to scope the new activity?
  NERC’s Events Analysis database and associated reports provide data that can be used to analyze performance and guide interventions.

- How will we measure performance? What metrics define and track success?
  For determining the effectiveness of the interventions discussed above related to Decision System Support Failures, net decreasing trends in the following four metrics over the subsequent 18 months following initiation of the interventions will indicate success.

  - Metric 1: Total count of all Full EMS Outages reported within a rolling 12-month period, as reported through the NERC Events Analysis Process
  - Metric 2: Total count of all Partial EMS Outages reported within a rolling 12-month period, as reported through the NERC Events Analysis Process
  - Metric 3: Mean duration of Full EMS Outages reported within a rolling 12-month period, as reported through the NERC Events Analysis Process
  - Metric 4: Mean duration of Partial EMS Outages reported within a rolling 12-month period, as reported through the NERC Events Analysis Process
An event occurs due to models and/or model inputs used in day-ahead and/or real-time being inaccurate or not available.

**NOTE: THIS GAP ANALYSIS NEEDS FURTHER REVIEW AND ANALYSIS. THE RISC IS RECOMMENDING IT BE ANALYZED THROUGH THE “RELIABILITY RISK CONTROL PROCESS.”**

### Based on the existing efforts described above:

- Are the existing efforts in this area sufficient?

  Yes. There are a number of areas for potential improvement to industry modeling efforts, and various activities are underway to make those improvements.

  1. **Generator Dynamics:** Generator modeling has become suspect in trying to perform interconnection-wide dynamic analysis and cannot necessarily be counted on to correctly predict system behavior.
     
     Response: NERC’s Modeling Working Group (MWG) is working to develop an industry supported standardized component model library and common data exchange format, which will assist in the resolution of this problem. The North American Transmission Forum (NATF) and Eastern Interconnection Reliability Assessment Group (ERAG) are also developing modeling guidelines in this area. These efforts should be sufficient to address this concern at this time.

  2. **Load Behavior:** The use of new technologies is changing load characteristics and behavior, which makes traditional load modeling obsolete.
     
     Response: WECC and other entities have developed composite load models for multiple types of loads for each bus with differing characteristics. Some of those load models are adaptive, changing characteristics when exposed to different voltages. WECC is implementing the use of the composite load model for regional interconnection-wide studies. Additionally, ISO New England is performing research on the composition of their loads and the characteristics in preparation for implementing a composite load for its system. At this time, monitoring these efforts are sufficient steps toward addressing this area of concern. Additional efforts may be appropriate.

  3. **Frequency Response:** Inaccurate modeling of frequency response leads to a failure to predict system behavior during disturbances.
     
     Response: A work plan is underway with the ERAG Multi-Regional Modeling Working Group (MMWG) to develop “generic” governor model light load case from the 2012 series and to adjust individual governor models in the 2013 series to reflect responsiveness. The work plan also calls for delivery of a corrected light load 2014 case by August 1, 2014.

  4. **Inter-Area Oscillations:** Models are insufficiently robust to predict inter-area oscillations, leading to behaviors that have not been analyzed and protected against.
     
     Response: NERC’s MWG is undertaking efforts to enhance system model validation. Additionally, WECC is developing a West-wide System Model that will help in their analysis of this problem. These efforts should be sufficient to address this concern at this time; however, analysis may identify additional work to be undertaken in the future.

  5. **Equipment Modeling:** A lack of standardized component models for BES equipment (e.g., static var compensators, static synchronous compensators, DC converter stations, frequency shifting transformers, etc.) impedes the construction of valid power system models needed to accurately predict interconnection-wide power system behavior.
     
     Response: NERC’s Modeling Working Group (MWG) is working to develop a industry supported standardized component model library and common data exchange format, which will assist in the resolution of this problem. An initial library of standardized models will be created using the current Regionally-approved dynamic model libraries. Additional models from the Institute of Electrical and Electronics Engineers (IEEE) and other appropriate organizations will be added as appropriate. Models for new technological innovations will be developed, validated, and added to the library of standardized models. This effort should be sufficient to address this concern.

  6. **Modeling Errors – Errors in powerflow and dynamics models lead to predicted system behavior that differs from reality.**
     
     Response: Regional Entities are reviewing and comparing governor models against the 2010 governor survey done as part of the Frequency Response Initiative. The ERAG is testing a new topology database, which is expected to be in service in 2014. NERC’s MWG is working to develop an industry supported standardized component model library and common data exchange format, which will assist in the resolution of this problem. The MWG is also beginning to consolidate modeling guidelines in support of generator owner and transmission modeling personnel, and is in the process of field testing a Model Validation Procedure. Additionally, efforts to standardize approach to modeling (node-breaker versus bus-branch) may reduce the potential for errors by eliminating the need for maintaining multiple models.

  7. **Modeling Consistency:** Differences in understanding of model parameters leads to models that do not accurately predict system behavior.
     
     Response: NERC’s Modeling Working Group (MWG) is working to develop an industry supported standardized component model library and common data exchange format, which will assist in the resolution of this problem. The North American Transmission Forum (NATF) and Eastern Interconnection Reliability Assessment Group (ERAG) are also developing modeling guidelines in this area. These efforts should be sufficient to address this concern at this time.

  8. **Model Compatibility:** Inability to share models through a common protocol lead to less detailed models and modeling error that can affect accurate prediction of power system behavior.
     
     Response: The NERC MWG has been tasked to develop an industry supported standardized component model library and common data exchange format. The MWG is investigating the potential for use of the Common Information Model (CIM) as a standardized data exchange protocol for sharing information between companies and across interconnections. Additionally, the MOD 8 Standards Development project to modify NERC Reliability Standards MOD-010 through MOD-013 to improve transparency of data needed to accurately study power systems. These efforts should be sufficient to address this concern at this time.

  9. **Approaches to Modeling:** Planning and Operations models that use different representations (node-breaker versus bus-branch) lead to inconsistent understanding of contingencies and duplication of modeling efforts, both of which may lead to inaccurate prediction of power system behavior.
     
     Response: NERC’s MWG is proposing an effort to incorporate node-breaker modeling in off-line powerflow and dynamics cases and analysis. This initial effort should be sufficient to address this concern at this time.
10. Special Protection Systems/Remedial Action Schemes: Lack of modeling of SPS and RAS result in unexpected and detrimental BES behavior during a disturbance.
Response: Research to develop modeling methods for modeling Special Protection Systems and Remedial Action Schemes in order to determine their potential interaction is underway with the WECC Modeling SPS and RAS Ad Hoc Task Force (MSRATF). This effort is sufficient to address this concern at this time.

11. Protection Systems: Lack of accurate protection system details in dynamics models leads to predicted behavior differing from actual power system behavior.
Response: Research is underway on linking dynamics programs to existing corporate relay databases. While this holds promise, it can currently only be done for limited portions of an interconnection at this time.

12. Turbine and Boiler Controls: Lack of understanding of how turbine and boiler controls interact with the power system has resulted in unexpected losses of generation.
Response: NERC has been seeking to perform research on which aspects of turbine and boiler controls should be modeled to correctly predict the behavior of generation during system disturbances. Defining which functions and behaviors should be modeled for transient and mid-term dynamics, coupled with recommendations on additional modeling of generator protection systems (such as Volts/Hertz, under-voltage, and under-frequency relays) will greatly improve the industry's ability to predict generation performance during disturbances. Under the guidance of the System Analysis and Modeling Subcommittee (SAMS), NERC will be seeking participation in this effort from Generator Owners, turbine manufacturers, and other technical experts. This effort should be sufficient to address this concern at this time.

13. Model Input Data: Bad data, or lack of data, leads to a model used in operations producing an invalid result, negatively impacting operator decision making.
Response: Project 2010-03 (Modeling Data) and project 2010-04 (Demand Data) are both standards projects intended develop more consistency around the data used in modeling and forecasting. These efforts should be sufficient to address this concern at this time.

14. Seams Coordination: Differences in fundamental assumptions between areas lead to inconsistency in local modeling and simulation results, negatively impacting operator decision making.
Response: There are limited activities in this area at this time. RISC recommends further analysis be done by the Planning Committee in this area.

- Are all of the existing efforts needed? If not, what can be eliminated?
  Yes.

- Are any of the existing efforts duplicative of what other organizations are doing?
  No.

- Are any of the existing efforts done in concert with the work of other organizations?
  Yes. As discussed above, efforts are being undertaken in collaboration with regional entities, registered entities, and other organizations, such as the NATF and IEEE.

- If the existing efforts are not sufficient – what gaps do you see and how do you propose to solve them?
  Existing efforts are sufficient at this time.

If new efforts are needed: (No)

- Is the new effort within NERC’s scope or should it be directed to another organization?

- What gap in existing efforts was identified that this new effort was meant to address?

- What data is available to scope the new activity?

- How will we measure performance? What metrics will define and track success?
Based on the existing efforts described above:

- Are the existing efforts in this area sufficient? Yes.
- Are there several areas in which Equipment Maintenance and Management issues may manifest:

  1. Transmission Lines Failure. A transmission line physically fails, resulting in less ability to transport energy to serve load.
     
     Response: In general, NERC has not seen any unusual trend regarding the physical failure of transmission lines. NERC standards related to SOLs and IROLs, combined with market forces, have largely resulted in a strong desire to protect assets from damage. The exception in this area would be the impact of significant weather events on the transmission system, which are essentially transmission adequacy concerns. NERC’s Long Term Reliability Assessment is currently the place where such concerns are discussed and considered. These activities have been sufficient to address this concern.

  2. Transmission Substation Failure. Equipment at a substation physically fails, resulting in a loss of transmission, generation, or both.
     
     Response: NERC has identified that AC substation equipment failures are the second most significant contributor to disturbance events and automatic transmission outage severity. Analysis of the transmission outage and disturbance event information shows that circuit breakers are the most common type of AC substation equipment failure. NERC has formed a small subject matter expert technical group to further probe the AC substation equipment failures, particularly circuit breaker failures, and provide risk control solutions to improve performance. This activity is sufficient to address this concern until such time as conclusions are developed regarding how to proceed.

  3. Transmission Protection Systems Failure: A transmission protection system fails, resulting in equipment damage and/or larger areas of the system taking themselves out of service.
     
     Response: Project 2007-17 (Protection System Maintenance and Testing; completed), developed standards that specify how and when to maintain certain key protection system equipment. There is additional work regarding Reclosing Relays and Sudden Pressure Relays in progress at the request of the FERC. Also see the Protection System Gap Analysis. These activities are sufficient to address this concern.

  4. Generator Protection System Failure: A generation protection system fails, resulting in equipment damage and/or unnecessary reductions in available generation supply.
     
     Response: Project 2007-17 (Protection System Maintenance and Testing; completed), developed standards that specify how and when to maintain certain key protection system equipment. There is additional work regarding Reclosing Relays and Sudden Pressure Relays in progress at the request of the FERC. Also see the Protection System Gap Analysis. These activities are sufficient to address this concern.

  5. Generator Failure: A generator physically fails, resulting in less generation supply to serve load.
     
     Response: In general, NERC has not seen any unusual trends regarding generator performance. One highly visible exception is that of generator performance in abnormally cold weather. However, NERC’s Operating Committee has developed a guideline to address this concern, and NERC will be undertaking a communication and education campaign to ensure entities are aware of the guideline and the recommended practices it describes. Also see the Generator Availability Gap Analysis. These activities are sufficient to address this concern.

  6. Inter-Entity Maintenance and Testing Coordination: Multiple entities are testing or maintaining their equipment, resulting in a system that behaves unexpectedly.
     
     Response: The scope and magnitude of this risk is undefined. NERC’s Planning Committee will be working to analyze this risk and develop a proposal for next steps.

  7. Increased Generation Plant Complexity: A plant fails or is subjected to forced derate because complex parasitic modifications and/or retrofits create increased operational risks to the overall power block (for example, clean air retrofits required to comply with the Mercury and Air Toxics Standards).
     
     Response: The scope and magnitude of this risk is undefined. NERC’s Planning Committee will be working to analyze this risk and develop a proposal for next steps.

- Are all of the existing efforts needed? If not, what can be eliminated?
  Yes.

- Are any of the existing efforts duplicative of what other organizations are doing?
  No.

- Are any of the existing efforts done in concert with the work of other organizations?
  No.

- If the existing efforts are not sufficient—what gaps do you see and how do you propose to solve them?
  We do not see any gaps at this time. However, depending on the results of the special subject matter expert technical group investigating substation failure, gaps may be identified that require specific interventions. We recommend NERC continue to monitor this issue and be prepared to respond as conclusions are determined.

If new efforts are needed: (No)

- Is the new effort within NERC’s scope or should it be directed to another organization?

- What gap in existing efforts was identified that this new effort was meant to address?

- What data is available to scope the new activity?

- How will we measure performance? What metrics will define and track success?
Coordinated Attack on Multiple Facilities

**DISCUSSION DRAFT**

An event occurs due to a physical attack on infrastructure.

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<td>OC, PC, CIPC, and associated Subcommittees</td>
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<td>Spare Equipment Database</td>
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Based on the existing efforts described above:

- Are the existing efforts in this area sufficient?
  While the ERO has worked with industry to produce physical security guidance and the ES-ISAC remains a resource for information sharing, more work should be devoted to ensuring proper protection across North America. Issues that should be looked at further include:
  1. Shooting of high voltage transmission lines, bushings, and transformers
  2. Copper theft
  3. Unauthorized access to electric facilities (substations, generation sites, control centers)
  4. Security training (bomb threat, piggybacking, suspicious package procedures, security exercises, suspicious activity reporting)
  5. Entity response to a coordinated attack on multiple critical facilities

- Are all of the existing efforts needed? If not, what can be eliminated?
  Yes. No current effort should be eliminated.

- Are any of the existing efforts duplicative of what other organizations are doing?
  No.

- Are any of the existing efforts done in concert with the work of other organizations?
  Yes. For example, the Joint Product Physical Security (JPPS) is a NERC best practices document currently in development, built in conjunction with the Department of Homeland Security, Federal Bureau of Investigation, and the Royal Canadian Mounted Police. The document will address physical security protection measures and provide items for consideration to industry. The GridEx II exercise, scheduled for November 13-14, 2013, will be a physical and cybersecurity exercise with approximately 140 organizations from industry, government, and academia.

- If the existing efforts are not sufficient — what gaps do you see and how do you propose to solve them?
  While NERC has had numerous opportunities for physical security training and the development of relevant guidelines, there are different levels of sophistication and maturity across North America. Some entities are excellent in this area, while others are still learning. Sharing of best practices and collaborating through peer assessments will help ensure maturity in this area is increasing. Peer assessments will suggest industry best practices with a focus on mitigating a single site attack/sabotage or a coordinated physical attack to targeted electrical infrastructure. CIPC guidelines, in conjunction with American Society for Industrial Security (ASIS International) Physical Security Manual best practices, can be used to develop a voluntary physical security outreach program that will highlight current practices, inform entities of recent physical security events, and communicate current threats and vulnerabilities. Such an outreach and awareness campaign would focus on learning and advancing the industry to a more consistent and robust physical security posture.

If new efforts are needed:
- Is the new effort within NERC’s scope or should it be directed to another organization?
  Yes. However, collaborating with other entities (such as the North American Transmission Forum, the North American Generator Forum, and others) will be essential to ensuring industry experts are sharing their knowledge and entities are receiving information efficiently.

- What gap in existing efforts was identified that this new effort was meant to address?
  While NERC has had numerous opportunities for physical security training and the development of relevant guidelines, there are different levels of sophistication and maturity across North America. Some entities are excellent in this area, while others are still learning. Efforts should be undertaken to increase industry maturity.

- What data is available to scope the new activity?
  Voluntary reporting, lessons-learned from events (PGE Metcalf substation event), and metrics from outside the Electricity Sub-sector to determine can be used to determine general effectiveness.

- How will we measure performance? What metrics will define and track success?
  Success can be measured by increased reporting/engagement to the ES-ISAC, as well as through voluntary reporting and feedback.
Based on the existing efforts described above:

- Are the existing efforts in this area sufficient?
  
  Yes. These efforts are summarized below, along with a brief description of how the risk is being controlled.

  1. Generator Outages and Deratings: Generation adequacy in real time is insufficient due to outages or deratings, leading to an inability to balance generation and load.
     
     Response: NERC has been collecting generator performance and event data from Generator Owners (GOs) for over three decades. The data is used to calculate important performance statistics and supports bulk power trend analysis by providing information on forced outages, maintenance outages, planned outages, and deratings. NERC also uses historical GADS data to trend outage impact to system reliability, including severity risk index (SRI) curves. The SRI was developed to track annual changes and establish performance reference for the bulk power system's characteristics. The annual SRI curves have been applied prospectively for particular risk events and performance assessments. Other than isolated incidents (such as the February 2011 Southwest Cold Weather Event, which is being addressed through development of a guideline and an education/awareness campaign), trends have not indicated any significant concerns in this area. Any trends identified in this area would be communicated to the industry through NERC's reliability assessments. At this time, this risk seems to be adequately addressed.

  2. Loss of Fuel: Generation adequacy in real time is insufficient due to a lack of fuel, leading to an inability to balance generation and load.
     
     Response: NERC has written a special assessment related to increased dependence on natural gas, highlighting this risk and making specific recommendations. It is anticipated that consideration of this risk will become part of the seasonal and long-term reliability assessments as well. At this time, NERC is relying primarily on voluntary industry actions and the actions of other organizations (e.g., FERC, organized markets, regional study groups, etc...) to address this concern. NERC is also considering enhancing its Generator Availability Data System to track gas-related outages more closely, and will be working with its stakeholder groups to identify lessons learned and common practices. NERC's Planning Committee will be working to establish a task force to consider the benefits or integrated strategic planning efforts between the gas and power industries, with a focus on ensuring fuel supply adequacy.
     
     Aside from concern with increased natural gas dependence, at this time, this risk seems to be adequately addressed.

  3. Frequency Responsive Reserve Availability: Frequency recovers slowly following a disturbance due to a lack of Frequency Responsive Reserves.
     
     Response: BAL-003 (recently modified as part of Project 2007-12 Frequency Response, which is now pending regulator approval) is intended to address this concern. If future analysis indicates this to be a reliability problem, additional efforts to ensure adequate provision of frequency responsive reserves (e.g., federal, state, or local regulation; market development) may be required in some areas. However, at this time, this risk seems to be adequately addressed.

  4. Regulating Reserve Availability: System balancing performance is outside expected tolerances due to a lack of Regulating Reserves.
     
     Response: BAL-001 (currently being modified as part of 2010-14.1 Balancing Authority Reliability-Based Controls) is intended to address this concern. At this time, this risk seems to be adequately addressed.

  5. Contingency Reserves Availability: Contingency Reserves are unavailable to replace lost generation, resulting in excessive reliance on Frequency Responsive or Regulating Reserves.
     
     Response: BAL-002 (currently being modified as part of 2010-14.1 Balancing Authority Reliability-Based Controls) is intended to address this concern. At this time, this risk seems to be adequately addressed.

- Are all of the existing efforts needed? If not, what can be eliminated?
  
  Yes.

- Are any of the existing efforts duplicative of what other organizations are doing?
  
  No.

- Are any of the existing efforts done in concert with the work of other organizations?
  
  No.

- If the existing efforts are not sufficient – what gaps do you see and how do you propose to solve them?
  
  Existing efforts are sufficient.

- If new efforts are needed: (No)

  - Is the new effort within NERC's scope or should it be directed to another organization?

  - What gap in existing efforts was identified that this new effort was meant to address?

  - What data is available to scope the new activity?

  - How will we measure performance? What metrics will define and track success?
### Increased dependence on Natural Gas Generation

#### DISCUSSION

**Related NERC Standards**
- None specifically address this issue.

**NERC Standards Development Projects**
- None

**Other NERC and Industry Activities**
- NERC Reliability Assessments
- GC, PC, associated Subcommittees

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<td>• NERC Staff</td>
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<td>• Planning Committee Chair</td>
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#### Non-NERC Activities
- ISOs, RTDs, Pipelines: Market Solutions
- Entities: Planning, Regulatory communications and lobbying
- Industry: Awareness and Study, Conferences
- FERC: Technical Conferences; docket on inter-industry coordination
- NAESB: Gas Electric Harmonization Task Force

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Based on the existing efforts described above:

- **Are the existing efforts in this area sufficient?** At this time, yes.
  
  There are four primary failure modes which need to be considered. These are summarized below, along with a brief description of how the risk is being controlled.

  1. **Electric outages:** Load management or forced outages result in the loss of key gas transportation components (e.g., electric compressor stations, electric controls at non-electric compressor stations), leading to further fuel interruptions and generation loss.
     - **Response:** NERC has written a special assessment, highlighting this risk and making specific recommendations. At this time, NERC is relying on voluntary industry actions and the actions of other organizations (e.g., FERC, organized markets, regional study groups, etc...) to address this concern.

  2. **Gas curtailments:** High demand for gas results in insufficient pipeline capacity to serve all customers; using non-firm transportation to supply gas-fired generation results in curtailment of fuel and subsequent loss of the generation.
     - **Response:** NERC has written a special assessment, highlighting this risk and making specific recommendations. It is anticipated that consideration of this risk will become part of the seasonal and long-term reliability assessments as well. At this time, NERC is relying primarily on voluntary industry actions and the actions of other organizations (e.g., FERC, organized markets, regional study groups, etc...) to address this concern. NERC is also considering enhancing its Generator Availability Data System to track gas-related outages more closely, and will be working with its stakeholder groups to identify lessons learned and common practices.

  3. **Pipeline transportation system fails:** A key component of the gas transportation system fails, resulting in the concurrent loss of multiple generation sources.
     - **Response:** NERC has written a special assessment, highlighting this risk and making specific recommendations. It is anticipated that consideration of this risk will become part of the seasonal and long-term reliability assessments as well. At this time, NERC is relying on voluntary industry actions and the actions of other organizations (e.g., FERC, organized markets, regional study groups, etc...) to address this concern.

  4. **Pipeline and Gas Supply Adequacy:** Because of external conditions (e.g., a heat wave), the gas system is unable to meet with firm gas or transportation commitments.
     - **Response:** The scope and magnitude of this risk is undefined. NERC’s Planning Committee will be working to establish a task force to consider the benefits or integrated strategic planning efforts between the gas and power industries, with a focus on ensuring fuel supply adequacy.

- **Are all of the existing efforts needed? If not, what can be eliminated?** Yes.

- **Are any of the existing efforts duplicative of what other organizations are doing?**
  
  No. While many regions (e.g., planning coordinators, groups of planning coordinators, interconnection/regional study groups) are performing studies, regional differences and challenges must be uniquely studied.

- **Are any of the existing efforts done in concert with the work of other organizations?**
  
  Yes. NERC has undertaken this issue in close collaboration with other entities from both the power and natural gas industries.

- **If the existing efforts are not sufficient — what gaps do you see and how do you propose to solve them?**
  
  At this time, we believe existing efforts are sufficient. However, close monitoring of this issue is appropriate to ensure it is being properly addressed. Reliability assessments are a key tool NERC can leverage to support tracking and trending of this issue.

If new efforts are needed: (No)

- **Is the new effort within NERC’s scope or should it be directed to another organization?**

- **What gap in existing efforts was identified that this new effort was meant to address?**

- **What data is available to scope the new activity?**

- **How will we measure performance? What metrics will define and track success?**
Essential Reliability Services Task Force

Scope

Background
The amount of variable renewable generation is expected to grow considerably as federal policies and regulations are developed and implemented by individual states and provinces throughout North America. The proposed levels of commitment to renewable variable generation is one component of an ongoing resource mix shift. It is imperative that power system planners and operators understand the potential and cumulative reliability impacts associated with large scale integration of variable generation, an overall capacity reduction in larger base-load generation, increased participation from demand resources and distributed generation, and a more prominent reliance on natural gas-fired generation.

Variable generation, in particular, has different characteristics and respond differently on the system. As larger amounts of variable generation are added to the system, they will displace the traditional large, rotating machines and the operating characteristics those machines provided. Beyond capacity and energy characteristics, essential reliability services (ERS), such as inertia, frequency response, and voltage control, must be maintained across a given system to ensure reliable operation. There may be other characteristics or functions that make up the suite of ERS.

ERS are the elemental ‘reliability building blocks’ from resources (generation and demand) necessary to maintain Bulk Power System (BPS) reliability. These ‘reliability building blocks’ have historically been provided by large and conventional generation. In contrast, in many areas of North American today and in the near future, retirement of conventional generation coupled with increasing variable generation can further strain the availability of ERS unless due considerations are given in planning.

To meet the needs of the future bulk power system, maintaining sufficient ERS will include a mix of market approaches, technology enhancements, and reliability rules or other regulatory rule changes. While the solution sets will likely be different in various regions, regulators will be called on to make appropriate adjustments to market rules and tariffs across North America.

Purpose
The ERSTF has a multi-faceted purpose that includes a technical foundation of ERS, educate and inform industry, regulators, and the public about ERS, develop an approach for tracking and trending ERS, and formulate recommendations to ensure the complete suite of ERS are provided and available. More specifically, the task force will reconcile a collection of analytical approaches for understanding potential reliability impacts as a result of increasing variable resources and how those impacts can affect system configuration, composition, and ERS.
Activities
As part of its inception, the task force will:

1. develop a technical reference document (primer) on ERS. The primer can be used as a reference manual for regulators and policy makers and to inform, educate, and build awareness on the reliability ramifications of a changing resource mix and the elements essential for the reliability of the BPS.

2. develop an approach and framework for the long-term assessment of essential reliability services to supplement existing resource adequacy assessments. The approach should include a series of metrics that can be continually measured for further evaluation.

3. develop specific recommendations for practices and proposed requirements, including potential reliability standards, that cover the planning, operations planning, and real-time operating timeframes.

Based on the work plan generated in this first phase of activity, the OC and PC will determine follow-on activities to support technical committee recommendations, implementation of enhanced reliability assessment approaches, and/or technical guidance to standard drafting teams.

Membership
NERC requests industry’s subject experts to continue their efforts and add additional members as needed, with final selection agreed to by the officers of the Planning Committee and Operating Committee. Members must be willing to commit their time to participate in the task force discussions and contribute to writing the final report.

The task force is comprised of the following:

- Co-chaired (OC/PC)
- One representative from each Regional Entity
- At least one representatives from the NERC Planning Committee
- At least one representatives from the NERC Operating Committee
- One member-at-large representing Canada
- Additional members can be added:
  - At the request of the Planning Committee sector representatives, or
  - As needed by the NERC coordinator
- Chair of Reliability Assessment Subcommittee (or designated liaison)
- Chair of System Analysis and Modeling Subcommittee (or designated liaison)
- NERC staff coordinator(s)
• Governmental members include, but not limited to:
  o Federal Energy Regulatory Commission
  o United States Department of Energy
  o National Energy Board, Canada

Guest participation of industry experts may be requested to support task force activities.

The task force co-chairs are appointed by the chairs of the NERC Planning and Operating Committee for the completion of the task for work. Representation on this task force follows established Planning and Operating Committee guidelines for participation.

Members are appointed by their Region or electric industry sector for two-year terms, without limit to the number of terms. Any Region or electric industry sector may name an alternate representative(s) who may attend task force meetings.

**Order of Business**

In general, the desired, normal tone of the task force business is to strive for constructive technically sound solutions which also achieve consensus. On the relatively few occasions where that desired outcome cannot be achieved, the task force will defer to a determination by the Planning and Operating Committees to settle the issue. If any strong minority opinions develop, those opinions may be documented as desired by the minority and forwarded to the PC and OC Chair for future meeting consideration.

**Reporting**

The task force is responsible to the Planning and Operating Committees for the completion of work associated with the scope items outlined above. Final work products of the task force will be approved as necessary by the Planning and Operating Committees and, if necessary, by the NERC Board of Trustees. The task force chairs will periodically apprise the Planning Committee, Operating Committee, and Board of Trustees, as required, on the task force’s status, activities, assignments, and recommendations.

**Meetings**

Weekly to biweekly conference calls can be expected. Additionally, two to three open in-person meetings per year may be needed.

Approved by the NERC Planning Committee: ____________, 2014
Approved by the NERC Operating Committee: ____________, 2014
## Essential Reliability Services Task Force (ERSTF) Work Plan
### 2014-2015 Work Plan

<table>
<thead>
<tr>
<th>Item</th>
<th>Activity</th>
<th>Abstract</th>
<th>Lead</th>
<th>Deliverables</th>
<th>Milestones</th>
</tr>
</thead>
</table>
| 1    | Technical Reference - Whitepaper | Develop a technical reference document (primer) on ERS. The primer can be used as a reference manual for regulators and policy makers and to inform, educate, and build awareness on the reliability ramifications of a changing resource mix. Recommendations for next steps included within whitepaper. Identify a standardized set of Essential Reliability Services (ERS) along with their associated definitions (in functional, technology-neutral, performance based terms) that can be used to meet the operational needs of the North American bulk power system.  
  - Define each ERS  
  - Describe why each ERS is important for bulk power system reliability  
  - Describe how each ERS fits into the | NERC Staff Review and endorsement by ERSTF  
Approved by PC/OC | 10-15 page document | Final Reviewed by OC/PC March 2014 Meeting |
## Essential Reliability Services Task Force (ERSTF) Work Plan
### 2014-2015 Work Plan

<table>
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<th>Lead</th>
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<th>Milestones</th>
</tr>
</thead>
</table>
|      |          | overall needs of the bulk power system as well as how each are related  
• Describe current and projected strains on ERS and how ERS are affected by a changing resource mix | ERSTF | • Special Assessment | Final Reviewed by OC/PC December 2014 Meeting |
| 2    | Special Reliability Assessment – Metrics and Approaches for Evaluating Essential Reliability Services | Develop an approach and framework for the long-term assessment of essential reliability services to supplement existing resource adequacy assessments. The new approach may include the development of metrics for further evaluation in future long-term reliability assessments.  
This assessment should include an evaluation and/or reconciliation of emerging ERS impacts in terms of current conditions and potential future trends.  
Identify metrics, procedures, and methodologies to determine the need for, provide, and maintain ERS for an electric | ERSTF | • Special Assessment | Final Reviewed by OC/PC December 2014 Meeting |
### Essential Reliability Services Task Force (ERSTF) Work Plan
#### 2014-2015 Work Plan

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<td>System.</td>
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<td></td>
<td>• How is the analysis performed?</td>
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<td>• What data is needed?</td>
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<td>• What are the parameters that can be used to gauge acceptable levels of ERS?</td>
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<td></td>
<td>• How are the parameters related to the overall composition of the resource mix, today and into the future?</td>
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<td></td>
<td>Frequency Response. What strains these services? How are areas strained by different scenarios?</td>
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<td>Scenario Reliability Assessment – Changing Resource Mix Ramifications to Essential Reliability Services</td>
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<td>● Scenario Assessment</td>
<td>Scope Reviewed by OC/PC December 2014 Meeting</td>
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<tr>
<td></td>
<td></td>
<td>Support with RAS/SAMS</td>
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<td></td>
<td>Final Report Reviewed by OC/PC June 2015</td>
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<td>4</td>
<td>Special Reliability</td>
<td>Develop specific recommendations for</td>
<td>ERSTF</td>
<td>● Whitepaper –</td>
<td>Scope</td>
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</table>

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## Essential Reliability Services Task Force (ERSTF) Work Plan
### 2014-2015 Work Plan

<table>
<thead>
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<th>Item</th>
<th>Activity</th>
<th>Abstract</th>
<th>Lead</th>
<th>Deliverables</th>
<th>Milestones</th>
</tr>
</thead>
</table>
|      | Assessment – Proposals for Performance Expectations of Essential Reliability Services | practices and proposed requirements, including reliability standards, that cover the planning, operations planning, and real-time operating timeframes |  | recommendations  
• SARs if needed  
• Guideline recommendations and draft | Reviewed by OC/PC June 2015 Meeting  
Final Report Reviewed by OC/PC December 2015 |

*See assessment scope document for more details on each activity/phase.*
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. The Standards Committee (SC) approved the Standard Authorization Request (SAR) for posting on March 1, 2007.
2. The SAR was posted for comment from March 19 through April 17, 2007.
3. The SC sought SAR drafting team nominations April 18 through May 2, 2007.
4. The SAR drafting team posted reply comments to industry comments received on the first posting of the SAR on June 8, 2007.
13. On December 12, 2013, the Standards Committee approved a waiver of the Standard Processes Manual to shorten the formal comment and ballot period, from 45 days to 30 days.

Description of Current Draft:

This is the second draft of a revised standard (eighth posting of a communications standard) requiring the use of standardized communication protocols during normal and emergency operations to improve situational awareness and shorten response time. The standard drafting team is posting this standard for a shortened 30 day formal Comment and 10 day Ballot period per the Standards Committee wavier.

Future Development Plan:

<table>
<thead>
<tr>
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Agenda Item 8.c
OC Meeting
March 4-5, 2014
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<th>Additional ballot of Standard</th>
<th>January 2014</th>
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<tr>
<td>2</td>
<td>Final ballot of Standard</td>
<td>February 2014</td>
</tr>
<tr>
<td>3</td>
<td>Board adopts standard</td>
<td>TBD</td>
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</table>
Definitions of Terms Used in Standard

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

Operating Instruction — A command by operating personnel responsible for the Real-time operation of the interconnected Bulk Electric System to change or preserve the state, status, output, or input of an Element of the Bulk Electric System or Facility of the Bulk Electric System. (A discussion of general information and of potential options or alternatives to resolve Bulk Electric System operating concerns is not a command and is not considered an Operating Instruction.)
A. Introduction

1. **Title:** Operating Personnel Communications Protocols
2. **Number:** COM-002-4
3. **Purpose:** To improve communications for the issuance of Operating Instructions with predefined communications protocols to reduce the possibility of miscommunication that could lead to action or inaction harmful to the reliability of the Bulk Electric System (BES).
4. **Applicability:**
   4.1. **Functional Entities**
      - 4.1.1 Balancing Authority
      - 4.1.2 Distribution Provider
      - 4.1.3 Reliability Coordinator
      - 4.1.4 Transmission Operator
      - 4.1.5 Generator Operator
5. **(Proposed) Effective Date:** The standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

B. Requirements

**R1.** Each Balancing Authority, Reliability Coordinator, and Transmission Operator shall develop documented communications protocols for its operating personnel that issue and receive Operating Instructions. The protocols shall, at a minimum: \[Violation Risk Factor: Low]\[Time Horizon: Long-term Planning]\n
1.1. Require its operating personnel that issue and receive an oral or written Operating Instruction to use the English language, unless agreed to otherwise. An alternate language may be used for internal operations.

1.2. Require its operating personnel that issue an oral two-party, person-to-person Operating Instruction to take one of the following actions:
   - Confirm the receiver’s response if the repeated information is correct.
   - Reissue the Operating Instruction if the repeated information is incorrect or if requested by the receiver.
- Take an alternative action if a response is not received or if the Operating Instruction was not understood by the receiver.

1.3. Require its operating personnel that receive an oral two-party, person-to-person Operating Instruction to take one of the following actions:
   - Repeat, not necessarily verbatim, the Operating Instruction and receive confirmation from the issuer that the response was correct.
   - Request that the issuer reissue the Operating Instruction.

1.4. Require its operating personnel that issue a written or oral single-party to multiple-party burst Operating Instruction to confirm or verify that the Operating Instruction was received by at least one receiver of the Operating Instruction.

1.5. Specify the instances that require time identification when issuing an oral or written Operating Instruction and the format for that time identification.

1.6. Specify the nomenclature for Transmission interface Elements and Transmission interface Facilities when issuing an oral or written Operating Instruction.

R2. Each Balancing Authority, Reliability Coordinator, and Transmission Operator shall conduct initial training for each of its operating personnel responsible for the Real-time operation of the interconnected Bulk Electric System on the documented communications protocols developed in Requirement R1 prior to that individual operator issuing an Operating Instruction. [Violation Risk Factor: Low] [Time Horizon: Long-term Planning]

R3. Each Distribution Provider and Generator Operator shall conduct initial training for each of its operating personnel who can receive an oral two-party, person-to-person Operating Instruction prior to that individual operator receiving an oral two-party, person-to-person Operating Instruction to either: [Violation Risk Factor: Low] [Time Horizon: Long-term Planning]
   - Repeat, not necessarily verbatim, the Operating Instruction and receive confirmation from the issuer that the response was correct, or
   - Request that the issuer reissue the Operating Instruction.

R4. Each Balancing Authority, Reliability Coordinator, and Transmission Operator shall at least once every twelve (12) calendar months: [Violation Risk Factor: Medium] [Time Horizon: Operations Planning]

4.1. Assess adherence to the documented communications protocols in Requirement R1 by its operating personnel that issue and receive Operating Instructions, provide feedback to those operating personnel and take corrective action, as appropriate to address deviations from the documented protocols.

4.2. Assess the effectiveness of its documented communications protocols in Requirement R1 for its operating personnel that issue and receive Operating Instructions and modify its documented communication protocols, as necessary.
R5. Each Balancing Authority, Reliability Coordinator, and Transmission Operator that issues an oral two-party, person-to-person Operating Instruction during an Emergency, excluding written or oral single-party to multiple-party burst Operating Instructions, shall either: [Violation Risk Factor: High][Time Horizon: Real-time Operations]

- Confirm the receiver’s response if the repeated information is correct (in accordance with Requirement R6).
- Reissue the Operating Instruction if the repeated information is incorrect or if requested by the receiver, or
- Take an alternative action if a response is not received or if the Operating Instruction was not understood by the receiver.

R6. Each Balancing Authority, Distribution Provider, Generator Operator, and Transmission Operator that receives an oral two-party, person-to-person Operating Instruction during an Emergency, excluding written or oral single-party to multiple-party burst Operating Instructions, shall either: [Violation Risk Factor: High][Time Horizon: Real-time Operations]

- Repeat, not necessarily verbatim, the Operating Instruction and receive confirmation from the issuer that the response was correct, or
- Request that the issuer reissue the Operating Instruction.

R7. Each Balancing Authority, Reliability Coordinator, and Transmission Operator that issues a written or oral single-party to multiple-party burst Operating Instruction during an Emergency shall confirm or verify that the Operating Instruction was received by at least one receiver of the Operating Instruction. [Violation Risk Factor: High][Time Horizon: Real-time Operations]

C. Measures

M1. Each Balancing Authority, Reliability Coordinator, and Transmission Operator shall provide its documented communications protocols developed for Requirement R1.

M2. Each Balancing Authority, Reliability Coordinator, and Transmission Operator shall provide training records related to its documented communications protocols developed for Requirement R1 such as attendance logs, agendas, learning objectives, or course materials in fulfillment of Requirement R2.

M3. Each Distribution Provider and Generator Operator shall provide its initial training records for its operating personnel such as attendance logs, agendas, learning objectives, or course materials in fulfillment of Requirement R3.

M4. Each Balancing Authority, Reliability Coordinator, and Transmission Operator shall provide evidence of its assessments, including spreadsheets, logs or other evidence of feedback, findings of effectiveness and any changes made to its documented communications protocols developed for Requirement R1 in fulfillment of
Requirement R4. The entity shall provide evidence that it took appropriate corrective actions as part of its assessment for all instances where an operating personnel’s non-adherence to the protocols developed in Requirement R1 is the sole or partial cause of an Emergency and for all other instances where the entity determined that it was appropriate to take a corrective action to address deviations from the documented protocols developed in Requirement R1.

M5. Each Reliability Coordinator, Transmission Operator, and Balancing Authority that issued an oral two-party, person-to-person Operating Instruction during an Emergency, excluding oral single-party to multiple-party burst Operating Instructions, shall have evidence that the issuer either: 1) confirmed that the response from the recipient of the Operating Instruction was correct; 2) reissued the Operating Instruction if the repeated information was incorrect or if requested by the receiver; or 3) took an alternative action if a response was not received or if the Operating Instruction was not understood by the receiver. Such evidence may include, but is not limited to, dated and time-stamped voice recordings, or dated and time-stamped transcripts of voice recordings, or dated operator logs in fulfillment of Requirement R5.

M6. Each Balancing Authority, Distribution Provider, Generator Operator, and Transmission Operator that was the recipient of an oral two-party, person-to-person Operating Instruction during an Emergency, excluding oral single-party to multiple-party burst Operating Instructions, shall have evidence to show that the recipient either repeated, not necessarily verbatim, the Operating Instruction and received confirmation from the issuer that the response was correct, or requested that the issuer reissue the Operating Instruction in fulfillment of Requirement R6. Such evidence may include, but is not limited to, dated and time-stamped voice recordings dated operator logs, an attestation from the issuer of the Operating Instruction, voice recordings (if the entity has such recordings), memos or transcripts.

M7. Each Balancing Authority, Reliability Coordinator and Transmission Operator that issued a written or oral single or multiple-party burst Operating Instruction during an Emergency shall provide evidence that the Operating Instruction was received by at least one receiver. Such evidence may include, but is not limited to, dated and time-stamped voice recordings, dated operator logs, electronic records, voice recordings (if the entity has such recordings), memos or transcripts.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, “Compliance Enforcement Authority” means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Data Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to
provide other evidence to show that it was compliant for the full time period since the last audit.

Each Balancing Authority, Distribution Provider, Generator Operator, Reliability Coordinator, and Transmission Operator shall each keep data or evidence for each applicable Requirement for the current calendar year and one previous calendar year, with the exception of voice recordings which shall be retained for a minimum of 90 calendar days, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If a Balancing Authority, Distribution Provider, Generator Operator, Reliability Coordinator, or Transmission Operator is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

**Compliance Monitoring and Assessment Processes**

Compliance Audit  
Self-Certification  
Spot Checking  
Compliance Investigation  
Self-Reporting  
Complaint

**1.3. Additional Compliance Information**

None
### COM-002-4 Operating Personnel Communications Protocols

<table>
<thead>
<tr>
<th>R#</th>
<th>Time Horizon</th>
<th>VRF</th>
<th>Violation Severity Levels</th>
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<td></td>
<td></td>
<td><strong>Lower VSL</strong></td>
</tr>
<tr>
<td>R1</td>
<td>Long-term Planning</td>
<td>Low</td>
<td>The responsible entity did not specify the instances that require time identification when issuing an oral or written Operating Instruction and the format for that time identification, as required in Requirement R1, Part 1.5. \ OR \ The responsible entity did not specify the nomenclature for Transmission interface Elements and Transmission interface Facilities when issuing an oral or written Operating Instruction, as required in Requirement R1, Part 1.6.</td>
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<tr>
<td>R #</td>
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<td>VRF</td>
<td>Lower VSL</td>
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<tr>
<td>R2</td>
<td>Long-term Planning</td>
<td>Low</td>
<td>N/A</td>
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<td>Long-term Planning</td>
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</tr>
<tr>
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<td>Time Horizon</td>
<td>VRF</td>
<td>Violation Severity Levels</td>
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<td></td>
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<td><strong>Lower VSL</strong></td>
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<td>R4</td>
<td>Operations Planning</td>
<td>Medium</td>
<td>The responsible entity assessed adherence to the documented communications protocols in Requirements R1 by its operating personnel that issue and receive Operating Instructions, but did not provide feedback to those operating personnel and took corrective action, as appropriate</td>
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<td>The responsible entity assessed adherence to the documented communications protocols in Requirement R1 by its operating personnel that issue and receive Operating Instructions, but did not provide feedback to those operating personnel</td>
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<td></td>
<td></td>
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<td>The responsible entity assessed the effectiveness of its documented communications protocols in Requirement R1 for its operating personnel that issue and receive Operating Instructions and modified its documented communication</td>
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<td>The responsible entity did not assess adherence to the documented communications protocols in Requirements R1 by its operating personnel that issue and receive Operating Instructions</td>
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<tr>
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<td>The responsible entity did not assess the effectiveness of its documented communications protocols in Requirement R1 for its operating personnel that issue and receive Operating Instructions.</td>
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</table>

The responsible entity did not assess adherence to the documented communications protocols in Requirements R1 by its operating personnel that issue and receive Operating Instructions AND
The responsible entity did not assess the effectiveness of its documented communications protocols in Requirement R1 for its operating personnel that issue and receive Operating Instructions.
## COM-002-4 Operating Personnel Communications Protocols

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<th>Violation Severity Levels</th>
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<td></td>
<td><strong>Lower VSL</strong></td>
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<td></td>
<td></td>
<td>protocols, as necessary</td>
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<td></td>
<td>AND</td>
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<td></td>
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<td>The responsible entity exceeded twelve (12) calendar months between assessments.</td>
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*Draft 8 Page 12 of 15 January 2, 2014*
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<th>Moderate VSL</th>
<th>High VSL</th>
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</table>
| R5  | Real-time Operations | High | N/A | The responsible entity that issued an Operating Instruction during an Emergency did not take one of the following actions:  
• Confirmed the receiver’s response if the repeated information was correct (in accordance with Requirement R6).  
• Reissued the Operating Instruction if the repeated information was incorrect or if requested by the receiver.  
• Took an alternative action if a response was not received or if the Operating Instruction was not understood by the receiver. | N/A | The responsible entity that issued an Operating Instruction during an Emergency did not take one of the following actions:  
• Confirmed the receiver’s response if the repeated information was correct (in accordance with Requirement R6).  
• Reissued the Operating Instruction if the repeated information was incorrect or if requested by the receiver.  
• Took an alternative action if a response was not received or if the Operating Instruction was not understood by the receiver. AND  
Instability, uncontrolled separation, or cascading failures occurred as a result. |
<table>
<thead>
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<th>R #</th>
<th>Time Horizon</th>
<th>VRF</th>
<th>Violation Severity Levels</th>
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</thead>
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<td></td>
<td></td>
<td>Lower VSL</td>
</tr>
<tr>
<td>R6</td>
<td>Real-time Operations</td>
<td>High</td>
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</tr>
<tr>
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<tr>
<td>R7</td>
<td>Real-time Operations</td>
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E. Regional Variances

None

Version History

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<td>August 8, 2005</td>
<td>Removed “Proposed” from Effective Date</td>
<td>Errata</td>
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<td>1</td>
<td>February 7, 2006</td>
<td>Adopted by Board of Trustees</td>
<td>Added measures and compliance elements</td>
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<td>November 1, 2006</td>
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<td>Revised in accordance with SAR for Project 2006-06, Reliability Coordination (RC SDT). Retired R1, R1.1, M1, M2 and updated the compliance monitoring information. Replaced R2 with new R1, R2 and R3.</td>
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<td>Interpretation of R2 adopted by Board of Trustees</td>
<td>Project 2009-22</td>
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<td>3</td>
<td>November 7, 2012</td>
<td>Adopted by Board of Trustees</td>
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The North American Electric Reliability Corporation (NERC) is a not-for-profit international regulatory authority whose mission is to ensure the reliability of the Bulk-Power System (BPS) in North America. NERC develops and enforces Reliability Standards; annually assesses seasonal and long-term reliability; monitors the BPS through system awareness; and educates, trains, and certifies industry personnel. NERC’s area of responsibility spans the continental United States, Canada, and the northern portion of Baja California, Mexico. NERC is the electric reliability organization (ERO) for North America, subject to oversight by the Federal Energy Regulatory Commission (FERC) and governmental authorities in Canada. NERC’s jurisdiction includes users, owners, and operators of the BPS, which serves more than 334 million people.

The North American BPS is divided into several assessment areas within the eight Regional Entity (RE) boundaries, as shown in the map and corresponding table below.
Chapter 1 - Introduction

Assessments of the potential impacts associated with severe geomagnetic disturbances (GMD) do not fall within the typical study repertoire that planning engineers and system operators employ to ensure safe and reliable operation of the interconnected power system. However, many elements of a GMD study are common to standard system performance and planning studies. This guide does not describe the basic steps to carry a traditional system study, but rather highlights GMD-specific considerations as well as studies that may be outside the scope of traditional studies.

1.1 Organization

The Geomagnetic Disturbance Task Force has produced four documents to provide practical information and guidance in the assessment of the effects of GMD on the Bulk-Power System. While interrelated, these documents each serve a distinct purpose and can be followed on a standalone basis.

Geomagnetic Disturbance Planning Guide
This document provides guidance on how to carry out system assessment studies taking the effects of GMD into account. It describes the types of studies which should be performed, challenges in implementing each study type, and identifies the analytical tools and data resources required in each case.

Transformer Modeling Guide
This guide summarizes the transformer models that are available for GMD planning studies. These fall into two categories: magnetic models that describe transformer var absorption and harmonic generation caused by geomagnetically-induced currents (GIC) and thermal models that account for hot spot heating also caused by GIC. In the absence of detailed models or measurements carried out by transformer manufacturers, the guide summarizes “generic” values (and the inherent limitations thereof) for use in GMD studies.

Application Guide for Computing Geomagnetically-Induced Current (GIC) in the Bulk-Power System
This reference document explains the theoretical background behind calculating geomagnetically-induced currents (GIC). A summary of underlying assumptions and techniques used in modern GMD simulation tools as well as data considerations is provided.

Operating Procedure Template
This document provides guidance on the operating procedures that can be used in the management of a GMD event. The document supports the development of tailored operating procedures once studies have been conducted to assess the effects of GMD on the system.

1.2 Scope of the Planning Guide

This document provides guidance to planning engineers on how to incorporate and take into account the effects of GMD in system planning studies. It also describes the types of studies needed to achieve different objectives such as equipment impact assessment and performance assessment of protection and control systems during a severe GMD event. This guide is not intended to provide step-by-step instructions on how to carry out a planning study, nor does it describe tool-specific capabilities and requirements.
Chapter 2 – GMD Planning Study Overview

GMD planning studies are aimed at achieving a number of objectives which can be met by following the general procedure outlined below:

1. Assess the behavior of the system in terms of voltage limits, potential voltage collapse, and cascading outages during GMD events by taking into account transformer var absorption caused by half-cycle saturation. The system must perform within applicable limits under various contingencies – such as forced outage of a shunt capacitor bank or static var compensator (SVC).

2. Assess thermal impacts on equipment. Hot spot heating of transformers due to GIC during a GMD event is a primary concern since automatic protection systems are not likely to operate on this basis. Reference temperature limits used in the thermal assessment are the short term emergency thresholds suggested in IEEE Std. C57.91 18 [1].

3. Assess the performance of protection and control (P&C) systems in terms of security and dependability.

2.1 GMD Event Representation

As in any other type of system study, modeling requirements and tools depend on the objectives of the study. There are four basic types of GMD-related studies (and combinations thereof).

2.1.1 GIC Time Domain Simulations

GIC time domain studies use time series of the geoelectric field as input data to represent the GMD event. These studies are used to assess the dynamic impact of GIC on the interconnected power system and its equipment by taking into consideration the peak values, duration, orientation and “waveshape” of the geoelectric field.

A GIC time-domain simulation solves the dc representation of the network and produces GIC flows and transformer reactive power absorption or var loss due to transformer half-cycle saturation. There are two forms of input to a time-domain study: a) a pre-defined time sequence of the geoelectric field values scaled to a given peak magnitude (V/km), or b) variation of the magnetic field at ground level as a function of time. The geoelectric field is calculated using methods such as the plane wave method (see [2]) and used to compute the induced voltage in the transmission lines, which is the driving function for the dc solution of the network at a given point in time. The modeling of the earth impedance is critical in this calculation.

On output, a time-domain simulation produces time sequences of GIC and var loss for every transformer in the network. The GIC time series can be used as input to a transformer impact simulation tool that takes into account both the magnitude and variation of GIC over time. (The NERC GMDTF Transformer Modeling Guide [3], in development at the time this guide is being prepared, will provide additional guidance).

A time sequence of var loss snapshots and corresponding power flows can be used to illustrate the progression of a storm as a function of time, but more importantly, it can be used as input for an eigenvalue-based dynamic stability assessment.

A time-domain simulation engine can also be used in real time simulation tools for control center environments [4], but such tools are not commercially available at this point in time.

The characteristics of the time sequence or “waveshape” are very important in the assessment of the thermal impact in transformers. Transformer hot spot heating is not instantaneous. It has a time constant typically in
the order of minutes; therefore, it is heavily dependent on past history, rise time, magnitude and duration of GIC in the windings.

Transformer absorption of reactive power has a much smaller time constant than hot spot heating and can be viewed as quasi-instantaneous. It is, therefore, less dependent on past history and event duration, and more dependent on GIC magnitude. However, when the geoelectric field is calculated from magnetic field data (dB/dt), and the earth model is not laterally uniform, the frequency content of the dB/dt waveform can have a significant effect on the induced geoelectric field [5].

2.1.2 Steady-State Simulations
In steady-state studies and GIC simulations assume the magnitude and orientation of the geoelectric field to be constant. For this type of study, the GIC flow and transformer reactive power absorption calculated for the geoelectric field assumption is incorporated into the load flow model. Steady-state studies are used to determine worst-case scenarios for var reserves, voltage limits, contingencies, and the evaluation of mitigating measures for a given overall geoelectric field magnitude.

Steady-state simulations use the GIC calculation results from the solution of the dc network for an assumed time-invariant geoelectric field magnitude and orientation to determine the var loss to be used in a load flow simulation. From a system (as opposed to equipment) point of view, system studies follow traditional methods once the GIC-caused var loss has been included in the power flow system model. Studies to evaluate the effects of GIC on the system are listed below.

- **Voltage collapse.** Voltage collapse can occur when the reactive power absorption from saturating transformers is high enough to bring voltages below safe operating values – which may be further aggravated when coupled with other system contingencies such as the loss of reactive power support devices. Under such operating conditions voltage collapse can occur when the system does not have enough var resources to support current operating conditions or to recover from a valid contingency (e.g., a fault).

- **Operating limits.** Voltage and power transfer limits must be maintained for safe recovery in the case of contingencies such as line faults and major equipment trips (e.g., SVCs, generators, and shunt capacitor banks).

2.1.3 Transformer Impact Assessments
In this type of study the impact on the thermal behavior of a transformer is assessed using a number of criteria including time series GIC data. These studies are used to identify at-risk transformers for a given geoelectric field magnitude in order to develop mitigating measures. A detailed discussion is presented in Chapter 4.

2.1.4 Harmonic Studies
Harmonic studies are used to assess the impact of harmonics on protection and control (P&C) systems, generators, shunt capacitor banks, and complex power electronic systems (e.g. HVDC and SVCs). These studies can identify potential vulnerabilities in protective relaying and control settings, as well as relay types (IEDs vs. electromechanical). In a typical study into P&C effects, a maximum credible total harmonic distortion (THD) and individual harmonic levels are estimated from maximum GIC flows in the least favorable geoelectric field orientation and used as the design basis for P&C studies. The relationship between GIC and harmonics generated by transformer half-cycle saturation is described in the NERC Transformer Modeling Guide [3]. This information can also be used to conduct frequency domain analysis to determine the availability of the essential shunt capacitors for var support during severe GMD events. Further discussion is presented in Chapter 4.
2.2 Analysis Tools
As the industry has expressed the need for GMD studies, analysis tools have become available and their capabilities have improved as the overall understanding of the GMD effects on the power system have improved. Commercially-available and open-source tools include, but are not necessarily limited to, the following:

- PowerWorld
- PSS/E
- PSLF
- OpenGIC/OpenDSS

These tools solve the dc network for a set of steady-state geoelectric field assumptions, and determine transformer var losses to be included into the power flow model (typically connected to a transformer as a constant var source). The GMD event is defined in terms of the magnitude and orientation of induced geoelectric field. The fidelity in defining the geoelectric field, however, varies between analysis tools. All tools permit a single uniform magnitude and orientation for the entire system to be defined while some also permit the geoelectric field to be specified on a circuit-by-circuit basis. Additionally, the transformer var loss may be seamlessly integrated into the power flow solution or may require user interaction.

2.3 State-of-the-Art and Model Confidence
Models, methods, and tools for assessment of GMD impacts are continuing to be improved and advanced. A brief summary of current assessment tools is provided with cautionary statements regarding the validation and use of such tools and models.

- **Earth models.** The US Geological Survey has produced a catalog of uniformly-layered earth models for the continental US [6]. Metatech Corporation also produced several uniformly-layered earth models for the continental US, and the parameters for four of these models are provided in Meta R-321 [7]. These models have a significant impact on the calculated geoelectric field used to compute GIC in any given transmission network and should be selected using the most up to date information available. Direct validation of the earth models is not available at this point in time. Indirect model validation will require moderate GMD events and a significant GIC monitoring infrastructure.

- **Reactive power loss models.** These models are well understood for single-phase transformers, and to a large extent, for 5-limb and shell-form type three-phase transformers. However, there is uncertainty in models of three-leg core type designs. The NERC Transformer Modeling Guide [3] provides some guidance, but transformer testing is necessary to validate modeling assumptions.

- **Harmonic current injections.** As with the reactive power loss models for the fundamental frequency, harmonic currents can be reasonably derived for single-phase transformers, 5-limb, and shell-form type transformers. However, unlike fundamental frequency relationships to GIC, harmonic current injections are much more dependent on accuracy of the transformer parameters. Further guidance is provided in [3].

- **Transformer hot spot thermal models.** Transformer manufacturers are just beginning to create dynamic hot spot heating models which can be applied to system planning studies. The NERC Transformer Modeling Guide [3] provides some guidance, but transformer testing is necessary to validate manufacturer models.
• **dc network model.** The dc network consists of circuit resistances, transformer winding resistances, and station grounding resistances (see [2]). In principle, the model is straightforward, and has a high level of confidence so long as transmission line and transformer resistances are known. Resistance values derived from power flow models can contain considerable errors. Effective station grounding resistance (ground grid resistance including the effects of grounded shield wires and/or multi-grounded distribution neutrals) is a key parameter in the dc model. If not known from measurements or sophisticated simulation methods, it is very difficult to assign credible default values.

### 2.4 Initial Screening

The first step in a GMD planning study is to determine the level of detail and complexity needed. Utility planners should consider carrying out detailed (as opposed to screening) studies in cases where there has been history of system or equipment issues during moderate GMD events such as the March 13, 1989 and October 31, 2003 solar storms. Issues to examine are:

- Capacitor bank tripping,
- Tripping of FACTS devices such as SVC and HVDC,
- Voltage dips/fluctuations of 1% or more that are clearly attributable to the GMD event,
- Generator tripping, and
- Unexpected post-event accumulation of dissolved gasses in transformers.

If the examination of historical event logs does not indicate any of the above issues, power flow analysis that takes into account the effects of GIC (i.e., transformer var absorption) should be used to determine whether more detailed studies are warranted. Systems with operating voltages at or below 200 kV, and without past issues, may not require additional detailed studies to be performed given the minimal GIC expected on this portion of the interconnected power system [8]. A procedure for performing an initial screening analysis is as follows:

1. Determine the design-basis geoelectric field peak magnitude (V/km) for the appropriate geographical area of the system. Guidance in this determination can be obtained from the NERC GIC Application Guide [2].

2. Compute GIC flows using a dc model of the system. Estimate transformer var loss to be used in power flow.

3. Perform power flow analysis using system load levels and stressed system conditions using generic models for transformer reactive power absorption. Loss of reactive power sources such as shunt capacitor banks and SVCs (on protection) should be considered as valid contingencies associated with the GMD event. A conservative approach is to assume that all transformers are single-phase; however, in some cases this approach will be overly conservative. If voltage fluctuations do not exceed 3% and operational limits are met, then more detailed power flow studies are probably not necessary.

4. Verify that the thermal impact on transformers is below applicable thresholds as described in Chapter 4.

If the power flow simulations show voltage fluctuations above 3% under normal criteria contingencies or if thermal limits associated with generic transformer capability curves are approached, then it is necessary to carry out more detailed studies as further described in Chapters 3 and 4. Note that the 3% voltage fluctuation screening criteria provides margin to account for the quality of input data obtained from load flow models. It is not an operational parameter.
In the case of a GMD event, system impact studies are very similar to standard system planning or outage management studies. The main differences are:

- Reactive power absorption in transformers must be modeled to ascertain if voltage limits are met.
- System interconnections must be taken into consideration with more detail to account for reactive power losses in neighboring networks. Reasonable approximations can be obtained by modeling two or more key buses into the neighboring network.
- There are additional contingencies to be considered when performing equipment impact considerations.

The guidelines presented here are not intended to provide direction to the planning engineer on how to carry out system studies, but rather to provide awareness on what additional considerations should be taken into account to plan for a GMD event.

### 3.1 Reliability Criteria

The scientific understanding of credible storms and their impact on the interconnected power system is evolving. Consequently, several schools of thought exist for determining the design-basis event on which to base impact assessment:

1. The interconnected power system should withstand the most severe event based on both a) frequency of occurrence – and b) local geographical and geological features. Unfortunately, statistical extrapolations must be performed using limited data; thus, the error bars can be quite large for low probability events. The most widely mentioned frequency of occurrence is 1 in 100 years; however, the resulting storm severity can vary significantly depending on model data and assumptions. Studies that predict such severe impact on the system have not been duplicated independently.

2. The system will be designed and operated to withstand the most severe event (for given geomagnetic latitude and earth resistivity characteristics) as determined on the basis of a balance between costs and impact. Since the system and equipment impact is localized, a severe GMD would cause little if any permanent equipment damage with a managed load and generation rejection approach.

3. Do not assume that there is a fixed design basis event. Increase the geoelectric field intensity until reactive power losses force substantial load and generation rejection. Use this value with the appropriate margin as the maximum GMD event to assess transformer impact.

For the purposes of this guide, it will be assumed that the system planner has determined a design basis value that it takes into account geography, geomagnetic latitude and earth resistivity as further described in the NERC GMDTF GIC Application Guide [2].

### 3.2 System Model

The dc equivalent system model is thoroughly discussed in the NERC GIC Application Guide [2]. Some of the high level considerations are:

- Modeling only those portions of the network which are 230 kV and above has been suggested [11]. In some systems it may be appropriate to model the network below 230 kV. Which voltage levels to include in the model depends on the types of connections and location of the transformer stations. A more complete discussion of the rationale behind the selection of the minimum voltage level for a GMD study can be found in [8]

- The extent to which the ac system is modeled should be consistent with existing practices. If interconnections are represented in the model by equivalent networks, then sensitivity studies should be carried out to validate the equivalent representation. These sensitivity studies should be based on an
explicit model which includes at least two key buses into the neighboring system. A delta-connected load station would not be considered a key bus, whereas a generation station or a station with autotransformers would be considered a key station. A more detailed discussion of the accuracy of different approaches to define equivalent networks is found in [2].

- The dc network model should be consistent in size and scope with the ac model with the following exceptions.
  - The dc model does not include shunt capacitor banks.
  - The dc model does not need to include stations with ungrounded transformers. Ungrounded or surge arrester-grounded transformers could be represented as a high resistance branch, but this can lead to numerical instability of the model [2].
  - Equivalent circuits in the ac model are generally not directly translatable into dc equivalents. Guidance on dc network equivalent circuits is provided in the NERC GIC Application Guide [2].
  - Interconnections to lower kV portions of the system, not explicitly represented in the dc network, may need to be represented by an equivalent model.

Guidance on modeling transformer var losses as a function of GIC flows within power flow models is provided in [3].

### 3.3 System Impact Assessment Studies

For a given geoelectric field magnitude and direction, determine GIC flows and associated transformer var loss. From this point determine if voltage criteria and operating limits are met using power flow analysis that takes into account the GIC-caused var losses. Standard methodology to assess operating limits and contingencies should be used.

Points to consider when performing system impact studies are provided below.

- Several general orientations of the geoelectric field should be considered. The number of orientations to consider should be determined on a system basis; however, dividing the number of potential geoelectric field orientations into 30° increments has been successfully used [4].

- The assumption that the East-West geoelectric field orientation is the worst case is not justifiable from the point of view of var loss because its effects are quasi-instantaneous, and the orientation of the geoelectric field changes continuously during a GMD event.

- Reactive power margins (see [8] and [10]) can be identified in different parts of the system for different geoelectric field orientations [11].
  - A single geoelectric field orientation is unlikely to be the worst case for all zones. Thus, the geoelectric field orientation which results in the largest increase to total system reactive power losses in the system is not a sufficient indicator of the worst case.
  - A conservative approach is to divide the system in zones on the basis of var margins, and assume var margins for the worst geoelectric field orientation for each zone.

- The GIC flows must be determined for each change in system configuration, whether due to contingencies or potential mitigation strategy, during the course of the evaluations.

- Loss of reactive power sources such as shunt capacitor banks and SVCs (on protection) should be considered as valid contingencies.
Chapter 4 – Equipment Impact Assessment

A significant concern regarding the effects of a GMD event is the possibility of damage of major equipment – especially damage to costly and long replacement lead time equipment such as generators, SVCs, and HV/EHV transformers. From a technical point of view, each type of equipment needs different considerations on the basis of impact and whether or not existing automatic protection is sufficient to prevent long term effects.

4.1 Transformer Thermal Impact Screening Process

The effects of half-cycle saturation on HV and EHV transformers, namely localized “hot spot” heating, are relatively well understood qualitatively, but rather difficult to quantify. A transformer GMD impact assessment requires thresholds that must take into consideration GIC magnitude and duration, as well as transformer physical characteristics such as design and condition (age, gas content, and moisture in the oil). A simple threshold on the basis of GIC current alone cannot take into account such factors and would be difficult to justify as a screening threshold. The NERC GMDTF phase 1 report [12] provides the following guidance in this respect:

- Use the temperature limits for safe transformer operation suggested in the IEEE Std. C57.91 standard for hot spot overheating during short-term emergency operation. The standard does not suggest that exceeding these limits will result in transformer failure, but rather undue aging of cellulose in the paper-oil insulation, and the potential for the generation of gas bubbles in the bulk oil. Thus, from the point of view of potential transformer damage, these thresholds can be considered conservative.

- To be consistent with IEEE Std. C57.91 suggested limits, the worst case temperature rise for winding and metallic part (e.g., tie plate) heating should be estimated taking into consideration the construction characteristics of the transformer as they pertain to dc flux offset in the core (e.g., single-phase, shell, 5 and 3-leg three-phase construction).

- Take into consideration temperature increases due to ambient temperature and transformer loading. For planning purposes, maximum ambient temperature and loading temperature to a full heat run should be used.

- Take into consideration the “waveshape” of the reference GMD event in terms of peak magnitude, duration and frequency of the geoelectric field, and the fact that winding and metallic part hot spot heating have different thermal time constants with respect to GIC. In other words, the hot spot temperature rise will be different if the GIC currents are sustained for 2 or 10 minutes at a given GIC peak magnitude.

- Take into consideration the “effective” current in transformers and in autotransformers, reflecting the different GIC ampere-turns in the common and the series windings (see [2]). The effective current is expressed on a "per phase" basis and can be very different from the neutral currents obtained from GIC neutral measurement devices.

There are three different ways to carry out a thermal impact screening:

1. **Transformer manufacturer GIC capability curves.** These curves relate permissible peak GIC (obtained by the user from a steady state calculation) and loading for a specific transformer; example manufacture capability curves are plotted in Figure 1. Presentation details vary between manufacturers and limited information is provided concerning the assumptions used to generate these curves; in particular, the assumed waveshape or duration of the effective GIC. Some manufacturers assume that the “waveshape” of the GIC in the transformer windings is a square pulse of 2, 10, or 30 minutes in duration. While they are simple to use, manufacturers maintain that in the near term, such capability curves have to be developed for every transformer design and vintage in the absence of transformer standards defining thermal duty due to GIC.
2. **Generic GIC capability curves**, such as the ones in the NERC Transformer Modeling Guide [3]. These curves assumed a pre-defined GIC waveshape (e.g. the GMDTF reference storm or the March 1989 storm) and the hot spot temperatures are estimated with thermal transfer functions [14]. The hot spot thermal transfer functions used are based on what is believed to be conservative measurements and assumptions. The effect of transformer construction is taken into consideration using the generic magnetic models produced by the NERC GMD Task Force phase 2 project. Thresholds are based on IEEE Std. C57.91 emergency loading hot spot limits. At this point in time, limited comparisons with manufacturer’s GIC capability curves are available. Initial comparisons with a limited number of transformers suggest that the generic capability curves are conservative, meaning, a lower peak GIC causes higher hot spot heating (see Fig. 2).
3. **Thermal response simulation.** Details of this implementation can be found in [14]; however, the input is the effective time series GIC flowing through a transformer (taking into account the actual configuration of the system) and the output is the hot spot temperature time sequence for each transformer [3]. Example GIC input and hotspot temperature time series values are shown in Figure 2. The hot spot thermal transfer functions can be obtained from measurements or calculations provided by transformer manufacturers or defaults, such as the ones shown in the NERC Transformer Modeling Guide, can be used instead. Hot spot temperature thresholds are based on IEEE Std. C57.91 emergency loading hot spot limits.

![Sample tie plate temperature calculation](image)

**Fig. 2:** Sample tie plate temperature calculation. Blue trace is incremental temperature and red trace is the magnitude of the GIC/phase [14].
It is important to reiterate that the characteristics of the time sequence or “waveshape” are very important in the assessment of the thermal impact in transformers. Transformer hot spot heating is not instantaneous. The thermal time constant of transformer windings and metallic parts is typically of the order of minutes; therefore, hot spot temperatures are heavily dependent on loading, history, rise time, magnitude and duration of GIC in the windings.

4.2 Generator, Capacitor Bank, SVC, and Protective Relaying Impacts
System harmonic analyses are necessary to investigate harmonic-related system impacts of GMD. Low-order harmonic current injections can travel considerable distances through the transmission system. Thus, at any location in the system the harmonic currents and voltages may represent the aggregated contribution of multiple GIC-saturated transformers. As such, harmonic withstand capabilities of any given system component should not be solely evaluated against the harmonic injections of a particular transformer (e.g. the harmonic currents flowing into a generator are not solely due to saturation of the GSU transformer). Harmonic injection models are provided in the NERC Transformer Modeling Guide [3].

SVCs may trip if excessive harmonic current and voltage distortion cause intentional protective relay operation, excessive interactions with the SVC control system, or due to protection misoperation (false tripping) due to vulnerabilities of the protection system.

If the protective relaying of a shunt capacitor bank is such that it cannot detect harmonic overcurrents (e.g. microprocessor based relaying schemes as explained in the NERC GMDTF phase 1 report) it may be prudent to carry out simulations to have a sense of the GIC level for which a specific shunt capacitor bank may trip or fail. System resonant behavior plays a large role in establishing capacitor bank harmonic current duty. Resonances are often related to specific system conditions, so it may be necessary to study a large range of possible system configurations, including a wide range of permutations of capacitor bank status, in order to identify worst-case harmonic current stress.

Harmonic currents flowing into a generator cause a magnetic field that rotates relative to the generator’s rotor. The oscillating magnetic field, as seen by the rotor, causes additional heating of the rotor. This is similar to the effect of negative-sequence fundamental currents on generators, except that harmonic currents do not need to be negative sequence to cause this heating. Ideally, generator protection would remove the unit from service before damage could result [15]. However, according to [16], protective relaying may not act before there is undue over-heating caused by harmonics. Most modern generator protection relays specifically ignore non-fundamental current components.

4.3 Harmonic Impact Studies
The industry has limited availability of appropriate software tools to perform the harmonic analysis. General purpose electromagnetic transients programs can be used, via their frequency domain initial conditions solution capability. However, building network models that provide reasonable representation of harmonic characteristics, particularly damping, across a broad frequency range requires considerable modeling effort and expert knowledge. Use of simplistic models would result in highly unpredictable results.

There are a few dedicated harmonic analysis programs available to the industry, which perform their analysis in the frequency domain and apply reasonable rules for defining frequency-dependent characteristics of system components. Some of these are limited to a single harmonic source, thus requiring the user to perform superposition of the phasor harmonic components externally. Others model only line-mode propagation characteristics, and are not configured to model ground mode behavior.
The desired modeling tool should have the following characteristics:

- Model multiple harmonic current sources with defined phase angles and magnitudes.
- Perform analysis for both line and ground modes. Alternatively, should perform phase domain analysis.
- Provide appropriate frequency-dependent representation of system component impedances. The ideal tool should be able to take input data from common fundamental-frequency databases, and convert to proper frequency-dependent representation using rules in the absence of better data, with a minimum of user intervention.
- Provide voltage and currents for any bus or branch in the system for the superimposed injections, with results shown in phase and sequence component form for individual harmonics, and resolved into the time domain to provide the peak voltage for the superposition of harmonic components.

Harmonic analysis results can be compared to the withstand capabilities of various equipment to determine if tripping, failure to trip when appropriate, or material damage is a possibility. Unfortunately, this tolerance level is poorly defined for most equipment, with the possible exception of capacitors. IEEE Standard 18 provides ample information on the withstand limit of capacitor units [17]. However, the sensitivity of capacitor bank protection systems is not as well defined. Harmonic impact on generators is dependent on the sequence component of the harmonic current flowing into the generator, as the harmonics need to be resolved into the rotor reference frame to determine the equivalent rotor frequency and the resulting rotor heating potential.
Chapter 5 - Evaluation of Mitigation Measures and GIC Monitoring

Depending on the modeled effects in the system, mitigating measures can take one of the following forms:

- Reassignment of var resources,
- System reconfiguration, normally by bringing key circuits in and out of service,
- Load rejection,
- Using GIC reduction devices (GRDs) on SVC transformers to ensure they can provide reactive support during any event, and
- Using GIC reduction devices to maintain transformer currents below an arbitrary threshold (independent of GIC "waveshape") or to ensure that key transformers remain in service during any event.

It should be noted that a GRD on a GSU (Generator Step Up) transformer would not prevent a generator from tripping on unbalance or negative sequence protection. Usage of GRDs should always be conditional to the results of system suitability studies (protection impact and failure modes) as well as functional requirements including those provided in [12]. Additionally, the application of GRDs must consider the failure of a GRD as a valid contingency.

The studies required for the evaluation of mitigation measures are essentially the same ones used to assess impact. The only difference is that mitigation measures introduce system configuration changes which must be evaluated with the same guidelines described in Chapters 3 and 4.

5.1 Integration of Equipment Impact and System Impact Studies

System impact studies are aimed at maintaining the safe and reliable operation of the power system; whereas, equipment impact studies are aimed at maintaining the integrity of major assets. As mitigating measures introduce system configuration changes that affect both, an iterative process is required. The integration of system and equipment impact studies can be approached either in a top-down or bottom-up fashion.

The top-down approach includes the following procedural steps:

1. Carry out system impact studies assuming the maximum design-basis geoelectric field.
2. Evaluate mitigating measures (if any) to maintain limits.
3. Carry out equipment impact assessment using the ultimate system configuration, including contingencies. If equipment considerations require additional mitigating measures that entail system reconfiguration, repeat the system studies and iterate.

The procedures comprising the bottom-up approach are:

1. Carry out system impact studies increasing the geoelectric field up to the point where mitigation measures to maintain limits are necessary. Define this as the threshold configuration and GIC level.
2. Carry out equipment impact assessment using the threshold configuration, including contingencies. If equipment considerations require mitigating measures, reduce the magnitude of the geoelectric field to the point where there are no equipment issues.
3. If the threshold scenario is lower than the design basis scenario, increase the geoelectric field to defined staged mitigating measures iterating between system and equipment impact studies.
The advantage of the bottom-up approach is that it results in staged mitigating measures. This would be consistent with a strategy that combines operating measures with other mitigation strategies, such as system re-configuration and possibly a limited number of GRDs. The advantage of the top-down approach is that the system is expected to withstand the design basis event without having to worry about intermediate mitigating actions.
References


[7] Metatech R-321 The Late-Time (E3) High-Altitude Electromagnetic Pulse (HEMP) and Its Impact on the U.S. Power Grid


### Appendix I - NERC GMD Task Force Leadership Roster

<table>
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Application Guide

Computing Geomagnetically-Induced Current in the Bulk-Power System

December 2013
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Preface

The North American Electric Reliability Corporation (NERC) is a not-for-profit international regulatory authority whose mission is to ensure the reliability of the Bulk-Power System (BPS) in North America. NERC develops and enforces Reliability Standards; annually assesses seasonal and long-term reliability; monitors the BPS through system awareness; and educates, trains, and certifies industry personnel. NERC’s area of responsibility spans the continental United States, Canada, and the northern portion of Baja California, Mexico. NERC is the electric reliability organization (ERO) for North America, subject to oversight by the Federal Energy Regulatory Commission (FERC) and governmental authorities in Canada. NERC’s jurisdiction includes users, owners, and operators of the BPS, which serves more than 334 million people.

The North American BPS is divided into several assessment areas within the eight Regional Entity (RE) boundaries, as shown in the map and corresponding table below.
Introduction

During geomagnetic disturbances, variations in the geomagnetic field induce quasi-dc voltages in the network which drive geomagnetically-induced currents (GIC) along transmission lines and through transformer windings to ground wherever there is a path for them to flow. The flow of these quasi-dc currents in transformer windings causes half-cycle saturation of transformer cores which leads to increased transformer hotspot heating, harmonic generation, and reactive power absorption – each of which can affect system reliability. As part of the assessment of geomagnetic disturbances (GMDs) impacts on the Bulk-Power System, it is necessary to model the GIC produced by different levels of geomagnetic activity. This guide presents theory and practical details for GIC modeling which can be used to explain the inner workings of commercially-available GIC modeling software packages or for setting up a GIC calculation procedure.

Organization
The Geomagnetic Disturbance Task Force has produced four documents to provide practical information and guidance in the assessment of the effects of GMD on the Bulk-Power System. While interrelated, these documents each serve a distinct purpose and can be followed on a standalone basis.

Geomagnetic Disturbance Planning Guide
This document provides guidance on how to carry out system assessment studies taking the effects of GMD into account. It describes the types of studies which should be performed, challenges in implementing each study type, and identifies the analytical tools and data resources required in each case.

Transformer Modeling Guide
This guide summarizes the transformer models that are available for GMD planning studies. These fall into two categories: magnetic models that describe transformer var absorption and harmonic generation caused by GIC and thermal models that account for hot spot heating also caused by GIC. In the absence of detailed models or measurements carried out by transformer manufacturers, the guide summarizes “generic” values (and the inherent limitations thereof) for use in GMD studies.

Application Guide for Computing Geomagnetically-Induced Current (GIC) in the Bulk-Power System
This reference document explains the theoretical background behind calculating geomagnetically-induced currents (GIC). A summary of underlying assumptions and techniques used in modern GMD simulation tools as well as data considerations is provided.

Operating Procedure Template
This document provides guidance on the operating procedures that can be used in the management of a GMD event. The document supports the development of tailored operating procedures once studies have been conducted to assess the effects of GMD on the system.
Overview

An example of the geomagnetic field induction process in a simplified network is depicted in Figure 1.

**Figure 1: GIC flow in a simplified power system.**

GIC are considered quasi-dc relative to the power system frequency because of their low frequency (0.0001Hz to 1 Hz); thus, from a power system modeling perspective GIC can be considered as dc. The flow of these quasi-dc currents in transformer windings causes half-cycle saturation of transformer cores which leads to increased transformer hotspot heating, harmonic generation, and reactive power absorption – each of which can affect system reliability. As part of the assessment of geomagnetic disturbances (GMDs) impacts on bulk power systems, it is necessary to model the GIC produced by different levels of geomagnetic activity.

The process for computing GIC in a bulk power system comprises two steps (see Figure 2). First, the geoelectric field must be estimated or directly determined from available geomagnetic data and earth conductivity models. When performing steady-state GIC calculations, the geoelectric field can be estimated from general tables which take into account both geomagnetic latitude and earth conductivity. Secondly, GIC flows are computed using circuit analysis techniques with a dc model of the bulk power system. Once the GIC flows are determined they are used as input data to other system studies such as power flow analysis and thermal analysis of transformers.
The following sections present the theory and practical details for the electric field calculations and the GIC modeling. Modeling refinements to source fields and earth conductivity structures are discussed in later sections.

Several open source and commercially available modeling software packages have included many of the GIC calculations procedures described herein. Therefore, this guide can be used as an explanation of the internal working of these software packages or as guidance for setting up a calculation procedure.
Chapter 1 – Geoelectric Field Calculations

GIC modeling uses geoelectric field values as input. When examining the GIC flow patterns across a network, it can be useful to perform steady state GIC calculations based on an assumed magnitude and direction of the geoelectric field. This approach is explained in the next section. However, determination of the GIC which occur over time during an actual geomagnetic disturbance requires the calculation of a time series geoelectric fields produced in response the geomagnetic field variations. The theory and procedures for performing these calculations are the topics of this section.

The geomagnetic field variations experienced by power systems at the earth’s surface originate from electric currents flowing in the ionosphere or magnetosphere at heights of 100 km or greater. Compared to the heights of these source currents, the height of the transmission lines is insignificant and the electric field at the height of the transmission line can be assumed to be the same as the electric field at the earth’s surface.

The magnetic field variations induce electric currents in the earth which also produce magnetic fields that contribute to the magnetic disturbances observed at the earth’s surface. Inside the earth, the induced currents act to cancel external magnetic field variations leading to a decrease of the currents and fields with depth. At low frequencies, the skin depth $\delta$ is characterized by

$$\delta = \sqrt{\frac{2}{\omega \mu \sigma}}$$

and is dependent upon: the angular frequency, $\omega$, in radians; the conductivity, $\sigma$, in S/m; and the free space value for the magnetic permeability $\mu_0 = 4\pi \times 10^{-7}$ H/m [1].

Given the range of frequencies relevant to GIC (0.0001Hz to 1 Hz) and the conductivity values within the earth, magnetic field variations can penetrate hundreds of kilometers below the surface. Thus, the conductivity down through the earth's crust and into the mantle must be taken into account when determining the electric field at the surface. Additionally, the geoelectric field calculations must take into account the frequency-dependent behavior of the earth response. One method of accounting for frequency dependence is to decompose the magnetic field variations into their frequency components, calculate the earth response (surface impedance) at each frequency, and then combine these frequency components to give the electric field variation with time.
Theory

The relationship between the geomagnetic field, earth surface impedance and the geoelectric field is described in (2) and (3)

\[ E_x(\omega) = Z(\omega)H_x(\omega) \]  
\[ E_y(\omega) = -Z(\omega)H_y(\omega) \]

where \( E_x(\omega) \) is the Northward geoelectric field (V/m), \( E_y(\omega) \) is the Eastward geoelectric field (V/m), \( H_x(\omega) \) is the Northward geomagnetic field intensity (A/m), \( H_y(\omega) \) is the Eastward geomagnetic field intensity (A/m), and \( Z(\omega) \) is the earth surface impedance (\( \Omega \)).

The relationship between the geomagnetic field intensity, \( H(\omega) \), and the geomagnetic field density, \( B(\omega) \), is given by,

\[ B(\omega) = -\mu_0 H(\omega) \]

where, \( \mu_0 \) is the magnetic permeability of free space.

The surface impedance, \( Z(\omega) \), depends on the earth conductivity structure below the power system. The variation of conductivity with depth can be represented using a 1-D layered, laterally uniform earth model as depicted in Figure 3. A one-dimensional, or 1-D, model ignores lateral variations in conductivity but provides a reasonable approximation in many situations. However, near a conductivity boundary such as a coastline, a 2-D or 3-D earth model may provide more accurate results. 2-D and 3-D modeling considerations are discussed in later chapters.

![Figure 3: 1-D layered earth conductivity model](image)

The impedance at the surface of the earth can be calculated using recursive relations in a manner analogous to transmission line theory. Each layer is characterized by its propagation constant

\[ k_n = \sqrt{j\omega\mu_0\sigma_n} \]
where, $\omega$ is the angular frequency (rad/sec), $\mu_0$ is the magnetic permeability of free space, $\sigma_n$ is the conductivity of layer $n$ ($\Omega^{-1}m^{-1}$), and $r_n$ is the thickness of layer $n$ (m).

For the bottom layer where there are no reflections, the impedance at the surface is

$$Z_n = \frac{j\omega\mu_0}{k_n}$$  \hspace{1cm} (6)

Equation 7 is used to calculate the reflection coefficient seen by the layer above

$$r_n = \frac{1-k_n}{1+k_n} \left( \frac{Z_{n+1}}{j\omega\mu_0} \right)$$  \hspace{1cm} (7)

which can then be used to calculate the impedance at the top surface of that layer

$$Z_n = j\omega\mu_0 \left( \frac{1-r_n}{k_n} \left( 1 + r_n e^{-2k_n d_n} \right) \right)$$  \hspace{1cm} (8)

These steps are then repeated for each layer up to the earth's surface [3].

The propagation constants and corresponding impedances are functions of frequency, thus, the sequence of calculations has to be repeated at each frequency. The exact frequencies needed to calculate the electric fields depend on the sampling rate of the magnetic data and the duration of the data used. The final set of surface impedance values represent the transfer function of the earth relating the electric and magnetic fields which will be used in the calculations of the geoelectric fields.

Frequency domain techniques are commonly employed to compute the geoelectric field. The sequence of operations for calculating geoelectric fields in this manner is shown in Figure 4. Starting with a time series of magnetic field values, i.e. $B(t)$, a Fast Fourier Transform (FFT) is used to obtain the frequency spectrum (magnitude and phase) of the magnetic field variations, $B(\omega)$. The magnetic field spectral value at each frequency is then multiplied by the corresponding surface impedance value (and divided by $\mu_0$) to obtain the geoelectric field spectral value, $E(\omega)$. This then gives the frequency spectrum of the geoelectric field. An inverse Fast Fourier Transform (IFFT) is then used to obtain the geoelectric field values in the time domain, $E(t)$.

**Figure 4: Using magnetic data to calculate geoelectric fields.**

Time domain methods, such as the one presented in [4] and [5], can also be used to compute the geoelectric field as the two methods are numerically equivalent.
Practical Details

Using the previously described 1-D modeling technique to represent the frequency-dependent behavior of the earth requires suitable values for the thicknesses and conductivities of the various layers. Skin depths, at the frequencies of concern in GIC studies, are kilometers or greater so only the average conductivities over depths on these scales need to be considered. Magnetic field variations pass through thin surface layers unaffected; therefore, the conductivities of surface soil layers are unimportant. Consequently, 'earth resistivity' values commonly used in fundamental frequency calculations (i.e., 60Hz) are not appropriate for GIC studies. Instead earth models have to be specially constructed.

The conductivity of surface layers of the earth depends on the rock type: ranging from very resistive igneous rocks to more conductive sedimentary rocks. Below the surface layers, the earth consists of the crust, which is resistive, and below the crust is the mantle where increased pressures and temperatures lead to higher conductivities, as illustrated in Figure 5.

![Figure 5: Schematic of the internal structure of the Earth](image-url)

- Crust 0-100 km thick
- Lithosphere (crust and upper-most solid mantle)
- Asthenosphere
- Mantle
- Outer core
- Inner core
- Solid
- Liquid
- Core
- Not to scale

To scale
For a specific region, an earth conductivity model can be assembled from the results of magnetotelluric studies and geological information. Such earth conductivity models for various physiographic regions of North America are available from the United States Geological Survey (USGS - http://geomag.usgs.gov/conductivity) and the Geological Survey of Canada (GSC). Model locations and physiographic regions for the United States are shown in Figure 6. It is important to note that these models are preliminary and are expected to change with further assessments and validation. As such, caution is required when selecting and applying these models.

Figure 6: Location of 1-D earth resistivity models with respect to physiographic regions of the contiguous United States [6].
Example Calculation

Preliminary earth conductivity models for IP-4 and PT-1 regions, provided by USGS, are shown in Figure 7 and Figure 8 respectively.

Figure 7: IP-4 (Great Plains) 1-D Earth conductivity model [6]

Figure 8: PT-1 (Piedmont) 1-D Earth conductivity model [6]

Resistivity values and depths have been interpreted from published geological reports and maps, and may differ from actual conditions measured by a geophysical survey and/or borehole.
The surface impedance for each of these models is shown in Figure 9 and was calculated using equations (5) to (8). The frequency response data provided in Figure 9 demonstrate the differences that can exist between various physiographic regions, and that these differences are frequency dependent.

**Figure 9: Frequency response of two layered Earth conductivity models.**

The frequency response (magnitude and phase) of the earth surface impedance can then be used with either measured or synthetic geomagnetic field data to calculate the induced geoelectric field. Example calculations made using the magnetic field data for March 13-14, 1989 are provided here. Data collected by magnetic observatories in the US are available from the USGS [http://geomag.usgs.gov/](http://geomag.usgs.gov/) and Canadian observatories from the GSC [http://www.nrcan.gc.ca/geomag](http://www.nrcan.gc.ca/geomag) or through the INTERMAGNET web site [http://www.intermagnet.org/](http://www.intermagnet.org/).

A Fast Fourier Transform (FFT) of the magnetic data from the Ottawa Magnetic Observatory gives the magnetic field spectrum shown in Figure 10a [7]. These spectral values are multiplied by the surface impedance values (see Figure 10b) which results in the geoelectric field spectrum shown in Figure 10c. An inverse Fast Fourier Transform (IFFT) of this spectrum then gives the geoelectric field values in the time domain. These calculations are made using the eastward component of the geomagnetic field to determine the northward component of the geoelectric field (see (2)) and using the northward component of the magnetic field to give the eastward component of the geoelectric field (see (3)). The original geomagnetic field data and calculated geoelectric fields in the time domain are shown in Figure 11. The time series values of $E_x$ and $E_y$ can be used as inputs in subsequent GIC modeling and analysis.
Figure 10: Frequency domain parameters in geoelectric field calculations [7].
a) Geomagnetic field spectrum, b) Surface impedance, and c) Geoelectric field spectrum

Figure 11: Recordings from the Ottawa Magnetic Observatory and calculated geoelectric field for March 13-14, 1989 [7].

In some situations, an extreme case (i.e., a 1-in-100 year) storm may be denoted by the estimated maximum geoelectric field magnitude. Depending upon the analysis being performed, this magnitude may be applied directly or used to scale historical measurement data.

Statistical analysis of geoelectric fields, calculated using geomagnetic field data from IMAGE stations located in Northern Europe, was applied in [8] to determine the range of geomagnetic storm intensities that might be expected to occur once in a 100 year period. This analysis indicates a 100-year peak geoelectric field of 5 V/km and 20 V/km for high and low conductive regions, respectively. These geoelectric field values were projected for
high latitude regions only, and considerable research continues to explore potential geomagnetic storm intensities for North America. However, an important outcome from the research presented in [8] is the effect of geomagnetic latitude on the resulting geoelectric fields. Research findings indicated that the geoelectric field magnitudes may experience a dramatic drop across a boundary located at about 40-60 degrees of geomagnetic latitude.

The geomagnetic latitude for North America is shown in Figure 12. As shown, the inhabited regions of the U.S. and Canada span approximately 35 degrees of geomagnetic latitude (35 degrees to 70 degrees). Research by Pulkkinen, et al, indicates that the geoelectric field is highly dependent on the geomagnetic latitude [8] as indicated by the maximum geoelectric field magnitudes estimated assuming low earth conductivity, for two historical storms and plotted in Figure 13.
Figure 13: Geomagnetic latitude distributions of the maximum computed geoelectric field

Relative scaling or correction factors that account for the influence of geomagnetic latitude on the estimated geoelectric field magnitude can be determined from the data presented in Figure 13, or using data from other events and earth conductivities. As shown in Figure 13, the estimated geoelectric field consistently portrays an order of magnitude and exponential drop between 40 and 60 degrees for both storms and in both hemispheres. A set of scaling factors which capture these observations is provided in Table 1.

Table 1: Scaling Factors for 1-in-100 Year Storm

<table>
<thead>
<tr>
<th>Geomagnetic Latitude (Degrees)</th>
<th>Scaling Factor (α)</th>
</tr>
</thead>
<tbody>
<tr>
<td>≤ 40</td>
<td>0.100</td>
</tr>
<tr>
<td>41</td>
<td>0.112</td>
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<tr>
<td>42</td>
<td>0.126</td>
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<tr>
<td>57</td>
<td>0.708</td>
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<tr>
<td>58</td>
<td>0.794</td>
</tr>
<tr>
<td>59</td>
<td>0.891</td>
</tr>
<tr>
<td>≥ 60</td>
<td>1.000</td>
</tr>
</tbody>
</table>
The following procedure can be used to scale the geoelectric field values of a 1-in-100 year GMD event provided in [8] to account for general features of a specific region such as earth conductivity and geomagnetic latitude.

1. Select the 100-year storm magnitude of 5 V/km for regions with high earth conductivity or 20 V/km for regions assumed to have low earth conductivity.

2. Scale the 100-year geoelectric field magnitude to account for local geomagnetic latitude using the correction factors, \( \alpha \), provided in Table I using linear interpolation.

\[
|E|_{corrected} = \alpha \times |E|_{100-year}
\]

3. For systems spanning several geographic and/or physiographic regions a weighted average or the largest projected value may be used as a conservative approach.

It should be noted that this is a general scaling factor and that geoelectric fields calculated with more specific earth conductivity information may actually be lower than those estimated in [8]. For instance [5] estimates that the geoelectric field in Quebec during the March 1989 event was in the order of 2 V/km as opposed to the 6 V/km value that could be gathered from Figure 13 (b). The cause of the two outlying data points, i.e. 6 V/km and 12 V/km shown in Figures 13(a) and 13(b), respectively, is a current research topic, and is not well understood by the scientific community at the time of publication of this report.
Chapter 2 – Modeling GIC

Because GIC are very low frequency, the ac network model is generally reduced to its dc equivalent [9]. The following sections describe the modeling theory and component models necessary for calculating GIC in a bulk power system.

Theory

In the nodal admittance matrix method the power network is considered as nodes connected together and to ground. Driving voltages (emfs) are converted to equivalent current sources. For a voltage source $e$ and impedance $z$, the corresponding equivalent circuit has components $y = 1/z$ and $j = e/z$. A matrix solution is then obtained for the voltage of each node. The node voltages are then used to obtain the GIC in the network.

To develop the general equations for the nodal admittance matrix method consider nodes $i$ and $k$ in the middle of a network as shown in Figure 14. Here, $y_{ik}$ represents the admittance of the transmission line between nodes $i$ and $k$ (note that $y_{ik} = y_{ki}$), and $y_i$ and $y_k$ represent the admittances to ground from nodes $i$ and $k$ respectively.

![Figure 14: Modelling GIC using the nodal admittance matrix method](image)

Applying Kirchhoff’s current law we can write an equation for any node $i$ of the form

$$\sum_{k=1}^{N} i_{ki} = i_i, \quad k \neq i \quad (10)$$

The current in a line is determined by the current source, the voltage difference between nodes at the ends of the line, and the admittance of the line

$$i_{ki} = j_{ki} + (v_k - v_i) y_{ki} \quad (11)$$

Substituting into (10) gives

$$\sum_{k=1}^{N} j_{ki} + \sum_{k=1}^{N} (v_k - v_i) y_{ki} = i_i \quad (12)$$
We make the further substitution

\[ J_i = \sum_{k=1}^{N} I_{ki} \]  \hspace{1cm} (13)

where \( J_i \) is the total of the equivalent source currents directed into each node. Thus we obtain the equation

\[ J_i + \sum_{k=1}^{N} (v_k - v_i) y_{ki} = i_i \]  \hspace{1cm} (14)

This equation involves the nodal voltages, \( v_i \), and the current to ground from each node, \( i_i \) as unknowns. The nodal voltage \( v_i \) is related to the current to ground \( i_i \) by Ohm’s law so we can substitute for either \( v_i \) or \( i_i \) to obtain equations involving only one set of unknowns. In this derivation we make the substitution

\[ i_i = v_i y_i \]  \hspace{1cm} (15)

Substituting for \( i_i \) gives equations involving only the node voltages \( v_i \) as the unknowns:

\[ J_i + \sum_{k=1}^{N} (v_k - v_i) y_{ki} = v_i y_i \]  \hspace{1cm} (16)

Regrouping terms gives

\[ J_i = v_i y_i + \sum_{k=1}^{N} v_k y_{ki} - \sum_{k=1}^{N} v_k y_{ki} \]  \hspace{1cm} (17)

This can be written in matrix form

\[ \begin{bmatrix} J \end{bmatrix} = \begin{bmatrix} Y \end{bmatrix} \begin{bmatrix} V \end{bmatrix} \]  \hspace{1cm} (18)

where the column matrix \([V]\) contains the voltages \( v_k \) and \([Y]\) is the admittance matrix in which the diagonal elements are the sums of the admittances of all paths connected to node \( i \), and the off-diagonal elements are the negatives of the admittances between nodes \( i \) and \( k \), i.e.

\[ Y_{ii} = y_i + \sum_{k=1}^{N} y_{ki} \quad k \neq i \]  \hspace{1cm} (19)

\[ Y_{ki} = -y_{ki} \]  \hspace{1cm} (20)

The voltages of the nodes are then found by taking the inverse of the admittance matrix and multiplying by the nodal current sources.

\[ \begin{bmatrix} V \end{bmatrix} = \begin{bmatrix} Y \end{bmatrix}^{-1} \begin{bmatrix} J \end{bmatrix} \]  \hspace{1cm} (21)

These node voltages can be substituted into (11) to give the currents in the branches and into (15) to give the currents to ground from each node.
An important feature of the single-phase dc modeling technique described herein is that the resulting GIC flows are total “three-phase” quantities. For example, the GIC flow computed using (17) is the summation of all three phases. As such, the computed values must be divided by three if per-phase values are required. The same holds true for transformers. The exception is the GIC flow in the substation ground grid. In this case, the computed GIC is the actual GIC flow into the grid and does not require further modification.

Because of matrix sparsity, a direct solution of (21) is not practical for realistic bulk power systems due to the large number of buses involved. As a result, sparse matrix techniques such as those presented in [10] and [11] are generally used to simplify the computation.

An example GIC calculation of a theoretical six bus power system is provided in Appendix B.

**Time Series Calculations**

Although future improvements are to be expected, currently most analyses – performed using commercially available tools – assume a uniform geoelectric field and apply the steady state calculation approach. In the steady-state approach, a geoelectric field value is assumed and used as input to the GIC model. However, there are situations where time series GIC data are required, for example thermal analysis of transformers. A convenient procedure for scaling the results of either the steady-state method, in particular computing GIC flows for various geoelectric fields, or for creating time series GIC data follows.

GIC is computed for a 1 V/km Eastward geoelectric field (Northward component is assumed zero) and again for a 1 V/km Northward geoelectric field (Eastward component is assumed zero). The results of these two calculations can then be scaled using any arbitrary geoelectric field provided that the geoelectric field is laterally uniform in the geographic region under consideration [12]. The scaling function is described in (22)

\[
GIC_{\text{new}} = |E| \left( GIC_E \sin \theta + GIC_N \cos \theta \right)
\]

where \(GIC_{\text{new}}\) is the new value of GIC (amps), \(|E|\) is the magnitude of the arbitrary geoelectric field (V/km), \(\theta\) is the angle of the geoelectric field vector (radians), \(GIC_E\) is the GIC due to a 1 V/km Eastward geoelectric field (amps), and \(GIC_N\) is the GIC due to a 1 V/km Northward geoelectric field (amps). Time series geoelectric field data in concert with (22) can be used to construct time series GIC flows needed for transformer thermal models or other such analyses.
Practical Details

Introduction

One of the first steps in calculating GIC in a bulk power system is to develop a dc equivalent model of the system. These models are normally assembled using a combination of information from: 1) ac models used to perform power flow analysis or short circuit studies, 2) available equipment resistance data, and 3) geographic information for the substations. The example system provided in Figure 15 shows many of the various system components which require dc models. Such components include: transformers, transmission lines, shunt reactors, series capacitor, substation ground grids, and GIC blocking devices. Generators can be excluded from the analysis because they are isolated at dc from the rest of the transmission system; thus, an equivalent dc model is not required. Additional modeling details that are normally not a part of the ac model, but which are required to assemble the dc model include: geographic locations of the substations (latitude/longitude), equivalent substation ground grid resistance (including the effects of overhead shield wires and other ground current paths) and dc winding resistance of transformers and shunt devices (e.g. shunt reactors). The following sections describe methods for developing a dc model of each of the components represented in Figure 15.

Figure 15: Single-line diagram of example power system used to demonstrate the various components that require dc models

The dc model data required for the individual network components are summarized in Table 2. Additional details for each component are covered in subsequent sections of this chapter. There can be significant
difference between the desired model data and an estimated value (based on a next best alternative) which can lead to inaccurate representation of GIC distribution in some modeled network branches. To assure best accuracy and the data consistency needed for sharing model data with other study engineers, estimated values should only be used when the desired resistive data is not obtainable.

Table 2: Summary of network component and associated resistive data for a one-phase GIC network model

<table>
<thead>
<tr>
<th>Network Component</th>
<th>Most Appropriate Data For Accurate Modeling</th>
<th>Best Alternative Estimate - When Desired Model Data Is Not Available</th>
<th>Data Sources and Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>Grounded wye winding of conventional transformer</td>
<td>Measured dc resistance of the winding at nominal tap and adjusted to 75 °C and divided by 3 (see note)</td>
<td>50% of the total per-unit copper loss resistance converted to actual ohms at winding base values and divided by 3</td>
<td>dc resistance and copper loss resistance are obtained from transformer test records. Transformer copper loss resistance from power flow model data base.</td>
</tr>
<tr>
<td>Autotransformer series windings</td>
<td>Measured dc resistance of each winding at nominal tap and adjusted to 75 °C and divided by 3 (see note)</td>
<td>50% of the total per-unit copper loss resistance converted to actual ohms at full winding base values and divided by 3</td>
<td>dc resistance and copper loss resistance are obtained from transformer test records. Transformer copper loss resistance from power flow model data base.</td>
</tr>
<tr>
<td>Autotransformer common winding</td>
<td>Measured dc resistance of each winding at nominal tap and adjusted to 75 °C and divided by 3 (see note)</td>
<td>50% of the total per-unit copper loss resistance converted to actual ohms at ( V_{H} ) winding base values and divided by ( (V_{H}/V_{X}-1)^{2} ) and divided by 3</td>
<td>dc resistance and copper loss resistance are obtained from transformer test records. Transformer copper loss resistance from power flow model data base.</td>
</tr>
<tr>
<td>Shunt reactor</td>
<td>Measured dc resistance of winding adjusted to 75 °C and divided by 3 (see note)</td>
<td>Measured ac copper loss resistance of winding at factory test temperature and divided by 3</td>
<td>dc resistance and copper loss resistance are obtained from test records.</td>
</tr>
<tr>
<td>Ground grid to remote earth including the effects of overhead shield wires</td>
<td>Measured value from ground grid test</td>
<td>Calculated value from design modeling</td>
<td>Commissioning or routine grounding integrity test data, or ground grid design software.</td>
</tr>
<tr>
<td>Neutral blocking device</td>
<td>Nameplate ohms for a resistor; 100 ( \mu \Omega ) for solid ground modeled as a resistor; 1 M( \Omega ) for capacitor (modeled as a resistance)</td>
<td>Not applicable</td>
<td>Depends on capability of network modeling software, but the study tool must be able to handle this branch as closed, open, or fixed value of resistance.</td>
</tr>
<tr>
<td>Transmission line</td>
<td>One third of the individual phase dc resistance adjusted to 50 °C</td>
<td>One third of the individual phase ac resistance adjusted to</td>
<td>Conductor manufacturer tables, system electrical design data, network model</td>
</tr>
</tbody>
</table>

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### Power Transformers

Power transformers are represented by their dc equivalent circuits, i.e. mutual coupling between windings and windings without physical connection to ground are excluded. An exception to this, as described later, is the series winding of an autotransformer which is always included in the model. Dc models are generally used for the purposes of computing GIC; however, time-domain models which replicate the behaviour of the transformer over a wide band of frequencies (including dc) can be constructed. For brevity, only dc models will be discussed here.

**Important note:** Resistance values used for modeling transformers in the dc network are best obtained from transformer test reports. If these data are not readily available then the dc resistance of the transformer windings may be estimated using positive sequence resistance data contained in power flow and short circuit models. However, it should be stressed that estimated values may contain considerable error. An evaluation performed by the NERC GMD TF on a select number of transformers indicated that the magnitude of error between estimated resistance values and those provided in transformer test reports can be on the order of 35% or higher. Thus, estimated values should only be used in situations when dc winding resistances are unavailable.

### Generator Step-Up Transformers

The dc equivalent circuit of a delta grounded-wye generator step-up unit (GSU) is provided in Figure 16. Note that the delta winding is not included in the dc equivalent because it does not provide a steady-state path for GIC flow. The HO terminal refers to the neutral point that is ordinarily connected directly to the substation ground grid model (neutral bus shown in Figure 19). If GIC mitigation equipment is employed, the impedance of the GIC blocking device would be inserted between the HO terminal and the equivalent ground resistance of the station.

**Figure 16: Single-Phase dc equivalent circuit of a GSU**
$R_{W1}$ in Figure 16 is defined as the dc resistance of the grounded-wye winding. The dc resistance of the grounded-wye winding may be estimated using positive sequence resistance data. The per-unit positive sequence resistance, $R_{HX}$, includes both the resistance of the high-voltage winding (Ohms), $R_H$, and the referred value of the low voltage winding (Ohms), $R_X$, as indicated in (23),

$$R_{HX} = \frac{R_H + n^2 R_X}{Z_{bh}}$$

(23)

where $Z_{bh}$ refers to the base impedance (Ohms) on the high-voltage side of the transformer and $n$ is the transformer turns ratio ($V_H / V_X$). The assumption is made that the high-voltage winding resistance and the referred value of the low-voltage winding are approximately equal [9] and [13]; thus, the resistance of the high voltage winding can be estimated using (24)

$$R_H = \frac{1}{2} \cdot R_{HX} \cdot Z_{bh}$$

(24)

Skin effect and changes in the resistance as a function of winding operating temperature are usually ignored.

**Two-Winding and Three-Winding Transformers**

The dc equivalent circuit of both a two-winding and three-winding transformer is provided in Figure 17. Note the delta tertiary winding (if applicable) is not included in the model since it does not provide a path for GIC to flow in steady-state. Both winding neutral nodes (i.e. X0 and H0) are modeled explicitly. In some cases, either the X0 or H0 terminal may be ungrounded. The neutral terminal of grounded wye windings (e.g. X0 or H0) is ordinarily connected directly to the substation ground grid model (neutral bus shown in Figure 19) or left floating depending on the application. If GIC mitigation equipment is employed, the impedance of the GIC blocking device would be inserted between the HO and/or XO terminals and the equivalent ground resistance of the station. Ungrounded wye windings are excluded in GIC calculations because they do not provide a path for GIC flow.

**Figure 17: Single-phase dc equivalent circuit of a two-winding or three-winding transformer**
R\(w_1\) and R\(w_2\) in Figure 17 refer to the dc winding resistance values of the high voltage or extra-high voltage and medium voltage windings, respectively. If test report data are not available then the dc winding resistances may be estimated using the same procedure described for GSUs.

**Autotransformers**

The dc equivalent circuit of an autotransformer is provided in Figure 18.

Note that the delta tertiary winding (if present) is not included in the model because it does not provide a steady-state path for GIC flow. The common autotransformer neutral terminal (H0/X0) is modeled explicitly, and is is ordinarily connected directly to the substation ground grid model (neutral bus shown in Figure 19). If necessary to model GIC mitigation equipment, the impedance of the device would be inserted between the HO terminal and the equivalent ground resistance of the station.

**Figure 18: Single-phase dc equivalent circuit of a two-winding or three-winding autotransformer**

Rs and Rc are defined as the dc resistance of the series and common windings, respectively. The dc resistance of the series and common windings can be estimated using (10) and (11), where \(R_{HX}\) is the per-unit positive sequence resistance, and \(n = \frac{V_H}{V_X}\) or the ratio of the line-to-ground voltages of the H and X terminals,

\[
R_s = \frac{I}{2} \cdot R_{HX} \cdot Z_{bh} \tag{25}
\]

\[
R_c = \frac{I}{2} \cdot \frac{R_{HX} \cdot Z_{bh}}{(n - 1)} \tag{26}
\]

**Substation Ground Grid and Neutral Connected GIC Blocking Devices**

The equivalent resistance of the substation ground grid (including the effects of any transmission line overhead shield wires and/or distribution multi-grounded neutral conductors if applicable) to remote earth must be included in the model. The fundamental frequency ac resistance is typically used because it is approximately
equivalent to the dc resistance. Note there is only a single substation ground resistance value for each substation; thus, it is connected to a common “neutral” bus, in the network model, as depicted in Figure 19, where \( R_{\text{gnd}} \) is the resistance to remote earth of the substation ground grid. The number of connections to the neutral bus shown in Figure 19 is determined by the number of grounded-wye transformer windings located in the substation.

**Figure 19: Electrical model of substation ground grid to remote earth for use in GIC calculations**

![Neutral Bus with \( R_{\text{gnd}} \)]

The electrical model of a GIC blocking device is depicted in Figure 20, where \( R_b \) is the resistance of the GIC blocking device. For study purposes, this network branch element must be capable of representing three possible states: solidly grounded; resistive grounded; and capacitive grounded. The three states can be modeled effectively as a resistor using a different resistance value for each possible state of the branch element. For example, a direct connection to ground would be represented as \( R_b = 0.1 \, \text{m}\Omega \), a blocking device represented by \( R_b = 1.0 \, \text{M}\Omega \), and a neutral resistor (if employed) would be represented by its specified resistance.

**Figure 20: Electrical model of GIC blocking device between transformer neutral and substation ground grid as used in GIC calculations**

![Transformer Neutral with \( R_b \) and \( R_{\text{gnd}} \)]

Depending on the type of modeling software that is used, the model presented in Figure 20 may be used in all cases with the difference being the value used for \( R_b \) to represent the various grounding arrangements. This enables accuracy without exceeding program computational limits associated with the numbers zero and infinity. A capacitive GIC blocking device presents very high impedance to GIC; thus, it can be modeled as a high resistance (e.g. 1.0 M\( \Omega \)), whereas, a solid ground is modeled as low resistance (e.g. 100 \( \mu \Omega \)). The actual resistance is used for a resistive blocking device.

**Transmission Line Models**

Changes in magnetic field density, \( B \), with respect to time result in an induced electric field as explained in Chapter 1. The driver of GIC is the geoelectric field (the electric field at the surface of the earth) integrated along the length of each transmission line which can be represented by a dc voltage source:

\[
V_{dc} = \int \vec{E} \cdot d\vec{l} \tag{27}
\]
where, $\vec{E}$ is the geoelectric field at the location of the transmission line, and $d\vec{l}$ is the incremental line segment length including direction. If the geoelectric field is assumed uniform in the geographical area of the transmission line, then only the coordinates of the end points of the line are important, regardless of routing twists and turns. The resulting incremental length vector $d\vec{l}$, becomes $\vec{L}$. Both $\vec{E}$ and $\vec{L}$ can be resolved into their $x$ and $y$ coordinates. Thus, (27) can be approximated by (28)

$$\vec{E} \cdot \vec{L} = E_x L_x + E_y L_y$$

(28)

where, $E_x$ and $E_y$ are the northward and eastward geoelectric fields (V/m), respectively, and $L_x$ and $L_y$ are the northward and eastward distances (m), respectively. If the geoelectric field is non-uniform, then (27) must be used. To obtain accurate values for the distance between substations (and to be consistent with substation latitudes and longitudes obtained from GPS measurements) it is necessary to take into account the non-spherical shape of the earth [14]. The earth is an ellipsoid with a smaller radius at the pole than at the equator. The precise values depend of the earth model used. The WGS84 model which is used in the GPS system is recommended. See Appendix A for details on computing $L_x$ and $L_y$.

The dc equivalent circuit of a transmission line is depicted in Figure 21.

**Figure 21: Three-phase transmission line model and its single-phase equivalent used to perform GIC calculations**

![Three-phase transmission line model](image)

$V_{dc}$ refers to the induced voltage computed using (27) or (28) and $R_{dc}$ corresponds to the dc resistance of the phase conductors including the effects of conductor bundling if applicable.

The resistive data from ac power flow and fault studies is useable for modeling line resistance in GIC studies. Although it is preferred to use the dc resistance ($R_{dc}$) of the transmission line, it is acceptable to use the ac resistance ($R_{ac}$) value in most cases. The difference between $R_{dc}$ and $R_{ac}$ at 50 °C is less than 5% for conductors up to 1.25 inch in diameter, and less than 10% up to 1.5 inch diameter conductor. Conductor sizes beyond 1.5 inches in diameter should be evaluated for possible impact to model accuracy as the difference between ac and dc resistance could be significant for long transmission lines.

Although there is minimal difference between $R_{dc}$ and $R_{ac}$ at the same temperature, there is a considerable difference between resistance at ambient temperature and the values typically used in power flow studies. The resistance of a transmission conductor will be 10 to 15% higher at 50 °C than at 20 °C. Although less conservative, modeling with resistance at 50 °C is preferred because a loaded system is more susceptible to adverse impact under GIC conditions and the most stressful condition to study.
Shield wires are not included explicitly as a GIC source in the transmission line model [15]. Shield wire conductive paths that connect to the station ground grid are accounted for in ground grid to remote earth resistance measurements and become part of that branch resistance in the network model.

**Blocking GIC in a Line**

Series capacitors are used in the bulk power system to re-direct power flow and improve system stability. Series capacitors present very high impedance to the flow of GIC. This effect can be included in the model in a number of ways, one of which is by adding a very large resistance (e.g. 1 MΩ) in series with the nominal dc resistance of the line (see $R_{dc}$ in Figure 21) or removing the line from the model completely. Additional modeling complications arise when lines are segmented to accommodate the effects of non-uniform geoelectric fields, and special care must be taken to ensure numerical stability.

**Shunt Devices**

The bulk power system generally uses two types of shunt elements to help control system voltage: shunt capacitors and shunt reactors. Shunt capacitors present very high impedance to the flow of GIC, and are consequently excluded in the dc analysis. Shunt reactors connected directly to the substation bus or transmission lines, on the other hand, can provide a low impedance path for GIC and should be included in the analysis. The dc model of a grounded-wye shunt reactor is the same as that of a grounded-wye winding of a GSU. If dc winding resistance values are unknown, they can be estimated using an assumed $X/R$ ratio. Note that $X/R$ ratio of a typical dead-tank shunt reactor can be far greater than the $X/R$ ratio of a typical transformer of the same MVA rating. It is not uncommon for the $X/R$ ratio of large shunt reactors to exceed 1000.
Chapter 3 - Modeling Refinements

The preceding calculation methods use two particular assumptions in order to simplify the calculations: 1) the magnetic field variations are uniform over the area of the power system and 2) the earth conductivity structure only varies with depth (i.e., there are no lateral variations in conductivity). To improve the accuracy of the calculated geoelectric fields both the structure of the source magnetic field and the lateral variations in conductivity should be considered.

Non-Uniform Source Fields

Various near-space electric current systems can generate magnetic field fluctuations anywhere on the ground. The spatial structure of the source field is highly dependent on the type of the source: for example magnetopause currents, tail current, ring current and auroral currents, all have distinct spatial signatures. Further, different sources dominate at different latitudes. However, magnetic field-aligned currents bring large amounts of near-space current down into the high-latitude ionosphere at about 100 km above the surface of the earth with amplitudes of millions of amperes [16]. These ionospheric currents are known as auroral currents or electrojets. The electrojet model is a crude approximation for the source of the geomagnetic field, but can be used as a basis for computing GIC and understanding GMD phenomenon in general.

As an example of non-uniform source fields, consider the auroral electrojet which is the cause of magnetic substorms that are responsible for the largest GIC in power systems. The magnetic and geoelectric fields produced by the auroral electrojet can be calculated using the complex image method [17]. First formulas are presented for the assumption that the electrojet can be considered as a line current at a height of 100 km. Then it is shown how the complex image method can be extended to include the width of the electrojet.

Figure 22 shows a line current at a height $h$ above the earth's surface. The total variation fields at the earth's surface are due, as mentioned earlier, to the field of the external source plus the field due to the currents induced in the earth. However, it has been shown that the "internal" fields are approximated, to good accuracy, by the fields due to an image current at a complex depth. This means that the complex skin depth, $p$, can be represented as a reflecting surface so that the image current is the same distance below this level as the source current is above (Figure 22). The magnetic and geoelectric fields are then given by the source and image currents and their distances from the location on the surface as shown in Figure 22.

**Figure 22:** Distances to an external line current at a height, $h$, and an image current at a complex depth $h+2p$ from a location on the earth's surface.
The magnetic and geoelectric fields at horizontal distance, \( x \), from the source current are then given by

\[
B_x = \frac{\mu_0 I}{2\pi} \left( \frac{h}{h^2 + x^2} + \frac{h + 2p}{(h + 2p)^2 + x^2} \right)
\]

(29)

\[
B_z = \frac{\mu_0 I}{2\pi} \left( \frac{x}{h^2 + x^2} - \frac{x}{(h + 2p)^2 + x^2} \right)
\]

(30)

\[
E_y = -\frac{j\omega\mu_0 I}{2\pi} \ln \left[ \frac{\sqrt{(h + 2p)^2 + x^2}}{\sqrt{h^2 + x^2}} \right]
\]

(31)

Where the complex skin depth is related to the surface impedance by the expression

\[
p = \frac{Z_s}{j\omega\mu_0}
\]

(32)

In practice, the auroral electrojet spreads over about six degrees of geomagnetic latitude. The current profile is difficult to determine but the studies that have been made shows that it can vary considerably. In practice, without special studies for each event, we cannot specify the current profile of the electrojet. However, a simple way to include the width of the auroral electrojet is to assume that the current has a Cauchy distribution. It can be shown that the fields produced by this current profile with a half-width \( a \) at a height \( h \) are the same as the fields produced by a line current at a height \( h + a \) [18]. The expressions for the magnetic and geoelectric fields at the earth’s surface in this case are

\[
B_x = \frac{\mu_0 I}{2\pi} \left( \frac{h + a}{(h + a)^2 + x^2} + \frac{h + a + 2p}{(h + a + 2p)^2 + x^2} \right)
\]

(33)

\[
B_z = -\frac{\mu_0 I}{2\pi} \left( \frac{x}{(h + a)^2 + x^2} - \frac{x}{(h + a + 2p)^2 + x^2} \right)
\]

(34)

\[
E_y = -\frac{j\omega\mu_0 I}{2\pi} \ln \left[ \frac{\sqrt{(h + a + 2p)^2 + x^2}}{\sqrt{(h + a)^2 + x^2}} \right]
\]

(35)

These geoelectric fields can be used as input into a power system model to calculate the GIC that would be produced by an electrojet at a specified location relative to the power system.
Non-Uniform Earth Structure

Another factor affecting the geoelectric field is conductivity boundaries, such as at a coast line or different geological regions within the power network under study [7]. The horizontal conductivity structure at the interface of a land/sea boundary (i.e. coastline), is characterized by a sharp change as depicted in Figure 23.

Figure 23: Geoelectric fields perpendicular to coastline

The higher conductivity of the sea in relation to the land means that higher electric currents are induced in the sea as compared with the land. When these currents are directed perpendicular to the coast there is a difference in the current density “arriving” at the coast from the sea compared to that “departing” from the coast into the land. Because charge cannot accumulate at the boundary, this condition gives rise to a potential gradient that acts to decrease the current in the sea and increase the current in the land so as to achieve current continuity at the boundary. Thus on the landward side of the boundary the geoelectric field perpendicular to the boundary is larger than would be expected from simply considering the land conductivity alone [7]. The size of the increased geoelectric field and how far it extends inland depend on the conductivity of the area, the depth of the sea and the characteristics of the geomagnetic field [7]. A method for investigating the coastal effect on geoelectric fields and GIC calculations can be found in [19].

Including Neighboring Systems

GIC can flow in or out of the network from/to adjacent networks and in most cases accurate modeling at system boundaries requires including the effects of neighboring systems. Unless the complete neighboring system (and its neighbors) is to be included in the GIC modeling, it is necessary to represent the adjacent system by an equivalent circuit.

Determining accurate equivalent networks in GIC calculations is an ongoing research topic; however, to date, there are at least three methods that can be used to represent the neighboring system:

1. Ignore the neighboring network and leave the connection as an open circuit. This is the simplest method and requires the least amount of information from the neighboring grid.
2. Represent the neighboring network as the line to the first substation and its resistance to ground.

3. Represent the neighboring network as a very long line. For situations, as commonly occurs, where the line resistance is much greater than the resistance to ground through the substation, $R_L \gg R_S$, it can be shown that this leads to an equivalent circuit with $V_{th} = V_L$ and $R_{th} = R_L$ as shown in Figure 24.

The most accurate choice of the equivalent circuits is the third model, i.e. representing the Thevenin equivalent as a line voltage and line resistance as shown in Figure 24. Ignoring the neighboring network gives the greatest calculation error [20].

![Figure 24: Thevenin equivalent circuit for a neighboring network determined from the resistance and induced voltage in the first transmission line](image)

The discussion above relates specifically to the treatment of neighboring areas for GIC flow analysis within the study area. Studies of GIC-related effects, such as ac voltage depression or harmonics require that the neighboring systems present reasonable boundary conditions to the area or system where detailed study is desired. To achieve these boundary conditions, it is typically necessary for the GIC flow through transformers within some extent of the neighboring systems to also be reasonably accurate. Thus, the area of GIC flow study must generally be wider in extent than the system where these effects are to be evaluated. Simulation results provided in [20] show that modeling four buses into the neighboring network yield results that are indistinguishable from those obtained using the full network model.
References


Appendix I – Calculating Distance Between Substations

Consider a transmission line between substations A and B as shown in Fig A.1. Assuming a spherical earth, the NS distance is simply calculated from the difference in latitude of substations A and B. However, there is no similar simple relationship for the EW distance because, as shown in Fig A.1, lines of longitude converge as they approach the pole. Consequently it is necessary to take into account the latitude of the substations when converting their longitudinal separation into a distance.

To get more accurate values (and to be consistent with substation latitudes and longitudes obtained from GPS measurements) it is necessary to take into account the non-spherical shape of the earth. The earth is an ellipsoid with a smaller radius at the pole than at the equator. The precise values depend of the earth model used. Here we use the WGS84 model (Table A.1) which is used in the GPS system.

![Figure A.1. Substation Location Coordinates](image)

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Symbol</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Equatorial radius</td>
<td>a</td>
<td>6378.137 km</td>
</tr>
<tr>
<td>Polar radius</td>
<td>b</td>
<td>6356.752 km</td>
</tr>
<tr>
<td>Eccentricity squared</td>
<td>e²</td>
<td>0.00669437999014</td>
</tr>
</tbody>
</table>

The North-South distance is given by:

\[
L_N = \frac{\pi}{180} M \cdot \Delta lat
\]  

(A.1),

where, \( M \) is the radius of curvature in the meridian plane and is described by (A.2)

\[
M = \frac{a \left(1 - e^2 \right)}{\left(1 - e^2 \sin^2 \phi \right)^{\frac{3}{2}}}
\]  

(A.2).
Substituting in the values from Table A.1. gives the expression for the Northward distance in km:

\[ L_N = (111.133 - 0.56 \cos(2\phi)) \cdot \Delta \text{lat} \quad (A.3) \]

where, \( \Delta \text{lat} \) is the difference in latitude (degrees) between the two substations A and B, and \( \phi \) is defined in (A.4) as the average of the two latitudes:

\[ \phi = \frac{\text{Lat}_A + \text{Lat}_B}{2} \quad (A.4). \]

Similarly the East-West distance is given by:

\[ L_E = \frac{\pi}{180} N \cos \phi \cdot \Delta \text{long} \quad (A.5), \]

where \( N \) is the radius of curvature in the plane parallel to the latitude as defined in (A.6) and \( \Delta \text{long} \) is the difference in longitude (degrees) between the two substations A and B

\[ N = \frac{a}{\sqrt{1 - e^2 \sin^2 \phi}} \quad (A.6). \]

Substituting the values from Table A.1 gives the following expression for the Eastward distance in km.

\[ L_E = (111.5065 - 0.1872 \cos 2\phi) \cdot \cos \phi \cdot \Delta \text{long} \quad (A.7). \]
Appendix II - Example of GIC Calculations

The following section describes the steps that can be taken to compute GIC flow in a power system. The example six-bus system that will be analyzed is shown in Figure B.1. Bus numbers are shown at bus locations. Encircled numbers refer to circuit nodes that will be used later in the calculation of GIC.

**Figure B.1: Example system used to compute GIC**

Required system data are provided in Tables B-1 through B-3.

**Table B-1: Substation location and ground grid resistance**

<table>
<thead>
<tr>
<th>Name</th>
<th>Latitude</th>
<th>Longitude</th>
<th>Grounding Resistance (Ohms)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Sub 1</td>
<td>33.613499</td>
<td>-87.373673</td>
<td>0.2</td>
</tr>
<tr>
<td>Sub 2</td>
<td>34.310437</td>
<td>-86.365765</td>
<td>0.2</td>
</tr>
<tr>
<td>Sub 3</td>
<td>33.955058</td>
<td>-84.679354</td>
<td>0.2</td>
</tr>
</tbody>
</table>

**Table B-2: Transmission line information**

<table>
<thead>
<tr>
<th>Line</th>
<th>From Bus</th>
<th>To Bus</th>
<th>Length (km)</th>
<th>Resistance (Ohms/phase)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>2</td>
<td>3</td>
<td>121.03</td>
<td>3.525</td>
</tr>
<tr>
<td>2</td>
<td>4</td>
<td>5</td>
<td>160.18</td>
<td>4.665</td>
</tr>
</tbody>
</table>

**Table B-3: Transformer and autotransformer winding resistance values**

<table>
<thead>
<tr>
<th>Name</th>
<th>Resistance W1 (ohm/phase)</th>
<th>Resistance W2 (ohm/phase)</th>
</tr>
</thead>
<tbody>
<tr>
<td>T1</td>
<td>0.5</td>
<td>N/A</td>
</tr>
<tr>
<td>T2</td>
<td>0.2 (series)</td>
<td>0.2 (common)</td>
</tr>
<tr>
<td>T3</td>
<td>0.5</td>
<td>N/A</td>
</tr>
</tbody>
</table>

For these calculations we use the geomagnetic coordinate system with x axis in the northward direction, y axis in the eastward direction, and z axis vertically downward. The procedure described in Appendix A can be used to compute northward and eastward distances and are shown in Table B-3.
Table B-3: Eastward and northward distance calculation results

<table>
<thead>
<tr>
<th>Line</th>
<th>From Bus</th>
<th>To Bus</th>
<th>Northward Distance (km)</th>
<th>Eastward Distance (km)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>2</td>
<td>3</td>
<td>-77.499</td>
<td>-92.96</td>
</tr>
<tr>
<td>2</td>
<td>4</td>
<td>5</td>
<td>39.518</td>
<td>-155.22</td>
</tr>
</tbody>
</table>

Assuming an electric field magnitude of 10 V/km with Eastward direction, the resulting induced voltages were computed using (28) and found to be as shown in Table B-4.

Table B-4: Induced voltage calculation results

<table>
<thead>
<tr>
<th>Line</th>
<th>From Bus</th>
<th>To Bus</th>
<th>Induced Voltage (Volts)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>2</td>
<td>3</td>
<td>-929.6</td>
</tr>
<tr>
<td>2</td>
<td>4</td>
<td>5</td>
<td>-1552.3</td>
</tr>
</tbody>
</table>

The next step is to construct an equivalent circuit of the system. An equivalent circuit of the system shown in Figure B-1 is provided in Figure B-2. Note the node names correspond to the locations indicated in Figure B-1.

Figure B-2: Equivalent circuit of example system

Although the equivalent circuit shown in Figure B-2 can be solved directly, it is more convenient to perform the calculations using nodal analysis where the voltage sources are converted to current sources, and all impedance elements are converted to their equivalent admittances. The resulting equivalent circuit is shown in Figure B-3.

Figure B-3: Equivalent circuit of example system in nodal form
The admittance matrix of the circuit shown in Figure B-3 can be readily constructed, and is shown in general form in (B.1):

\[
Y = \begin{bmatrix}
\frac{3}{R_{T1}+3R_{G1}} + \frac{3}{R_{L1}} & \frac{-3}{R_{L1}} & 0 & 0 \\
\frac{-3}{R_{L1}} & \frac{3}{R_{s}} + \frac{3}{R_{L1}+3R_{G2}} & \frac{-3}{R_{s}} & 0 \\
0 & \frac{-3}{R_{s}} & \frac{3}{R_{s}+3R_{L2}} & \frac{-3}{R_{L2}} \\
0 & 0 & \frac{3}{R_{L2}} & 0 + \frac{3}{R_{T3}+3R_{G3}} \\
\end{bmatrix}
\tag{B.1}
\]

Substituting the appropriate values into (B.1) results in (B.2):

\[
Y = \begin{bmatrix}
3.578 & -0.851 & 0 & 0 \\
-0.851 & 19.601 & -15 & 0 \\
0 & -15 & 15.643 & -0.643 \\
0 & 0 & -0.643 & 3.37 \\
\end{bmatrix}
\text{mho}\tag{B.2}
\]

The resulting nodal current injections were found to be:

\[
I_{L1} = \frac{3V_{L1}}{R_{L1}} = -791.15 \text{ amps} \quad I_{L2} = \frac{3V_{L2}}{R_{L2}} = -998.23 \text{ amps}
\]

The current vector can be constructed using the nodal currents as shown in (B.3):

\[
I = \begin{bmatrix}
-I_{L1} \\
I_{L1} \\
-I_{L2} \\
I_{L2}
\end{bmatrix}
\tag{B.3}
\]

The resulting node voltages are computed using Ohms Law

\[
V = [Y]^{-1}I = \begin{bmatrix}
229.72 \\
36.25 \\
87.08 \\
-279.56
\end{bmatrix}
\tag{B.4}
\]

The GIC flows (all three phases combined) are computed using various relationships derived from the circuit. The results are as follows:

\[
I_{T1} = V_{1} \left( \frac{3}{R_{T1}+3R_{G1}} \right) = 626.5 \text{ amps} \tag{B.5}; \\
I_{12} = I_{L1} + (V_{1} - V_{2}) \frac{3}{R_{L1}} = -626.5 \text{ amps} \tag{B.6}; \\
I_{s} = (V_{2} - V_{3}) \frac{3}{R_{s}} = -762.45 \text{ amps} \tag{B.7}; \\
I_{c} = V_{2} \left( \frac{3}{R_{c}+3R_{G2}} \right) = 135.95 \text{ amps} \tag{B.8}; \\
I_{34} = I_{L2} + (V_{3} - V_{4}) \frac{3}{R_{L2}} = -762.45 \text{ amps} \tag{B.9}; \\
I_{T3} = V_{4} \left( \frac{3}{R_{T3}+3R_{G3}} \right) = -762.45 \text{ amps} \tag{B.10}.
\]
The per-phase GIC values can be determined from the results provided in (B.5)-(B.10) by dividing by 3.

Similar calculations were performed with varying orientations of the electric field. A neutral blocking device was also considered in the neutral of the autotransformer by setting the corresponding substation ground grid resistance to a very large value (1MΩ). The results of these calculations are provided in Tables B-5 and B-6. The per-phase GIC values can be determined from the results provided in Tables B-5 and B-6 by dividing the values shown by 3.

<table>
<thead>
<tr>
<th>E</th>
<th>Orientation (degrees)</th>
<th>I_11 (amps)</th>
<th>I_12 (amps)</th>
<th>I_s (amps)</th>
<th>I_c (amps)</th>
<th>I_34 (amps)</th>
<th>I_73 (amps)</th>
</tr>
</thead>
<tbody>
<tr>
<td>10</td>
<td>0</td>
<td>409.87</td>
<td>-409.87</td>
<td>126.78</td>
<td>-536.65</td>
<td>126.78</td>
<td>126.78</td>
</tr>
<tr>
<td>10</td>
<td>30</td>
<td>668.21</td>
<td>-668.21</td>
<td>-271.43</td>
<td>-396.78</td>
<td>-271.43</td>
<td>-271.43</td>
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<tr>
<td>10</td>
<td>60</td>
<td>747.50</td>
<td>-747.50</td>
<td>-596.91</td>
<td>-150.59</td>
<td>-596.91</td>
<td>-596.91</td>
</tr>
<tr>
<td>10</td>
<td>90</td>
<td>626.50</td>
<td>-626.50</td>
<td>-762.45</td>
<td>135.95</td>
<td>-762.45</td>
<td>-762.45</td>
</tr>
<tr>
<td>10</td>
<td>120</td>
<td>337.63</td>
<td>-337.63</td>
<td>-723.69</td>
<td>386.06</td>
<td>-723.69</td>
<td>-723.69</td>
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<tr>
<td>10</td>
<td>150</td>
<td>-41.71</td>
<td>41.71</td>
<td>-491.02</td>
<td>532.73</td>
<td>-491.02</td>
<td>-491.02</td>
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<tr>
<td>10</td>
<td>180</td>
<td>-409.87</td>
<td>409.87</td>
<td>-126.78</td>
<td>536.65</td>
<td>-126.78</td>
<td>-126.78</td>
</tr>
</tbody>
</table>

Table B-5: Results without neutral blocking device

<table>
<thead>
<tr>
<th>E</th>
<th>Orientation (degrees)</th>
<th>I_11 (amps)</th>
<th>I_12 (amps)</th>
<th>I_s (amps)</th>
<th>I_c (amps)</th>
<th>I_34 (amps)</th>
<th>I_73 (amps)</th>
</tr>
</thead>
<tbody>
<tr>
<td>10</td>
<td>0</td>
<td>-107.60</td>
<td>107.60</td>
<td>107.59</td>
<td>0.00</td>
<td>107.59</td>
<td>107.59</td>
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<tr>
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<td>30</td>
<td>-444.72</td>
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<td>0.00</td>
<td>444.72</td>
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<tr>
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<td>-662.68</td>
<td>662.68</td>
<td>662.68</td>
<td>0.00</td>
<td>662.68</td>
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<tr>
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<td>90</td>
<td>-703.07</td>
<td>703.07</td>
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<td>0.00</td>
<td>703.07</td>
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<tr>
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<td>120</td>
<td>-555.08</td>
<td>555.08</td>
<td>555.08</td>
<td>0.00</td>
<td>555.08</td>
<td>555.08</td>
</tr>
<tr>
<td>10</td>
<td>150</td>
<td>-258.35</td>
<td>258.35</td>
<td>258.36</td>
<td>0.00</td>
<td>258.36</td>
<td>258.36</td>
</tr>
<tr>
<td>10</td>
<td>180</td>
<td>107.60</td>
<td>-107.60</td>
<td>-107.59</td>
<td>0.00</td>
<td>-107.59</td>
<td>-107.59</td>
</tr>
</tbody>
</table>

Table B-6: Results with neutral blocking device installed in the neutral of the autotransformer
### Appendix III – NERC GMD Task Force Leadership Roster

<table>
<thead>
<tr>
<th>Position</th>
<th>Name and Title</th>
<th>Company</th>
<th>Contact Info</th>
</tr>
</thead>
<tbody>
<tr>
<td>Chair</td>
<td>Kenneth Donohoo, P.E.</td>
<td>Oncor Electric Delivery</td>
<td>214.743.6823  k <a href="mailto:kenneth.donohoo@oncor.com">kenneth.donohoo@oncor.com</a></td>
</tr>
<tr>
<td></td>
<td>Director, System Planning</td>
<td>2233 B Mountain Creek Parkway Dallas, TX 75211</td>
<td></td>
</tr>
<tr>
<td>Vice Chair</td>
<td>Frank Koza, P.E.</td>
<td>PJM Interconnection, LLC</td>
<td>610.666.4228  k <a href="mailto:kozaf@pjm.com">kozaf@pjm.com</a></td>
</tr>
<tr>
<td></td>
<td>Executive Director of Infrastructure Planning</td>
<td>955 Jefferson Ave Norristown, PA 19403</td>
<td></td>
</tr>
<tr>
<td>Team Leader</td>
<td>Luis Marti, Ph.D., PE</td>
<td>Hydro One Networks</td>
<td>416.345.5317  l <a href="mailto:luis.marti@HydroOne.com">luis.marti@HydroOne.com</a></td>
</tr>
<tr>
<td>Equipment Model Development and Validation</td>
<td>Manager, Professional Development and Special Studies</td>
<td>483 Bay Street TCT15N Toronto, ON M5G 2P5</td>
<td></td>
</tr>
<tr>
<td>Team Leader</td>
<td>Randy Horton, Ph.D., P.E.</td>
<td>Southern Company Services</td>
<td>205.257.6352  j <a href="mailto:jrhorton@southernco.com">jrhorton@southernco.com</a></td>
</tr>
<tr>
<td>GIC Model Development and Validation</td>
<td>Chief Engineer, Transmission Technical Support</td>
<td>42 Inverness Parkway Birmingham, AL 35242</td>
<td></td>
</tr>
<tr>
<td>Team Leader</td>
<td>Frank Koza, P.E.</td>
<td>PJM Interconnection, LLC</td>
<td>610.666.4228  k <a href="mailto:kozaf@pjm.com">kozaf@pjm.com</a></td>
</tr>
<tr>
<td>System Operating Practices, Tools, and Training</td>
<td>Executive Director of Infrastructure Planning</td>
<td>955 Jefferson Ave Norristown, PA 19403</td>
<td></td>
</tr>
<tr>
<td>Technical Support</td>
<td>Richard Lordan</td>
<td>EPRI</td>
<td>650.855.2435  r <a href="mailto:rilordan@epri.com">rilordan@epri.com</a></td>
</tr>
<tr>
<td>Electric Power Research Institute</td>
<td>Technology Director</td>
<td>3420 Hillview Avenue Palo Alto, CA 94304</td>
<td></td>
</tr>
<tr>
<td>Technical Support</td>
<td>Jason Taylor</td>
<td>EPRI</td>
<td>865.218.8077  j <a href="mailto:jtaylor@epri.com">jtaylor@epri.com</a></td>
</tr>
<tr>
<td>Electric Power Research Institute</td>
<td>Project Manager</td>
<td>942 Corridor Park Blvd Knoxville, TN 37932</td>
<td></td>
</tr>
<tr>
<td>Position</td>
<td>Name and Title</td>
<td>Company</td>
<td>Contact Info</td>
</tr>
<tr>
<td>--------------------------</td>
<td>-------------------------------------</td>
<td>-----------------------------------------</td>
<td>-------------------------</td>
</tr>
<tr>
<td>NERC Staff Coordinator</td>
<td>Noha Abdel-Karim, Ph.D. Senior</td>
<td>NERC 3353 Peachtree Rd NE, Suite 600</td>
<td>404.446-4699</td>
</tr>
<tr>
<td></td>
<td>Engineer, Reliability Assessment</td>
<td>Atlanta, GA 30326</td>
<td><a href="mailto:noha.karim@nerc.net">noha.karim@nerc.net</a></td>
</tr>
<tr>
<td>NERC Staff Coordinator</td>
<td>Mark Olson Standards Developer</td>
<td>NERC 3353 Peachtree Rd NE, Suite 600</td>
<td>404.446.9760</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Atlanta, GA 30326</td>
<td><a href="mailto:mark.olson@nerc.net">mark.olson@nerc.net</a></td>
</tr>
</tbody>
</table>
Minimum Scope Outline
For
Subcommittees of the NERC OC

**Purpose**
The ________________ Subcommittee (XXX) assists the NERC Operating Committee (OC) in enhancing Bulk Electric System (BES) reliability by implementing the goals and objectives of the OC Strategic Plan.

**Functions**

*Examples from the EAS...*

I. The EAS, in coordination with NERC Staff, will:
      b. Manage and coordinate the development and publishing of Lessons Learned.
      c. Identify improvements to event analysis reporting.
      d. Provide feedback to industry on EA Process topics
      e. Solicit feedback from industry stakeholders to improve the EA Process.

II. To facilitate the sharing of event analysis information with the NERC Operating Committee (OC) and its subcommittees, EAS will:
   a. Invite and facilitate registered entity presentations of event reports at OC meetings.
   b. Provide status of and direction on implementation of Lessons Learned.
   c. Provide trending updates.

III. The EAS, in coordination with NERC Subcommittees and Working Groups, will share information, identify trends, and make recommendations to the industry which address:
   a. Reliability risks
   b. Human performance
   c. Lessons learned

IV. The EAS will partner with regional entities, registered entities and other industry forums to:
a. Obtain input of Regional personnel and reliability stakeholder groups as resources to the EAS, leveraging their experience and knowledge.

b. Address reliability issues.

c. Recommend quality improvements to reliability standards based on lessons learned and trends drawn from events.

**Deliverables**

*Examples from the EAS...*

- Annually review Event Analysis Process document
  - Published Lessons Learned
  - Regular updates to the Operating Committee with Information and recommendations related to the Event Analysis process
  - Input to the NERC Performance Analysis Subcommittee’s (PAS) annual State of Reliability Report

**Reporting**

The Subcommittee reports to the OC, and shall maintain communications with other groups as necessary on relevant issues.

**Officers**

The NERC OC Chair appoints the Subcommittee officers (Chair and Vice Chair) for a specific term (generally two years). The subcommittee officers may be reappointed for additional terms. The officers are considered members of the subcommittee and may vote. The Subcommittee Chair is considered a non-voting member of the OC and is expected to attend the regular standing committee meetings to report on assignments, or provide a summary report of the group’s activities, and advise the OC on important issues at a minimum. (for the ORS-Both officers must be Reliability Coordinator representatives.) The Vice Chair is considered an important succession planning billet with the anticipation that the Vice Chair will be appointed as Subcommittee Chair for the next term.

**Membership**

The Subcommittee will consist of: ...

**Meeting Procedures**

- Quorum: 50 percent of subcommittee members eligible to vote
- Actions requiring a vote shall require a quorum and a simple majority vote of those members present.
• All other procedures follow those of the "Organization and Procedures Manual for the NERC Standing Committees."

**Confidential Sessions**
The Chair of the subcommittee may limit attendance at a meeting or portion of a meeting, based on confidentiality of the information to be disclosed at the meeting. Such limitations should be applied sparingly and on a non-discriminatory basis as needed to protect information that is sensitive to one or more parties.

**Subgroups**
The Subcommittee may form working groups, task groups, and task forces as needed to assist the subcommittee in carrying out standing or ad hoc assignments. Task group chairs (or delegates) are expected to attend the regular subcommittee meetings to report on assignments or provide a summary report of the group’s activities at a minimum.
Events Analysis Subcommittee (EAS) Scope

**Purpose**

The Event Analysis Subcommittee (EAS) assists the NERC Operating Committee (OC) in enhancing Bulk Electric System (BES) reliability by implementing the goals and objectives of the OC Strategic Plan.

The Event Analysis Subcommittee (EAS) is a cross-functional group of industry experts that will support and maintain a cohesive and coordinated event analysis (EA) process across North America with industry stakeholders. EAS will support development of lessons learned, promote industry-wide sharing of event causal factors and assist NERC in implementation of related initiatives to lessen reliability risks to the Bulk Electric System.

**Functions**

I. The EAS, in coordination with NERC Staff, will:
   b. Manage and coordinate the development and publishing of Lessons Learned.
   c. Identify improvements to event analysis reporting.
   d. Provide feedback to industry on EA Process topics.
   e. Solicit feedback from industry stakeholders to improve the EA Process.

II. To facilitate the sharing of event analysis information with the NERC Operating committee (OC) and its subcommittees, EAS will:
   a. Invite and facilitate registered entity event analysis presentations of event reports at OC meetings.
   b. Provide status of and direction on implementation of Lessons Learned.
   c. Provide trending updates.

III. The EAS, in coordination with NERC Subcommittees and Working Groups, will share information, identify trends through analysis of events, and make recommendations to the industry which address:
   a. Reliability risks
   b. Human performance
   c. Need for training
   d. Lessons learned
   e. Good industry practices

IV. The EAS will partner with regional entities, registered entities and other industry forums to:
   a. Obtain input of Regional Entity personnel and reliability stakeholder groups as resources to the EAS, leveraging their experience and knowledge.
b. Address reliability issues.

c. Based on lessons learned and trends drawn from events, recommend quality improvements to existing Reliability Standards or development of new Reliability Guidelines or Reliability Standards where gaps are identified based on lessons learned and trends drawn from events identified.

d. Annually survey the Regional Entities to assess the value lessons learned.

**Deliverables**

- **Annually** review Event Analysis Process document
- Recommend need for training in coordination with Personnel Subcommittee (PS)
- Publish Lessons Learned
- Develop Reliability Guidelines
- Identify significant risk and the need for NERC Alerts
- Updates to the Operating Committee
- Input to the NERC Performance Analysis Subcommittee’s (PAS) annual State of Reliability Report
- Information and recommendations related to the Event Analysis process

**Reporting**

The EAS reports to the NERC Operating Committee, supports the PAS and shall maintain communications with the NERC Planning Committee (PC) and other groups as necessary on relevant issues.

**Officers**

The NERC OC Chair appoints the Subcommittee officers (Chair and Vice Chair) for a specific term (generally two years). The subcommittee officers may be reappointed for additional terms. The officers are considered members of the subcommittee and may vote. The Subcommittee Chair is considered a non-voting member of the OC and is expected to attend the regular standing committee meetings to report on assignments, or provide a summary report of the group’s activities, and advise the OC on important issues at a minimum. The Vice Chair is considered an important succession planning billet with the anticipation that the Vice Chair will be appointed as Subcommittee Chair for the next term.

**Membership**

The EAS will consist of:

- One (1) voting member from each of the eight Regional Entities, approved by the OC.
- One (1) voting member from each of the eight Regions to represent industry stakeholder interests. Members may be suggested by the EAS and will be approved by the OC.
- ERO Staff Representative
- With approval by the OC, additional members may be added:
  - At the request of the EAS,
  - At the request of the OC sector representatives, or
  - As needed by the ERO Staff Representative.
The NERC OC Chair appoints the EAS officers (Chair and Vice Chair) for a specific term (generally two years).

**Meeting Procedures**
The subcommittee officers may be reappointed for additional terms. The EAS officers are considered members of the subcommittee and may vote. The EAS may recommend officer candidates for the OC Chair’s consideration following a supporting motion. The vice chair should be available to succeed the chair.

**Order of Business**
The desire is to strive for consensus in normal EAS business. If the desired outcome cannot be achieved, the EAS will hold a vote as noted below. If any strong minority opinions develop, those opinions may be documented as desired by the minority and forwarded to the OC Chair for future meeting consideration.

**Meeting Procedures**
- Quorum: 50 percent of subcommittee members eligible to vote
- Actions requiring a vote shall require a quorum and a simple majority vote of those members present.
- All other procedures follow those of the “Organization and Procedures Manual for the NERC Standing Committees.”

**Confidential Sessions**
The chairman of the subcommittee may limit attendance at a meeting or portion of a meeting, based on confidentiality of the information to be disclosed at the meeting. Such limitations should be applied sparingly and on a non-discriminatory basis as needed to protect information that is sensitive to one or more parties.

**Subgroups**
The EAS may form working groups, task groups, and task forces as needed to assist the subcommittee in carrying out standing or ad hoc assignments. Task group chairs (or delegates) are expected to attend the regular subcommittee meetings to report on assignments or provide a summary report of the group’s activities at a minimum.

**Reporting**
The EAS reports to the NERC Operating Committee, supports the PAS and shall maintain communications with the NERC Planning Committee (PC) and other groups as necessary on relevant issues.

**Meetings**
Four to six open meetings per year, or as needed, with supplemental telephone conferences.

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<thead>
<tr>
<th>Date</th>
<th>Reviewers/Approval</th>
<th>Revision Description</th>
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EAS Scope - Draft 0425201201292014  3
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<th>Date</th>
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<td>06/19/2013</td>
<td>Transitioned the EAWG into the Event Analysis Subcommittee (EAS).</td>
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<tr>
<td></td>
<td>XX/XX/2013</td>
<td>Updated EAS Scope to reflect changes in the OC Strategic Plan.</td>
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Developed by: Event Analysis Working Group (EAWG)
Approved by: Operating Committee (OC)
# NERC News

## January 2014

### Reliability Risk Management

- **NERC Response to FERC Open Meeting**

### Standards

- **Standards Committee Year End Report**
- **CIP V5 Revisions Technical Conferences and Preview of Upcoming Work**
- **Status Update: Order No. 754**
- **Upcoming Events**

### NERC Filings

- **Documents Filed with FERC and/or Canada during the Month**

### Careers

- **NERC Seeks Talented Professionals**

### NERC Committees Year-End Review

- **Critical Infrastructure Protection Committee**
- **Operating Committee**
- **Planning Committee**
- **Standards Committee**
Reliability Risk Management

NERC Response to FERC Open Meeting
NERC was pleased to work with FERC staff to provide a preliminary update on the bulk power system performance during the January 6-8 extreme cold weather event at FERC’s open meeting today. While it is too early to draw conclusions or comparisons to other events, NERC continues to work with the industry to gather data to help direct analytical efforts, which will include lessons learned and recommendations for further improving preparation and processes during extreme circumstances.

NERC has established a solid events analysis foundation to learn from events and disturbances, to identify reliability risks and, ultimately, to further enhance reliability efforts. This will be an extensive effort, but we are confident that NERC and the industry can reach the goal of maintaining reliability, while improving efforts where needed. FERC, NERC and stakeholders share a common interest in ensuring the reliability of the bulk power system of North America, and will continue our work together toward that end. Joint FERC/NERC Presentation

Standards

Standards Committee Year End Report
The Standards Committee revised its charter and will present it to the Board of Trustees for approval at the February 7 meeting. The revisions incorporate additional mention of the Standards Committee’s working relationship with NERC standards staff; recognition of the Standards Committee’s role on communication issues related to the standards development process now that the Standards Committee’s communication subcommittee has been retired; and language that more prominently recognizes the role of NERC technical committees during the authorization and monitoring of field tests conducted by standard drafting teams.

The Standards Committee also provided a report reviewing the 2013 Board-approved SC reforms’ effectiveness and the need for additional reforms. In addition to the revisions to the charter, the reforms include a 2014 consensus building approach that more actively uses the Reliability Issues Steering Committee to triage new and emerging issues prior to consideration of the issue in the standards development process; uses the Standards Authorization Request drafting teams to build consensus, balancing equal and effective approaches, including standards, to address known reliability gaps; and encourages the use of consensus building tools throughout the standards development process.

The Standards Committee also included a reform to limit the parallel posting of Standard Authorization Requests and standards for comment and ballot to uses covered by Section 16 waivers.

CIP V5 Revisions Technical Conferences and Preview of Upcoming Work
To encourage early dialogue regarding the four main directives in FERC Order No. 791, which call for revisions to the suite of Version 5 CIP standards, NERC led CIP Version 5 Revisions technical conferences in Atlanta on January 21 and in Phoenix on January 23.

During these day-long discussions, stakeholders discussed considerations and perspectives on addressing the directives to provide informal input to the future drafting team, and NERC staff from the Standards, Critical Infrastructure, and Enforcement departments interacted with the industry prior to standard drafting team activity. As a result, the technical conferences provided both NERC and attendees with a better sense of the high expectations of the standards development efforts for the upcoming year.

Slides from the presentations are posted on the CIP Version 5 Revisions project page, and NERC will post a summary of the technical conferences early next month.

On January 29, the Standards Committee appointed a standards drafting team, with 10 members and two co-chairs, to develop the revisions directed in FERC
Order No. 791. The roster will be posted to the project page soon. Please consult the NERC Standards calendar for dates of upcoming standards drafting team activity. In the meantime, contact Standards developers Marisa Hecht and Ryan Stewart with questions about the revisions or to request to join the drafting team plus list.

Status Update: Order No. 754
February 1 marks the beginning of the 30-day period before the 18-month milestone for transmission planners working on the Order No. 754 Data Request. In accordance with the data request, each transmission planner in the United States must provide NERC data for buses at or above 200 kV and below 300 kV by March 3. Canadian transmission planners who previously acknowledged the data request are also encouraged to provide data for a complete continent-wide record.

Transmission planners can make their 18-month data submittal via the Order No. 754 project page. The project page contains background information, links to either register or log-in to the data reporting portal, and a revised Requests for Clarifications and Responses document, dated July 12, 2013.

The data reporting portal will be open through the last reporting period in the fourth quarter of 2014. Entities that have submitted all voltage categories must submit a final authorization letter from their organization (see a sample authorization on p. 24 of the data request) to complete the data reporting obligation. Transmission planners should periodically check the project page for project status. If needed, contact DataRequest754@nerc.net or the project manager, Scott Barfield-McGinnis, with questions. The data request was developed in accordance with the NERC Rules of Procedure, Section 1600 — Request for Data or Information and was approved by the NERC Board of Trustees on August 16, 2012.

Upcoming Events
- PRC-005: Version 2 Implementation, and Version 4 Standard Development Update webinar: 3-4 p.m. Eastern, February 13 | Register
- TOP/IRO Revisions technical conferences: March 3-4, St. Louis, Mo., and March 6, Arlington, Va., | Registration and details coming soon

These technical conferences will focus on the revisions to proposed TOP and IRO standards that were directed by FERC in a November 21, 2013, Notice of Proposed Rulemaking. During the conferences, NERC will identify and assess concerns regarding the TOP and IRO Standards, such as the monitoring of System Operating Limits, unknown operating states, and outage coordination. The December 2013 issue of NERC News contains more information on NERC’s plans to review and work these key transmission operations standards.
- Spring Standards and Compliance workshop: April 1-3, San Diego, Calif., Register | Details

This three-day workshop will present stakeholders with valuable information about standards development, compliance monitoring and operations, and other initiatives. The fee, US$300 to attend the workshop in person or US$100 to attend via webinar, will be payable by Visa, MasterCard or check. As always, we will begin the workshop with an optional NERC Standards and Compliance 101 presentation from 10 a.m. to noon on April 1. An agenda for the workshop will be released in the coming months.

NERC Filings to FERC
(click on the link for full filing)

January 2, 2014
Status Report Informational Filing in Response to FERC’s March 4, 2013 Order
NERC submits this quarterly report on the status of an investigation into PacifiCorp’s allegations in a November 16, 2012 complaint against the Western Electricity Coordinating Council
and the Los Angeles Department of Water and Power. FERC directed NERC to file quarterly status reports until the investigation is completed, in its March 4, 2013 order on the complaint.

January 24, 2014
NERC Answers to EEI Protest and Comments
NERC submits a motion for leave to answer and answer to the protest and comments of the Edison Electric Institute.

January 29, 2014
Analysis of NERC Standards Process Results, Fourth Quarter 2013
NERC submits its fourth quarter 2013 ballot results in response to the FERC January 18, 2007 Order requiring NERC to closely monitor and report the voting results for NERC Reliability Standards each quarter for three years.

NERC Filings in Canada, click here
(click on the link above for full filing)

January 8, 2014
Filing Regarding the Western Electricity Coordinating Council

Notice of Filing for Deferral of Action Regarding Revisions to the Transmission Operations (“TOP”) and Interconnection Reliability Operations and Coordination (“IRO”) Reliability Standards

Notice of Filing of WECC Regional Reliability Standard IRO-006-WECC-2-Qualified Transfer Path Unscheduled Flow (“USF”) Relief and WECC Regional Definition of “Relief Requirement”

Careers at NERC

ES-ISAC Cybersecurity Specialist
Location: Washington, DC
Details

CIP Compliance Auditor
Location: Washington, DC
Details

Compliance Auditor
Location: Atlanta
Details

Compliance Enforcement Analyst
Location: Washington, DC
Details

Bulk Power System Awareness Engineer

Location: Atlanta
Details

Senior Reliability Engineer
Location: Atlanta
Details

Senior Web Developer
Location: Atlanta
Details

Database Administrator, Information Technology
Location: Atlanta
Details

Helpdesk Level 1, Helpdesk Services
Location: Atlanta
Details

Human Performance and Training Analyst
Location: Atlanta
Details

Manager Reliability Assessments
Location: Atlanta
Details

Standards Developer
Location: Atlanta
Details

2013 NERC Committees Year-End Review

Critical Infrastructure Protection Committee
Summary of key CIPC accomplishments in 2013 and strategic goals for 2014:

2013 Key Accomplishments

- CIPC Charter Updated – Accepted by the Board of Trustees at the December 2013 meeting.
- Personnel Security Clearances Task Force Report – Accepted by Board at the August 2013 meeting.
• **Electricity Sub-sector Information Sharing Task Force Report** – Accepted by the Board at the August 2013 meeting.

• **Security Guideline for the Electricity Sub-sector: Physical Security Response** – The Physical Security Response Guideline was revised with the most significant update a new appendix containing a sample “quick reference flip chart” document that can be easily adapted for a particular entity’s specific physical security policies and procedures. Approved by CIPC at the December 2013 meeting.

2014 Strategic Goals

• **Continued Collaboration with Electricity Sector Information Sharing and Analysis Center (ES-ISAC)**
  The ESISTF report is in the second phase developing outreach to the industry in collaboration with the ES-ISAC. This ESISTF report and the accepted Personnel Security Clearance Task Force report, both contain actionable recommendations for ES-ISAC’s implementation. The ES-ISAC has requested that both task forces work with ES-ISAC staff to implement these recommendations.

• **Coordination with the Reliability Issues Steering Committee (RISC)**
  CIPC continues to support RISC efforts with a CIPC representative that provides technical guidance for risk identification, gap analyses, and prioritization. CIPC, through its cyber subcommittee, will specifically provide guidance on Digital Credential Management.

• **Cyber Attack Tree Task Force (CATTF)**
  The CATTF continues to work diligently on a very complicated subject. All sections of the cyber attack trees continue to be expanded, including scenarios causing multi-Bulk Electric System (BES) instabilities (e.g., disruptions to transmission, distribution, generation and load) and scenarios impacting situational awareness (e.g., disruptions to communications, energy management systems, distribution management systems, and Supervisory Control and Data Acquisition “SCADA”). At the March 2014 CIPC meeting the CATTF will review its results and recommendations for cyber attack tree components. The CATTF is targeted to complete their study later this year.

• **Bulk Electric System Security Metrics Working Group (BESSMWG)**
  The BESSMWG research conducted to date has not found any data (either from DOE 417s or from the ES-ISAC) which could contribute to trending in the development of measurements or metrics. Leadership from both the BESSMWG and NERC executive staff will meet in early February to discuss plans for delivering measurable BES security metrics to industry in 2014. The effort will review obstacles and new sources of available cyber security data to map out a path forward and involve the participation of the Reliability Assessment and Performance Analysis department.

• **GridEx II After Report and Scenario Planning for GridEx III**
  The GridEx Working Group will begin work by mid-year analyzing the after report from GridEx II and communicating recommendations to the CIPC Executive Committee for any future CIPC actions. Work will begin later this year with preparations for the next NERC Grid Exercise scheduled for fall 2015.

**Other CIPC Projects and Topics Under Consideration:**

• Handling scalability of large scale critical infrastructure protection related events.
• Investigating options for escalating high-level decision making.
• Implementation of the Cyber Risk Information Sharing Program (CRISP).
• Development of a Cyber Security Capability Maturity (C2M2) style approach in projects such as the long-term reliability assessment (LTRA) and BESSMWG.
• Respond to updated National Infrastructure Protection Plan (NIPP) and other outcomes from the Executive Order and Presidential Policy Directives (PPD) work.

Operating Committee
The OC is the NERC standing committee chartered by the NERC Board of Trustees to promote enhanced bulk power reliability in both the short-term planning and real time operations timeframes.

2013 Key Initiatives
• Reliability Guidelines – The OC developed and approved two Reliability Guidelines in 2013 and began development of a third.
  ▪ The OC approved the Reliability Guideline: Operating Reserve Management in October 2013.
  ▪ In December 2013, the OC approved posting for a 45-day comment period the draft Reliability Guideline: Generating Unit Operations during Complete Loss of Communications. It is expected that work will be completed on this guideline in 2014.
• MISO Reliability Plan – In June, 2013, an Operations Reliability Coordination Agreement (ORCA) was reached between MISO and the interested parties. Given this agreement, the parties recommended the OC’s approval of the revised MISO reliability plan. The OC approved the revised MISO Reliability Plan, in accordance with Requirement 2 of IRO-001-1.1.
• NERC Interchange Distribution Calculator (IDC) – On March 31, 2013, NERC successfully transitioned the NERC IDC and related NERC reliability tools (e.g., System Data Exchange) to the IDC Association, an association of IDC users.
• Governing Documents – The OC approved a revised Charter and Strategic Plan at its September 2013 meeting, which were approved by the Board of Trustees at its November 7, 2013 meeting.
• NERCnet (ISN) – Based on industry input, the OC recommended NERC abide by certain transition requirements (intended to assure a smooth transition) as it worked to decommission NERCnet in 2014.
• The OC commented on the Coordinate Interchange Standard Drafting Project and the PER Informal Development Project. It also responded to the Board’s COM-003 Resolution.
• Arizona-Southern California Outages on September 8, 2011 – The OC analyzed the April 2012 report on the September 8, 2011 Arizona-Southern California outages and continues to monitor WECC’s specific responses to the recommendations identified in the report. The OC directed the Operating Reliability Subcommittee (ORS) to complete a survey of RCs related to the use of real-time contingency analysis and RC/TOP communications related to reliability tool failures. The ORS is currently drafting a reliability guideline that addresses reliability tools and status notifications.

2014 Major Initiatives
• OC Realignment of Activities and Organization – focus on the realignment and reprioritization of the work of its subgroups.
• Investigate methods to assure continuing high reliability with significant renewables penetration.
• Continue work on ongoing reliability topics of interest, such as GMD, implementing lessons learned from the SW Outage, and monitoring implementation of the ORCA.
• Event Analysis Subcommittee (EAS) – enhance the identification and publication of lessons learned and event reports.
• Annual State of Reliability Report – The OC’s Operating Reliability Subcommittee will review and develop the post-seasonal assessment sections of NERC’s 2014 State of Reliability report.

Planning Committee
Along with the committee’s development of a strategic plan and its annually produced reliability assessments, the NERC PC is actively engaged in a number of areas that are important to maintaining the reliability of the Bulk-Power system of North America.

2013 Key Initiatives
• NERC 2013 State of Reliability report – The 2013 report further advances risk identification methods that help foster improved reliability performance. The PC has formed the AC Substation Equipment Task Force (ACSETF) in response to the report’s recommendation.
• 2013 Special Reliability Assessment: Accommodating an Increased Dependence on Natural Gas for Electric Power, Phase II Report – Recommendations from this report recommend further regional analysis and enhancements to NERC’s reliability assessments. Quantitative measures and risk profiles are needed to better understand the impact to regional resource adequacy and the electric system’s resilience to disruptions in the natural gas supply chain.
• Supplement to the 2013 Long-Term Reliability Assessment: Probabilistic Assessment – The supplement to the 2013 Long-Term Reliability Assessment provides probabilistic indices by assessment area based on a common method and approach. This report is the first edition to a series of biennial efforts.
• Misoperations Task Force Report – The report analyzed protection system misoperation data, researched possible root causes, and developed observations, conclusions and recommendations to help registered entities decrease risk by focusing on the most frequent causes of protection system misoperations.
• 2013 Summer Reliability Assessment – Annual report on resource adequacy and industry preparations to maintain reliability for the upcoming summer season.
• Completion of Southwest Outage NERC Recommendations – A number of recommendations have been addressed by the PC in response to the Southwest Outage report. The PC has leveraged its technical working groups to provide guidance on wide area reliability issues including consistency in model parameters, angular separation, and sharing overload relay trip settings, and long-term and seasonal studies.
• Strategic Plan and Charter Enhancements – The PC’s Strategic Plan was enhanced, conforming to the ERO strategic plan.
• Geomagnetic Disturbance Task Force (GMDTF) – Two key documents were developed by the Task Force: 1) Geomagnetically Induced Currents (GIC) Modeling and Application Guideline and 2) Planning Study Guideline. These documents are used to establish a common study approach that can be used to model and analyze the impacts of GIC on the transmission system. These documents will provide instruction and guidance to the industry and ultimately provide the technical framework for the development of the GMD Reliability Standards (Phase II).

2014 Major Initiatives
• 2014 Reliability Assessment Reports – The PC expects to submit two annual assessment reports to the NERC Board of Trustees for their consideration; the 2013 Long-Term Reliability Assessment and the 2013/2014 Winter Reliability Assessment.
• 2014 State of Reliability report – The State of Reliability Report will provide an industry reference for historical bulk power system reliability, analytical insights with a path for
actionable remedies, and enable the discovery and prioritization of specific risk control steps.

- **Geomagnetic Disturbance Task Force** – The GMDTF sponsored the Standards Authorization Request (SAR) needed to initiate the standards development process. The task force has developed GIC modeling and planning study guidelines. This information, along with the development of the reference storm (design day), will provide the technical specifications needed for the development of the GMD Reliability Standards. The GMDTF is also developing a pilot assessment to better understand the planning approaches that will be used in Phase II of the GMD Reliability Standards.

- **Support of Standards Development** – The PC continues to support the NERC Standards Development process with subcommittees of the PC conducting essential technical research into current and proposed areas of reliability issues to either highlight on-going issues or improve the industry’s body of knowledge relating to system planning and reliable operation of the bulk power system. Additionally, subject-matter experts from the PC and its technical groups will continue to support the informal development of several Modeling, Data and Analysis (MOD) Reliability Standards. The PC is also engaged with the Standards Committee on technical discussions regarding the BPS reliability impacts of the demand response and distributed resources—highlighted as emerging long-term reliability challenges in numerous NERC assessments.

- **Completion of the Integration of Variable Generation Task Force (IVGTF) Work Plan** – In response to the NERC 2009 Summary Report on Accommodating High-Levels of Variable Generation, the IVGTF is addressing the recommendations through a series of 12 efforts on specific issues such as wind forecasting, distributed variable resources, and capacity contributions of variable generation. A final report is expected in mid-2014 which will be the culmination of this task force’s work to address the reliability challenges of integrating large amounts of variable generation.

- **Essential Reliability Services Task Force** – The PC has formed a task force as a follow on action to the recommendations from the 2013 Long-Term Reliability Assessment. The task force will focus on expanding NERC’s methodology for reliability assessment. The new approach may include the development of metrics for further evaluation in future long-term reliability assessments and supplement the existing resource adequacy measures. The task force will also develop a technical reference document on essential reliability services, which include frequency response, inertia, voltage stability, ramping capability, and other operational requirements needed to ensure BPS reliability. A technical reference manual for regulators and policy makers is needed to inform, educate, and build awareness on the reliability ramifications of a changing resource mix.

- **Coordination with the Reliability Issues Steering Committee (RISC)** – The PC continues to support RISC efforts and provide technical guidance for risk identification, develop gap analyses, and prioritize focus areas. The PC will specifically provide guidance on modeling and data concerns that should be considered as “high-risk” gaps as well as other risk areas detailed in the State of Reliability Report and Long-Term Reliability Assessment. The PC has focused its efforts on two key risk areas (titles of risk areas may be adjusted):
  - Adaptation and Planning for Change
  - Operational Modeling and Model Inputs

**Standards Committee**
The Standards Committee has revised its charter and will present it to the Board of Trustees for approval at its February 7, 2014 meeting. The
following changes have been made to the charter:

- General clean up.
- Additional mention of the SC’s working relationship with NERC Standards staff.
- Recognition of the SC’s role on communication issues related to the standards development process now that the SC’s communication subcommittee has been retired.
- As requested by the Operating Committee, language that more prominently recognizes the role of NERC technical committees during the authorization and monitoring of field tests conducted by standard drafting teams.

Resolution of the August 9, 2013 Appeal
On August 9, 2013, an appeal was filed by the Canadian Electricity Association, Essential Power LLC, and the Midcontinent Independent System Operator, Inc. challenging the SC’s actions on July 10 and July 18, 2013, as a violation of process steps required in the Standards Processes Manual. As part of the September 24, 2013 Resolution, the SC Chair and NERC’s Vice President of Standards are to report to the Board on reforms made to respond to the appeal.

2014 Reforms
At its February 2013 meeting, the Board approved the 2013 SC reforms, requesting an SC report in 2014 on the reforms’ effectiveness and the need for additional reforms. A report on these reforms will be presented to the Standards Oversight and Technical Committee (SOTC) at the February 6, 2014 meeting.

In response to both the resolution of the August Appeal and the Board’s approval of the 2013 SC reforms, the new 2014 reforms include:

1. Revisions to the SC Charter.
2. A 2014 consensus building approach that:
   a. More actively uses the Reliability Issues Steering Committee (RISC) to triage new and emerging issues, prior to consideration of the issue in the standards development process; and
   b. Instead of the ad hoc groups used in 2013, the reform proposes to use the existing Standards Authorization Request (SAR) drafting teams to build consensus, balancing equal and effective approaches, including standards, to address known reliability gaps; and
   c. Encourages the use of consensus building tools throughout the standards development process.
3. The parallel combination of SAR and Standard for comment and ballot will be limited to uses covered by Section 16 – waivers (consistent with September Resolution).
SRI Enhancement
NERC Performance Analysis Subcommittee

February 17, 2014
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Introduction

In August 2010, the Reliability Metrics Working Group (RMWG) released its Integrated Bulk Power System Risk Assessment Concepts paper introducing new concepts, such as the “universe of risk” of the bulk power system. In the concepts paper, a method to assess “event-driven” risks was introduced and the Severity Risk Index (SRI) was established to quantify the impact of various events of the bulk power system. As methods were analyzed, the SRI became a foundational attempt to quantify the performance of the bulk power system on a daily basis. It was designed to provide comparative context for evaluating current and historical performance of the system. The concept of quantifying “events” was not viable since there is no mechanism to aggregate operational data in a manner consistent with the concept of an event. However, it was determined that the daily measure of performance of the system was a good surrogate, still allowing for investigation, identification of ranges of performance and other measures important to gauge the current and historic bulk power system reliability. The concepts paper and SRI refinement calculation were endorsed by NERC’s Operating Committee (OC) and Planning Committee (PC) in September 2010. Subsequently, a companion whitepaper Integrated Risk Assessment Approach – Refinement to Severity Risk Index [Note: Move footnote 3. here.] was developed and approved by OC and PC in March 2011.

The NERC Performance Analysis Subcommittee (PAS) (the successor to the RMWG) has continued this analysis following the release of the State of Reliability Report 2013. At their April 2013 meetings, the Operating Committee (OC) and Planning Committee (PC) approved the 2013 State of Reliability Report and provided recommendations to enhance the Severity Risk Index (SRI).

This Report builds on previous work of the RMWG and the PAS and presents methods to address the recommendations and enhancements suggested by the OC and the PC.

OLD Severity Risk Index (SRI\textsubscript{OLD}) Graphical Depiction & Proposed Severity Risk Index (SRI\textsubscript{bps})

As defined in the Integrated Risk Assessment Approach – Refinement to Severity Risk Index whitepaper, the SRI\textsubscript{OLD} is a daily blended metric where transmission loss, generation loss, and load loss events are aggregated into a single value that measures performance of the system. Each element (transmission, generation, and load loss) is weighted by the inventory for that element to rate each day’s performance and determine significant days for appropriate performance analysis. SRI\textsubscript{OLD} values range from zero (a theoretical condition in which virtually no elements out of service) to 1,000 (a theoretical condition in which every transmission line, all generation units and all load lost (for more than 12 hours) across the system in a single day). The SRI\textsubscript{OLD} was designed to be fungible and usable for the entirety of NERC as well as applied more granularly, such as at a reliability coordinator level.

Figure 1 captures the daily severity risk index value based on calculation from 2008 to 2012 including the historic significant events used to pilot the calculation. On a yearly basis, these daily performance measurements are sorted in descending order to evaluate the year-on-year performance of the system. Since there is significant disparity between daily values calculated, the curve is depicted using a logarithmic scale. Table 1 lists the top 10 SRI\textsubscript{OLD} days for 2012, with the triggering event recorded for the day.

The Performance Analysis Subcommittee, in its previous State of Reliability Reports, has used this graphic to provide a quantitative graph that supports the assessment of the daily performance of the bulk power system, which has apparently been beneficial. It displays the full range of the performance for each day of the year, in a descending impact order, and allows for year on year comparisons of performance. Since it is sorted in a descending impact order, the left side of the chart generally displays the performance of the days that were most taxing to the bulk power system, while the right side of the chart displays those days which had limited impacts across the bulk power system. Finally, the central, more linear section of the chart, displays the “normal day” impacts within the bulk power system. This graphic has been updated to reflect the proposed changes in calculating SRI\textsubscript{bps}, and is shown in Figure 2. Table 2 lists the top 10 SRI\textsubscript{bps} days for 2012, with the triggering events recorded for each day.

\begin{itemize}
  \item \url{http://www.nerc.com/docs/pc/rmwg/Integrated_Bulk_Power_System_Risk_Assessment_Concepts_Final.pdf}
  \item \url{http://www.nerc.com/docs/pc/rmwg/SRI_Equation_Refinement_May6_2011.pdf}
  \item \url{http://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/2013_SOR_May%2015.pdf}
\end{itemize}
Figure 1: NERC Annual Daily Severity Risk Index (SRI\textsubscript{OLD}) Sorted Descending

![Descended SRI\textsubscript{OLD} Graph]

Table 1: 2012 NERC Top 10 SRI\textsubscript{OLD} Days

<table>
<thead>
<tr>
<th>Date</th>
<th>SRI</th>
<th>Generation</th>
<th>Transmission</th>
<th>Load Loss</th>
<th>Weather-Influenced?</th>
<th>Cause Description</th>
<th>Interconnection</th>
</tr>
</thead>
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<tr>
<td>Oct 29</td>
<td>27.89</td>
<td>1.95</td>
<td>1.78</td>
<td>24.16</td>
<td>✓</td>
<td>Hurricane Sandy</td>
<td>Eastern</td>
</tr>
<tr>
<td>Jun 29</td>
<td>19.94</td>
<td>2.49</td>
<td>1.37</td>
<td>16.08</td>
<td>✓</td>
<td>Thunderstorm Derecho</td>
<td>Eastern</td>
</tr>
<tr>
<td>Oct 30</td>
<td>6.63</td>
<td>2.76</td>
<td>3.35</td>
<td>0.51</td>
<td>✓</td>
<td>Hurricane Sandy</td>
<td>Eastern</td>
</tr>
<tr>
<td>Jun 30</td>
<td>4.71</td>
<td>1.62</td>
<td>1.96</td>
<td>1.13</td>
<td>✓</td>
<td>Thunderstorm Derecho</td>
<td>Eastern</td>
</tr>
<tr>
<td>Aug 28</td>
<td>4.21</td>
<td>1.65</td>
<td>0.32</td>
<td>2.23</td>
<td>✓</td>
<td>Hurricane Isaac</td>
<td>Eastern</td>
</tr>
<tr>
<td>Jul 18</td>
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<td>1.90</td>
<td>1.60</td>
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<td>Severe Thunderstorm</td>
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<tr>
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<td>0.98</td>
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<td>1.13</td>
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<tr>
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<td>1.28</td>
<td>1.40</td>
<td>0.66</td>
<td>✓</td>
<td>Hurricane Isaac</td>
<td>Eastern</td>
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Table 2: 2012 NERC Top 10 SRI$_{bps}$ Days

<table>
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<tr>
<th>Date</th>
<th>NERC SRI &amp; Components</th>
<th>Weather-Influenced?</th>
<th>Cause Description</th>
<th>Interconnection</th>
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<td>SRI</td>
<td>Generation</td>
<td>Transmission</td>
<td>Load Loss</td>
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<tr>
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<td>8.87</td>
<td>2.62</td>
<td>1.37</td>
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<td>Oct 30</td>
<td>7.15</td>
<td>2.91</td>
<td>3.35</td>
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<td>2.05</td>
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<tr>
<td>Jun 30</td>
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<td>1.70</td>
<td>1.96</td>
<td>1.08</td>
</tr>
<tr>
<td>Jul 18</td>
<td>4.40</td>
<td>2.00</td>
<td>1.60</td>
<td>0.80</td>
</tr>
<tr>
<td>Jul 20</td>
<td>3.49</td>
<td>1.12</td>
<td>1.72</td>
<td>0.65</td>
</tr>
<tr>
<td>May 29</td>
<td>3.38</td>
<td>1.92</td>
<td>1.36</td>
<td>0.09</td>
</tr>
<tr>
<td>Dec 20</td>
<td>3.37</td>
<td>1.60</td>
<td>0.67</td>
<td>1.10</td>
</tr>
<tr>
<td>Aug 8</td>
<td>3.34</td>
<td>1.15</td>
<td>2.13</td>
<td>0.06</td>
</tr>
<tr>
<td>Dec 21</td>
<td>3.32</td>
<td>1.54</td>
<td>1.23</td>
<td>0.55</td>
</tr>
</tbody>
</table>
Recommendation for Enhancement of OLD SRI (SRI\textsubscript{OLD})

The SRI\textsubscript{OLD} was originally designed to measure the impact of all system events that result in loss of transmission lines, generating units, or load loss regardless of whether the load loss was a result of loss of supply at the transmission level or generation level or was a direct result of outages at the distribution level.

One of the recommendations for enhancing the SRI was to revise it so that it better represents events resulting in load loss as the result of a loss of supply from the transmission or generation facilities that make up the bulk power system, rather than the loss of distribution system components. This focuses our attention on those events that directly apply to the performance of the transmission system and generation resources to which NERC’s reliability objectives apply.

Based on this recommendation, PAS is proposing an enhancement to the OLD SRI (SRI\textsubscript{OLD}) which is referred to in this document as bulk power system SRI (SRI\textsubscript{bps}). The SRI\textsubscript{bps} refers to the SRI where the load loss component of the daily SRI is more indicative of transmission or generation related events which result in loss of service to distribution customers. All other components of SRI\textsubscript{bps} would remain the same except for the load represented in the load loss component. This places the emphasis on load loss events that were caused by bulk power system facilities.
Generation, Transmission and Distribution-related Load Loss Segregation

One of the recommendations which PAS has evaluated is the method by which load loss is calculated and integrated into the SRI results. Based upon early work done by PAS, the OC and PC suggested that load loss events be weighted. Methods to determine the magnitude of load loss events were limited. Initially PAS collected load loss values from records maintained by the Office of Electricity Delivery & Energy Reliability of the U.S Department of Energy via Form OE-417. However, load loss values were available only on notable days, specifically those days in which a reporting threshold was exceeded. A further complication is that load loss data from Form OE-417 does not differentiate load loss due to generation, transmission or distribution sources. Using this data for load loss potentially overestimates the impact of bulk power system performance on the days which meet the filing criteria of Form OE-417. Finally, the manner in which the reported load loss values were used did not reflect whether the day’s results were predominantly caused by weather or other external forces.

Since the purpose of SRI is to indicate the performance of bulk power system, distribution impacts should be excluded from this calculation. Since 2011, the IEEE Distribution Reliability Working Group (DRWG) Benchmark Study has provided the industry with data to evaluate the performance of power delivery to distribution customers, as measured by industry reliability metrics. Analysis of the data collected in this study demonstrated that the load loss on many of these reportable days was predominantly the result of significant distribution outages, thus corroborating the need to modify the means for calculating the load loss component. The benchmark data collected by the IEEE Distribution Reliability Working Group is a better source of load loss data for the SRI than the load loss data extracted from Form OE-417 reports, since it captures the effects from both distribution outages as well as those created upstream of the distribution system. Further, it contains data for every day of the year, not just those days in which a reporting threshold was exceeded. It is expected that in the future analysis can be performed using the IEEE standard definition of a major event, evaluating its relevance for the bulk power system. This could address the concern expressed by the OC and PC regarding the effect of external influences or other occurrences, such as weather.

Bulk Power System SRI (SRI\textsubscript{bps}) Concept and Calculation

SRI\textsubscript{bps} is a metric in which the load loss component only captures load loss resulting from transmission or generation sources, not the bulk power system. All other components of SRI\textsubscript{bps} are the same as the previously published and discussed SRI\textsubscript{OLD}. SRI\textsubscript{bps} does not take in account load lost due to distribution system sources. Therefore this approach corrects the effects that arise from use of Form OE-417 data, as discussed above.

Based on data from the IEEE DRWG Benchmark Study\textsuperscript{5}, various approaches to distinguish load loss due to generation or transmission\textsuperscript{6} have been used to calculate SRI\textsubscript{bps}. This study is performed annually and is believed to encompass the largest dataset across North America using industry-standard reliability metrics. It currently comprises almost one hundred million customers and has been conducted annually since 2003. The Distribution Reliability Working Group, which sponsors this study, has approved that the data can be supplied anonymously for calculations as are proposed here. Modifications to the submittal calendar are expected to align with the production of the State of Reliability Report.

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\textsuperscript{4} \url{http://energy.gov/oe/information-center/reporting/electric-disturbance-events-oe-417} The Electric Emergency Incident and Disturbance Report (Form OE-417) collects information on electric incidents and emergencies. The Department of Energy uses the information to fulfill its overall national security and other energy emergency management responsibilities, as well as for analytical purposes.

\textsuperscript{5} IEEE 1366-2012 IEEE Guide for Electric Power Distribution Reliability Indices establishes methods for determining that a major event has occurred using industry standard reliability metrics.

\textsuperscript{6} The IEEE DRWG Annual Benchmark Study does not explicitly distinguish between customer interruptions that are the result of generation or transmission; rather it identifies source outages that cause distribution customer interruptions.

Appendix B. IEEE Reliability Benchmark Data, \url{http://grouper.ieee.org/groups/td/dist/sd/doc/}

Bulk Power System SRI (SRI$_{bps}$) Equation

The PAS proposes the following method to calculate the load loss due to transmission or generation sources; calculation changes from SRI$_{OLD}$ to SRI$_{bps}$ are indicated with highlights:

\[ \text{SRI}_{bps} = [(\text{RPL}) \times w_L \times (\text{MW}_L) + w_T \times (N_T) + w_G \times (N_G)] \times 1000 \]

Where,

- \( \text{SRI}_{bps} \) = Severity Risk Index for specified event (assumed to span one day),
- \( w_L \) = 60%, weighting of load loss,
- \( \text{MW}_L \) = normalized MW of bps$_L$ in percent,

\[ \text{bps}_L = \left( \frac{\text{MW}_{\text{peak}}}{\text{Total}_{C/D}} \right) \times (\text{CL}_{bps}) \]

Where,

- \( \text{bps}_L \) = load loss due to transmission or generation sources (MW) for the day
- \( \text{MW}_{\text{peak}} \) = daily peak load (MW) is aggregated at NERC level obtained from FERC
- \( \text{Total}_{C/D} \) = Total Customer served for the day obtained from IEEE benchmark data
- \( \text{CL}_{bps} \) = Customers Interrupted due to transmission or generation sources for the day obtained from IEEE benchmark data

- \( w_T \) = 30% - weighting of transmission lines lost,
- \( N_T \) = normalized number of transmission lines lost in percent obtained from TADS$^7$ reports
- \( w_G \) = 10% - weighting of generators lost,
- \( N_G \) = normalized number of generators lost in percent obtained from GADS$^8$ reports
- \( \text{RPL} \) = load Restoration Promptness Level:
  - \( \text{RPL} = 1/4, \) if \( T_{CAIDI} < 50 \)
  - \( \text{RPL} = 2/4, \) if \( 50 \leq T_{CAIDI} < 100 \)
  - \( \text{RPL} = 3/4, \) if \( 100 \leq T_{CAIDI} < 200 \)
  - \( \text{RPL} = 4/4, \) if \( T_{CAIDI} \geq 200 \)

\( T_{CAIDI} \) = Transmission (or Generation Source) Customer Average Interruption Duration (in minutes) obtained from IEEE benchmark data$^8$

Additional information on formula and weighting factors above can be found at [http://www.nerc.com/docs/pc/rmwg/SRI_Equation_Refinement_May6_2011.pdf](http://www.nerc.com/docs/pc/rmwg/SRI_Equation_Refinement_May6_2011.pdf)

SRI Comparison for Specific Significant Days

SRI$_{OLD}$, while providing meaningful measurement of the daily performance of the bulk power system, created concern within certain audiences about the influence of the load loss events that were largely impacting the distribution system. The effect was confirmed after further analysis showed that the majority of reports filed under OE-417 were found to be associated with significant distribution system interruptions. The transition to SRI$_{bps}$ is intended as a corrective measure.

In order to determine whether such modification leads to better datasets for industry analysis, noteworthy events, which comprised approximately 9 days, were selected as case studies for comparison and were chosen to test “boundary

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$^7$ [http://www.nerc.com/pa/RAPA/tads/Pages/default.aspx](http://www.nerc.com/pa/RAPA/tads/Pages/default.aspx)

$^8$ [http://www.nerc.com/pa/RAPA/gads/Pages/default.aspx](http://www.nerc.com/pa/RAPA/gads/Pages/default.aspx)

conditions” for bulk power system impacts. These included February 2-5, 2011, which occurred primarily in the Texas Reliability Entity (TRE), and was related to extreme and extended cold that resulted in generation plant interruptions, related to the extreme temperatures. Next, on September 8, 2011, the Western Electric Coordination Council (WECC) reliability region experienced a substantial transmission-related event during periods of elevated temperature. On June 29, 2012, a substantial linear convective weather system, called a Derecho\textsuperscript{10}, passed through Illinois, Indiana, Ohio, continuing to the mid-Atlantic states, causing significant damage, largely to distribution system facilities. Finally, on October 29, 2012, Hurricane Sandy struck the eastern seaboard, with damage concentrated in New York and New Jersey and primarily affecting the local distribution systems; industry reports included October 30, 2012 impacts as well. Table 2 below compares SRI values with both approaches, notably the $\text{SRI}_{\text{OLD}}$ and $\text{SRI}_{\text{bps}}$. For the June 29 and October 29, 2012 events which were primarily caused by extreme weather and resulted in distribution system damage, as expected, the performance index as measured by the $\text{SRI}_{\text{bps}}$ score has been reduced. The opposite effect is experienced on February 2 and September 8, 2011 events, since the load losses were the result of bulk power system performance, the $\text{SRI}_{\text{bps}}$ is thus higher than the $\text{SRI}_{\text{OLD}}$. The intent of the SRI is to measure the severity of the impact of load loss due to bulk power system elements on the grid. As a result, it is believed this refinement to the SRI approach provides a more meaningful measure of the performance of the bulk power system, and delivers additional emphasis on the proper days.

**Table 3: SRI comparison for selected significant days.**

<table>
<thead>
<tr>
<th>Date</th>
<th>$\text{SRI}_{\text{OLD}}$</th>
<th>$\text{SRI}_{\text{bps}}$</th>
</tr>
</thead>
<tbody>
<tr>
<td>2/2/2011 – Cold Weather Event</td>
<td>10.3</td>
<td>10.8</td>
</tr>
<tr>
<td>9/8/2011 – Southwest Blackout</td>
<td>8.7</td>
<td>14.0</td>
</tr>
<tr>
<td>6/29/2012 – Thunder Storm Derecho</td>
<td>20.1</td>
<td>8.9</td>
</tr>
<tr>
<td>10/29/2012 – Hurricane Sandy</td>
<td>28.0</td>
<td>7.0</td>
</tr>
</tbody>
</table>

**SRI\textsubscript{OLD} and SRI\textsubscript{bps} : Comparative Charts**

This section shows charts and tables that illustrate the differences between the $\text{SRI}_{\text{OLD}}$ and the proposed $\text{SRI}_{\text{bps}}$ observed on days with extreme SRI values. Figures 3 and 4 show the values of both SRI for 70 days with the highest $\text{SRI}_{\text{OLD}}$ and the highest $\text{SRI}_{\text{bps}}$, respectively across the 5 year history, from 2008-2012. The charts below reflect the fact that the majority of days do not have load loss values, but solely reflect transmission and generation outages that result in a score for the day. Then, when load loss events have been captured, they are generally inflated substantially by the impact of distribution loss of load events.

**Figure 3: $\text{SRI}_{\text{OLD}}$ vs. $\text{SRI}_{\text{bps}}$ for 70 days with the highest $\text{SRI}_{\text{OLD}}$ values (2008-2012)**

\textsuperscript{10} [http://www.spc.noaa.gov/misc/AbtDerechos/derechofacts.htm](http://www.spc.noaa.gov/misc/AbtDerechos/derechofacts.htm) By definition, if the swath of wind damage extends for more than 240 miles (about 400 kilometers), includes wind gusts of at least 58 mph (93 km/h) along most of its length, and several, well-separated 75 mph (121 km/h) or greater gusts, then the event may be classified as a derecho.
The deviation of the blue line from the red line in figure 3 shows that the worst regular SRI scores were not heavily influenced by transmission or generation load loss events.

The deviation of the red line from the blue line in figure 4 shows that only a few days (when the red line does not depart from the blue line) are the result of transmission or generation load loss events. This lack of correlation is the primary driver for the refinement to the load loss data collection process.

Table 4 lists ten dates with the largest values of SRI_{OLD} and SRI_{bps}. There are seven common entries in these lists; however, the order of the dates differs. The events which are highly influenced by the load loss due to distribution sources ranks higher in the list of SRI_{OLD}. Whereas, events which are highly influenced by the load loss due to transmission or generation sources ranks higher in the list of bulk power system SRI (SRI_{bps}). In particular, the day with the largest SRI_{OLD} for the five years, October 29, 2012 (Hurricane Sandy), ranks fifth with respect to SRI_{bps}; conversely, the day with the largest SRI_{bps} for the five years, September 8, 2011 (Southwest Blackout Event), ranks only eighth with respect to SRI_{OLD}.

<table>
<thead>
<tr>
<th>Date</th>
<th>SRI_{OLD}</th>
<th>Date</th>
<th>SRI_{bps}</th>
</tr>
</thead>
<tbody>
<tr>
<td>10/29/2012</td>
<td>28.0</td>
<td>9/8/2011</td>
<td>14.0</td>
</tr>
<tr>
<td>6/29/2012</td>
<td>20.1</td>
<td>2/2/2011</td>
<td>10.8</td>
</tr>
<tr>
<td>10/29/2011</td>
<td>12.2</td>
<td>5/29/2012</td>
<td>8.9</td>
</tr>
<tr>
<td>2/2/2011</td>
<td>10.3</td>
<td>10/30/2012</td>
<td>7.2</td>
</tr>
<tr>
<td>9/12/2008</td>
<td>9.5</td>
<td>10/29/2012</td>
<td>7.0</td>
</tr>
<tr>
<td>9/8/2011</td>
<td>8.7</td>
<td>1/4/2008</td>
<td>5.3</td>
</tr>
<tr>
<td>8/28/2011</td>
<td>8.3</td>
<td>9/1/2008</td>
<td>4.9</td>
</tr>
<tr>
<td>10/30/2012</td>
<td>6.8</td>
<td>6/30/2012</td>
<td>4.7</td>
</tr>
</tbody>
</table>
Conclusion of Analyses of SRI_{OLD} and SRI_{bps} and Recommendation

Analyses of five years of data using SRI_{OLD} and SRI_{bps}, pairwise comparisons of values and assessment of top impacting days (for 2012 and for the five year history) were performed to determine the impact of modifying the method of incorporating load loss data into the severity risk score. Additional analysis was performed using a variety of statistical tests, as outlined in Appendix A. The results of these tests demonstrate that statistical results of SRI_{OLD} are materially similar to the statistical results of SRI_{bps}. Thus, no bias is being introduced statistically as a result of the proposed change. However, other statistical results demonstrate the benefit of transitioning from SRI_{OLD} to SRI_{bps}, notably the Delta comparison discussed in Appendix A highlights this benefit. Days that were predominantly weather influenced, and generally impacted the distribution system are de-emphasized with SRI_{bps}. Days that were predominantly bulk power system events, especially those that related to load loss within the bulk power system are highlighted with the modified calculation. Additionally, incorporating load loss events on days where no event reports had occurred previously allows for a more comprehensive dataset for the industry to evaluate.

It is recommended that the industry modify the calculation method to incorporate the effect of bulk power system load loss events by transitioning from SRI_{OLD} to SRI_{bps}. It is further recommended this change be effective in the 2014 State of Reliability Report.
APPENDIX A

Statistical Analyses Conducted

In this appendix, statistical properties of these variables are investigated and statistically significant trends are described. Both indices, SRI\textsubscript{OLD} and SRI\textsubscript{BPS}, indicate consistency in the performance of the bulk power system, as measured by the severity risk index over the 5-year period. Further, the analysis confirms statistically significant difference between SRI\textsubscript{OLD} and SRI\textsubscript{BPS}: SRI\textsubscript{OLD} is on average smaller than SRI\textsubscript{BPS}. Results of the significant changes by year and by season are obtained for SRI\textsubscript{OLD} and SRI\textsubscript{BPS} with some similarities and some differences between them. For example, for both indices, summer values are statistically significantly greater than any other season; and winter is greater than fall. However, only for SRI\textsubscript{BPS}, spring values are statistically significantly greater in fall. Test on Homogeneity of variance shows essentially similar dispersion (variance) of SRI\textsubscript{OLD} and SRI\textsubscript{BPS}.

\textbf{SRI\textsubscript{OLD} and SRI\textsubscript{BPS}: Descriptive Statistics and Paired t-test}

The 2008-2012 SRI\textsubscript{OLD} dataset contains 1827 daily observations. The basic descriptive statistics are shown in Table 5 and the histogram is shown in Figure 5.

![Histogram of SRI\textsubscript{OLD}](image)

**Table 5: Basic descriptive statistics SRI\textsubscript{OLD}**

<table>
<thead>
<tr>
<th>N</th>
<th>Mean</th>
<th>Std Dev</th>
<th>Median</th>
<th>Minimum</th>
<th>Maximum</th>
<th>Sum</th>
</tr>
</thead>
<tbody>
<tr>
<td>1827</td>
<td>1.646</td>
<td>1.138</td>
<td>1.462</td>
<td>0.347</td>
<td>27.994</td>
<td>3007.350</td>
</tr>
</tbody>
</table>

![Histogram of SRI\textsubscript{OLD}](image)
The 2008-2012 SRI\textsubscript{bps} dataset also contains 1827 daily observations. The basic descriptive statistics are shown in Table 6 and the histogram is shown in Figure 6.

<table>
<thead>
<tr>
<th>Table 6: Basic descriptive statistics of SRI\textsubscript{bps}</th>
</tr>
</thead>
<tbody>
<tr>
<td>N</td>
</tr>
<tr>
<td>------</td>
</tr>
<tr>
<td>1827</td>
</tr>
</tbody>
</table>

Next, the statistical analysis identified significant differences between SRI\textsubscript{OLD} and SRI\textsubscript{bps}. Because these two variables are calculated for the same set of days and are significantly correlated (the correlation 0.755 with p-value <0.0001), we apply a paired t-test on the difference in daily observations. The null hypothesis about the equality of expected values must be rejected (p=0.0026) and the alternative hypothesis that the expected old SRI is smaller than the expected SRI\textsubscript{bps} is accepted.

For a statistical comparison of the variances of SRI\textsubscript{OLD} and SRI\textsubscript{bps}, Brow and Forsythe's test for Homogeneity of variances is applied. It results in the conclusion that we cannot reject the null hypothesis on the equality of the variances of the distributions of old SRI and SRI\textsubscript{bps}, SRI\textsubscript{bps}. This analysis, if conducted as the sole means of comparing SRI\textsubscript{OLD} to SRI\textsubscript{bps}, would lead to the conclusion that on a given day, we can expect a smaller value of SRI\textsubscript{OLD} than SRI\textsubscript{bps} (the expected value of SRI\textsubscript{OLD} is smaller than the expected value of SRI\textsubscript{bps}).

Since this result didn’t fully support the expected results, additional analysis was undertaken, where the 1827 occurrences were separated into those days which had load loss events previously as reported through OE-417 (334 days of the 1827, or 18%) versus those which had no load loss data (1493 days of the 1827, or 82). The goal of this test is to investigate whether the relationship between the indices is similar on days without loss of load (we name them days of Type 1) and on days with loss of load used for the SRI\textsubscript{OLD} calculations (days of Type 2). First, we define a new variable, Delta, equal to the difference of SRI\textsubscript{OLD} than SRI\textsubscript{bps}. The previous test confirmed that the expected value of Delta is negative (with p-value 0.0026). Next we considered the distribution of Delta separately for Type 1 and Type 2 days; the results are shown in Table 7 and the histogram showing Delta for Type 1 and Type 2 is shown in Figure 7.
The statistics reveal the noteworthy difference in Delta for days of different types. On days of Type 1 (without loss of load) $\text{SRI}_{\text{OLD}}$ is on average smaller than $\text{SRI}_{\text{bps}}$; on days of Type 2 (with loss of load) $\text{SRI}_{\text{OLD}}$ is on average greater than $\text{SRI}_{\text{bps}}$. Series of ANOVA tests resulted in the following conclusions:

1. There is a highly significant difference in distribution of Delta on days of Type 1 and days of Type 2 (i.e. the shapes of the histograms are different);
2. Hypothesis on the homogeneity of the variances of Delta for these subsets has to be rejected (i.e. the spread of values of Delta is statistically significantly greater on days of Type 2);
3. Hypothesis of the equality of the expected values of Delta for these subsets has to be rejected (i.e. one expects to have greater difference between $\text{SRI}_{\text{OLD}}$ than $\text{SRI}_{\text{bps}}$ on days with loss of load than on days without loss of load);
4. T-test on the sign of Delta on days of Type 1 results in rejection of the null hypothesis on the zero expected value of Delta (i.e. we accept the alternative hypothesis that on days without loss of load the expected $\text{SRI}_{\text{OLD}}$ is smaller than the expected $\text{SRI}_{\text{bps}}$);
5. T-test on the sign of Delta on days of Type 2 results in rejection of the null hypothesis on the zero expected value of Delta (i.e. we accept the alternative hypothesis that on days with loss of load the expected $\text{SRI}_{\text{OLD}}$ is greater than the expected $\text{SRI}_{\text{bps}}$)

**Table 7: Sample Statistics for Delta**

<table>
<thead>
<tr>
<th>Type of Day</th>
<th>N</th>
<th>Delta</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td><strong>Mean</strong></td>
</tr>
<tr>
<td>1</td>
<td>1493</td>
<td>-0.15</td>
</tr>
<tr>
<td>2</td>
<td>334</td>
<td>0.36</td>
</tr>
</tbody>
</table>

![Figure 7: Distribution of Delta](image)
In summary, while SRI$_{bps}$ would lead to a slightly higher value on any given day (or about 80% of the calculated values), for a day where an SRI$_{OLD}$ incorporated an OE-417 report, or for the corresponding 20% of calculated values, the resulting value would be substantially lower. These tests demonstrate precisely the importance of migrating from SRI$_{OLD}$ to SRI$_{bps}$.

**SRI$_{OLD}$: Time Trend, Seasonal and Annual Changes**

This section presents the SRI$_{OLD}$ time trend by running the correlation analysis and the linear regression that relates time and the SRI value. A positive (negative) slope of the linear regression line, or time trend line, indicates that, on average, the SRI$_{OLD}$ values increase (decrease) in time. Additionally, the test on significance of the regression (or, equivalently, significance of the correlation between SRI$_{OLD}$ and the time variable) detects whether the positive (negative) slope has been observed by chance or its value is statistically significant and, therefore, points out to a declining (improving) performance, as measured by the index. Scatter plot and the linear regression line are shown in Figure 8.

![Figure 8: Scatter plot and the linear regression line for SRI$_{OLD}$](image)

The linear regression line has a small positive slope (0.00002525); however, the regression is not statistically significant (p=0.6169). Equivalently, the correlation analysis yields the positive correlation of 0.012 between time variable and SRI$_{OLD}$, which is not statistically significant (i.e. the test on zero correlation fails to reject the null hypothesis with the same p-value 0.6169). Thus, we conclude that the positive slope of the trend line very likely occurred by chance and does not provide statistically significant evidence about declining performance of the system; in the other words, on average, the SRI$_{OLD}$ remained consistent from 2008 to 2012.

Figure 9 reveals noticeable seasonal changes in the SRI$_{OLD}$. They can be studied via time series analysis or by applying a straightforward ANOVA tests. We investigated the seasonal impact on SRI by running one-way ANOVA with a four-level variable for season$^{11}$. The test results in a highly statistically significant dependence of the SRI on the season (the test on the equality of the excepted SRI for all seasons should be rejected with p<0.0001). The sample parameters by season are listed in Table 8.

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$^{11}$ For this study, seasons are defined as follows: Winter from December 1st to February 28th (or 29th); Spring from March 1st to May 31st; Summer from June 1st to August 31st; and Fall from September 1st to November 30th.
Table 8: Sample parameters of SRI_{OLD} by season

<table>
<thead>
<tr>
<th>Season</th>
<th>N</th>
<th>SRI_{OLD}</th>
<th>Mean</th>
<th>Std Dev</th>
</tr>
</thead>
<tbody>
<tr>
<td>Winter</td>
<td>452</td>
<td>1.604</td>
<td>0.878</td>
<td></td>
</tr>
<tr>
<td>Spring</td>
<td>460</td>
<td>1.552</td>
<td>0.662</td>
<td></td>
</tr>
<tr>
<td>Summer</td>
<td>460</td>
<td>1.974</td>
<td>1.182</td>
<td></td>
</tr>
<tr>
<td>Fall</td>
<td>455</td>
<td>1.452</td>
<td>1.557</td>
<td></td>
</tr>
</tbody>
</table>

Fisher's Least Square Difference test that compares all pairs of season results in the following conclusion: at the 5% significance level, **Summer SRI_{OLD} is greater than SRI_{OLD} for any other season, and in Winter SRI_{OLD} is greater than in fall.** All other pairs have essentially similar expected SRI_{OLD} value.

Finally, the statistical analysis of the annual changes in the Old SRI was performed. The sample parameters by year are listed in Table 9.

Table 9: Sample parameters of SRI_{OLD} by year

<table>
<thead>
<tr>
<th>Year</th>
<th>N</th>
<th>SRI_{OLD}</th>
<th>Mean</th>
<th>Std Dev</th>
</tr>
</thead>
<tbody>
<tr>
<td>2008</td>
<td>366</td>
<td>1.695</td>
<td>0.826</td>
<td></td>
</tr>
<tr>
<td>2009</td>
<td>365</td>
<td>1.566</td>
<td>0.655</td>
<td></td>
</tr>
<tr>
<td>2010</td>
<td>365</td>
<td>1.679</td>
<td>0.674</td>
<td></td>
</tr>
<tr>
<td>2011</td>
<td>365</td>
<td>1.505</td>
<td>1.268</td>
<td></td>
</tr>
<tr>
<td>2012</td>
<td>366</td>
<td>1.785</td>
<td>1.806</td>
<td></td>
</tr>
</tbody>
</table>

The one-way ANOVA test results in a highly statistically significant dependence of the SRI_{OLD} on year (the test on the equality of the excepted Old SRI for the five years should be rejected with p<0.008). Finally, Fisher’s Least Square Difference test that compares all pairs of year’s results in the following conclusion: at the 5% significance level, **in 2011 SRI_{OLD} is smaller than SRI for 2009, 2010, 2012; in 2009 SRI_{OLD} is smaller than SRI_{OLD} in 2012.** All other pairs of years have essentially similar expected SRI_{OLD} value.

**SRI_{bps}: Time Trend, Seasonal and Annual Changes**

This section presents the SRI_{bps} time trend by running the correlation analysis and the linear regression that relates time and the SRI_{bps} value. A positive (negative) slope of the linear regression line, or time trend line, indicates that, on average, the SRI_{bps} values increase (decrease) in time. Additionally, the test on significance of the regression (or, equivalently, significance of the correlation between SRI_{bps} and the time variable) detects whether the positive (negative) slope has been observed by chance or its value is statistically significant and, therefore, points out to a declining (improving) performance, as measured by the index. The scatter plot and the linear regression line are presented in Figure 9.
Figure 9: Scatter plot and the linear regression line for SRI_{bps}

The linear regression line has a small negative slope (-0.00006141); however, the regression is not statistically significant (p=0.069). Equivalently, the correlation analysis yields the negative correlation of -0.0425 between time variable and SRI_{bps}, which is not statistically significant (i.e. the test on zero correlation fails to reject the null hypothesis with the same p-value 0.069). Thus, we conclude that the negative slope of the trend line very likely occurred by chance and does not provide statistically significant evidence about improving performance of the system; in the other words, on average, the SRI_{bps} remained consistent from 2008 to 2012.

Note that while the main conclusions about time trends of SRI_{bps} and SRI_{old} are the same, the numerical results for the indices differ. First, slopes of their time trend lines have different signs, negative and positive, respectively. Even though these values are not statistically significant to indicate an improvement or a decline of the system, there is a difference in the p-values of the tests that led to this conclusion. P-value of 0.6169 means a high confidence in a horizontal time trend for SRI_{old}, while p-value of 0.069 does not provide this confidence and is “almost” significant to reject the hypothesis on a horizontal time trend for SRI_{bps} (if we have tested the hypothesis not at the significance level 5%, but at the significance level 6.9%, we would have to reject it).

Figure 10 reveals noticeable seasonal changes in SRI_{bps}. The box plot of the SRI_{bps} observations by season\textsuperscript{12} is shown in Figure 10 (1 stands for winter, 2 for spring, 3 for Summer, and 4 for Fall values; a number next to an outlier is the day number in the five-year dataset).

\textsuperscript{12} For this study, seasons are defined as follows: Winter from December 1\textsuperscript{st} to February 28\textsuperscript{th} (or 29\textsuperscript{th}); Spring from March 1\textsuperscript{st} to May 31\textsuperscript{st}; Summer from June 1\textsuperscript{st} to August 31\textsuperscript{st}; and Fall from September 1\textsuperscript{st} to November 30\textsuperscript{th}. 

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We investigated the seasonal impact on SRI_{bps} by running one-way ANOVA with a four-level variable for season. The test results in a highly statistically significant dependence of SRI_{bps} on the season (the test on the equality of the expected SRI_{bps} for all seasons should be rejected with p<0.001). The sample parameters by season are listed in the Table 10.

**Table 10: Sample parameters of SRI_{bps} by season**

<table>
<thead>
<tr>
<th>Season</th>
<th>N</th>
<th>Mean</th>
<th>Std Dev</th>
</tr>
</thead>
<tbody>
<tr>
<td>Winter</td>
<td>452</td>
<td>1.669</td>
<td>0.810</td>
</tr>
<tr>
<td>Spring</td>
<td>460</td>
<td>1.644</td>
<td>0.521</td>
</tr>
<tr>
<td>Summer</td>
<td>460</td>
<td>2.017</td>
<td>0.714</td>
</tr>
<tr>
<td>Fall</td>
<td>455</td>
<td>1.464</td>
<td>0.856</td>
</tr>
</tbody>
</table>

Fisher’s Least Square Difference test that compares all pairs of seasons results in the following conclusion: at the 5% significance level, Summer SRI_{bps} is greater than SRI_{bps} for any other season, in Spring SRI_{bps} is greater than in Fall, and in Winter SRI_{bps} is greater than in Fall. All other pairs have essentially similar expected daily SRI_{bps} value. To compare a dispersion (or spread) of the seasonal SRI_{bps}, we apply Brown-Forsythe’s test for homogeneity of variances for its seasonal samples. At the 5% significance level, Fall SRI_{bps} has a greater variance than Winter SRI_{bps} and Spring SRI_{bps} has a smaller variance than both Summer and Winter SRI_{bps}. Statistically significantly greater variance means a greater spread of values of the population. Seemingly surprising acceptance of the null hypothesis for the seasons with two extreme values of the sample standard deviation, Spring and Fall, can be explained by the “irregularity” (in particular, asymmetry and heavy tails) of these distributions. Note that our choice of Brown-Forsythe’s test for homogeneity of variances is also explained by its robustness under non-normality of distributions.

Finally, the statistical analysis of the annual changes in SRI_{bps} was performed. The sample parameters by year are listed in Table 11.

**Table 11: Sample parameters of SRI_{bps} by year**
The one-way ANOVA test results in a highly statistically significant dependence of SRI$_{bps}$ on year (the test on the equality of the excepted SRI$_{bps}$ for the five years should be rejected with $p<0.0001$). Finally, Fisher’s Least Square Difference test that compares all pairs of years results in the following conclusion: at the 5% significance level, the 2011 SRI$_{bps}$ is smaller than SRI$_{bps}$ for any other year; the 2009 SRI$_{bps}$ is smaller than SRI$_{bps}$ in 2008 and 2012. All other pairs of years have essentially similar expected SRI$_{bps}$ value.

<table>
<thead>
<tr>
<th>Year</th>
<th>N</th>
<th>SRI$_{bps}$</th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>Mean</td>
<td>Std Dev</td>
<td></td>
</tr>
<tr>
<td>2008</td>
<td>366</td>
<td>1.801</td>
<td>0.674</td>
<td></td>
</tr>
<tr>
<td>2009</td>
<td>365</td>
<td>1.664</td>
<td>0.528</td>
<td></td>
</tr>
<tr>
<td>2010</td>
<td>365</td>
<td>1.742</td>
<td>0.611</td>
<td></td>
</tr>
<tr>
<td>2011</td>
<td>365</td>
<td>1.504</td>
<td>1.041</td>
<td></td>
</tr>
<tr>
<td>2012</td>
<td>366</td>
<td>1.785</td>
<td>0.813</td>
<td></td>
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</table>
References


### ALR 1-4 BPS Transmission Related Events Resulting in Loss of Load

<table>
<thead>
<tr>
<th>Metric Number</th>
<th>ALR1-4</th>
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</thead>
<tbody>
<tr>
<td>Submittal Date</td>
<td>February 27, 2009, revised November 12, 2013</td>
</tr>
<tr>
<td>Sponsor Group</td>
<td>PAS</td>
</tr>
<tr>
<td>Short Title</td>
<td>Transmission related events resulting in loss of load</td>
</tr>
<tr>
<td>Metric Description</td>
<td></td>
</tr>
<tr>
<td>- Number of transmission related events resulting in loss of load</td>
<td></td>
</tr>
<tr>
<td>- Duration and loss of firm load involved in ALR1-4 events</td>
<td></td>
</tr>
</tbody>
</table>

**Purpose**

To track BPS transmission related events which resulted in firm Load Loss. This will allow planners and operators to validate their design and operating criteria assuring acceptable performance of the system.

**How will it be suited to indicate performance?**

The relative number within any given BA, Reliability Organization, Planning Authority, or Interconnection will be assessed to establish a trend of Transmission related events.

**Formula**

- Number of events in a year.
  - “Event” is an unplanned disturbance that produces an abnormal system condition due to equipment failures/system operational actions (either intentional or unintentional) that result in the loss of firm system demands for more than 15 minutes, utilizing the subset of data provided in accordance with EOP-004-2: Event Reporting EOP-004-2 as described below:
  1. Loss of firm load for 15 minutes or more:
     - a. 300 MW or more for entities with previous year’s demand of 3,000 MW or more.
     - b. 200 MW or more for all other entities.
  2. BES Emergency requiring manual firm load shedding of 100 MW or more.
  3. BES Emergency resulting in automatic firm load shedding of 100 MW or more (via automatic undervoltage or underfrequency load shedding schemes, or SPS/RAS).
  4. Transmission loss event with an unexpected loss within an entities’ area, contrary to design, of three or more BES Elements caused by a common disturbance (excluding successful automatic reclosing) resulting in a firm load loss of 50 MW or more.

- Duration in Hour
- Loss of firm load (MW)

**Time Horizon**

Historical and current year perspective

**Metric Start Time or Baseline**

2002, or whenever data first became available

**Data Collection Interval and Roll Up**

NERC Standard EOP-004 and OE-417 requires reporting of the data. Applicable Event Analysis reports will also be included.

**Ease of Collection**

Data is available; may require some adjustments to accommodate all the different groups for measurement.

**Aggregation**

BA, Reliability Organization, Planning Authority, or Interconnection

**Linkage to NERC Standard**

NERC Standard EOP-004 and OE-417

**Linkage to Data Source**

NERC data base

**Need for Validation or Pilot**

Need to validate completeness and consistency of reporting by entities
Load loss due to the response of voltage sensitive load and load that is disconnected from the system by end-user equipment is not included.

<table>
<thead>
<tr>
<th>Reporting</th>
<th>Bar Chart or line chart</th>
</tr>
</thead>
<tbody>
<tr>
<td>Publications and Documentation (e.g., section of LTRA)</td>
<td>Annual state of reliability report and NERC reliability indicator dashboard</td>
</tr>
</tbody>
</table>

1 Load loss due to the response of voltage sensitive load and load that is disconnected from the system by end-user equipment is not included.
Standards Independent Experts Review Project
An Independent Review by Industry Experts
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<td>Quality Scores</td>
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<tr>
<td>Overall Results</td>
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<td>Results by Family</td>
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<td>Findings</td>
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<td>Next Steps</td>
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</tbody>
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Executive Summary

The North American Electric Reliability Corporation (NERC) retained five industry experts (Team) to independently review the NERC Reliability Standards, setting the foundation for a plan that will result in a set of clear, concise and sustainable body of Reliability Standards. The primary scope was an assessment of the content and quality of the Reliability Standards, including identification of potential Bulk-Power System (BPS) risks that were not adequately mitigated (gaps1). As standards are evolving, the project addressed two sets: requirements Enforceable in 20132 and those that are Future Enforceable3. A secondary task was to suggest an improved organizational structure for the standards, if beneficial. However, the Critical Infrastructure Protection (CIP) standards were not addressed as they require specialized expertise.

The Team established an assessment process to develop recommendations for each requirement. The initial assessment determined whether a requirement should be retired. The remaining requirements were given a content and quality grade. A reliability risk level was assigned and the Team recommended prioritization of future work based on their risk and grades.

Key findings were as follows:

1. Through the application of a consistent set of criteria that included the NERC Reliability Principles, Paragraph 81 criteria, and a qualitative risk assessment, the Team recommended retirement of 147 requirements (36 percent) and retaining 257 in the Future Enforceable set. Namely, based on the Team’s assessment, non-reliability requirements exist in the standards which do not contribute to managing reliability risks. The Team further recommended consolidation within the retained requirements resulting in 232 requirements, with an overall requirement reduction of 43 percent. The recommended retirement and consolidation of requirements would enable industry to focus on impactful activities without increased risk to reliability.

2. Of the 257 retained Future Enforceable requirements, the Team found
   a. Eighty one (81) requirements are in “Steady-State”4 (i.e., no work needed), and
   b. One hundred seventy six (176) requirements need further enhancement to address content and quality issues.

3. Gaps were identified where risks to reliability are not adequately mitigated in the current set of standards: outage coordination, governor frequency response, situational awareness models, and clear three-part communications.

4. While significant improvements were found in recently developed standards, the majority are not yet at Steady-State. The updated standards have 21 percent fewer requirements than those they replaced, resulting in standards that are more focused on the most important activities for reliability. However, improvement in quality and content are required to reach Steady-State.

The Team made the following key near- and long-term recommendations:

1. Remove the recommended 147 requirements from the Actively Monitored List,5 and retire them. Focus initial improvement efforts on 16 high-risk standards with lower content scores.
2. Continue development of risk-based approaches to identify high priority reliability issues that need to be addressed by a standard, e.g., Reliability Issues Steering Committee (RISC) and Events Analysis.
3. Realign the standards from the current 14 families into 10 families grouped by functions needed for reliability.
4. Address identified gaps.
5. At an appropriate time in the CIP standards development, conduct an evaluation of the CIP requirements using a team of physical security, cyber security and power system operations experts.

---

1 The areas where risks to the BPS are not adequately mitigated in the standards may be referred to as “gaps” throughout this report.
2 The Team defined Reliability Standards that are currently enforceable or will become enforceable in 2013 as the “Enforceable in 2013” set of Reliability Standards.
3 The “Future Enforceable” group of standards and requirements include Enforceable in 2013 standards and those that have been approved by the Board or by the FERC and are currently pending enforceability. Requirements that will be replaced by the approved standards were not included in this group.
4 Steady-State was defined as standards that meet the quality and content criteria defined in this report. They are clear, concise, sustainable (stable), necessary for accountability, and sufficient to maintain the reliability of the BPS. These standards do not require further work absent a change in risks, technology, practice, or other impetus.
5 The Electric Reliability Organization’s (ERO) Compliance Monitoring and Enforcement Program (CMEP) Annual Implementation Plan is the annual operating plan for compliance monitoring and enforcement activities. The 2013 Implementation Plan includes a set of Reliability Standards (Actively Monitored List) that were selected based upon ERO-identified high-risk priorities and a three-tiered approach to compliance auditing.
Chapter 1 – Overview

This review is focused on developing a foundation for a plan that transforms NERC’s\(^6\) current set of standards to a body of clear, concise, sustainable (stable) standards necessary for accountability and sufficient to maintain the reliability of the BPS (Steady-State). Steady-State standards are both necessary and sufficient to ensure that Registered Entities carry out their responsibilities under the Functional Model in a manner that maintains an Adequate Level of Reliability.\(^7\)

Both industry and the Federal Energy Regulatory Commission (FERC) have raised the concern\(^8\) that there are too many requirements and a significant number of which do not contribute materially to the reliability of the BPS. This creates several challenges: (1) registered entities may lose focus on the most critical matters that can adversely impact reliability, (2) large amounts of industry resources, such as technical expertise, money and time, are diverted from high priority activities in order to demonstrate compliance, and (3) significant resources are dedicated to participate on standards drafting teams, reviewing and commenting on proposed new standards.

NERC retained five industry experts (Team) to independently review the NERC Reliability Standards, setting the foundation for a plan that will result in a set of clear, concise, and sustainable body of Reliability Standards. The primary scope was an assessment of the content and quality of the Reliability Standards, including identification of potential BPS risks that were not adequately mitigated (gaps). Thirteen of the 14 families of standards were evaluated, consisting of 91 standards with 446 requirements that are enforceable, or will become enforceable, in North America. The CIP family, containing nine standards and 43 requirements, and regional standards, were not included in this review.

Team Composition

The Team consisted of five independent industry experts (Ed Ernst, Bill Thompson, Brian Silverstein, Jim McIntosh, and John Meyer) and a sixth participant from FERC (Darrell Platt). The Team members have over 230 years of combined experience in the electric utility industry. Their areas of experience and competence included power systems engineering, relaying, transmission system planning, transmission and power system operations (including control center operations and dispatching, generation operations, transmission operations, and maintenance). The independent consultants brought executive leadership, experience from all three U.S. Interconnections, backgrounds working in investor-owned utilities (IOUs) and public power, and experience in both vertically integrated and regional transmission organizations/independent system operator (RTO/ISO) market environments and small entities. The Team also had experience working with the Canadian Provinces and Mexico. The FERC participant offered an additional perspective to the Team’s discussions that included a thorough knowledge of previous FERC orders and an understanding of various requirements’ contributions to BPS reliability. Biographies are provided in Appendix A.

NERC executive management team and staff provided overall NERC Management vision and oversight to the Team, including direction that the project should be an independent review and the results should include the Team’s findings. In addition, NERC Standards Committee (SC) members participated at various times with the Team to observe and offer comments (generally no more than two SC members per meeting). The Team also requested that standard drafting team member representatives and informal development group members discuss the importance and history of certain requirements.

Scope of Work

The Team’s scope of work was focused on conducting an independent review and evaluation of each requirement and subrequirement of the non-CIP NERC Reliability Standards. The review assessed the current status of the NERC Reliability Standards and developed an understanding for the level of work necessary to transform the standards to Steady-State,

\[^6\] NERC’s mission is to ensure the reliability of the BPS. To accomplish this, NERC develops and enforces Reliability Standards; annually assesses seasonal and longterm reliability; monitors the BPS through system awareness; and educates trains and certifies industry personnel.

\[^7\] The Adequate Level of Reliability Task Force and supporting documents can be located on the NERC website at: http://www.nerc.com/comm/Other/Pages/Adequate%20Level%20of%20Reliability%20Task%20Force%20ALRTF.aspx

\[^8\] Concerns were raised at the FERC Technical Conference “Priorities for Addressing Risks to the Bulk Power System”, which is located on the FERC website at: http://ferc.gov/EventCalendar/EventDetails.aspx?ID=5561&CalType=%20&CalendarID=116&Date=&View=ListView
along with the determination of any existing reliability gaps. As its secondary task, the Team identified a revised
organizational structure for the standards to align them with reliability functions.

The Team conducted its detailed review and evaluation for (1) the standards Enforceable in 2013 and (2) the Future
Enforceable version of the standards.

<table>
<thead>
<tr>
<th>Enforceable in 2013</th>
<th>Future Enforceable</th>
</tr>
</thead>
<tbody>
<tr>
<td>• Requirements that are currently enforceable</td>
<td>• Requirements that are currently enforceable and not proposed to be replaced by the Board or FERC</td>
</tr>
<tr>
<td>• Requirements that will become enforceable in 2013</td>
<td>• Requirements that will become enforceable in 2013 and are not proposed to be replaced by the Board or FERC</td>
</tr>
<tr>
<td></td>
<td>• Requirements that are approved by the Board</td>
</tr>
<tr>
<td></td>
<td>• Requirements that are approved by FERC</td>
</tr>
</tbody>
</table>

Table 1: Sets of Reliability Standards Examined

The findings and recommendations from this independent review, including the need for improvements, areas where risks
to the BPS are not adequately mitigated in the standards (referred to herein as “gaps”), retirements, consolidations and the
addition of a New Construct serve as a foundation and guide for NERC’s 2014–2016 Reliability Standards Development
Plan (RSDP). Further, the results and recommendations offer guidance to existing and future drafting teams.

Relationship to Other Activities

The Team noted the importance of continued concurrent development of the NERC initiatives outlined below, and
incorporated a number of existing and ongoing activities into its assessment.

- **Paragraph 81**
  Paragraph 81\(^{10}\) is an initiative focused on retiring requirements that either: (a) provide little protection to the BPS,
  (b) are unnecessary, or (c) are redundant. This initiative is being conducted in two phases — Phase 1 identified 34
  requirements for retirement and was filed with FERC on February 28, 2013. Phase 2 will review more complex
  candidates identified by industry. The Team used the Paragraph 81 criteria as one of the tests to determine if a
  requirement would be recommended for retirement. The Team also cross-checked its findings with the Phase 2
  candidates, and used this comparison to stimulate verification discussions.

- **Current Standards Development Work**
  The current development work identified in the 2013-2015 RSDP will bring the ERO’s standards program current
  with its obligations to address regulatory directives and conduct five-year reviews of all standards, all within (or
  earlier than) the plan’s 2013-2015 time horizon. This work must be completed to lay a foundation for
  implementation of the strategic recommendations identified in this report. There is urgency to complete work in
  2013, while maintaining the quality of the projects, so work can begin as soon as the 2014-2016 RSDP is endorsed
  by the Board.

  Efforts that have been ongoing in the standards area include:
  - Complete five-year reviews and on-going standards development projects;

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\(^{9}\) “New Construct” refers to a new organizational structure for the Reliability Standards. The sections of the new structure are explained in Chapter 4 of this report and outlined in Appendix C.

\(^{10}\) Paragraph 81 refers to this paragraph in the March 15, 2012 FERC Order Accepting with Conditions the Electric Reliability Organization’s Petition Requesting Approval of New Enforcement Mechanisms and Requiring Compliance Filing; *North American Electric Reliability Corporation*, 138 FERC ¶ 61,193 at P 81 (2012).
Resolve outstanding FERC directives;

Increased efficiencies and effectiveness of the Standards Development Process, including the addition of informal development activities to assess direction prior to formal standards development; and

Support the Team’s review of the Reliability Standards.

Because the Team’s activities occurred simultaneous with the aforementioned projects, through NERC staff, the Team informed existing standard drafting teams and informal development groups of the recommendations for specific requirements. Through this, the Team’s recommendations were then integrated into the ongoing activities.

**Reliability Assurance Initiative**

The Reliability Assurance Initiative (RAI) seeks to implement a risk-based compliance monitoring approach, including consideration of an entity’s internal controls to obtain a reasonable assurance of compliance with Reliability Standards. The initiative is also designed to support efforts related to Find, Fix and Track (FFT) enforcement concepts and a reasonableness approach to zero tolerance.\(^\text{11}\)

This transformation initiative compliments the Team’s recommendations. Standards and compliance fit together – the requirements set forth actions for which there must be accountability, and compliance verifies that accountability. However, industry must be able to focus on reliability during standards development, with confidence of how compliance will be assessed. The RAI will strive to make compliance expectations clear and conduct compliance assessment to foster learning wherever possible.

**Events Analysis**

The Events Analysis department provides data to support decisions regarding where the ERO should focus its efforts. This group conducts Root Cause Analyses (RCAs) to determine what actions, or lack of actions, have the greatest impact on BPS reliability. While the database of the results is still in its infancy, the group has collected several years of data. Using this data, they have begun to draw initial inferences and develop more targeted research, follow-on questions, or verification of other data sources. In addition to the RCA database, the group is working to support the development of an industry near-miss database to enable the early identification of reliability issues and formulate interventions and remediation strategies to reduce the potential of disturbances.

The Team consulted with the Events Analysis group to determine if any of the requirements recommended for removal led or contributed to an event. The Events Analysis group provided support for the Team’s recommendations with the understanding that this support was based on the available data. While the Team believes this will be very valuable in the future for prioritizing standards efforts, the current database of RCAs includes approximately 320 categorized events to date and will continue to grow. The Team encourages industry to support these efforts with timely and complete event analysis reports and participation in the cause code assignment process.\(^\text{12}\)

**Reliability Issues Steering Committee (RISC)**

The RISC is an advisory committee that reports directly to the Board. It triages and provides front-end, high-level leadership and accountability for nominated issues of strategic importance to BPS reliability. As a part of its work, the RISC reviewed 41 topics identified by NERC staff in terms of their potential threat to reliability. The RISC grouped these topics into broad risk areas, and then ranked each area as a High, Medium, or Low Priority. The Team used the RISC rankings as one way to validate its work.

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11 For further information regarding the RAI and whitepapers see the NERC website at: [Reliability Assurance Initiative](http://www.nerc.com/pa/rrm/ea/EA%20Program%20Document%20Library/ERO_Event_Analysis_Program_Document_Version_1_Feb_2012.pdf)

Chapter 2 - Project Process

Evaluation Process and Criteria

Scoring System and Evaluation Flow Diagram
The Team created a flow diagram to ensure its evaluations were repeatable for every requirement. The flow diagram below took the Team through a series of specific questions for each requirement.

![Evaluation Flow Chart](image)

*Figure 1: Evaluation Flow Chart*
The evaluations began with the Team review of each requirement to determine if it:

- does not support a Reliability Principle, \(^{13}\)
- meets the Paragraph 81 criteria, \(^{14}\) or
- is better suited as a guideline. \(^{15}\)

If the requirement met at least one of the above criteria, it was recommended for retirement. All remaining requirements should be retained, though some can be consolidated as noted below.

The Team then evaluated each requirement that was retained for content and quality (i.e., the scoring system). Specific criteria were identified that defined a Steady-State requirement—three criteria for content and twelve for quality—using the following documents:

- The NERC Functional Model
- NERC Rules of Procedure
- Ten Benchmarks for an Excellent Reliability Standard
- Acceptance Criteria of a Reliability Standard
- Results Based Standards materials development guidance
- FERC Order 672 (Order containing the 16 factors for a standard)
- FERC Order 693 (Order approving the initial body of Reliability Standards)
- Additional FERC Orders (including Order 748, Order 890, and Order 729)

**Evaluation Criteria**

After reviewing the above documents, the Team determined that the below criteria identified whether a requirement had reached Steady-State:

**Content**

1. Is the content of the requirement technically correct, including identifying who does what and when?
2. Are the correct functional entities identified?
3. Are the appropriate actions, for which there should be accountability, included or is there a gap?

**Quality**

1. Should the requirement stand alone as is or should it be consolidated with other standards?
2. Is it drafted as a results-based standard (RBS) requirement (performance, risk (prevention) or capability) and does it follow the RBS format (e.g., sub-requirement structure)?
3. Is it technologically neutral?
4. Are the expectations for each function clear?

\(^{13}\) The Team evaluated the Reliability Principles and determined that the Reliability Principles required two additions. See Appendix B.

\(^{14}\) The March 15, 2012 FERC Order Accepting with Conditions the Electric Reliability Organization’s (ERO) Petition Requesting Approval of New Enforcement Mechanisms and Requiring Compliance Filing, North American Electric Reliability Corporation, 138 FERC ¶ 61,193 at P 81 provided the opportunity for the ERO to evaluate requirements, which resulted in the Paragraph 81 project. The Paragraph 81 criteria can located in the Phase 1 Technical Paper, which can be located on the NERC website at: [http://www.nerc.com/pa/Stand/Pages/Project2013-02_Paragraph_81.aspx](http://www.nerc.com/pa/Stand/Pages/Project2013-02_Paragraph_81.aspx)

\(^{15}\) The NERC technical committees develop guidelines. The processes for each are contained in each committee’s charter. The Planning Committee’s Report/Reliability Guideline Approval Process for approving guidelines is contained in Appendix 4 of its charter; the Operating Committee’s Reliability Guidelines Approval Process is contained in Appendix 3 of its charter.
5. Does the requirement align with the purpose?
6. Is it a higher solution than the lowest common denominator?
7. Is it measureable?
8. Does it have a technical basis in engineering and operations?
9. Is it complete and self-contained?
10. Is the language clear and does not contain ambiguous or outdated terms?
11. Can it be practically implemented?
12. Does it use consistent terminology?

Each requirement was given a score of 0 to 3 for content and 0 to 12 for quality, with 0 being the lowest score. Finally, each requirement was evaluated for risk to reliability based on the Team’s experience, taking into consideration the ranking developed by the RISC and the violation risk factor (VRF) for each requirement.

**Validation of Work**

Following the evaluation for each requirement, the Team validated its work against other industry work to (1) ensure the body of requirements recommended for retention was sufficient to cover reliability needs, (2) determine if any requirements recommended for retirement should be retained based on industry data, and (3) validate the risk impact rating on each requirement. The Team’s validation process did not focus on ensuring total agreement with past work, rather to confirm there was a valid basis for variances. In addition, work products were reviewed for consistency and data recording errors.

Specifically, the Team’s validation process included the following:

1. A review was conducted of all of the requirements recommended for retention to make sure they were sufficient in scope to adequately address reliability. The Team used a new organization structure (New Construct – see Appendix C) for organizing standards that was based on the 2002 Standards Authorization Committee’s “White Paper on NERC’s Set of Organization Standards.” This New Construct, which is described in Chapter 4, helped verify that the retained requirements were sufficient as well as how the requirements fit together.

2. Sufficiency of the requirements recommended for retention was verified by conducting a comparison to the NERC Functional Model.

3. Requirements recommended for retention were compared to the Paragraph 81 recommendations (both the Phase 1 and Phase 2 candidates) to determine whether any of the retained requirements should be reconsidered for retirement.

4. Consultation with the Events Analysis team determining if any of the requirements recommended for retirement led or contributed to an event.

5. Requirements considered for retirement were reviewed against their reported violation history.

6. Requirements considered for retirement were further reviewed against the current VRF and the RISC ranking. If these requirements had either a high VRF or a high RISC ranking, further validation was pursued to ensure that the retirement of the requirement would have minimal impact on the reliability of the BPS.
Chapter 3 – Results of Analysis

The Team documented its detailed analysis and recommended changes. The results can be used as a foundation and guidance towards NERC’s 2014-2017 Reliability Standards Development Plan (RSDP).

Recommended for Retirement
A three-part test was used for initial screening of all requirements to determine if a requirement was needed to maintain the reliability of the BPS, as described in Chapter 2.

For the group of standards that are Enforceable in 2013, the Team found 44 percent of the requirements were not needed to maintain reliability and were recommended for retirement. Although there were three tests under which a requirement could have received a recommendation for retirement, the majority (81 percent) were based on the Paragraph 81 criteria. Common reasons were:

- Does not support a Reliability Principle (see, Appendix B)
- Duplicative
- Addresses market issues, not a reliability matter
- Administrative or documentation

In fact, at the requirement level, 10 of the recommendations for retirement in the Enforceable in 2013 set (eight in the Future Enforceable set) were already approved by the Board for retirement under Paragraph 81 Phase 1. There was progress made in eliminating unneeded requirements in the Future Enforceable set – the total number of requirements is reduced from 446 to 404, with only 36 percent recommended for retirement.

Content Scores
As the Team focused on improving requirements that should be kept, the content and quality evaluations examined only those requirements that remain after recommended retirements. Content Scores represent the technical basis of a requirement and are scored of 0 to 3 based on the attributes given in Chapter 2.

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16 See, Appendix E for a table documenting the recommendations.
17 There was a greater number at the sub-requirement level (34 in total, including CIP, within 19 Reliability Standards).
18 The Team did not evaluate content and quality for the TPL standards that will be replaced by TPL-001-4, thus in the Enforceable in 2013, this standard family is not represented.
The Team found that in the Future Enforceable set, 124 out of 257 retained requirements (48 percent) were correct and complete from a content standpoint and received a score of 3. Because the Team agreed that a requirement should score a 3 to be considered Steady-State, the remaining requirements need to be part of NERC’s transformation activities. The Team recognized incremental improvement from the Enforceable in 2013 set to the Future Enforceable set. The most common deficiencies include the need to identify all of the functional entities that the requirement should apply to and clearly describing required actions.

**Quality Scores**

Quality Scores represent how well a requirement is written, and are scored of 0 to 12 based on the attributes given in Chapter 2.
Chapter 3 – Results of Analysis

Figure 4: Quality Scores

While the Team identified some improvement from the Enforceable in 2013 set to the Future Enforceable set, significant improvement is still needed. Common deficiencies include requirements that were incomplete or not self-contained, contained unclear language, and were difficult to measure. The Team agreed that a Steady-State requirement should score between 11 and 12. Fifty-six percent of requirements are currently at this level.

Overall Results
The Team used the measures of content and quality to describe the status of the retained requirements, and concluded that a Content Score of 0, 1 or 2, or a Content Score of 3 with a Quality Score less than 11, indicates that a requirement should be enhanced.

Figure 5: Overall Scores for Future Enforceable Requirements

Twenty percent of the Future Enforceable requirements are in Steady-State requiring no further work. About 44 percent should be enhanced for content, quality, and to address any gaps.

Results by Family
The NERC Reliability Standards are currently organized into 14 families. CIP was excluded from this analysis.

There is significant variation across the different families of standards. For example, the single standard in the Nuclear (NUC) family is in Steady-State. On the other hand, 85 percent of the requirements in the Interchange Scheduling and Coordination (INT) family are recommended for retirement, with none of the remaining requirements in Steady-State. All 14 of the requirements in the Communications (COM) family should be enhanced. The findings in Figure 6 may be reflective of whether a family was updated. This figure provides an indication of where NERC should focus attention.
How Are Updated Standards Doing?

Of the 63 standards in the Future Enforceable set, 18 have been updated. This represents 93 out of 404 requirements. The Team examined these 18 standards to measure if the standards are improving.

The first observation is that the total number of requirements in the updated standards decreased from 117 to 93, a 21 percent consolidation. Almost half of the requirements in the Enforceable in 2013 set are recommended for retirement, dropping to 18 percent in the Future Enforceable set. There is a much more dramatic change in the number of requirements that were recommended for retirement between Enforceable in 2013 versus Future Enforceable when focusing on updated standards compared to the entire set of standards. The Team concluded that the work of the drafting teams has resulted in a smaller set of requirements that are focused on the most important activities for reliability.

See Appendix D for list of Future Enforceable standards that have been updated. The TPL standards were not included in this analysis, as the standards being replaced by TPL-001-4, which is pending FERC approval, were not scored. PRC-004 was included as there was improvement. MOD-028 was not included as it is recommended for retirement.
Requirements in updated standards with the lowest content scores have improved. Nevertheless, the Team believes all requirements should be technically correct in the three criteria areas. Only 42 percent of the updated requirements meet this mark compared to 48 percent when looking at all standards.

The updated standards have cleaned up the lowest quality scores. Nevertheless, only 57 percent of requirements are at an acceptable score of 11 or 12, which is about the same as when looking at all standards.
Chapter 4 - New Construct

After evaluating the Enforceable in 2013 and Future Enforceable Reliability Standards, the Team determined that the requirements should be organized into a New Construct to facilitate a needed fundamental change. There are several ways to organize the body of requirements into standards and families, as shown below. To some extent, all of these approaches are used in the existing standards, which often lead to duplication and confusion when related matters appear in different standards.

- By Functional Entity (Reliability Coordinator (RC), Transmission Operator (TOP), Balancing Authority (BA), etc.)
- By Function (Balance, Operate, Plan, Maintain, etc.)
- By Activity (i.e., develop a plan or policy, disseminate, train, maintain, execute, communicate, evaluate and report)
- By Timeframe (near-term, long-term)

Development of standards under the ERO framework began with legacy standards assembled over decades. A 2002 White Paper on NERC's Set of Organization Standards identified 11 families of standards:

1. Assess Transmission Future Needs and Develop Transmission Plans
2. Determine Facility Ratings, Operating Limits, and Transfer Capabilities
3. Design, Install, and Coordinate Control and Protection Systems
4. Define (Physical) Connection requirements
5. Balance Resources and Demand
6. Monitor and Assess Short-term Transmission Reliability - Operate Within Limits
7. Coordinate Interchange
8. Coordinate Operations
9. Prepare for and Respond to Abnormal or Emergency Conditions
10. Prepare for and Respond to Blackout or Island Conditions
11. Monitor and Analyze Disturbances, Events, and Conditions

The current set of standards is organized into 14 families:

1. Communications (COM)
2. Critical Infrastructure Protection (CIP)
3. Emergency Preparedness and Operations (EOP)
4. Facilities Design, Connections, and Maintenance (FAC)
5. Interchange Scheduling and Coordination (INT)
6. Interconnection Reliability Operations and Coordination (IRO)
7. Modeling, Data, and Analysis (MOD)
8. Nuclear (NUC)
9. Personnel Performance, Training, and Qualifications (PER)
10. Protection and Control (PRC)
11. Resource and Demand Balancing (BAL)

12. Transmission Operations (TOP)
13. Transmission Planning (TPL)
14. Voltage and Reactive (VAR)

Based on a life-cycle approach, the Team is recommending a New Construct with the following standard families (see Appendix C for graphical representation).

1. Transmission Planning
2. Facility Limits and Capabilities
3. Protection Systems
4. Infrastructure Maintenance
5. Operations
   - Interchange and Balancing
   - Operate Within Limits
   - Emergency Response
6. System Recovery
7. Authority, Communication and Human Factors
8. Control Center and Communication Capabilities
9. Critical Infrastructure Protection
10. Nuclear Interface

This New Construct will facilitate the development of standards around common topics or ‘themes.’ This would eliminate overlap, duplication and potentially conflicting language found in the requirements today. An example of this is the development of a single standard related to ‘Authority’ of the RC, BA and TOP. Currently, language related to an Authority is covered in various requirements in the EOP, IRO, TOP, and PER standards. A single Authority standard brings all the requirements related to Authority into one standard.
Chapter 5 - Findings, Recommendations and Conclusions

Current State of Standards

The state of the Enforceable in 2013 and Future Enforceable Reliability Standards is shown on the chart below. The content and quality score for each is an average for those Requirements not recommended for retirement. The resulting average scores are below the acceptable levels of 3 for Content and 11 or 12 for Quality which indicates that fundamental change must occur to move the current body of standards to Steady-State. The last bubble on the chart shows the Steady-State goal. The number of requirements inside of each bubble represents all requirements in the Enforceable in 2013 and Future Enforceable standards (both those that are retained and those recommended for retirement).

The average for the Future Enforceable body of standards shows incremental movement. Although some individual standards or requirements have made significant progress, there has not been enough to demonstrate movement toward Steady-State.

Findings

1. One hundred forty seven requirements should be retired and an additional twenty-five consolidated, with a further recommendation to consider additional consolidations.  
   
2. A number of areas were identified where risks to the BPS are not adequately mitigated in the Reliability Standards (gaps); key areas of concern are: (see, Appendix F for a complete list):
   
   a. Outage Coordination
   
   b. Governor Frequency Response

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21 The Team is recommending consolidation of 25 requirements. The Team also recommended that consolidation of additional requirements be considered.

22 See draft Authority Standard in Appendix H.
c. Situational awareness tools, such as Real-Time Contingency Analysis (RTCA) in Energy Management Systems (EMS) (recommendation 22 of the 2003 Blackout report)

d. Lack of requirement for use of three-part communications

3. Twenty percent of Future Enforceable requirements currently meet the Steady-State criteria for quality and content (scores of 11 or 12 for quality and 3 for content).

4. Current Reliability Standards revision processes, though they have resulted in requirements consolidation and reduction, are not significantly changing the content and quality of the requirements needed to create a final body of standards in Steady-State.

5. The current standard organizational construct can create duplication of requirements in various standards families. They should be reorganized to eliminate this duplication.

6. There are market-based and other non-reliability requirements (e.g., administrative) in the NERC Reliability Standards.

7. Throughout the standards, registered entities are required to put in place plans, policies, procedures and methodologies. There are often requirements to develop, solicit, and incorporate feedback, as well as disseminate, post, maintain and train personnel on the documents. These activities can be administrative and the requirements are not consistent.

**Recommendations**

Based on the above findings, the Team made the following specific recommendations to NERC regarding the non-CIP standards:

**Near-Term**

1. Pursue actions to retire 147 of 404 Future Enforceable requirements - these specific requirements are in listed in Appendix E. (Finding #1 and #6)

2. Remove requirements that are recommended for retirement in the Enforceable in 2013 and Future Enforceable sets of requirements from the Actively Monitored List for compliance assessment. (Finding #1)

3. Initiate actions to address gaps identified by the Team - see Appendix F for specific details. (Finding #2)

4. Focus improvement efforts on the 16 high-risk standards with lower content scores - see Appendix G for a list of standards. (Findings #3 and #4)

5. All future changes to requirements must meet the criteria used in this project, with a goal of 3 in content and 11 or 12 in quality. (Finding #3)

6. Pursue consolidation and organization of certain standards or requirements around the ‘themes’ of Authority, Emergency Operations (EOP) and Interconnected Reliability Operations (IRO) - see Appendix H for the proposed Authority standard. (Finding #5)

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24 Id., Communications Protocols, Recommendation #26

25 Steady State was defined as standards that meet the quality and content criteria defined in this report. They are clear, concise, sustainable (stable), necessary for accountability and sufficient to maintain the reliability of the bulk power system. These standards do not require further work absent a change in technology, practice, or other impetus.

26 1) Authority of the RC, BA, TOP and other entities tasked with the reliable operations of the BPS. (see Appendix H for draft language)
   2) EOP 001, EOP 002 and EOP 003 standards that deal with the non-blackstart or non-system restoration aspects of emergency operations.
   3) IRO 003-2, 005-4, 008-1, 009-1, 014-2 standards that deal with the theme of Monitor, Analysis and Actions to address Adverse Reliability Impacts, and potential or actual SOL/IROL violations. See the Requirement Evaluations spreadsheet for details regarding additional work needed on these standards.
7. NERC, in conjunction with industry, should continue to develop its risk-based approach for identifying reliability issues and appropriate solutions, which could include standards, guidelines, alerts, etc. NERC should consult with RISC and the technical committees to determine when the development of a standard is the appropriate solution to maintain a focused, concise number of standards or requirements. NERC should consider ways to better link this into the standards process. (Findings #1, #2, #5 and #6)

**Longer-Term**

1. Move to the New Construct for the standards in a measured manner - see Appendix C for details. (Finding #5)

2. Review and update the NERC Functional Model. Use process mapping to expand the tasks identified in the Functional Model to facilitate maintenance of a focused, concise number of standards or requirements. (Findings #2, #3, #4 and #5)

3. Explore dashboards to measure reliability and trends to monitor potential risks to the reliability of the BPS and use this information to deploy other mechanisms to address reliability (e.g., alerts, guides, etc.). Dashboard monitoring can assist in mitigating the growth of the number of standards, reduce the number of existing standards and associated compliance monitoring. (Findings #2, #3, #4 and #5)

**Additional Recommendations**

In addition, the Team made the following recommendations:

1. NERC should, at an appropriate time in the CIP standards development, commission a team of experts to review and evaluate the CIP requirements similar to the review accomplished herein, with physical security, cyber security and power system operations experts on the team.

2. The Team determined that registration was outside of the scope of this project, but recognizes that it will become an issue. The Team recommends that NERC investigate registration solutions (“light” functions, registration by requirement, by asset, by personnel, etc.).

3. The Team determined that evaluation of the regional standards was outside of the scope of this project. However, the Team recommends that NERC or the Regional Entities review them to identify candidates for retirement or consolidation with continent-wide standards. If not, these standards should, at a minimum, be aligned with continent-wide standards. Finally, the regional standards will need to align with the new family construct.

4. Expectations for compliance assessment, whether through clear measures, Reliability Standard Audit Worksheets (RSAWs) or other tools, should be clarified during the standards development process.

5. As standards are revised, do not include requirements that do not mitigate risks to reliability, do not support a reliability principle, or meet Paragraph 81 criteria, as outlined in the content tests for this review.

6. Standard Authorization Requests (SARs) must provide clear reliability direction consistent with the recommendations contained herein to drafting teams so expected outcomes are achieved.

7. Retain requirements to have plans, policies, procedures, methods, etc., where needed. Retire requirements that describe their administration, develop a guideline that describes good practices, and clean-up terminology for names, including NERC glossary definitions. For example, clarify requirements to “have” versus “implement” a plan, policy, procedure, methodology, etc.
Next Steps

The recommendations in this report will inform the 2014–2016 RSDP. A projected schedule for the development and endorsement of the 2014–2016 RSDP is as follows:

- **July/August:** The Team’s report will be posted on the NERC website with the Member Representatives Committee (MRC), the Standards Oversight and Technology Committee (SOTC) and the materials for the August Board meeting.
- **July/August:** NERC staff, in conjunction with selected members from the SC, will develop a draft 2014–2016 RSDP.
- **August 14:** The Team’s report will be presented to the Board.
- **August:** The Team’s report and supporting materials will be posted in a permanent location on the NERC website.
- **August through Early September:** The draft 2014–2016 RSDP will be posted on the NERC website for industry comment.
- **September:** The draft 2014–2016 RSDP will be revised.
- **October:** The 2014–2016 RSDP will be presented to the SC.
- **November:** The 2014–2016 RSDP will be presented to the Board.

Conclusion

The Team completed its review and scoring of all Enforceable in 2013 and Future Enforceable requirements, excluding CIP and the regional standards. Recommendations were made to retire requirements that were insignificant to reliability, duplicative, or that could be appropriately consolidated into other standards. A plan was developed to prioritize and reform the requirements that were retained to meet the defined Steady State quality and content grade. Lastly, a new standard family construct was presented which will improve understanding, simplify enforcement, and minimize duplicate requirements from being created.

Although the Team’s recommendations resulted in a reduction of the Future Enforceable Reliability Standards’ requirements from 404 to 232, the reliability of the BPS will be improved, not degraded. The remaining standards and their requirements are, or recommended to be, results-based that directly impact BPS reliability. Steady State quality and content in each standard will further ensure that the requirement is clearly understood, facilitates compliance and improves enforcement for all. This focus towards only results-based Reliability Standards will improve the overall BPS reliability. Further, moving to a body of stable standards enable registered entities to improve BPS reliability by focusing scarce resources on activities that directly impact reliability such as operations, planning and maintenance, rather than (1) modifying processes and procedures in order to be compliant with new or revised standards, and (2) commenting on numerous versions of standards that are under development.
Ed Ernst

Henry Edwin Ernst's (Ed) career in electric power system planning and operations spans 25 years, and he has 12 years of experience in marketing, sales, service, financial analysis, and business strategy development. Most recently, Ernst served as a Director of Transmission Planning at Duke Energy Company. In that role, Ernst directed a team that was responsible for the long-range transmission plan for Duke Energy Carolinas, compliance with relevant NERC and regional standards, and compliance with FERC OATT requirements.

Prior to his position as director, Ernst served as Manager of Grid Operations Engineering at Duke, responsible for overseeing the team who provided technical and OATT tariff support for real-time control area operations and reliability coordinator services for Duke Energy and neighboring interconnected utilities. Ernst also held positions providing engineering support to Duke’s real-time System Operations Center, training for Duke’s Control Center System Operators and Substation Operators, and software application development for Duke’s System Operations Center.

In addition to his 25 years in electric power system planning and operations, Ernst has 12 years of experience in Duke’s retail operations area. During those years, Ernst led Duke's efforts on Demand Side Management programs, as well as leading or overseeing a variety of positions in Duke’s retail operations area including product and program development, market research and marketing strategy.

Ernst currently serves as a Duke Energy representative to several industry groups, including the SERC Engineering Committee, VACAR Reliability Agreement Executive Committee, North Carolina Transmission Planning Collaborative, and Eastern Interconnection Planning Collaborative Technical Committee.

He earned a bachelor of science in electrical engineering from North Carolina State University, a master of electric power engineering from Rensselaer Polytechnic Institute, and a master of business administration from the University of North Carolina at Charlotte.

Jim McIntosh

Jim McIntosh (Mac) is ZGlobal’s Senior Vice President of Operations. Mac has more than 40 years of California Grid Operations Management experience and has played an important role on both WECC and NERC Operating Committees. His focus at ZGlobal has been in Renewable Resource Integrations, Expert Witness testimony relative to Grid Operations, Synchrophasor technology, hydro, pumped storage, steam plant, scheduling, and Balancing Area Operations.

As California ISO Director and Executive Operations Advisor, Jim McIntosh worked to solve the operational challenges of renewable resource integration. He was also involved with creating renewable interconnection standards to meet grid reliability requirements. Mr. McIntosh oversaw the design of the critical asset wing of the new CAISO control center and brought on line the first renewables dispatch desk in the United States. In helping to create the most modern control center in the world, Mr. McIntosh also facilitated a unique partnership with Google to develop situational awareness screens to equip operators with high-tech visualization tools that are integral to maintaining reliability as California achieves its 33 percent renewable goals.

For most of Mr. McIntosh’s decade-long career at the ISO, he served as Director of Grid Operations and was at the helm of the control center for much of the duration of the California energy crisis before switching his focus to renewable integration and becoming Director of Renewable Resource Integration and Grid Architecture.

Prior to joining the ISO as the Director of Scheduling in 2000, Mr. McIntosh worked for Pacific Gas and Electric Company for 29 years in various capacities including grid operations, hydro system, steam plant operations and substation operations. He has been a transmission dispatcher, scheduler, generation dispatcher and shift supervisor, as well as Manager of Operations and Director of Grid Outage Coordination and Scheduling. He is certified by NERC as a Reliability Coordinator.

Between 2005 and 2010, Mr. McIntosh represented the ISO on the NERC Operating Committee. In addition, he has served as the ISO representative to the WECC Operating Committee and he represented WECC on the NERC Variable Generation
Appendix A – Independent Expert Biographies

Task Force. Mr. McIntosh is the past chair of the WECC Interchange Subcommittee. He was also the vice chair for the NERC Interchange Committee.

Mr. McIntosh is a 30-year member of the American Power Dispatcher’s Association. He holds a B.A. in business management from Saint Mary’s College.

John Meyer
Frederick John Meyer (John) retired in 2007 after working 37 years in the power industry for Houston Lighting and Power (HL&P) and Reliant Energy. He is currently chair of the SPP Regional Entity Board of Trustees and is a non-affiliated Director since 2011 of WECC. In addition, since retirement Meyer has performed consulting services for South Texas Electric Cooperative (STEC), a G&T Coop in ERCOT. In this consulting role he provided testimony in transmission need and reliability before the Public Utility of Texas (PUCT) as well as testimony in Renewable Transmission Development and reliable system operations following renewable integration.

Prior to his retirement from Reliant Energy, Meyer was the Vice President of Regional Transmission Organization Activities for Reliant Resources and served on WECC’s Reliability Policy Issues Committee. In this role for Reliant, he developed policy on market design relating to all U. S. Regional Transmission Organizations (RTO) and Independent System Operators (ISO). He also was the contact person with FERC on Reliant filings and FERC Standard Market Design. Previously, Meyer was the Vice President of Asset Commercialization for Reliant Energy.

Before working for the unregulated part of Reliant Energy, Meyer worked 25 years for the regulated utility, Houston Lighting & Power (HL&P). His various assignments and experience at HL&P included General Manager of Engineering, General Manager of Energy Control & Dispatch, Manager of System Planning and Relaying and General Manager of Gas/Oil Power Plant Operations.

Meyer’s industry involvement includes NERC’s Planning Committee, Market Interface Committee and Stakeholders (Members) Committee. Meyer previously served as vice chair of IEEE’s Houston Chapter, was chair of the ERCOT Stakeholder Committee and was twice chair of ERCOT’s Technical Advisory Committee.

Meyer received the Gulf Coast Power Association Power Star Award in 2008 for his contributions to the ERCOT energy markets. He also received the PUCT Commissioner’s Award for leading the stakeholders in ERCOT and getting an agreement among them for the ERCOT energy market protocols. He earned a bachelor of science in electrical engineering with honors from Lamar University and a master of science in electrical engineering from the University of Houston. He completed the executive develop program in business administration from the University of Michigan.

Brian Silverstein
Brian Silverstein recently retired from 33 years at Bonneville Power Administration, where he focused on transmission reliability, market and policy issues. As Senior Vice President for Transmission Services, Silverstein was responsible for planning, design, construction, operations, maintenance, and sales for 15,000 miles of 115-kV through 500-kV transmission in six states. He also was accountable for meeting safety, reliability, financial, risk management and customer satisfaction objectives.

Prior to his role as SVP, Silverstein served as Vice President for Planning and Asset Management at Bonneville. His duties included grid planning for expansion, interregional interconnections, generation integration, and customer service. Silverstein sponsored deploying an asset management framework to sustain existing funds in transmission assets and expand the grid to meet agency objectives at lowest life cycle costs.

This year Silverstein was elected to serve as chair of the interim Board Committee for the WECC Reliability Coordinator and was on the WECC Board of Directors for three years. He was previously a member of the Reliability Issues Steering Committee for NERC.

Silverstein obtained his bachelor of engineering in electrical engineering from The Cooper Union and his master of engineering in electric power from Rensselaer Polytechnic Institute.
Bill Thompson

William L. Thompson (Bill) most recently was Director of the System Operations Center for Dominion Virginia Power, where he was responsible for the safe, reliable, and economic operation of the company’s bulk power system. His responsibilities included generation dispatch, transmission operations (including transmission switching), transmission access sales and marketing, management of the Energy Management System, and the statistical analysis and reports associated with energy delivery. In 2005, Mr. Thompson directed the transition of Dominion’s transmission operations as Dominion joined PJM, the Regional Transmission Operator in 13 states. He has served on the Board of Directors at SERC, where he also served as chair of the SERC Board Compliance Committee for three years prior to his retirement.

Prior to his position as director, Thompson, who had been with Dominion for 38 years until retiring, worked in relay protection in Transmission and Distribution; he also served as Chief Electrical Engineer in the Power Station Engineering Department (Fossil, Hydro, and Nuclear), and then Director of Electrical Engineering in the Nuclear Department. A previous chair of the SERC Operating Committee, he obtained a Green Belt in the Six Sigma Program at Dominion, and he currently serves as a member of the Board of Advisors for SOS Intl LLC. He is a licensed Professional Engineer in the State of Virginia.

Thompson earned a bachelor of science degree in electrical engineering from Virginia Polytechnic Institute and State University and a master of business administration from Averett College.
Appendix B - Reliability Principles

Reliability Principles

1. Interconnected bulk power 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 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 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 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.

6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.

7. The reliability of the interconnected bulk power systems shall be assessed, monitored, and maintained on a wide-area basis.

8. Bulk power systems shall be protected from malicious physical or cyber attacks.

In addition, after review of the aforementioned principles, the Team identified two needed additions:

9. Equipment shall be maintained as required for reliable Bulk-Power System operation.

10. Information necessary for the identification, analysis, prevention of, or response to, events and issues relating to the reliability of the Bulk-Power System shall be developed, maintained and shared with appropriate Functional Entities.

## Appendix C - New Construct

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<tr>
<td>Assess Transmission Future Needs and Develop Transmission Expansion Plans--- not Operational Planning</td>
<td>Determine Facility Ratings, Operating Limits, and Transfer Capabilities</td>
<td>Design, Install, and Coordinate Control and Protection Systems</td>
<td>Maintain BPS infrastructure, including adequate vegetation mgt.</td>
<td>Coordinate Interchange and Balance Resources and Demand</td>
<td>Operate within Limits - Monitor and Assess Short-term Transmission Reliability/</td>
<td>Prepare for and Respond to Abnormal or Emergency Conditions</td>
<td>Prepare for and Respond to Blackout or Island Conditions</td>
<td>Staff real-time operations with trained and certified personnel who have authority to act and have clarity of communication protocols</td>
<td>Have adequate control center, communication capabilities, etc to support real-time operations</td>
</tr>
</tbody>
</table>

<p>| TPL, MOD 10-15, MOD 24-27 | All FAC’s except FAC003; possibly MOD 004 and MOD 008 | All PRC’s except PRC-001 R1 (training) 005,008,011.01 7 (Maintenance &amp; Testing) | FAC 003, PRC 005, PRC 008, PRC 011, PRC 017 | INT and BAL | IRO, TOP, VAR | EOP related to emergency operation of an ‘intact’ system, EOP 004 | EOP related to blackstart | PER, COM related to Communication protocol | EOP, TOP, IRO COM- related to hardware | CIP | NUC |</p>
<table>
<thead>
<tr>
<th>Transmission Planning</th>
<th>Facilities Limits and Capabilities</th>
<th>Protections Systems</th>
<th>Infrastructure Maintenance</th>
<th>Operations</th>
<th>System Recovery</th>
<th>Authority, Communication and Human Factors</th>
<th>Control Center and Communication Capabilities</th>
<th>Cyber Security</th>
<th>Nuclear Interface</th>
</tr>
</thead>
<tbody>
<tr>
<td>Determine Facility Safety, Design, Standard, and Transfer Systems</td>
<td>Maturity ESC Infrastructure including adequate vegetation management</td>
<td>Coordinate Market and Cooperation Strategies</td>
<td>Operate within Limits - Monitor and Maintain Transmission Reliability</td>
<td>Prepare and Respond to Abnormal and Emergency Conditions</td>
<td>Skill real-time operations with trained and certified personnel who have authority to act and have knowledge of communication protocols</td>
<td>Ensure high-level security and confidentiality, including protection from cyber security threats</td>
<td>Ensure reliable interface between Nuclear Plants and ESC</td>
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**Appendix C – New Construct**

<table>
<thead>
<tr>
<th>TPL</th>
<th>MOD</th>
<th>FAC</th>
<th>FACIC</th>
<th>FACIE</th>
<th>FACM</th>
<th>FACI</th>
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<th>FACIIE</th>
<th>FACIM</th>
<th>FACII</th>
<th>FACIIIC</th>
<th>FACIIIE</th>
<th>FACMII</th>
<th>FACIIIM</th>
<th>FACIIIME</th>
<th>FACIIIMEC</th>
<th>FACIIIMECC</th>
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### Future Enforceable Standards that have been updated

<table>
<thead>
<tr>
<th>Standard</th>
<th>Description</th>
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<tbody>
<tr>
<td>BAL-001-1</td>
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<td>BAL-003-1</td>
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<td>COM-001-2</td>
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<td>COM-002-3</td>
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<tr>
<td>EOP-004-2</td>
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<tr>
<td>FAC-001-1</td>
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<td>FAC-003-3</td>
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<td>IRO-001-3</td>
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<td>IRO-002-3</td>
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<td>IRO-005-4</td>
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<tr>
<td>IRO-014-2</td>
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<tr>
<td>PRC-001-2</td>
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<td>PRC-004-2.1a</td>
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<td>PRC-005-2</td>
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<tr>
<td>TOP-001-2</td>
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<td>TOP-002-3</td>
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<td>TOP-003-2</td>
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<tr>
<td>VAR-001-3</td>
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### Appendix E - Requirements Recommended for Retirement

<table>
<thead>
<tr>
<th>Standard</th>
<th>Req.</th>
<th>Rationale</th>
</tr>
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<tbody>
<tr>
<td>BAL-001-1</td>
<td>R3.</td>
<td>This is a definition; not a requirement. Definition in Glossary of Overlap Regulation Service needs to be updated to cover R3 and R4 implementation</td>
</tr>
<tr>
<td>BAL-001-1</td>
<td>R4.</td>
<td>This is a definition; not a requirement. Definition in Glossary of Overlap Regulation Service needs to be updated to cover R3 and R4 implementation</td>
</tr>
<tr>
<td>BAL-002-1a</td>
<td>R5.</td>
<td>Administrative. This is a compliance reporting measure, not a unique performance requirement.</td>
</tr>
<tr>
<td>BAL-004-0</td>
<td>R1.</td>
<td>Does not support a reliability objective as defined by the Reliability Principles.</td>
</tr>
<tr>
<td>BAL-004-0</td>
<td>R2.</td>
<td>Does not support a reliability objective as defined by the Reliability Principles.</td>
</tr>
<tr>
<td>BAL-004-0</td>
<td>R3.</td>
<td>Does not support a reliability objective as defined by the Reliability Principles.</td>
</tr>
<tr>
<td>BAL-004-0</td>
<td>R4.</td>
<td>Does not support a reliability objective as defined by the Reliability Principles.</td>
</tr>
<tr>
<td>BAL-005-0.2b</td>
<td>R2.</td>
<td>P81 Phase 1.</td>
</tr>
<tr>
<td>BAL-005-0.2b</td>
<td>R3.</td>
<td>P81. Duplicative of R1.</td>
</tr>
<tr>
<td>BAL-005-0.2b</td>
<td>R8.</td>
<td>P81. Outdated due to technology.</td>
</tr>
<tr>
<td>BAL-005-0.2b</td>
<td>R9.</td>
<td>P81. This is a definition not a requirement</td>
</tr>
<tr>
<td>BAL-005-0.2b</td>
<td>R10.</td>
<td>P81. This is a definition not a requirement</td>
</tr>
<tr>
<td>BAL-005-0.2b</td>
<td>R11.</td>
<td>P81. This is a business practice and is automated in most EMS software.</td>
</tr>
<tr>
<td>BAL-005-0.2b</td>
<td>R12.</td>
<td>P81. This in the ACE equation so does not need to be repeated.</td>
</tr>
<tr>
<td>BAL-005-0.2b</td>
<td>R13.</td>
<td>P81. This is after the fact and is automated in most EMS software.</td>
</tr>
<tr>
<td>BAL-005-0.2b</td>
<td>R16.</td>
<td>This is a guide for the quality of the EMS system. Provide to the 2009-02 team for consideration.</td>
</tr>
<tr>
<td>BAL-006-2</td>
<td>R1.</td>
<td>This is only for energy accounting. Covered by tagging requirements</td>
</tr>
<tr>
<td>BAL-006-2</td>
<td>R2.</td>
<td>This is only for energy accounting. Covered by tagging requirements</td>
</tr>
<tr>
<td>BAL-006-2</td>
<td>R3.</td>
<td>This is only for energy accounting. Covered by tagging requirements (automated)</td>
</tr>
<tr>
<td>BAL-006-2</td>
<td>R4.</td>
<td>This is only for energy accounting. Covered by tagging requirements (automated)</td>
</tr>
<tr>
<td>BAL-006-2</td>
<td>R5.</td>
<td>This is only for energy accounting. Covered by tagging requirements (automated)</td>
</tr>
<tr>
<td>EOP-001-2.1b</td>
<td>R6.</td>
<td>P81. Duplicative of R4 and the Attachment</td>
</tr>
<tr>
<td>EOP-002-3.1</td>
<td>R2.</td>
<td>P81. Duplicative - requirement to take action is in R1.</td>
</tr>
<tr>
<td>EOP-002-3.1</td>
<td>R3.</td>
<td>P81. Duplicative of what is required to be in the plan under attachment 1 of EOP-001.</td>
</tr>
<tr>
<td>EOP-002-3.1</td>
<td>R6.</td>
<td>P81. Duplicative of BAL standards to meet CPS and DPS</td>
</tr>
<tr>
<td>EOP-002-3.1</td>
<td>R9.</td>
<td>P81. This is a market (tariff) issue.</td>
</tr>
<tr>
<td>EOP-003-2</td>
<td>R2.</td>
<td>P81. Duplicative of PRC-010 and TPL standards</td>
</tr>
<tr>
<td>EOP-003-2</td>
<td>R4.</td>
<td>P81. Duplicative of PRC-010 and TPL standards</td>
</tr>
<tr>
<td>EOP-003-2</td>
<td>R5.</td>
<td>P81. Duplicative of R1 and also covered under standards for TOP (TOP-002-3)</td>
</tr>
<tr>
<td>EOP-003-2</td>
<td>R6.</td>
<td>P81. Duplicative; an entity does the same actions as when not islanded.</td>
</tr>
<tr>
<td>EOP-003-2</td>
<td>R7.</td>
<td>P81. Duplicative of PRC-010 R1</td>
</tr>
<tr>
<td>EOP-004-2</td>
<td>R3.</td>
<td>P81. Administrative. Could also combine into R1</td>
</tr>
<tr>
<td>EOP-005-2</td>
<td>R7.</td>
<td>P81. This is a logical action that does not require a std.</td>
</tr>
<tr>
<td>EOP-005-2</td>
<td>R8.</td>
<td>P81. Duplicative with EOP-005-2 R1.3 (have a plan) and RC authority in IRO-001-1.1b R3</td>
</tr>
<tr>
<td>EOP-005-2</td>
<td>R12.</td>
<td>P81. Duplicative with PER-005 R3</td>
</tr>
<tr>
<td>EOP-006-2</td>
<td>R7.</td>
<td>P81. This is a logical action that should be in the plan and does not require a std.</td>
</tr>
<tr>
<td>EOP-006-2</td>
<td>R8.</td>
<td>P81. This is a logical action that should be in the plan and does not require a std.</td>
</tr>
<tr>
<td>FAC-002-1</td>
<td>R2.</td>
<td>P81 Phase 1.</td>
</tr>
<tr>
<td>FAC-008-3</td>
<td>R4.</td>
<td>P81 Phase 1.</td>
</tr>
<tr>
<td>FAC-008-3</td>
<td>R5.</td>
<td>P81 Phase 1.</td>
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<tr>
<td>FAC-010-2.1</td>
<td>R3.</td>
<td>More appropriate as a Guideline. This is a checklist.</td>
</tr>
<tr>
<td>FAC-010-2.1</td>
<td>R4.</td>
<td>More appropriate as a Guideline. Description of appropriate coordination does not rise to a Standard.</td>
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<tr>
<td>FAC-010-2.1</td>
<td>R5.</td>
<td>P81 Phase 1.</td>
</tr>
<tr>
<td>FAC-011-2</td>
<td>R3.</td>
<td>More appropriate as a Guideline. This is a checklist.</td>
</tr>
<tr>
<td>FAC-011-2</td>
<td>R4.</td>
<td>More appropriate as a Guideline. Description of appropriate coordination does not rise to a Standard.</td>
</tr>
<tr>
<td>FAC-011-2</td>
<td>R5.</td>
<td>P81 Phase 1.</td>
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<tr>
<td>Standard</td>
<td>Req.</td>
<td>Rationale</td>
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<tr>
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<tr>
<td>IRO-004-2</td>
<td>R1.</td>
<td>P81. The intent is covered in IRO-008 R1 and is also duplicative of other IRO standards (IRO-001-1.1 R3)</td>
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<tr>
<td>IRO-014-2</td>
<td>R2.</td>
<td>P81. Administrative.</td>
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<tr>
<td>MOD-001-1a R2.</td>
<td>Same as R1</td>
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<td>MOD-001-1a R3.</td>
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<td>MOD-001-1a R4.</td>
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<td>MOD-001-1a R5.</td>
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<td>MOD-001-1a R6.</td>
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<td>MOD-001-1a R7.</td>
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<tr>
<td>MOD-001-1a R8.</td>
<td>Same as R1</td>
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<tr>
<td>MOD-001-1a R9.</td>
<td>Same as R1</td>
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<tr>
<td>MOD-004-1 R2.</td>
<td>P81. This is a business practice.</td>
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<tr>
<td>MOD-004-1 R7.</td>
<td>P81. This is a business practice.</td>
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<td>MOD-008-1 R5.</td>
<td>P81. Administrative.</td>
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<td>MOD-016-1.1 R2.</td>
<td>Same as MOD-016, R1.</td>
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<td>MOD-016-1.1 R3.</td>
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<td>MOD-017-0.1 R1.</td>
<td>Same as MOD-016, R1.</td>
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<td>MOD-018-0 R1.</td>
<td>Same as MOD-016, R1.</td>
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<td>MOD-018-0 R2.</td>
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<td>MOD-019-0.1 R1.</td>
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<td>MOD-021-1 R1.</td>
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<td>MOD-021-1 R2.</td>
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<td>MOD-021-1 R3.</td>
<td>Same as MOD-016, R1.</td>
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<tr>
<td>MOD-028-2 R1.</td>
<td>P81. Calculation of ATC is a market (tariff) issue. Determination of TTCs for operational reliability is covered under FAC 12-1 (no longer enforced), 13-1 and 13-2. Other TOP and IRO Standards require operation within limits. NAESB or another organization will need to develop the needed business practices for ATC.</td>
<td></td>
</tr>
<tr>
<td>MOD-028-2 R2.</td>
<td>Same as MOD-028, R1.</td>
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<td>MOD-028-2 R4.</td>
<td>Same as MOD-028, R1.</td>
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<td>MOD-028-2 R7.</td>
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<td>MOD-028-2 R8.</td>
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<td>MOD-028-2 R10.</td>
<td>Same as MOD-028, R1.</td>
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<td>MOD-028-2 R11.</td>
<td>Same as MOD-028, R1.</td>
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<tr>
<td>MOD-029-1a R1.</td>
<td>Same as MOD-028, R1.</td>
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<td>Rationale</td>
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<tr>
<td>MOD-029-1a</td>
<td>R2.</td>
<td>Same as MOD-028, R1.</td>
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<tr>
<td>MOD-029-1a</td>
<td>R3.</td>
<td>Same as MOD-028, R1.</td>
</tr>
<tr>
<td>MOD-029-1a</td>
<td>R4.</td>
<td>Same as MOD-028, R1.</td>
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<td>MOD-029-1a</td>
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<tr>
<td>MOD-029-1a</td>
<td>R7.</td>
<td>Same as MOD-028, R1.</td>
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<td>MOD-029-1a</td>
<td>R8.</td>
<td>Same as MOD-028, R1.</td>
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<td>MOD-030-2</td>
<td>R1.</td>
<td>Same as MOD-028, R1.</td>
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<td>MOD-030-2</td>
<td>R2.</td>
<td>Same as MOD-028, R1.</td>
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<tr>
<td>MOD-030-2</td>
<td>R3.</td>
<td>Same as MOD-028, R1.</td>
</tr>
<tr>
<td>MOD-030-2</td>
<td>R4.</td>
<td>Same as MOD-028, R1.</td>
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<tr>
<td>MOD-030-2</td>
<td>R5.</td>
<td>Same as MOD-028, R1.</td>
</tr>
<tr>
<td>MOD-030-2</td>
<td>R7.</td>
<td>Same as MOD-028, R1.</td>
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<tr>
<td>MOD-030-2</td>
<td>R8.</td>
<td>Same as MOD-028, R1.</td>
</tr>
<tr>
<td>MOD-030-2</td>
<td>R10.</td>
<td>Same as MOD-028, R1.</td>
</tr>
<tr>
<td>MOD-030-2</td>
<td>R11.</td>
<td>Same as MOD-028, R1.</td>
</tr>
<tr>
<td>PER-004-2</td>
<td>R2.</td>
<td>P81. Duplicative with currently enforceable IRO and TOPs related to managing SOLs and IROL's.</td>
</tr>
<tr>
<td>PRC-010-0</td>
<td>R2.</td>
<td>P81. Administrative. Approved by BOT.</td>
</tr>
<tr>
<td>PRC-022-1</td>
<td>R2.</td>
<td>P81 Phase 1.</td>
</tr>
<tr>
<td>PRC-010-0</td>
<td>R2.</td>
<td>P81. Administrative.</td>
</tr>
<tr>
<td>TPL-001-4</td>
<td>R1.</td>
<td>P81. Appropriate as a Guideline. Model and data requirements are in the MOD standards. This requirement is more of a best practice on considerations such as load level, generation patterns, contingencies, etc. It may often be regional in nature.</td>
</tr>
<tr>
<td>VAR-001-3</td>
<td>R5.</td>
<td>Each Purchasing-Selling Entity and Load Serving Entity shall arrange for (self-provide or purchase) reactive resources – which may include, but is not limited to, reactive generation scheduling; transmission line and reactive resource switching; and controllable load– to satisfy its reactive requirements identified by its Transmission Service Provider.</td>
</tr>
<tr>
<td>VAR-001-3</td>
<td>R6.</td>
<td>P81. Duplicative of TOP Standards that require Operator to have necessary information to operate reliably.</td>
</tr>
<tr>
<td>VAR-001-3</td>
<td>R7.</td>
<td>P81. Duplicative of R2 of this std and TOP 001.</td>
</tr>
<tr>
<td>VAR-001-3</td>
<td>R8.</td>
<td>P81. Duplicative of R2 of this std and TOP 001.</td>
</tr>
<tr>
<td>VAR-002-2b</td>
<td>R5.</td>
<td>P81 Duplicative - covered under OATT.</td>
</tr>
</tbody>
</table>
## Appendix F - BPS Risks Not Adequately Mitigated (Gaps)

<table>
<thead>
<tr>
<th>Priority</th>
<th>GAP</th>
<th>Recommendation</th>
</tr>
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<tbody>
<tr>
<td>High</td>
<td>Outage Coordination</td>
<td>Included in proposed Authority Standard. See Appendix I - draft Authority Standard.</td>
</tr>
<tr>
<td>High</td>
<td>Governor Frequency Response</td>
<td>Develop a standard/requirement for governor frequency response for GO/GOPs for inclusion in appropriate BAL standard(s).</td>
</tr>
<tr>
<td>High</td>
<td>EMS RTCA models</td>
<td>Develop a standard that defines the requirements for EMS RTCA models or the performance expectations of the models (Project 2009-02 - Real-Time Monitoring and Analysis Capabilities).</td>
</tr>
<tr>
<td>High</td>
<td>Lack of requirement for use of three-part communications</td>
<td>Resolve COM-002 and COM-003 by requiring three-part communication for operational directives and for registered entity defined operational instructions that involve taking specific actions or steps that would cause a change in status or output of the BPS or a generator. This does not include three-part communication for myriad of conversations where information is being exchanged or options are being discussed.</td>
</tr>
<tr>
<td>Medium</td>
<td>Verification of accuracy of planning models</td>
<td>Develop a guideline for verifying the accuracy of the various planning models developed under the existing MOD 010-MOD 015 standards.</td>
</tr>
<tr>
<td>Medium</td>
<td>Short circuit/fault duty models</td>
<td>Develop a standard/requirement for short circuit/fault duty models that would fit with the existing MOD 010-MOD 015 standards.</td>
</tr>
</tbody>
</table>
| Medium   | Infrastructure maintenance                | • Develop a dashboard indicator to assure adequacy of current equipment maintenance programs  
• Substation/switchyard equipment  
• Transmission line maintenance  |
### Appendix G - High Risk Standards Requiring Improvement

<table>
<thead>
<tr>
<th>Standard Number</th>
<th>Standard Score Content</th>
<th>Standard Score Quality</th>
</tr>
</thead>
<tbody>
<tr>
<td>BAL-002-1a</td>
<td>1.8</td>
<td>9.2</td>
</tr>
<tr>
<td>COM-001-2</td>
<td>1.1</td>
<td>9.0</td>
</tr>
<tr>
<td>COM-002-3</td>
<td>1.0</td>
<td>12.0</td>
</tr>
<tr>
<td>EOP-006-2</td>
<td>2.3</td>
<td>11.7</td>
</tr>
<tr>
<td>IRO-001-3</td>
<td>2.0</td>
<td>8.0</td>
</tr>
<tr>
<td>IRO-005-4</td>
<td>2.0</td>
<td>11.0</td>
</tr>
<tr>
<td>IRO-008-1</td>
<td>1.3</td>
<td>11.0</td>
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<tr>
<td>IRO-009-1</td>
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<td>PER-005-1</td>
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<td>PRC-001-2</td>
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<td>PRC-006-1</td>
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<td>PRC-010-0</td>
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</tr>
<tr>
<td>PRC-015-0</td>
<td>0.0</td>
<td>5.0</td>
</tr>
<tr>
<td>PRC-018-1</td>
<td>0.2</td>
<td>5.0</td>
</tr>
<tr>
<td>PRC-022-1</td>
<td>1.0</td>
<td>12.0</td>
</tr>
<tr>
<td>TOP-001-2</td>
<td>2.0</td>
<td>10.4</td>
</tr>
</tbody>
</table>
Appendix H – Proposed “Authority” Standard

As an example of the near-term recommendation #7 “Pursue consolidation and organization of certain standards or requirements around the ‘themes’ of Authority, Emergency Operations (EOP) and Interconnected Reliability Operations (IRO)” which is related to Finding #5, the below Authority standard was proposed. This proposed standard can be used by a future Standard Drafting Team.

### Proposed Language - Consolidated Authority Language

| Authority R1. | Each Reliability Coordinator, Transmission Operator and Balancing Authority shall have the requirement and authority to take actions, including issuing a Reliability Directive, to prevent, mitigate and respond to an Emergency or Adverse Reliability Impact. |
| Authority R2. | Each Reliability Coordinator, Transmission Operator and Balancing Authority shall have the requirement and authority to approve, deny or cancel planned outages of its EMS, telecom and other hardware, and associated analysis tools. |
| Authority R3. | Each Reliability Coordinator, Transmission Operator and Balancing Authority shall have the requirement and authority to approve, deny or cancel planned outages of its Elements and Facilities. |
| Authority R4. | Each Reliability Coordinator, Transmission Operator and Balancing Authority shall provide its System Operators with the responsibility and authority to implement the actions under R1, R2 and R3. |
| Authority R5. | Each Transmission Operator, Balancing Authority, Generator Operator, and Distribution Provider shall comply with directions from a Reliability Coordinator, Transmission Operator or Balancing Authority under R1 unless it communicates to the RC, TOP or BA that it cannot because the direction cannot be physically implemented or unless such actions would violate safety, equipment, regulatory, or statutory requirements. |
| Authority R6. | Each Reliability Coordinator shall comply with directions from another Reliability Coordinator under R1 unless it communicates to the other RC that it cannot because compliance with the direction cannot be physically implemented or unless such actions would violate safety, equipment, regulatory, or statutory requirements. |
| Authority R7. | Each RC shall have the authority and responsibility to develop and implement a generation and transmission outage coordination process across TOPs and BAs in their footprint. The authority may be delegated (not the responsibility). |
| Authority R8. | Each RC shall have the authority and responsibility to develop and implement a generation and transmission outage coordination process between its adjacent RCs. |
| Authority R9. | The outage coordination process described in R7 and R8 shall cover the time period from the current operating hour out through at least 36 months. |
### Existing Language

<table>
<thead>
<tr>
<th>Standard</th>
<th>Requirement</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>EOP-002-3.1 R1.</td>
<td></td>
<td>Each Balancing Authority and Reliability Coordinator shall have the responsibility and clear decision-making authority to take whatever actions are needed to ensure the reliability of its respective area and shall exercise specific authority to alleviate capacity and energy emergencies.</td>
</tr>
<tr>
<td>IRO-001-3 R1.</td>
<td></td>
<td>Each Reliability Coordinator shall have the authority to act or direct others to act (which could include issuing Reliability Directives) to prevent identified events or mitigate the magnitude or duration of actual events that result in an Emergency or Adverse Reliability Impact.</td>
</tr>
<tr>
<td>IRO-001-3 R2.</td>
<td></td>
<td>Each Transmission Operator, Balancing Authority, Generator Operator, and Distribution Provider shall comply with its Reliability Coordinator’s direction unless compliance with the direction cannot be physically implemented or unless such actions would violate safety, equipment, regulatory, or statutory requirements.</td>
</tr>
<tr>
<td>IRO-001-3 R3.</td>
<td></td>
<td>Each Transmission Operator, Balancing Authority, Generator Operator, and Distribution Provider shall inform its Reliability Coordinator upon recognition of its inability to perform as directed in accordance with requirement R2.</td>
</tr>
<tr>
<td>IRO-006-5 R1.</td>
<td></td>
<td>Each Reliability Coordinator and Balancing Authority that receives a request pursuant to an Interconnection-wide transmission loading relief procedure (such as Eastern Interconnection TLR, WECC Unscheduled Flow Mitigation, or congestion management procedures from the ERCOT Protocols) from any Reliability Coordinator, Balancing Authority, or Transmission Operator in another Interconnection to curtail an Interchange Transaction that crosses an Interconnection boundary shall comply with the request, unless it provides a reliability reason to the requestor why it cannot comply with the request.</td>
</tr>
<tr>
<td>TOP-001-2 R1.</td>
<td></td>
<td>Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall comply with each Reliability Directive issued and identified as such by its Transmission Operator(s), unless such action would violate safety, equipment, regulatory, or statutory requirements.</td>
</tr>
<tr>
<td>PER-001-0.2 R1.</td>
<td></td>
<td>Each Transmission Operator and Balancing Authority shall provide operating personnel with the responsibility and authority to implement real-time actions to ensure the stable and reliable operation of the Bulk Electric System.</td>
</tr>
<tr>
<td>IRO-002-3 R1.</td>
<td></td>
<td>Each Reliability Coordinator shall provide its System Operators with the authority to approve, deny or cancel planned outages of its own analysis tools.</td>
</tr>
<tr>
<td>Independent Experts proposed “Authority” Standard</td>
<td>Research on existing standards</td>
<td>Additional Comments</td>
</tr>
<tr>
<td>--------------------------------------------------</td>
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</tr>
<tr>
<td><strong>Authority R1</strong>&lt;br&gt;Each RC, TOP and BA shall have the requirement and authority to take actions, including issuing a Reliability Directive, to prevent, mitigate and respond to an Emergency or Adverse Reliability Impact.</td>
<td><strong>IRO-001-1.1 R1</strong>&lt;br&gt;The RC shall have clear decision-making authority to act and to direct actions to be taken by TOPs, BAs, GOPs, TSPs, LSEs, and PSEs within its RC Area to preserve the integrity and reliability of the BES. These actions shall be taken without delay, but no longer than 30 minutes.</td>
<td><strong>TOP-001-1a R1</strong>&lt;br&gt;Each TOP shall have the responsibility and clear decision-making authority to take whatever actions are needed to ensure the reliability of its area and shall exercise specific authority to alleviate operating emergencies.</td>
</tr>
<tr>
<td><strong>Authority R2</strong>&lt;br&gt;Each RC, TOP and BA shall have the requirement and authority to approve, deny or cancel planned outages of its EMS, telecom and other hardware, and associated analysis tools.</td>
<td><strong>EOP-008-1 R1</strong>&lt;br&gt;Each RC, BA, and TOP shall have a current Operating Plan describing the manner in which it continues to meet its functional obligations with regard to the reliable operations of the BES in the event that its primary control center functionality is lost.&lt;br&gt;1.2. A summary description of the elements required to support the backup functionality.&lt;br&gt;These elements shall include, at a minimum:&lt;br&gt;1.2.1. <em>Tools and applications</em> to ensure that System Operators have situational awareness of the BES.&lt;br&gt;1.2.2. <em>Data communications</em>.&lt;br&gt;1.2.3. <em>Voice communications</em>.&lt;br&gt;1.2.4. <em>Power source(s)</em>.&lt;br&gt;1.2.5. Physical and cyber security.</td>
<td><strong>IRO-002-2 R8</strong>&lt;br&gt;Each RC shall control its Reliability Coordinator analysis tools, including approvals for planned maintenance. Each Reliability Coordinator shall have procedures in place to mitigate the effects of analysis tool outages.</td>
</tr>
<tr>
<td><strong>Authority R3</strong></td>
<td><strong>TOP-003-1 R1</strong></td>
<td><strong>TOP-001-1a R1</strong>&lt;br&gt;Each TOP shall have the responsibility and clear decision-making authority to take whatever actions are needed to ensure the reliability of its area and shall exercise specific authority to alleviate operating emergencies.</td>
</tr>
<tr>
<td>Each RC, TOP and BA shall have the requirement and authority to approve, deny or cancel planned outages of its Elements and Facilities.</td>
<td>GOP and TOP shall provide planned outage information.</td>
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</tr>
<tr>
<td><strong>TOP-003-1 R4</strong> Each RC shall resolve any scheduling of potential reliability conflicts.</td>
<td><strong>TOP-003-1 R6</strong> The RC shall coordinate with TOPs, BAs, and GOPs as needed to develop and implement action plans to mitigate potential or actual SOL, CPS, or DCS violations. The RC shall coordinate pending generation and transmission maintenance outages with TOPs, BAs, and GOPs as needed in both the real time and next-day reliability analysis timeframes.</td>
<td></td>
</tr>
<tr>
<td><strong>Authority R4</strong> RC, TOP and BA shall provide its System Operators with the responsibility and authority to implement the actions under R1, R2 and R3.</td>
<td>Note: This is redundant, the appropriate authorities and responsibilities are implicit in the sited standards above.</td>
<td></td>
</tr>
<tr>
<td><strong>Authority R5</strong> Each TOP, BA, GOP, and DP shall comply with directions from a RC, TOP or BA under R1 unless it communicates to the RC, TOP or BA that it cannot because the direction cannot be physically implemented or unless such actions would violate safety, equipment, regulatory, or statutory requirements.</td>
<td>Note: This is redundant, the appropriate authorities and responsibilities are implicit in the sited standards above.</td>
<td></td>
</tr>
</tbody>
</table>
| **Authority R6** Each RC shall comply with directions from another RC under R1 unless it communicates to the other RC that it cannot because compliance with the direction cannot be physically | **IRO-014-1 — Procedures, Processes, or Plans to Support Coordination Between Reliability Coordinators**  
IRO-015-1 — Notifications and Information Exchange Between Reliability Coordinators | Note: It is not appropriate for one RC to give a “directive” to another RC. This action could have adverse reliability impacts. The RC is the highest reliability authority for its footprint and should not jeopardize reliability in it’s area for the improvement of another. Rather, |
implemented or unless such actions would violate safety, equipment, regulatory, or statutory requirements.

| Authority R7 | Each RC shall have the authority and responsibility to develop and implement a generation and transmission outage coordination process across TOPs and BAs in their footprint. The authority may be delegated (not the responsibility). |
| Authority R8 | Each RC shall have the authority and responsibility to develop and implement a generation and transmission outage coordination process between its adjacent RCs. |

**IRO-014-1 R1**

The RC shall have Operating Procedures, Processes, or Plans in place for activities that require notification, exchange of information or coordination of actions with one or more other RCs to support Interconnection reliability. These Operating Procedures, Processes, or Plans shall address Scenarios that affect other RC Areas as well as those developed in coordination with other RCs.

R1.1. These Operating Procedures, Processes, or Plans shall collectively address, as a minimum, the following:

- **R1.1.1.** Communications and notifications, including the conditions under which one RC notifies other RCs; the process to follow in making those notifications; and the data and information to be exchanged with other RCs.
- **R1.1.2.** Energy and capacity shortages.
- **R1.1.3.** Planned or unplanned outage information.
- **R1.1.4.** Voltage control, including the

<table>
<thead>
<tr>
<th>IRO-016-1 — Coordination of Real-time Activities Between Reliability Coordinators</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>R1.</strong> The RC that identifies a potential, expected, or actual problem that requires the actions of one or more other RCs shall contact the other RC(s) to confirm that there is a problem and then discuss options and decide upon a solution to prevent or resolve the identified problem.</td>
</tr>
</tbody>
</table>

| TOP-003-1 R6 | The RC shall coordinate with TOPs, BAs, and GOPs as needed to develop and implement action plans to mitigate potential or actual SOL, CPS, or DCS violations. The RC shall coordinate pending generation and transmission maintenance outages with TOPs, BAs, and GOPs as needed in both the real time and next-day reliability analysis timeframes. |
coordination of reactive resources for voltage control.  
**R1.1.5.** Coordination of information exchange to support reliability assessments.  
**R1.1.6.** Authority to act to prevent and mitigate instances of causing Adverse Reliability Impacts to other Reliability Coordinator Areas.

<table>
<thead>
<tr>
<th>Authority R9</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>The outage coordination process described in R7 and R8 shall cover the time period from the current operating hour out through at least 36 months.</strong></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>TPL-001-0.1</th>
</tr>
</thead>
</table>
| **R1.** The PA and TP shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned such that, with all transmission facilities in service and with normal (pre-contingency) operating procedures in effect, the Network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services at all Demand levels over the range of forecast system demands, under the conditions defined in Category A of Table I. To be considered valid, the PA and TP assessments shall:  
**R1.1.** Be made annually.  
**R1.2.** Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.  
**R1.3.** Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category A of Table 1 (no contingencies). The specific elements selected (from each of the following categories) shall be acceptable to the associated Regional Reliability Organization(s).  
**R1.3.1.** Cover critical system conditions and study years as deemed appropriate by the entity performing the study.  
**R1.3.2.** Be conducted annually unless changes to system conditions do not warrant such analyses.  
**R1.3.3.** Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.  
**R1.3.4.** Have established normal (pre-contingency) operating procedures in |

**Note:** In order to perform studies as stipulated in TPL-001-0.1, Known long term outages are included. In addition, these studies are shared with neighboring RCs. This practice both informs the neighbors of long term outages as currently known, and their expected impacts.
R1.3.5. Have all projected firm transfers modeled. Standard TPL-001-0.1 — System Performance Under Normal Conditions
Page 2 of 5
R1.3.6. Be performed for selected demand levels over the range of forecast system demands.
R1.3.7. Demonstrate that system performance meets Table 1 for Category A (no contingencies).
R1.3.8. Include existing and planned facilities.
R1.3.9. Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.
R1.4. Address any planned upgrades needed to meet the performance requirements of Category A.
## RISC Triage of Independent Experts’ Appendix F – BPS
### Risks not adequately Mitigated (Gaps)

<table>
<thead>
<tr>
<th>Priority</th>
<th>GAP</th>
<th>IEPR Recommendation/RISC Triage</th>
</tr>
</thead>
<tbody>
<tr>
<td>High</td>
<td>Outage Coordination</td>
<td>Included in proposed Authority Standard. See Appendix I - draft Authority Standard.</td>
</tr>
<tr>
<td></td>
<td><strong>Recommended RISC triage:</strong></td>
<td>Recommend that the Operating Committee (OC) review the need for a new Standard or revised Standards on outage coordination (including the Expert’s proposed authority Standard) versus the implementation of a tool other than, or in addition to, a Standard, if a Standard is deemed needed. The OC is to present its findings on this issue to RISC for discussion and prioritization, which is to be completed by the end of the second quarter 2014.</td>
</tr>
<tr>
<td>High</td>
<td>Governor Frequency Response</td>
<td>Develop a standard/requirement for governor frequency response for GO/GOPs for inclusion in appropriate BAL standard(s).</td>
</tr>
<tr>
<td></td>
<td><strong>Recommended RISC triage:</strong></td>
<td>Same as Outage Coordination, above.</td>
</tr>
<tr>
<td>High</td>
<td>EMS RTCA models</td>
<td>Develop a standard that defines the requirements for EMS RTCA models or the performance expectations of the models (Project 2009-02 - Real-Time Monitoring and Analysis Capabilities).</td>
</tr>
<tr>
<td></td>
<td><strong>Recommended RISC triage:</strong></td>
<td>Have the Standards Committee chair coordinate a discussion between one of the Independent Experts with the Project 2009-02 - Real-Time Monitoring and Analysis Capabilities SAR drafting team, the associated Standards Developer and SC’s Project Management and Oversight Subcommittee liaison to determine whether the scope of the current SAR is sufficient to address Expert’s concern or whether SAR needs to be expanded. If SAR needs to be expanded, it is recommended that the SAR drafting team post a revised SAR for comment prior to end of 2013.</td>
</tr>
<tr>
<td>High</td>
<td>Lack of requirement for use of three-part communications</td>
<td>Resolve COM-002 and COM-003 by requiring three-part communication for operational directives and for registered entity defined operational instructions that involve taking specific actions or steps that would cause a change in status or output of the BPS or a generator. This does not include three-part communication for myriad of conversations where information is being exchanged or options are being discussed.</td>
</tr>
<tr>
<td></td>
<td><strong>Recommended RISC triage:</strong></td>
<td>Address via RISC and OC</td>
</tr>
</tbody>
</table>
responses to the August 15, 2013 Board of Trustee questions on COM-002-3 and COM-003-1, as well as Standards Project 2007-02 (COM-003-1).

<table>
<thead>
<tr>
<th>Medium</th>
<th>Verification of accuracy of planning models</th>
<th>Develop a guideline for verifying the accuracy of the various planning models developed under the existing MOD 010-MOD 015 standards.</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td><strong>Recommended RISC triage:</strong> No additional action recommended, given the Expert’s concerns are with the scope of Standards Project 2010-3 (Consolidation of MOD 10 through 15) and the Experts are satisfied with direction of project.</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Medium</th>
<th>Short circuit/fault duty models</th>
<th>Develop a standard/requirements for short circuit/fault duty models that would fit with the existing MOD 010-MOD 015 standards.</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td><strong>Recommended RISC triage:</strong> Same as verification of accuracy of planning models.</td>
<td></td>
</tr>
</tbody>
</table>

| Medium | Infrastructure maintenance | • Develop a dashboard indicator to assure adequacy of current equipment maintenance programs  
• Substation/switchyard equipment  
• Transmission line maintenance |
<table>
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<tr>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td><strong>Recommended RISC triage:</strong> Experts are not recommending a Standard. Thus, recommend that Planning Committee (PC) develop tools (other than a Standard) that address Expert’s concern. It is recommended that PC develop these tools and present them to RISC for informational purposes by the end of the second quarter of 2014.</td>
<td></td>
</tr>
</tbody>
</table>