Agenda

Operating Committee

June 10, 2014 | 1:00–5:00 p.m. (EDT)
June 11, 2014 | 8:00 a.m.–Noon (EDT)

Hyatt Regency Orlando International Airport
9300 Jeff Fiqia Blvd
Orlando, Florida

Introductions and Chair’s Opening Remarks

Trustee Janice Case 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
   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>September 16, 2014</td>
<td>1:00 to 5:00 p.m. (Pacific)</td>
<td>Vancouver BC</td>
<td>Hyatt Regency Vancouver</td>
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<tr>
<td>September 17, 2014</td>
<td>8:00 a.m. to Noon (Pacific)</td>
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<tr>
<td>December 9, 2014</td>
<td>1:00 to 5:00 p.m. (Eastern)</td>
<td>Atlanta, GA</td>
<td>Westin Buckhead Atlanta</td>
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<tr>
<td>December 10, 2014</td>
<td>8:00 a.m. to Noon (Eastern)</td>
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<tr>
<td>March 3, 2015</td>
<td>1:00 to 5:00 p.m.</td>
<td>TBD</td>
<td>TBD</td>
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<td>March 4, 2015</td>
<td>8:00 a.m. to Noon</td>
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<tr>
<td>June 9, 2015</td>
<td>1:00 to 5:00 p.m. (Eastern)</td>
<td>Atlanta, GA</td>
<td>Westin Buckhead</td>
</tr>
<tr>
<td>June 10, 2015</td>
<td>8:00 a.m. to Noon (Eastern)</td>
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</tbody>
</table>
2. **Consent Agenda – Chair Castle**
   a. March 4–5, 2014 Draft OC Meeting Minutes*

<table>
<thead>
<tr>
<th>Action</th>
<th>Objective: Approve consent agenda as a block.</th>
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</thead>
<tbody>
<tr>
<td>Approve</td>
<td></td>
</tr>
<tr>
<td>No</td>
<td><strong>Duration:</strong> 10 minutes</td>
</tr>
<tr>
<td><strong>Background Items:</strong> March 4-5, 2014 OC Meeting Minutes</td>
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3. **Chair’s Remarks**
   a. Report on May 6, 2014 Member Representatives Committee Meeting and the May 7, 2014 Board of Trustees Meeting*

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

<table>
<thead>
<tr>
<th>Action</th>
<th>Objective: Streamline the Action Item Process to improve its usefulness.</th>
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</thead>
<tbody>
<tr>
<td>None</td>
<td></td>
</tr>
<tr>
<td><strong>OC Strategic Plan Goal:</strong> None, this is an administrative item.</td>
<td></td>
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<tr>
<td><strong>Background:</strong> 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.</td>
<td></td>
</tr>
<tr>
<td><strong>Presentation:</strong> No</td>
<td><strong>Duration:</strong> 15 minutes</td>
</tr>
</tbody>
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5. **Subgroup Status Reports**
   a. Operating Reliability Subcommittee* – **Chair Joel Wise**
      i. Revised ORS Scope*
   b. Resources Subcommittee* – **Chair Gerry Beckerle**
      i. Revised RS Scope*
   c. Event Analysis Subcommittee* – **Chair Sam Holeman**
      i. Revised EAS Scope*
      ii. Review of the Reliability Guideline: Generating Unit Winter Weather Readiness
      iii. Lessons Learned Summary
   d. Personnel Subcommittee* – **Chair Laurel Hennebury**
      i. Revised PS Scope*

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

7. **Introduction to Bulk Electric System Question and Answer Session – Andy Rodriquez**
Action: None

Objective: Discuss the implementation of the definition of Bulk Electric System.

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

Action Item Number: None

Background: On March 20, 2014, the FERC approved the revised definition of Bulk Electric System. The definition includes bright line core criteria, with various enumerated inclusions and exclusions. As a result of the application of these BES Definition provisions, all Elements and Facilities necessary for the reliable operation and planning of the interconnected bulk power system will be included as BES elements. The Commission also approved the process for review of Elements on a case-by-case basis to allow for exceptions from the definition, where appropriate, as well as a process for entities to self-notify Regions of their respective determinations of BES elements. Entities should apply the definition of Bulk Electric System, including the respective inclusions and exclusions, to their asset inventory effective July 1, 2014.

On Tuesday, June 10, Andy Rodriquez will provide a brief introduction to the BES Business Process Q&A Workshop for OC, PC, and CIPC Members. Members of the OC, PC, and CIPC are invited to attend the Wednesday morning Question and Answer session regarding the Bulk Electric System definition and its application. Bob Cummings, NERC’s Director of Reliability Initiatives and System Analysis, will be available to answer questions about the core definition, inclusions, exclusions, self-determined notifications, and the exception process. It is expected that the OC will resume its meeting at 8:30 a.m. on Wednesday, June 11, 2014.

Additional information is available at Bulk Electric System Information.

Presentation: Yes

Duration: 10 minutes

Background Items: None

Notes:

8. Committee Matters

a. Operating Reliability Coordination Agreement (ORCA) Implementation – David Zwergel

Action: None

Objective: Review a status report related to the implementation of the ORCA.

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

Action Item Number: None

Background: 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 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.
b. Essential Reliability Services Task Force* – Ken McMcIntyre

**Action:** Endorse  
**Objective:** Review and discuss recent ERSTF activities.

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

**Action Item Number:** 1403-10

**Background:** The OC and PC approved the scope of the ERSTF at their March 2014 meetings. The ERSTF has a multi-faceted purpose that includes developing a technical foundation of Essential Reliability Services (ERS); educating and informing industry, regulators, and the public about ERS; developing an approach for tracking and trending ERS; formulating recommendations to ensure the complete suite of ERS are provided and available; and providing guidance necessary for operating a reliable grid.

The ERSTF held a Kick-off webinar meeting on April 21, 2014 to begin defining essential reliability services and to begin reviewing a draft Essential Reliability Services whitepaper. The ERSTF also met on May 16, 2014 by conference call to finalize the agenda for its first face-to-face meeting, which is scheduled for June 11, 2014 from 1 – 5 p.m. and June 12, 2014 from 8 a.m. – 12 p.m. at the Hyatt Regency Orlando Airport Hotel in Orlando, Florida. Additional information related to the task force is available at ERSTF.

**Notes:**

c. Reliability Guideline: Generating Unit Operations During Complete Loss of Communications* – Troy Blalock, Vice Chair of the Resources Subcommittee

**Action:** Approve  
**Objective:** Review, discuss and approve the responses to comments and the revised Reliability Guideline: Generating Unit Operations During Complete Loss of Communications.

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

**Action Item Number:** 1209-19

**Background:** At its December 10-11, 2013 meeting, the Operating Committee approved posting the draft Reliability Guideline: Generating Unit Operations During Complete Loss of Communications for a 45-day industry comment period. The reliability guideline was posted on January 15, 2014, with comments due by February 28, 2014. The Resources Subcommittee formed a task team to review the comments and to develop responses to the comments, which are posted at Responses to Comments. In response to the comments received, the RS modified the reliability guideline.

**Notes:**
d. Eastern Interconnection Frequency Response Initiative – Troy Blalock, Vice Chair of the Resources Subcommittee

| Action: None | Objective: Review and discuss the status of the Eastern Interconnection Frequency Response Initiative. |
| OC Strategic Plan Goal: To investigate emergent issues that impact the reliability of the BES. |
| Action Item Number: 1403-07 |
| Background: At its March 2014 meeting, Resources Subcommittee Vice Chair Blalock provided an overview of the Eastern Interconnection Frequency Initiative Whitepaper. He noted that RS members from the Eastern Interconnection (EI) are working with balancing authorities on a voluntary basis to support an effort to improve EI frequency response. The current initiative focuses on the existing generator fleet with respect to the completeness and accuracy of the data provided in the 2010 NERC generator survey and improving their frequency response capabilities. Following a brief discussion, the OC approved a motion to support the Resources Subcommittee’s Eastern Interconnection Frequency Response Initiative and encourage participation by Eastern Interconnection balancing authorities and generator operators and owners. |
| Presentation: No | Duration: 15 minutes | Background Items: None |

Notes:

e. Lessons Learned – Improved Contractor Oversight – Bo Jones, Westar

| Action: None | Objective: Review and discuss a recently published Lesson Learned on improved contractor oversight submitted by Westar. |
| 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: Multiple instances of vendor performed work in stations without a verification method in place for ensuring work quality have caused significant system disturbances. |
| Presentation: Yes | Duration: 20 minutes | Background Items: None |

Notes: Bo Jones is the Director, NERC Compliance at Westar Energy. He has twenty two years of electric utility experience. The past three years specifically related to NERC Compliance. Prior to that time he worked in various engineering and management roles including in the areas of design, planning and operations. Mr. Jones has a Bachelors in Electrical Engineering - Kansas State University and a Masters in Engineering Management - University of Colorado. He is a Registered Professional Engineer in the states of Kansas and Texas.

f. Toronto, Ontario June 2013 Flooding Event – Aaron Cole, Hydro One

| Action: None | Objective: Review and discuss a severe flooding event that impacted the Toronto, Ontario metro area. |
| OC Strategic Plan Goal: Utilize the results of the Event Analysis Process to improve the reliable operation of the BES. |
| Action Item Number: None |
A severe local storm dropped several inches of rain in a very short period of time (approximately one-hour), resulting in the loss of about 20 percent of the IESO demand and upwards of 25 230 kV circuits.

**Presentation:** Yes  
**Duration:** 30 minutes  
**Background Items:** None

### g. July 3, 2013 Hydro Quebec Event – Pierre Paquet

**Action:** None  
**Objective:** Review and discuss an event that occurred on the Hydro Quebec system on July 3, 2013.

**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:** None  
**Presentation:** Yes  
**Duration:** 20 minutes  
**Background Items:** None

### h. 2014 Polar Vortex Weather Phenomenon Status Report – James Merlo, Director, Reliability Risk Management

**Action:** None  
**Objective:** Review and discuss the January 2014 cold weather events.

**OC Strategic Plan Goal:** Utilize the results of the Event Analysis Process to improve the reliable operation of the BES.

**Action Item Number:** 1403-04 and 1403-05

**Background:** In early January 2014 a Polar Vortex impacted the ERCOT and Eastern Interconnections. NERC and the impacted Regional Entities are documenting this cold weather event in a report, Phase 1 of which is expected to be available in late May 2014. Mr. Merlo will provide the OC with an overview of the report’s development.

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

### i. Electric/Natural Gas Coordination – Wes Yeomans, New York Independent System Operator

**Action:** None  
**Objective:** Discuss evolving issues and related coordination activities as the electric industry becomes increasingly dependent on natural gas as a fuel source.

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

**Action Item Number:** None

**Background:** With the retirement of traditional base load generating resources and increasing dependence on renewable and gas fired generation, coordination between the electric and gas industries and fuel assurance has become important. The FERC has taken steps to address coordination, and the two industries are working together to resolve coordination issues. Wes Yeomans, NYISO
Operations VP and Chair of the ISO/RTO Council's Electric & Gas Coordination Task Force, will discuss the coordination issues as observed by the NYISO and others, FERC initiatives, and Industry progress to achieve better coordination.

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<tr>
<th>Presentation</th>
<th>Duration</th>
<th>Background Items</th>
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<tr>
<td>Yes</td>
<td>45 minutes</td>
<td>None</td>
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Notes:

j. Oncor Voltage Reduction Program – **Either Nahawati, Manager – Operation Performance Review**

<table>
<thead>
<tr>
<th>Action</th>
<th>Objective</th>
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<tbody>
<tr>
<td>None</td>
<td>Review and discuss Oncor’s voltage reduction program and the results observed during its implementation during the 2014 Polar Vortex Weather Phenomenon.</td>
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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:** 1403-06

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<tbody>
<tr>
<td>At its March 2014 meeting, the Operating Committee conducted a review of the 2014 Polar Vortex Weather Phenomenon. Following its review, Chair Castle asked Alan Bern to provide an overview of Oncor’s voltage reduction program.</td>
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<tr>
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<th>Duration</th>
<th>Background Items</th>
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<tr>
<td>No</td>
<td>20 minutes</td>
<td>None</td>
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Notes:

k. Balancing Authority ACE Limit (BAAL) Field Trial – **Glenn Stephens and Tom Siegrist**

<table>
<thead>
<tr>
<th>Action</th>
<th>Objective</th>
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<tbody>
<tr>
<td>None</td>
<td>Review and discuss the Balancing Authority ACE Limit Field Trial</td>
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**OC Strategic Plan Goal:** The OC will be proactive in leading the focus on the prioritization of Reliability Standards development and improvement.

**Action Item Number:** 1212-21

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<tr>
<td>At its December 2011 meeting, the OC approved a request of the Balancing Authority Reliability-based Controls standard drafting team to continue the BAAL field trial until after the final ballot of the proposed BAL-001-1 standard. The drafting team will present an overview of the field trial.</td>
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Mr. Stephens and Mr. Siegrist are Chair and Vice Chair, respectively, on the Project 2010-14.1 (Phase 1 of Balancing Authority Reliability-based Controls: Reserves) Standard Drafting Team

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<tr>
<th>Presentation</th>
<th>Duration</th>
<th>Background Items</th>
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<td>Yes</td>
<td>15 minutes</td>
<td>To be provided prior to the OC meeting.</td>
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Notes:

l. Project 2014-04 (Physical Security)* – **Robert Rhodes, SPP**

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<thead>
<tr>
<th>Action</th>
<th>Objective</th>
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<tbody>
<tr>
<td>None</td>
<td>Review and discuss CIP-014-1 (Physical Security)</td>
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**OC Strategic Plan Goal:** The OC will be proactive in leading the focus on the prioritization of Reliability Standards development and improvement.

**Action Item Number:** None
**Background:** The FERC directed "The North American Electric Reliability Corporation (NERC), as the Commission-certified Electric Reliability Organization (ERO), to submit for approval one or more Reliability Standards that will require certain registered entities to take steps or demonstrate that they have taken steps to address physical security risks and vulnerabilities related to the reliable operation of the Bulk-Power System. The proposed Reliability Standards should require owners or operators of the Bulk-Power System, as appropriate, to identify facilities on the Bulk-Power System that are critical to the reliable operation of the Bulk-Power System. Then, owners or operators of those identified critical facilities should develop, validate and implement plans to protect against physical attacks that may compromise the operability or recovery of such facilities. The Commission directs NERC to submit the proposed Reliability Standards to the Commission within 90 days of the date of this order."

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<tr>
<th>Presentation:</th>
<th>Duration: 30 minutes</th>
<th>Background Items: CIP-014-1</th>
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<td>No</td>
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**Notes:**

- Project 2014-03 (Revisions to TOP/IRO Reliability Standards) – **David Souder**

<table>
<thead>
<tr>
<th>Action: None</th>
<th>Objective: Review and discuss proposed revisions to TOP and IRO Reliability Standards.</th>
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<tbody>
<tr>
<td>OC Strategic Plan Goal: The OC will be proactive in leading the focus on the prioritization of Reliability Standards development and improvement.</td>
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<table>
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<th>Action Item Number: None</th>
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**Background:** The primary goal of Project 2014-03 (Revisions to TOP/IRO Reliability Standards) is to address the concerns identified in the FERC NOPR proposing to remand IRO standards developed in Project 2006-06 (Reliability Coordination) and TOP standards developed in Project 2007-03 (Real-time Operations). On April 16, 2013, NERC submitted two petitions requesting Commission approval of TOP and IRO standards. One petition addresses three revised TOP Reliability Standards: TOP-001-2 (Transmission Operations), TOP-002-3 (Operations Planning), TOP-003-2 (Operational Reliability Data), and one Protection Systems (PRC) Reliability Standard, PRC-001-2 (System Protection Coordination) (collectively, the “TOP Standards”) to replace the eight currently-effective TOP standards. The second petition addresses four revised IRO Reliability Standards: IRO-001-3 (Responsibilities and Authorities), IRO-002-3 (Analysis Tools), IRO-005-4 (Current Day Operations), and IRO-014-2 (Coordination Among Reliability Coordinators) (collectively, the “IRO Standards”) to replace six currently-effective IRO standards.

On November 21, 2013, the Commission issued a NOPR proposing to remand these TOP and IRO Standards, stating that NERC “has removed critical reliability aspects that are included in the currently-effective standards without adequately addressing these aspects in the proposed standards.” For example, the Commission cites the fact that the proposed TOP Standards do not require Transmission Operators to plan and operate within all System Operating Limits (“SOLs”), which is a requirement in the currently effective standards.

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<tr>
<th>Presentation: No</th>
<th>Duration: 30 minutes</th>
<th>Background Items: None</th>
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**Notes:**

*Background materials included.*
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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</table>
| 1. Investor-owned utility | Gerry Beckerle, Ameren (15)  
Paul Johnson, American Electric Power (14) |
| 2. State/municipal utility | Doug Peterchuck, Omaha Public Power District (15)  
Richard Kinas (Orlando Utilities Commission (14) |
| 3. Cooperative utility | Keith Carman, Tri-State G&T Association (15)  
Chris Bolick, Associated Electric Cooperative, Inc. (14) |
| 4. Federal or provincial utility/Federal Power Marketing Administration | Tom Irvine, Hydro One Networks (15)  
Don Watkins, Bonneville Power Authority (15)  
Martin Huang, BC Hydro (14)  
Pierre Paquet, Hydro Québec TransÉnergie (15) |
| 5. Transmission-dependent utility | Dennis Florom, Lincoln Electric System (15)  
Ray Phillips, Alabama Municipal Electric Authority (14) |
| 6. Merchant electricity generator | J.T. Thompson, Constellation Energy (15)  
Open |
| 7. Electricity marketer | Open  
Open |
| 8. Large end-use electricity customer | Open  
Open |
| 9. Small end-use electricity customer | Open  
Kevin Conway, Intellibind (14) |
| 10. Independent system operator/regional transmission organization | Kenneth McIntyre, ERCOT (15)  
David Zwergel, Midwest ISO (14) |
| 11. Regional reliability organization¹ | ERCOT  
FRCC  
MRO  
NPCC  
RFC  
SERC  
SPP  
WECC  
Alan Bern, Oncor Energy Delivery  
Ron Donahey, Tampa Electric Company  
Lloyd Linke, Western Area Power Administration  
John G. Mosier, Jr., Northeast Power Coordinating Council  
John Idzior, ReliabilityFirst  
Stuart Goza, Tennessee Valley Authority  
Jim Useldinger, Kansas City Power and Light Company  
Jerry D. Rust, Northwest Power Pool Company |
William Chambliss, Virginia State Corporation Commission (14) |
| Officers | Chairman: Jim Castle, New York ISO  
Vice Chairman: Jim Case, Entergy |
| Government representatives²: | Rich Sabonya, Federal Energy Regulatory Commission  
Open (1)  
Open (1)  
Daniel Soulier, Régie de l’énergie |

¹ Appointed
Operating Committee

**Chairman**
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(423) 697-4115 Fx  
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The NERC Operating Committee Model

Operating Committee (OC)

Personnel Subcommittee (PS)
- Continuing Education Review Panel (CERP)

Interchange Subcommittee (IS)
- Joint Electronic Scheduling Subcommittee (JESS)

Resources Subcommittee (RS)
- Reserves Working Group (RWG)
- Frequency Working Group (FWG)
- Inadvertent Interchange Working Group (IIWG)

Operating Reliability Subcommittee (ORS)
- Telecommunications Working Group (TWG)
- Data Exchange Working Group (DEWG)

Event Analysis Subcommittee (EAS)
- Trends Working Group
- EMS Task Force (EMS TF)
- Event Analysis Update Team (EUT)
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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 unreliable 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.
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 chair of a committee may limit attendance at a meeting or portion of a meeting, based on confidentiality of the information to be disclosed at the meeting. Such limitations should be applied sparingly and on a 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

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<thead>
<tr>
<th>Name</th>
<th>Definition</th>
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<td><strong>Voting Members</strong></td>
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</tr>
<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>
<tr>
<td>Name</td>
<td>Definition</td>
<td>Members</td>
</tr>
<tr>
<td>-------------------------</td>
<td>----------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------</td>
<td>---------</td>
</tr>
<tr>
<td><strong>Voting Members</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>RE</td>
<td>Number of Members</td>
<td>1</td>
</tr>
<tr>
<td>FRCC</td>
<td>Proportional Voting</td>
<td>X</td>
</tr>
<tr>
<td>RFC</td>
<td></td>
<td>X</td>
</tr>
<tr>
<td>TRE</td>
<td></td>
<td>X</td>
</tr>
<tr>
<td>MRO</td>
<td></td>
<td>X</td>
</tr>
<tr>
<td>NPCC</td>
<td></td>
<td>X</td>
</tr>
<tr>
<td>SERC</td>
<td></td>
<td>X</td>
</tr>
<tr>
<td>SPP</td>
<td></td>
<td>X</td>
</tr>
<tr>
<td>WECC</td>
<td></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><strong>Total Voting Members</strong></td>
<td></td>
<td>26</td>
</tr>
<tr>
<td><strong>Non-Voting Members</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Government representatives</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>United States federal government</td>
<td></td>
<td>2</td>
</tr>
<tr>
<td>Canadian federal government</td>
<td></td>
<td>1</td>
</tr>
<tr>
<td>Provincial government</td>
<td></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>

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

   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.

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

**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 “kils” 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.
Meeting Minutes
Operating Committee
March 4–5, 2014

Hyatt Regency St. Louis at the Arch
St. Louis, MO

A regular meeting of the NERC Operating Committee (OC) was held on March 4–5, 2014, in St. Louis, Missouri. 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. Agenda Item 8.b – Essential Reliability Services Task Force
2. Agenda Item 8.e – Polar Vortex and Cold Weather Events
3. Agenda Item 8.g – OC Organization

Consent Agenda
By consent, the committee approved the minutes of the December 10–11, 2013 meeting.

Chair’s Remarks
Chair Castle summarized his verbal report of OC activities to the Board at its February 6, 2014 meeting. He highlighted 1) the work of the OC in developing the Reliability Guideline: Generating Unit Operations During Complete Loss of Communications, 2) the committee’s approval of Peak Reliability’s reliability plan, 3) the committee’s contribution to the NERC January Monthly Newsletter, and 4) its work in reviewing the scope of each of its subcommittees, which is part of a larger OC effort to review its organization.
OC Action Item Review
Chair Castle reviewed the list of action items and reported that several have been completed.

Trustee and Vice Chair Mr. Paul Barber
Chair Castle introduced Vice Chair of the NERC Board Dr. Paul Barber. Dr. Barber was elected to the Board of Trustees of NERC in February 2005 and was elected Vice Chair of the Board in February 2014. Dr. Barber is a senior executive with extensive technical knowledge and leadership experience in the electric power industry. He is currently the principal of Barber Energy and has held senior executive positions with Edison Mission Marketing and Trading and Citizens Power and its predecessors. Dr. Barber holds degrees from the United States Military Academy, BS (1965); University of Illinois, MS in Civil Engineering (1974), and MS in Electrical Engineering (1974); and Rensselaer Polytechnic Institute, PhD in Electric Power Engineering (1988).

Operating Reliability Subcommittee (ORS)
ORS Chair Joel Wise reported that at its February 2014 meeting the subcommittee 1) endorsed the revised SPP and ERCOT reliability plans, 2) was briefed on Alberta’s reliability framework and was informed that AESO intends to present a reliability plan to the subcommittee at its September 2014 meeting, 3) was briefed on the Eastern Interconnection Data Sharing Network’s business plans related to NERCnet, and 4) engaged in a lengthy discussion of the lessons learned from the January 2014 cold weather events.

Resources Subcommittee (RS)
Chair Castle reported that he appointed Gerry Beckerle as RS Chair and Troy Blalock as RS Vice Chair. He thanked Don Badley for his service as the RS chair for the prior two years. Chair Beckerle 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. In addition, he noted that FERC approved BAL-003-1 in January 2014 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.

Vice Chair Blalock provided an overview of the Eastern Interconnection Frequency Initiative Whitepaper (Presentation 5.b.i). He noted that RS members from the Eastern Interconnection (EI) are working with balancing authorities on a voluntary basis to support an effort to improve EI frequency response. The current initiative focuses on the existing generator fleet with respect to the completeness and accuracy of the data provided in the 2010 NERC generator survey and improving their frequency response capabilities. Following a brief discussion, Jerry Rust moved that the OC supports the Resources Subcommittee’s Eastern Interconnection Frequency Initiative and encourages participation by Eastern Interconnection balancing authorities and generator operators and owners. The committee approved the motion.

Event Analysis Subcommittee (EAS)
EAS Chair Sam Holeman provided an overview of subcommittee activities. The EAS is partnering with the Planning Committee’s Performance Analysis Subcommittee to develop the 2014 State of Reliability Report. He introduced Rich Bauer, Senior Reliability Specialist, who provided an overview of two recently posted
lessons learned (Identify Relay Programming Errors to Prevent Unintended Operations and A Generating Station Ground Mat Problem Led to the Trip of Two Generating Units (2000 MW)).

Personnel Subcommittee (PS)
On behalf of Laura Hennebury, chair of the PS, Chair Castle reviewed the subcommittee’s status report and noted that the PS is finalizing revisions to its scope.

Reliability Issues Steering Committee (RISC) Status Report
Vice Chair Case provided an overview of recent RISC activities. He reported that RISC is revising its charter to incorporate best practices and is working to improve transparency by continuing efforts to align the RISC prioritization and business planning process.

Reliability Risks 2014-2017
Andy Rodriquez, Director of Reliability Risk Analysis and Control, provided an overview of the proposed RISC 2014 deliverables, activities, and calendar (Presentation 6). Proposed 2014 activities include working with the Technical Committees to review the ERO Top Priorities 2014-2017 document and developing proposals for possible inclusion in the ERO Top Priorities 2015-2018 document, which would be submitted to the Board in February 2015.

Mr. Rodriquez also briefed the committee on the RISC’s Reliability Risk Management Process, which includes a reliability risk triage process (Presentation 7.b). He suggested that the OC should re-address two previously identified gaps: Human performance and Situation Awareness. Vice Chair Case will work with Mr. Rodriquez to better understand this request of the OC.

Operating Reliability Coordination Agreement (ORCA) Implementation
David Zwergel briefed the OC on the status of implementation activities related to MISO’s reliability plan and the ORCA (Presentation 8.a). MISO South Region market participants and asset owners successfully integrated into the MISO balancing authority on December 19, 2013. Mr. Zwergel provided an overview of the activities that occurred before the transition became effective.

Mr. Zwergel also provided an overview of the three phases of the ORCA, which is a temporary seams agreement. The ORCA provides 1) a conservative operating protocol during the transition period, 2) a transition period which allows operating entities to gain experience with potentially changing flow patterns, and 3) time to work on seams agreements. MISO and the Joint Parties are currently operating in Phase 1, which is scheduled to end on April 19, 2014. Phase 1 allows for a 2000 MW dispatch flow limit between MISO South and MISO North, unless there is congestion on coordinated flowgates where the dispatch flow limit can be reduced to 1500 MW. After this point, existing congestion management processes (TLR) are implemented. Phase 2 or Phase 3 allows limits to be set on a two day ahead or one day ahead basis (respectively). In both of these phases, existing congestion management processes (TLR) would be used to reliably manage congestion on coordinated flowgates. Phase 3 ends on April 1, 2015. MISO remains committed to proactively maintaining reliability, but doing so can and must be done on a comparable basis as is the policy today. To that end, existing congestion management processes (TLR)
would continue to reliably manage congestion as needed as it has for years (including during the ORCA), so the real issue is the development of fair, equitable and comparable processes, not reliability. Mr. Zwergel also noted that TLR issuances in the MISO South region have been significantly reduced since the integration.

MISO and the Joint Parties continue to work on key provisions in the ORCA. The ORCA is part of the MISO tariff and MISO cannot deviate from the terms of the agreement. MISO and the Joint Parties are developing criteria to identify non-coordinated (<5% response) flowgates, intra-day total dispatch flow limit, and operational transition period Phase 2 limits. With regard to non-coordinated (<5% response) flowgates, the goal is to develop proactive, efficient, reciprocal localized mitigation processes that do not unnecessarily impede BES transactions. Localized mitigation process could include local redispatch with compensation (on a reciprocal basis). Incorporating non-coordinated flowgates into the Dispatch Flow limit setting process should only be done in the event localized mitigation is unavailable or deemed to be ineffective.

During Mr. Zwergel’s briefing comments were received that are hereby included in Exhibit C. Those comments are also captured here:

1. Comments of Mr. Steve Corbin, SERC: SERC is very concerned with future reliability with the termination of the ORCA without a long term solution. The ORCA ends in April 2015 with what appears to be very slow movement in determining a solution to the reliability issues. SERC has seen more TLRs since the integration of Entergy and the other 14 entities into the MISO BA. We are not sure at this time if the increase in TLRs is driven by the recent cold weather, the recent integration or both.

   SERC does not want to see an end to the ORCA without a reliable long term solution, because calling TLRs on a daily basis should not be the norm in maintaining reliability across the Eastern Interconnection.

2. Comments of Mr. Todd Lucas, Southern: The Joint Parties believe MISO’s representation of available headroom in the Dispatch Flow can be misleading. The values represented in the presentation are based on monitoring two flowgates as Dave (Mr. Zwergel) noted in his comments and as indicated in the footnote. The Joint Parties believe a broader set of flowgates should be incorporated into the determination of the limits.

   All parties are working together to resolve some tough issues. The primary issue at hand is the treatment of low response flowgates. The Joint Parties have consistently expressed the need to proactively manage reliability to prevent getting into real time congestion requiring mitigation. To that end, the Joint Parties believe a set of Low Response flowgates should be incorporated into the Dispatch Flow limit setting process. The treatment of Low Response flowgates continues be a primary topic of discussion and impacts many areas of ORCA implementation.

**Essential Reliability Services Task Force (ERSTF)**

John Moura, Director of Reliability Assessment, provided an overview of the scope of the ERSTF and noted that with minor edits the scope was approved by the Planning Committee. The OC noted that the ERSTF needs to have strong input from an operations reliability perspective. The committee suggested that
representatives from regions and Interconnections that have a significant amount of variable energy resources should be asked to assign someone to the ERSTF. Furthermore, the OC expects to receive an ERSTF status report at each of its regularly scheduled meetings. Kevin Conway moved to approve the scope of the ERSTF. The committee approved the motion.

Trustee Mr. Douglas Jaeger
Chair Castle introduced Mr. Douglas Jaeger, who was elected to the Board of Trustees of NERC in February 2013. Mr. Jaeger served as Chief Executive Officer of Adolfson & Peterson Inc. (A&P), an $800 million, family-owned, national construction firm with market concentration in medical, energy, government, senior housing and education segments, from August 2008 through December 2013. In this role, he was responsible for the company's overall strategic direction, the growth and development of A&P's leadership team and the overall growth and performance of the business. Prior to joining A&P, Mr. Jaeger held the position of Vice President of Transmission for Xcel Energy. In this role, he was responsible for Xcel's high voltage transmission business, overseeing planning, engineering, construction and maintenance, reliable system operations and customer service. Additionally, Mr. Jaeger played a major role in market relations and public policy on energy-related matters including grid reliability and infrastructure investment.

Project 2007-02 – COM-002-04 (Operating Personnel Communications Protocols)
Howard Gugel, Director Performance Analysis, provided a status report of the development of COM-002-04. Just prior to the February 2014 Board meeting, the ballot body approved COM-002-04. However, because there were ballots submitted with comments, the standard drafting team must review those comments and determine if changes to the reliability standard are required. The drafting team’s review of the comments resulted in a few non-substantive changes; therefore, the reliability standard will be posted for a 10-day final ballot. That ballot period will likely occur in late March 2014, with the final results presented to the Board at its May 2014 meeting.

Geomagnetic Disturbance (GMD) Planning Guide
Frank Koza, chair of the GMD Mitigation standard drafting team, provided an overview of the GMD Planning Guide and the Application Guide: Computing Geomagnetically-Induced Current in the Bulk Power System (Presentation 8.d). He provided an update on the development of EOP-010 (GMD Operations) and TPL-007 (Transmission System Planned Performance during GMD). On May 16, 2013, FERC issued Order 779 which directed NERC to submit reliability standards that address the impacts of GMD on the reliable operation of the BPS. Stage 1 of the order addressed the development of operating procedures. Stage 2 standard(s) will require applicable registered entities to conduct initial and on-going assessments of the potential impact of benchmark GMD events on their respective system as directed in Order 779. The Second Stage GMD Reliability Standards must identify benchmark GMD events that specify what severity GMD events applicable registered entities must assess for potential impacts on the Bulk Power System. If the assessments identify potential impacts from benchmark GMD events, the reliability standards will require the registered entity to develop and implement a plan to mitigate the risk of instability, uncontrolled separation, or cascading as a result of a benchmark GMD event. The development of this plan cannot be limited to considering operational procedures or enhanced training alone, but will, subject to the potential impacts of the benchmark GMD events identified in the assessments, contain strategies for
mitigating the potential impact of GMDs based on factors such as the age, condition, technical specifications, system configuration, or location of specific equipment.

Adjourn and Reconvene
The committee adjourned at 5:02 p.m. CST and reconvened the following morning at 8:00 a.m. CST.

2014 Polar Vortex Weather Phenomenon Review
Mike Moon, Senior Director Reliability Risk Management, informed the OC that the purpose of this agenda topic is to capture relevant information on BPS operations and performance during the January 6-7, 2014 polar vortex weather phenomenon (Presentation 8.e). The ERO Polar Vortex Review Plan will consist of a two part report. Part 1 will be a detailed factual accounting of weather and system operations. Part 2 will be a performance assessment. Following Mr. Moon’s introductory remarks the following entities addressed the committee:

1. Bob Collins (ERCOT) – On January 6 ERCOT issued an EEA Level 1, which was followed almost immediately by the issuance of an EEA Level 2 due to the loss of a number of generating units during the morning load ramp. ERCOT resumed normal operations (EEA Level 0) approximately two hours later. During this event there was no firm load interruption, no known transmission challenges and minimal fuel restrictions. ERCOT and Texas Reliability Entity have scheduled a number of follow-up activities as a result of this weather event (e.g., requested additional information from generators on causes of trips, de-rates, and failure to start, improving wind forecast during icing and cold weather, and analyzing voltage reduction results).

2. Shawn Gehring (FirstEnergy) – FirstEnergy responded to PJM alerts and event preparation conference calls. FirstEnergy also had discussions with SF6 circuit breaker manufacturers. FirstEnergy has a Seasonal Readiness Checks Program which requires inspection of battery area heaters and the purging on breaker air receivers of moisture. Mr. Gehring reported that event preparation and update conference calls during the event kept system operators informed.

3. David Zwergel (MISO) – The polar vortex brought extreme weather conditions to the MISO region and temperatures in many areas were the coldest experienced in two decades. MISO issued a maximum emergency generation declaration on January 7 due to decreased wind generation, less available generation, and reduced imports. Based on preliminary findings, the number of forced outages escalated as the severe weather conditions moved into the MISO footprint. Freezing components and fuel restrictions caused challenges for many units. MISO will be exploring opportunities to improve coordination with gas pipeline operators and demand side resource availability.

4. Tom Hanzlik (South Carolina Electric and Gas) – Mr. Hanzlik provided a brief overview of this cold weather event which resulted in SCE&G shedding 265 MW of firm load, the curtailment of interruptible load and the implementation of voltage reduction. This was a capacity event for SCE&G due to the wide spread loss of generation. SCE&G is internally reviewing the effectiveness of its firm load shedding program.
5. Joel Wise (TVA) – TVA reliability coordinator (RC) initiated an EEA Level 1 and EEA Level 2 at the request of the TVA balancing authority on two occasions. No firm load was shed within the TVA RC footprint. While there were no adverse reliability impacts experienced in the TVA RC footprint during this event, the TVA RC did experience some constraints due to unscheduled flows which resulted in the use of the TLR process and the ORCA process to mitigate. Several generation facilities experienced forced outages due to the weather (e.g., frozen instrumentation, oil temperatures, and ice/snow impacting air intakes). The TVA RC began communicating with neighboring RCs and SERC staff on January 3. As the event progressed other reliability entities were added to the daily conference calls.

During its discussion of the above presentations the committee noted the following:
1. The Personnel Subcommittee needs to be engaged in hearing about these types of events from a system operator perspective.
2. Lessons learned need to be identified.
4. Impending coal fired generation and natural gas dependency.
5. System operators need to be confident that they can handle these types of events.
6. ERCOT forming a voltage reduction task force

Chair Castle tasked the EAS with reviewing the Winter Readiness reliability guideline. He also asked Alan Bern to provide a summary of the Oncor voltage reduction program at the next OC meeting.

**Eastern Interconnection Data Sharing Network (EIDSN)**
Rich Mandes, Southern, informed the OC that the mission of EIDSN is to develop a mechanism by which essential operational data can be shared securely, consistently, and efficiently among the EI reliability coordinators and other appropriate entities (*Presentation 8.f*). EIDSN wants to complete the transition of NERCnet by the end of the second quarter of 2014 (i.e., transition the Verizon contract to EIDSN). EIDSN is expected to develop a replacement NERCnet by the end of the first quarter of 2015.

Mr. Mandes also discussed the details leading to the formation of the EIDSN Corporation. The first board of directors meeting was held in February 2014. The EIDSN also created an Advisory Committee of key operational personnel within each member company. The Data Exchange Working Group and the Telecommunications Working Group are expected to report to the Advisory Committee in the near future.

Mr. Mandes reviewed the work of the New Network Leadership Team, which is being led by Jim McNierney, NYISO. He reviewed the new network development objectives and outlined the next steps/action items, which includes having a new vendor selection by August/September 2014.
OC Organization
Chair Castle reported that the OC Executive Committee and the subcommittee leadership met on March 3 to discuss subcommittee scope development. At the December 2013 meeting each subcommittee was tasked with reviewing its scope and to make revisions to meet the criteria presented in Chair Castle’s minimum subcommittee scope outline. The Executive Committee also discussed the scope of the Interchange Subcommittee to determine if some of the responsibilities of the IS could be assigned to one or more of the other subcommittees, thereby eliminating the need to have the IS.

NERC Monthly Newsletter
Chair Castle informed the committee that the OC leadership drafted a year-end summary report for inclusion in the January 2014 NERC Monthly Newsletter. He reported that the OC will continue to develop news articles for future newsletters as appropriate.

Planning Committee’s Performance Analysis Subcommittee
Melinda Montgomery, chair of the Performance Analysis Subcommittee, provided an update of subcommittee activities (Presentation 8.i). Ms. Montgomery provided an overview of revisions to reliability metric ALR1-4 (BPS Transmission Related Events Resulting in Loss of Load). At the December 2013 meeting, Chair Castle tasked the EAS with reviewing ALR1-4 prior to further committee action. EAS Chair Holeman noted that the EAS reviewed the revised reliability metric and recommends OC approval. Jacquie Smith moved to accept reliability metric ALR1-4. The committee approved the motion.

Ms. Montgomery reviewed a revision to the Severity Risk Index whitepaper. Following a brief discussion, Alan Bern moved to approve the revised Severity Risk Index whitepaper. The committee approved the motion.

Ms. Montgomery provided an update on the status of compliance metric ALR-CP1. Several comments were received from NERC staff and PC and OC reviewers. A new metric will go back to the metric team and the Compliance and Certification Committee for consideration of the comments received.

Ms. Montgomery also reviewed the release schedule for the 2014 State of Reliability Report. The schedule requires an OC conference call for report approval on April 23 or April 24. Chair Castle tasked Jerry Rust (chair), Darrel Yohnk, and Hassan Hamdar with reviewing the initial drafts.

Standards Independent Experts Review Project – An Independent Review by Industry Experts
Chair Castle noted that the Standards Independent Experts Review Project report identified four possible reliability gaps in the current or future enforceable reliability standards. The four possible reliability gaps are 1) outage coordination, 2) generator frequency response, 3) EMS real-time contingency analysis models, and 4) lack of requirements for use of three-part communications.

The OC agreed that the Executive Committee should meet with the Independent Experts to determine their intent behind the identification of the possible reliability gaps and to determine next steps.
Next Meeting
The next meeting of the Operating Committee will be on June 10–11, 2014 in Orlando, Florida.

Adjourn
There being no further business before the Operating Committee, Chair Castle adjourned the meeting on Wednesday, March 5, 2014 at 11:38 a.m. CST.

Larry Kezele
Larry Kezele
Secretary
OC Chair Verbal report to
NERC Board of Trustees May 7, 2014

We were very fortunate to have had as our guests two Board of Trustee members, Douglas Jaeger and Paul Barber, in attendance at our March 4th and 5th OC meetings in St. Louis. Thank you for being an engaged Board, for witnessing the OC in action, and for your kind words of support. Janice Case has expressed interest in attending our June meeting scheduled for Orlando airport Hyatt.

Operating Committee Highlights since our last Board meeting include:

**Essential Reliability Services Task Force (ERSTF)**

The Operating Committee approved the ERSTF scope and assigned a core group of OC members and contributors to participate on the ERSTF on behalf of the OC. The core OC group is being chaired by Ken McIntyre of ERCOT who will also serve as the co-Chair of the ERSTF along with a Planning Committee representative. The OC Fully supports the work that the ERSTF has in front of them in identifying and presenting characteristics such as inertia, frequency response, voltage control, and possibly others such as fuel mix as discussed yesterday, which must be maintained across a given system to ensure reliable operation.

**EAS “Vortex” & Cold Weather Events**

With several periods where frigid temperatures reached deep into the southern regions of NERC, this winter gave us the opportunity to take an objective look at our cold weather preparedness reliability guideline. Of the half dozen or so presentations from entities operating during the frigid periods, it is the Operating Committee’s sense that cold weather preparedness and operations appear to have greatly improved. The OC instructed the EAS to consolidate lessons learned from this winter so they can be more easily utilized by the industry. The OC also instructed the EAS to benchmark the current cold weather preparedness reliability guide with what was learned this winter and recommend potential enhancements to the Cold Weather Preparedness Reliability Guideline in time for use during next winter’s preparation.

**OC Organization**

During the last OC meeting the OC agreed on a minimum outline for the subcommittees to bring their scopes into alignment with each other, the OC charter and strategic plan, and other NERC governing documents. The subcommittees have been working hard on this item, and have been instructed to present their updated scopes to the OC for final approval at the June OC meeting.

**Independent Expert Report: Outage Coordination, Governor Freq Response, EMS RTCA Models**

The Standards Committee reviewed the Gaps as presented by the Independent Experts in their June 2013 report, developed a triage report and reviewed it with the RISC. The triage report requested that the Operating Committee opine on several of the proposed gaps, the OC reviewed the gaps as requested by the SC and RISC, and assigned the OCEC to have a more in depth discussion with the Independent Experts regarding the gaps. Following that OCEC & Independent Expert webinar that Val Agnew was kind enough to set up, the OCEC provided written feedback to the Standards Committee and the RISC with the OC opinions.
Complete Loss of communications to the Generators

I talked briefly about this effort at the last Board meeting that we posted the draft for public comment. I just want you to know that I personally reached out to both the transmission and generator forums and invited them to discuss within their groups and provide comments, and they were very helpful and accommodating. So Tom and Allen thanks for a good working relationship. This is on our June agenda for possible approval and I invite both forums to participate.

Mike Moon

Mike Moon has been the NERC Management liaison to the OC for the past few years and is now transitioning to new duties and responsibilities within NERC. I just want to thank Mike and Gerry Cauley for the services that Mike brought to the OC during his involvement with us. Mike’s insights, energy and drive to do the right thing for reliability helped make the OC a better committee. More importantly, Mike helped improve BES reliability. Mike Moon, the OC thanks you for your service.
NERC Operating Committee

Action Items

Dated: March 5, 2014

<table>
<thead>
<tr>
<th>Assignment</th>
<th>Description</th>
<th>Due Date</th>
<th>Progress</th>
<th>Status</th>
</tr>
</thead>
<tbody>
<tr>
<td>RS</td>
<td>HILF – RS to continue to work on re-tuning the Y2K Frequency Guideline</td>
<td></td>
<td></td>
<td>In Progress</td>
</tr>
<tr>
<td>OC meeting and item number</td>
<td>Assignment</td>
<td>Description</td>
<td>Due Date</td>
<td>Progress</td>
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<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>
</tr>
<tr>
<td>1212-09</td>
<td>OC</td>
<td>• Posting the ACE Diversity Guideline</td>
<td></td>
<td>Highlight on BANNER/TAB of OC Web-Page</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• Communicate Same to Industry</td>
<td></td>
<td></td>
</tr>
<tr>
<td>1212-21</td>
<td>BARC SDT</td>
<td>BARC Final Report of Field Trial – lay out the analysis –</td>
<td>Dec 2013</td>
<td>Need information from Drafting Team Facilitator.</td>
</tr>
<tr>
<td></td>
<td>(Jerry Rust and Gerry Beckerle)</td>
<td>lessons learned from field trial structure and testing</td>
<td></td>
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### December 2013 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>
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<tbody>
<tr>
<td>1312-04</td>
<td>Chair Castle</td>
<td>Letter to the Subcommittees charging them to review their scopes.</td>
<td>Chair Castle sent an email to the leadership of each of the OC’s subcommittees outlining his request. Subcommittees are expected to have final draft scopes at the June 2014 meeting.</td>
<td>In Progress</td>
<td></td>
</tr>
<tr>
<td>1312-06</td>
<td>ALR-C1 – Support NERC staff on working through this</td>
<td>Waiting on PAS and CCC</td>
<td>In Progress</td>
<td></td>
<td></td>
</tr>
<tr>
<td>1312-07</td>
<td>GridEx II Lessons Learned</td>
<td>Waiting on NERC Final report issued, will discuss at the June 2014 meeting.</td>
<td>In Progress</td>
<td></td>
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</table>

### March 2014 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>
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<tbody>
<tr>
<td>1403-01</td>
<td>Castle</td>
<td>Engage NERC Legal on the following questions: 1. Quorum requirements 2. Passing a motion (simple majority vs. 2/3 super majority) 3. The issue of membership balance. Confirm that since the parent committee (OC) is a sector balanced committee, all pertinent work products must be approved by the OC, then sector balance is not required at the subcommittee level</td>
<td>ASAP</td>
<td>Discussed with NERC Legal Shamai Elstein. He will provide feedback during the week of March 17.</td>
<td>Complete</td>
</tr>
<tr>
<td>1403-02</td>
<td>Castle</td>
<td>Electric/Gas Coordination</td>
<td>June Meeting</td>
<td>Wes Yeomans, NYISO, VP Operations will address the OC.</td>
<td>In Progress</td>
</tr>
<tr>
<td>Action Item</td>
<td>Responsible</td>
<td>Description</td>
<td>Due Date</td>
<td>Status</td>
<td></td>
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<tr>
<td>1403-03</td>
<td>OCEC</td>
<td>Coordination with the Independent Experts</td>
<td>March 2014</td>
<td>Held a webinar with the Independent Experts and developed a draft response.</td>
<td></td>
</tr>
<tr>
<td>1403-04</td>
<td>EAS</td>
<td>Benchmark Cold Weather Guideline</td>
<td>June Meeting</td>
<td>In Progress</td>
<td></td>
</tr>
<tr>
<td>1403-05</td>
<td>EAS</td>
<td>Coordinate Lessons Learned from the 2014 Cold Weather events and post for industry use.</td>
<td>May 2014</td>
<td>In Progress</td>
<td></td>
</tr>
<tr>
<td>1403-06</td>
<td>Alan Bern</td>
<td>Provide the OC with an overview presentation of the Oncor voltage reduction program</td>
<td>June Meeting</td>
<td>In Progress</td>
<td></td>
</tr>
<tr>
<td>1403-07</td>
<td>RS and Cummings</td>
<td>Verify that Frequency Response data is being collected.</td>
<td>June Meeting</td>
<td>In Progress</td>
<td></td>
</tr>
<tr>
<td>1403-08</td>
<td>Kezele</td>
<td>Post the ADI reliability guideline. This is very late (see OC Action Item 1212-09).</td>
<td>ASAP</td>
<td>In Progress</td>
<td></td>
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<tr>
<td>1403-09</td>
<td>Rust, Yohnk, Hassan</td>
<td>Review of the 2014 State of Reliability Report prior to the OC taking action.</td>
<td>April 2014 OC will conduct an email vote on or about April 23, 2014.</td>
<td>In Progress</td>
<td></td>
</tr>
<tr>
<td>1403-10</td>
<td>Castle</td>
<td>Seek OC volunteers to serve on the ERSTF</td>
<td>March 2014</td>
<td>In Progress</td>
<td></td>
</tr>
<tr>
<td>1403-11</td>
<td>Case</td>
<td>RISC – The OC will re-address two previously identified gaps: 1. Maintaining Situational Awareness 2. Workforce Capability and Human Error</td>
<td>June 2014</td>
<td>In Progress</td>
<td></td>
</tr>
<tr>
<td>1403-12</td>
<td>EIDSN</td>
<td>Keep the OC informed of the progress of: 1. The transition of NERCnet to EIDSN 2. The development of a replacement to NERCnet data sharing network</td>
<td>September 2014 Meeting</td>
<td>In progress</td>
<td></td>
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</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 NERC sponsored information technology tools and services which support operational coordination and by providing technical support and advice as requested.

Last Meeting: May 6, 2014
Duration: 1 Day

Next Meeting: September 9–10, 2014
Duration: 1½ Days

Location: Toronto, ON

Location: Vancouver, WA

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

Pending OC Approval Items:
• The ORS endorsed a revised scope. With the goal of presenting it to the OC for approval at its June meeting.

Key issues for OC Resolution:
• None

Key Issues for OC Information:
• Associated Electric Cooperative briefed the ORS on its reliability concerns for the Palmyra, MO load area. ORS agreed to request a review of data by the IDC Tools Member Association regarding that area and the associated modeling.
• Endorsed the revised SERC Regional reliability plan and the revised MISO reliability plan.
• ORS continue to draft a Reliability Guideline regarding Real-Time Tools Degradation – initial draft to the OC projected for the September 2014 OC 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 continue studying 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.
• Reliability Standards – The ORS received a status report regarding the following reliability standards projects:
  o Project 2014-04 (Physical Security)
  o Project 2014-03 (Revisions to TOP and IRO Standards)
  o Project 2009-03 (Emergency Operations)

**Current Initiatives/ Deliverables:**

• NERC ORS continues to receive updates from the IDC Tools Member Association. The Association and its IDC Working Group are performing Generator-to-Load data testing this summer and will report identified reliability benefits to the ORS when available. The ORS will continue to review the current status of the Parallel Flow Visualization project plan and any needed coordination with the NAESB Business Practices Subcommittee.

• The ORS will host a webinar in early June 2014 to review Project 2014-03 (Revisions to TOP/IRO Reliability Standards) as a collective body because of its significant impact on current IRO standards.

**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.
Operating Reliability Subcommittee

Scope

Purpose
The Operating Reliability Subcommittee (ORS) assists the NERC Operating Committee (OC) in enhancing Bulk Electric System (BES) reliability by providing operational guidance to the industry; by providing oversight to the management of NERC-sponsored information technology tools and services which support operational coordination and by providing technical support and advice as requested.

Functions
The ORS will:

1. Develop guidelines and programs to facilitate operating reliability coordination. Included among the processes supported by ORS are those related to:
   a. Real-time communications among registered entities, especially Reliability Coordinators.
   b. Exchange of operational data and modeling data among registered entities.
2. Disseminate operational information among the Reliability Coordinators and other reliability entities.
3. Provide oversight to the management of NERC-sponsored information technology tools and services that facilitate operational reliability coordination.
4. Respond to requests for technical input and guidance from the Operating Committee.
5. Review reliability plans, including:
   a. Approval of minor revisions
   b. Review other revisions and provide recommendations to the Operating Committee
6. Provide a forum for coordinating system operating procedures in all four Interconnections, including:
   a. Coordinate operating reliability standard implementation to promote consistency across the Interconnections.
   b. Prepare for the upcoming operating peak demand season.
   c. Review system disturbances and transaction curtailments for "lessons learned."
   d. Review Interconnection frequency events at each meeting.
7. Provide coordination between the IDC Tools Member Association and the Operating Committee regarding the applications managed by the Association.
8. Provide a forum for coordination of TLR business practices and reliability standards.
9. Provide oversight and guidance on aspects of interchange scheduling, including dynamic transfers, as it applies to impacts on reliable operations.
Deliverables

- Provide subcommittee report for the regularly scheduled Operating Committee meetings
- Endorse or approve as applicable revisions to Reliability Plans
- Develop comments on the annual State of Reliability report
- Develop comments on Adequate Level of Reliability metrics
- Develop recommendations to the Operating Committee on reliability guidelines
- Develop responses to other directives and requests of the Operating Committee

Reporting

The ORS reports to the OC and shall maintain communications with the Planning Committee (PC) and other groups as necessary on relevant issues.

Officers

The NERC OC Chair appoints the ORS officers (Chair and Vice Chair) for a specific term (generally two years). The subcommittee officers may be reappointed for additional terms. The ORS officers are considered members of the subcommittee and may vote. The ORS may recommend officer candidates for the OC Chair’s consideration following a supporting motion. Both officers must be Reliability Coordinator representatives.

Membership

1. One member from each Reliability Coordinator.
2. One additional non-Reliability Coordinator member from each region.
3. No single company may have multiple non-Reliability Coordinator members
4. Current non-Reliability Coordinator ORS members will be grandfathered as a member of the subcommittee and the subcommittee roster will indicate this grandfather status
5. Once the current grandfathered members resign their position on the committee then the ORS will receive applications for non-Reliability Coordinator membership based on the criteria in number two above. The selection process will be determined by the ORS.

As outlined in the OC’s “Subcommittee Organization and Procedures,” the ORS shall have sufficient expertise and diversity to be able to speak knowledgably for the industry and provide meaningful and useful guidance to assist the industry in the carrying out of its reliability responsibilities.

Executive Committee

The Executive Committee of the ORS is empowered by the ORS to act on its behalf between subcommittee meetings on matters where urgent actions are crucial and full subcommittee discussion is not practical. Ultimate ORS 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. The Executive Committee will be comprised of the ORS Chair, Vice Chair, along with three at large members. The Executive Committee members are elected by the ORS for a two year term. The Executive Committee members may be re-elected.
Meeting Procedures
1. Quorum: 50 percent of subcommittee members eligible to vote

2. 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.

Example: The Reliability Coordinators may hold meetings in closed session when discussing reliability issues that they deem security, compliance, or commercially sensitive.

Subgroups
The ORS 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.

1. Data Exchange Working Group (DEWG) – Responsible for supporting the data needs of Reliability Coordinators and developing a comprehensive Interregional Security Network (ISN) to facilitate the exchange of real-time, modeling, and other operational data to help ensure reliable electric power system operations.

2. Telecommunications Working Group (TWG) – Responsible for developing standards and practices used to plan, implement, operate, and maintain telecommunications facilities for the Interregional Security Network (ISN) and other interregional communication applications.
NERC Operating Committee
Sub-group Status Report

Group: Resources Subcommittee

Purpose: Status Update

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

Next Meeting: July 23-24, 2014 Location: Portland, OR
Duration: 1½ days

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

Pending OC Approval Items:

• The RS endorsed a revised RS Scope, with the goal of presenting it to the OC for approval at its 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 considered the comments received and developed responses to the comments. The RS also endorsed a revised guideline for the OC’s consideration.

Key issues for OC Resolution:

• None

Key Issues for OC Information

• 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 overview of the survey results.

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 with regard to the Interconnection Frequency Response Adequate Level of Reliability metric.

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)
DRAFT Resources Subcommittee

Scope
Revised April 24, 2014

Purpose
The Resources Subcommittee (RS) assists the NERC Operating Committee (OC) in enhancing Bulk Electric System (BES) reliability by implementing the goals and objectives of the OC Strategic Plan with respect to issues in the areas of balancing resources and demand, interconnection frequency, and control performance.

Functions
The RS accomplishes this by:

- Reviewing and assisting in the development of generation and load “balancing” standards. Which may include developing any necessary reference documents.
- Reviewing and assisting in the development of interconnection balancing standards to assure problems resulting from balancing do not adversely affect reliability.
- Providing oversight and guidance to working groups and task forces.
- Providing industry leadership and guidance on matters relating to balancing resources and demand issues as well as resulting issues related to interconnection frequency.
- Addressing the reliability aspects of inadvertent interchange creation, accounting, and payback.
- Review balancing authorities’ control performance (e.g., CPS and DCS) on a periodic basis.
- Address technical issues on automatic generation control (AGC), time error correction, operating reserve, and frequency response.
- Provide oversight and guidance on aspects of interchange scheduling as it applies to impacts on balancing and inadvertent interchange.

Deliverables
- Determination and issuance of yearly CPS Bounds Report
- Subcommittee report for the regularly scheduled OC meetings
- Endorsement of the Frequency Response Annual Analysis Report (Determination of the annual IFRO)
- Respond to other directives and requests of the NERC OC.
**Reporting**
The RS reports to the NERC OC and shall maintain communications with other groups as necessary on balancing resources and demand issues and interconnection frequency related issues.

**Officers**
The NERC OC Chair appoints the RS officers (Chair and Vice Chair) for a specific term (generally two years). The subcommittee officers may be reappointed for additional terms. The RS officers are considered members of the subcommittee and may vote. The RS 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 position is considered important for succession planning with the anticipation that the Vice Chair will be appointed as RS Chair for the next term. The RS may recommend officer candidates for the OC Chair’s consideration.

**Membership**
The RS shall have sufficient expertise and diversity to be able to speak knowledgably for the industry and provide meaningful and useful guidance to assist the industry in the carrying out of its reliability responsibilities. NERC segment membership balance resides with the parent committee (OC), allowing the subcommittee to focus on the expertise required to carry out its functions.

**General Requirements**
RS membership requirements are focused on *expertise* related to system control and control performance.

**Expertise**
The RS must have sufficient expertise within its ranks to fully understand the balancing (BAL) and other applicable standards.

**Commitment and Participation**
RS members must be committed to their service on the subcommittee. This means preparing for and actively participating in all subcommittee meetings in person or on conference calls. It also means writing and reviewing draft reports, serving on standard authorization request and standards drafting teams, if selected, and bringing issues to their Regional Entities, trade organizations, and utilities for further discussion and insight.

**Replacing Members**
The subcommittee may request a replacement for a member that misses three consecutive meetings without sending a proxy.

**Voting Members**
1. **Regional representatives.** Each Region should provide at least one member. The Regions are expected to select their representatives based on their expertise in the RS’s subject matter.

2. **Interconnections and countries.** If the set of Regional representatives does not provide for at least one representative from each interconnection and two representatives from the U.S. and Canada, the subcommittee chair, working with the NERC staff, will ask for additional members from the Regional reliability councils or trade organizations as necessary to fulfill these requirements.

3. No single company may have multiple members.

**Non-voting members — Guests and Observers**
RS meetings are open to others who wish to attend as a guest of the subcommittee. The chair will provide guests and observers the opportunity to contribute to the subcommittee’s discussions, provided the subcommittee’s voting members have sufficient time to:

1. Complete the debate of their motions, and
2. Complete the meeting agenda.

**Meeting Procedures**
**General**
The RS follows the meeting procedures explained in the following two documents:

1. NERC Antitrust Compliance Guidelines, and

**Quorum**
A quorum for conducting business is 50 percent of the RS members eligible to vote (either in person or calling in). If a quorum is not present then the subcommittee may not take any actions requiring a vote of the subcommittee. However, the chair may, with the consent of the members present, allow discussion of agenda items.

**Majorities**
The subcommittee uses a simple majority of the voting members present for all motions.

**Minority Opinions and Personal Comments**
The minutes of every RS meeting will include exhibits for minority opinions and personal comments, when provided. The chair shall communicate both the majority and any minority views when presenting subcommittee discussion results with the OC.

**Confidential Sessions**
The chair of the RS 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. To stay in the confidential session a signed “NERC Confidentiality Agreement for NERC Resources subcommittee Members” is required.
Subgroups

The RS may form task forces and working groups as necessary, without OC approval. The subcommittee must review the progress of its subgroups at least annually and decide to either continue or disband these groups as needed. Membership in the subgroups may consist of non-RS members to allow for expertise in desired areas.

Task forces are usually ad-hoc and are not expected to exist after completing their assignments. Conversely, working groups may be ongoing.

Task force and working group chairs (or delegates) are expected to attend the regular subcommittee meetings to report on assignments and subgroup activity.

Current working groups are:

- Frequency Working Group
- Inadvertent Interchange Working Group
- Reserve Working Group
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: March 02, 2014 Location: St Louis

Duration: 1 Day

Next Meeting: June 09, 2014 Location: Orlando, FL

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 March 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:

• Lessons Learned Presentation: Improved Contractor Oversight – Bo Jones, Westar Trending Working Group
• (TWG) currently reviewing the Reliability Guideline: Generating Unit Winter Weather Readiness in response to the EAS action item from the March 2014 NERC OC meeting.
• Energy Management System (EMS) Working Group is preparing for the annual Monitoring and Situation Awareness Conference to be held in September and hosted by PJM.
Agenda Item 5.c
OC Meeting
June 10-11, 2014

- **Current Initiatives/ Deliverables:**
  - Benchmark findings from the Polar Vortex with Reliability Guideline: Generating Unit Winter Weather Readiness to identify gaps and improvement opportunities.

- **Future Initiatives/ Deliverables:**
  - EMS Working Group – 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

- Participation on Essential Reliability Services Task Force (ERSTF) as directed by the OC.
  - EAS has two representatives on the ERSTF
  - Providing input to a white paper which can be used by regulators and policy makers to guide their decision making as non-traditional (synchronous) generators become a smaller share of the generating fleet, and renewable resources increase as a share of the generating fleet.
  - On-going coordination calls and face to face meetings 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
**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 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 enhancement to existing Reliability Standards or development of new Reliability Guidelines or Reliability Standards where gaps are identified.

d. Annually survey the Regional Entities to assess the value lessons learned.

**Deliverables**

- Annual 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

All work products (with the exception of Lessons Learned) intended for industry use (i.e. such as a manual, reliability guideline, reports, whitepapers, etc.) shall be approved by the NERC Operating Committee.

**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 voting members of 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.
  - These members must have a signed Non-Disclosure Agreement on file in order to participate in the Confidential Sessions described below.
Meeting Procedures
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.

- 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.

Meetings
Four to six open meetings per year, or as needed, with supplemental telephone conferences.

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<th>Date</th>
<th>Reviewers/Approval</th>
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| 1.0  | 06/19/2013| Developed by: Event Analysis Working Group (EAWG)  
Approved by: Operating Committee (OC)                                       | Transitioned the EAWG into the Event Analysis Subcommittee (EAS).                            |
| 1.1  | June/10/2013 | Developed by: Event Analysis Subcommittee (EAS)  
Approved by: OC                                                           | Updated EAS Scope to reflect changes in the OC Strategic Plan.                              |
NERC Operating Committee
Personnel Subcommittee Status Report
June 10-11, 2014

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

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

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

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

Pending OC Approval Items: None
Key Issues for OC Resolution: None
Key Issues for OC Information: Version 4.3 of CE Manual in revision, process mapping project in progress.

Current Initiatives/Deliverables
- CE Program 2014 audits completed

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CE 2014 Program Statistics

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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.
• Recruiting new members for the PS and CERP
• External Requests to Group:
  o Chair and vice chairs of the PS and EAS working to develop a process to identify training needs and support
  o Support OC’s RISC rep evaluation of Workforce Capability and Human Error related vulnerabilities.
• Internal Requests to Group:
  o SOCCED phase 2 advisory group formed in conjunction with the PCGC
  o 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
- Quarterly CE Program Report to PCGC and OC
- Guide to Writing Learning Objectives
- Guide to Selecting and Developing Learning Assessments
This document addresses the organizational structure of the NERC Personnel Subcommittee (PS). This document also defines the Personnel Subcommittee’s role of governing the NERC Continuing Education Program.

**Purpose**
The Personnel Subcommittee’s goal is to support the development of continuing education program requirements that promote excellence in training programs and advance improved performance of Bulk Power System personnel.

**Functions**
1. Serve as the technical training advisor to the NERC Operating Committee.
2. Serve as the governing body of the NERC Continuing Education Program responsible for oversight of the:
   a. Development and implementation of continuing education program requirements that advance the improved performance of the Bulk Power System personnel and promote excellence in training programs.
   b. Development and maintenance of a process to approve or accredit continuing education Providers and activities that seek approval or accreditation and meet NERC-approved continuing education requirements.
   c. Performance of periodic audits on continuing education Providers and training activities to ensure the approved or accredited Providers and training activities satisfy NERC continuing education requirements.
   d. Development and maintenance of an appeals process for disputed application reviews, probation or suspension of NERC-approved Provider status, or Continuing Education Hour disputes.
3. Provide input on fees for continuing education providers and learning activities.

**Deliverables**
1. Develop and maintain the Continuing Education Administrative Manual.
2. Oversee quarterly Continuing Education Program Provider course audits.
3. Prepare a Personnel Subcommittee Action Plan which aligns with the Operating Committee’s Strategic Plan.
**Reporting**
The Personnel Subcommittee reports to the Operating Committee and all work products for use by the industry must be approved by the OC. The Personnel Subcommittee shall maintain communications with other groups as necessary on relevant issues per the Operating Committee Charter and their strategic plan or per the direction of Operating Committee officers.

**Officers**
1. The Personnel Subcommittee officer-selection process will follow the Operating Committee Charter.
   a. The PS may recommend officer candidates for the OC Chair’s consideration following a supporting motion.
   b. The Vice Chair should be available to succeed the Chair.
2. The NERC OC Chair appoints the PS Chair and Vice Chair for a specific term (generally two years). The subcommittee officers may be reappointed for additional terms.
   a. The PS officers are considered members of the subcommittee and may vote.

**Duties**
Duties of Personnel Subcommittee officers:
1. Subcommittee Chair
   a. Lead Subcommittee activities, set the agendas for meetings, and act as spokesperson for the Personnel Subcommittee.
   b. Administer the Subcommittee meeting agendas and preside at the meetings.
   c. Represent the Subcommittee before the Operating Committee and other forums as appropriate.
   d. Execute decisions by the Operating Committee and perform other duties as directed by the Operating Committee.
   e. 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 at a minimum.
   f. Establish working groups or task forces as directed by the Subcommittee.
   g. Notify in writing all newly appointed representatives of existing or new working groups or task forces of their appointment.
2. Subcommittee Vice Chair
   a. Perform the duties of the Chair in his or her absence.
   b. Serve as parliamentarian during meetings.
   c. Assist the Chair as called upon.
3. NERC Staff
   a. Prepare the minutes of the Subcommittee meetings.
b. Maintain the Subcommittee records.
c. Assist the Chair and Vice Chair as called upon.

**Membership Qualifications:**
The Personnel Subcommittee will consist of individuals who have expertise in a systematic approach to training, which includes the analysis, design, development, implementation, and evaluation of training activities, and who broadly represent the major sectors of the electric utility industry and NERC Regions. Members should have:

1. Advanced training expertise, preferably in the bulk transmission system.
2. Significant experience in the electric utility industry. Parallel experience of training in the electric utility industry will suffice for both training and industry experience.
3. Knowledge and application of a systematic approach to training.
5. Be knowledgeable regarding reliable operations within their organizations.

**Expectations**
Personnel Subcommittee voting members are expected to:

1. Attend and participate in all Personnel Subcommittee meetings.
2. Express their opinions, as well as the opinions of the sector they represent, at committee meetings.
3. Complete committee assignments.
4. Inform assigned NERC staff 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 Chair dismissing those members.

**Representation**
The Personnel Subcommittee will work to ensure a diverse membership reflective of the electric utility industry footprint across North America.

The Personnel Subcommittee shall be comprised of up to 18 individuals to serve as voting members of the Personnel Subcommittee selected by a two thirds vote among existing Personnel Subcommittee members and confirmed by the Operating Committee Chair.

**Resignations, Vacancies, and Nonparticipation**
The Personnel Subcommittee shall follow the specifications on resignations, vacancies, and nonparticipation outlined in the Operating Committee Charter, including the following guidelines:

1. Members who resign will be replaced for the time remaining in the member’s term pursuant to a two thirds vote among existing PS members and confirmation by the Operating Committee Chair.
2. 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.

3. The chair may remove any member who has missed two consecutive meetings (even if the member has sent a proxy).

Meetings
The Personnel Subcommittee shall follow the specifications on meetings outlined in the Operating Committee Charter, including:

1. Quorum
   a. A quorum requires a simple majority of the voting members.

2. Voting
   a. Each voting member of the committee shall have one vote on any matter before the committee that requires a vote. Actions by members of the committee shall be approved upon receipt of the affirmative vote of a simple majority of the voting members of the committee present and voting (in person or by proxy) at any meeting in which a quorum is present. The Chair and Vice Chair may vote. Voting may take place during regularly scheduled in-person meetings or may take place via electronic mail, facsimile, or conference call.

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

5. Confidential sessions
   a. The Chair of a committee may limit attendance at a meeting or portion of a meeting based on the confidentiality of the information to be disclosed. Such limitations should be applied sparingly and on a non-discriminatory basis to protect information that is sensitive to one or more parties. A preference, when 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.

In the absence of specific provisions in the Scope document, the Personnel Subcommittee will follow Roberts Rules of Order, Newly Revised.

Subgroups
The Subcommittee may form working groups and task forces as needed to assist the subcommittee in carrying out standing or ad hoc assignments. Subgroup 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.

The Subcommittee will evaluate annually any subgroups. This evaluation should include a determination as to whether the subgroup status falls into one of the following categories:

- Task Complete- Subgroup is discontinued;
- Task Incomplete- Subgroup is discontinued;
- Task in Progress- Subgroup is continued; or
- Task in Progress- Subgroup is continued and subgroup members require updating.

**Current Subgroups:**
1. Continuing Education Review Panel (CERP)
Essential Reliability Services Task Force (ERSTF) Scope

**Background**

Essential Reliability Services (ERS) are the elemental ‘reliability building blocks’ from resources (generation and demand) necessary to maintain Bulk Power System (BPS) reliability. ERS are operational attributes from conventional generation, such as providing reactive power to maintain system voltages and physical inertia to maintain system frequency, necessary to reliably operate the BPS. In contrast, retirement of conventional generation in near future across many areas in North America, coupled with increasing variable generation installation can adversely impact the availability of ERS unless due considerations are given in planning and operations.

There are many factors that contribute to the need for reassessing reliability services. To include a few; variable renewable generation such as distributed, and utility scale solar, and wind generation, retirement of conventional power plants with substantial inertial response capability, increase use of demand response to address load relief, and the change in the operational landscape with integration of renewables and new technology that is used in conjunction with them, like energy storage. The proposed levels of commitment to renewable variable generation is one component of an ongoing shift in resource mix. 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 evident increase in reliance on natural gas-fired generation.

As larger amounts of variable generation are added to the system, they have strong potential to displace the traditional large, rotating machines and the operating characteristics those machines and the ancillary benefits to system reliability that these units provided. Variable generation, in particular, has different operating characteristics and responds differently to changes in frequency and voltage on the system. 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. These along with other characteristics or functions make up a suite of Essential Reliability Services or ERS.

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, it may be necessary for regulators to make appropriate adjustments to market rules and reliability standards that will ensure reliable operation of the BPS.
**Purpose**
The ERSTF has a multi-faceted purpose that includes developing a technical foundation of ERS; educating and informing industry, regulators, and the public about ERS; developing an approach for tracking and trending ERS; formulating recommendations to ensure the complete suite of ERS are provided and available; and providing guidance necessary for operating a reliable grid. More specifically, the ERSTF 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, operation and the need for increased ERS. The ERSTF will include membership from existing technical subcommittees and working groups to strengthen the task force platform, and thus producing results which will maintain, enhance, and sustain reliable operation of BPS.

**Activities**
1. Develop a technical reference document (primer) on ERS. The primer can be used as a reference manual for regulators and policy makers to inform, educate, and build awareness on the reliability ramifications of 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.
   a. Assess impacts on ERS due to increase in variable generation along with retirements of base generation. Articulate how each region is impacted by this scenario.
3. Develop specific recommendations for practices and proposed requirements, including potential reliability standards, that cover the transmission and generation planning, operations planning, and real-time operating procedures.
4. Compose a technically sound guidance document incorporating ERS in operations and operational planning. With retirement of base load generation plants, integration of variable resources and increased use of demand response for load relief; the operational landscape has changed and is projected to continue for near future. Operations personnel will face different methods and modes of operations; for e.g. with increased transmission line construction to accommodate renewable resources, increased number of reactive support devices are installed on the system to compensate for variability of renewables and voltage support. This philosophy and implementation is different from traditional operations with base load generators providing majority of voltage and reactive support.

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 Region
- 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 and/or Operating Committee sector representatives, or
  - As needed by the NERC coordinator
- One member of the Reliability Assessment Subcommittee (or designated liaison)
- One member of the System Analysis and Modeling Subcommittee (or designated liaison)
- One member of the Resources Subcommittee (or designated liaison)
- One member of the Frequency Working Group (or designated liaison)
- NERC staff coordinator(s)
- Governmental members include, but not limited to:
  - Federal Energy Regulatory Commission
  - United States Department of Energy
  - National Energy Board, Canada

Participation of additional industry subject matter experts may be requested to support task force activities.

The task force co-chairs will be appointed by the chairs of the NERC Planning Committee and Operating Committee. Representation on this task force follows established Planning Committee 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: March 5, 2014
Approved by the NERC Operating Committee: March 5, 2014
Reliability Guideline:
Generating Unit Operations During Complete Loss of Communications

Preamble:

It is in the public interest for the North American Electric Reliability Corporation (NERC) to develop guidelines that are useful for maintaining or enhancing the reliability of the Bulk Electric System (BES). The Technical Committees of NERC; Operating Committee (OC), Planning Committee (PC) and the Critical Infrastructure Protection Committee (CIPC) per their charters are authorized by the NERC Board of Trustees (Board) to develop Reliability (OC and PC) and Security Guidelines (CIPC). These guidelines establish a voluntary code of practice on a particular topic for consideration and use by BES users, owners, and operators. These guidelines are coordinated by the technical committees and include the collective experience, expertise and judgment of the industry. The objective of this reliability guideline is to distribute key practices and information on specific issues critical to maintaining the highest levels of BES reliability. Reliability guidelines are not to be used to provide binding norms or create parameters by which compliance to standards is monitored or enforced. While the incorporation of guideline practices are strictly voluntary, reviewing, revising, or developing a program using these practices is highly encouraged to promote and achieve the highest levels of reliability for the BES.

Purpose:

This Reliability Guideline provides a strategy for power plant operations in the case of complete loss of communications (both data and voice) between on-site generating unit(s) operator and the System Operator for the Balancing Area, Transmission Operator and Reliability Coordinator. This Reliability Guideline was developed as requested by the NERC OC as part of our industry’s response to the Severe Impact Resilience Task Force (SIRTF) Recommendations.

The Reliability Guideline applies primarily to Balancing Authorities and to Generator Operators. The applicability of this document to Balancing Authorities is to provide a resource for coordination and training guidelines for generators operator(s) should all communications be interrupted, particularly during a severe impact event. See Appendix (Training) below.

The Reliability Guideline outlines a coordinated operations strategy for generating unit(s) to stabilize system frequency when centralized guidance is not possible. It is designed to keep frequency within allowable limits and continued safe operation of generators while maintaining acceptable frequency control. The Reliability Guideline is not applicable to generation connected to asynchronous loads or systems not normally part of one of the Interconnections.
The Reliability Guideline is not meant to prevent generating unit operator(s) from taking actions necessary to protect the equipment under their supervision from damage to include if necessary to be taken off line in a safe manner. Protective equipment should not be bypassed or rendered inoperable in order to follow this guideline. Safety of personnel and prevention of damage to system equipment are the first responsibilities of electric system operators at all levels. Short term instabilities and power grid outages can only be made worse if damage is allowed to occur to system equipment.

This Guideline does not create binding norms, establish mandatory reliability standards or create parameters by which compliance with Reliability Standards are monitored or enforced. In addition, the Reliability Guideline is not intended to take precedence over any regional procedure.

Assumptions:

The basic assumptions made in the development of this guideline are as follows:

A. Loss of Communications – all data and voice communications, both primary and backup, are lost between the on-site generating unit(s) operator and the System Operator for the Balancing Area, Transmission Operator and Reliability Coordinator.

B. Generating Unit Status – some generating capacity remains in service or can be brought into service locally at the plant operator’s discretion, to serve the load over the period of lost communications. (This does not imply that steam units not already in service should be brought into service.)

C. Instrumentation – Generating unit(s) are equipped with frequency metering devices capable of displaying (and optionally recording) system frequency on both narrow (roughly 59.95 Hz to 60.05 Hz) and wide (roughly 58.0 Hz to 62.0 Hz) ranges. Alternatively, nomograms or other job aids that convert generator speed to frequency can be used.

D. Situation Awareness – The on-site generating unit(s) operator recognize that frequency is abnormal and a unique situation is occurring.

Guideline Details:

If communications between the on-site generating unit(s) operator and the System Operator is lost, the primary system information available to the on-site generating unit(s) operator will be frequency as measured locally by plant instrumentation. It may not be possible for the on-site generating unit(s) operator to determine if the grid remains intact or if the plant is operating as part of a local island. There may be clues that a disturbance has occurred. However, any constant frequency operations strategy must function equally well with an intact grid or under island conditions.

In order to maintain stable system operations with either an intact grid or as part of an island, it is necessary to maneuver generation output to match changes in system demand. Without communications from the System Operator, this can only be done by the on-site generating unit(s) operator controlling to frequency. This guideline proposes the following structure to achieve frequency control for the following Interconnections:
Eastern Interconnection

Deadband (Green Zone) – as long as the frequency trend stays reasonably close to 60.00 Hz, no control actions should be taken by generating unit(s). This deadband should be +/- 100 milliHertz (59.90 Hz to 60.10 Hz - See Chart 1 below).

Selective Response (Yellow Zone) – as the frequency trend moves outside the deadband boundaries but remains within reasonable operational limits it should be corrected by maneuvering generating unit(s) in a gradual manner. For the Eastern Interconnection, the Selective Response band should be beyond +/- 100 milliHertz but less than +/- 200 milliHertz (59.80 Hz to 60.20 Hz). The generation ramp rate recommended for Selective Response is roughly one percent of the unit rating per minute. On-site generating unit(s) operator should carefully observe frequency during Selective Response and cease maneuvering their units when frequency enters the deadband. It should be noted that a sustained frequency less than 59.90 Hz or greater than 60.10 Hz in the Eastern Interconnection is an indication that a disturbance has occurred.

Full Response (Red Zone) – when the frequency trend exceeds reasonable operational limits all units capable of responding should rapidly maneuver to balance load with generation. Full Response should be triggered when frequency is less than 59.80 Hz or greater than 60.20 Hz. If frequency continues to exceed the Full Response limits, all available generation at the plant should be maneuvered to the appropriate unit operating limits (i.e. fully loaded in the case of low frequency or at minimum load in the case of high frequency). In particular, all available generating capacity at the plant should be deployed to halt frequency decline when the frequency drops below the Full Response limit. On-site generating unit(s) operator(s) should carefully observe frequency during Full Response operation and reduce the ramp rate of their units when frequency reaches the Selective Response region.

Emergency Response – if the frequency trend continues to deteriorate, emergency measures will be required.

- **High Frequency** – high frequency Emergency Response will consist of maneuvering all available generation to its lowest stable operating point, followed by tripping of selected units.
  - **Low Minimums** – all generation should be maneuvered to its lowest stable minimum load operating point (with auxiliary fuel firing, if required) when frequency increases to 60.30 Hz.
  - **Unit Tripping** – when frequency increases to 60.50 Hz, plants with multiple units should trip generation offline. Generally, smaller units with minimal impacts to transmission should be taken offline first, so that as much capacity as possible remains online. Use operational judgment to minimize any adverse impacts. Subsequent generation should be taken offline as needed.
- **Low Frequency** – Emergency Response will consist of loading all available hydro generation, followed by commitment of quick-start generating unit(s) (primarily combustion turbines) and, finally, underfrequency load shedding.
- **Hydro** – all hydro generation should be loaded when frequency declines to 59.70 Hz
- **Quick-Start** – all quick-start generation resources should be committed when frequency drops below 59.60 Hz

For information, underfrequency load shed relays start to operate automatically when frequency declines to 59.50 Hz. Roughly ten percent of system load is typically shed at this point (note that specific frequencies and load percentages vary depending upon specific regional requirements). Additional load is typically shed as frequency continues to decline. The amount of load actually shed in any particular island will vary.

**Blackout Conditions** – if conditions continue to deteriorate, it will be necessary for on-site generating unit(s) operator(s) to separate from the synchronized grid in order to protect generating unit equipment. This typically takes place at roughly 58.00 Hz. (Note that this is based on turbine manufacturer’s recommendations that operation below this frequency can result in significant fatigue failure of the turbine blades and may vary with specific turbine design).

While it is desirable to maintain service continuity, it is unacceptable to allow generating unit equipment to suffer major damage that would impede the restoration of service after a major disturbance. However, it is important that units not be prematurely tripped when frequency is declining, since such action will cause system frequency to decline further and adversely affect other generators in the island. It is recommended that unless frequency is declining rapidly, units should remain connected to the system until the operation of automatic underfrequency load shedding relays is completed at roughly 58.00 Hz.

If a unit is removed from the transmission system by the on-site GOP and cannot continue operation on a self-supporting basis the GOP should shut down the Plant in an organized manner in preparation for restart. Such Operation should be continued until a request to re-synchronize the generating unit to the transmission system can be communicated to and approved by the System Operator. Maintaining generating unit(s) in hot standby mode will reduce the time required to restore the electrical system to normal operation.

The on-site generating unit(s) operator should make regular attempts to restore communications with the System Operator to convey the status of their generating unit(s) and always follow their Black Start Plans. This should include attempts to contact the Balancing Authority, Transmission Operator and/or Reliability Coordinator.
Notes:

1. Nuclear generating plants are expected to stay on line at a sustainable, stable output level as long as possible. Under no circumstances should this Reliability Guideline be interpreted as requiring nuclear generating plants to operate in a manner that will violate their regulatory requirements, endanger public safety or adversely impact the integrity of plant equipment.

2. It is recommended that generating unit(s) calibrate plant frequency equipment on an annual basis.
ERCOT Interconnection

**Deadband** (Green Zone) – as long as frequency trend stays reasonably close to 60.00 Hz, no control actions should be taken by generating unit(s). This deadband should be +/- 70 milliHertz (59.93 Hz to 60.07 Hz - See Chart 2 below). This dead-band is the “Secondary Control” dead-band and should not be confused with governor dead-band of the turbine governor. Turbine governor dead-bands are as required by ERCOT.

**Selective Response** (Yellow Zone) – as the frequency trend moves outside the dead-band boundaries but remains within reasonable operational limits it should be corrected by maneuvering generating unit(s) in a gradual manner. For the ERCOT Interconnection, the Selective Response band should be +/- 200 milliHertz (59.80 Hz to 60.20 Hz). The generation ramp rate recommended for Selective Response is roughly one percent of the unit rating per minute. On-site generating unit(s) operator should carefully observe frequency during Selective Response and cease maneuvering their units when frequency enters the dead-band.

**Full Response** (Red Zone) – when the frequency trend exceeds reasonable operational limits all units capable of responding should rapidly maneuver to balance load with generation. Full Response should be triggered when frequency is less than 59.80 Hz or greater than 60.20 Hz. If frequency continues to exceed the Full Response limits, all available generation at the plant should be maneuvered to the appropriate unit operating limits (i.e. fully loaded in the case of low frequency or at minimum load in the case of high frequency). In particular, all available generating capacity at the plant should be deployed to halt frequency decline when the frequency drops below the Full Response limit. On-site generating unit(s) operator(s) should carefully observe frequency during Full Response operation and reduce the ramp rate of their units when frequency reaches the Selective Response region.

**Emergency Response** – if the frequency trend continues to deteriorate, then emergency measures will be required.

- **High Frequency** – high frequency Emergency Response will consist of maneuvering all available generation to its lowest stable operating point, followed by tripping of selected units.
  - **Low Minimums** – all generation should be maneuvered to its lowest stable minimum load operating point (with auxiliary fuel firing, if required) when frequency increases to 60.50 Hz.
  - **Unit Tripping** – when frequency increases to 62.50 Hz, plants with multiple units should trip generation offline. Generally, smaller units with minimal impacts to transmission should be taken offline first, so that as much capacity as possible remains online. Use operational judgment to minimize any adverse impacts. Subsequent generation should be taken offline as needed. Note that turbine overspeed trips typically engage at 63.00 Hz with auxiliary governor action beginning at 61.80 Hz.
- **Low Frequency** – Emergency Response will consist of loading all available hydro generation, followed by commitment of Quick-start generating unit(s) (primarily combustion turbines) and, finally, underfrequency load shedding.
Hydro – all hydro generation should be loaded when frequency decreases to 59.50 Hz

Quick-Start – all quick-start generation resources should be committed when frequency drops below 59.50 Hz.

For information, underfrequency load shed relays start to operate automatically when frequency declines to 59.30 Hz roughly five percent of system load is typically shed at this point. An additional 10% of system load is shed if frequency continues to decline and declines to 58.90 Hz with a final system load shedding of 10 percent when frequency declines to 58.50 Hz. The amount of load actually shed in any particular island will vary.

Blackout Conditions – if conditions continue to deteriorate, it will be necessary for on-site generating unit(s) operator(s) to separate from the synchronized grid in order to protect generating unit equipment. This typically takes place at roughly 58.00 Hz. (Note that this is based on turbine manufacturer’s recommendations that operation below this frequency can result in significant fatigue failure of the turbine blades and may vary with specific turbine design).

While it is desirable to maintain service continuity, it is unacceptable to allow generating unit equipment to suffer major damage that would impede the restoration of service after a major disturbance. However, it is important that units not be prematurely tripped when frequency is declining, since such action will cause system frequency to decline further. It is recommended that unless frequency is declining rapidly, units should remain connected to the system until the operation of automatic underfrequency load shedding relays is completed at roughly 58.40 Hz. Off-frequency operations of steam turbines should be limited to 9 minutes below 59.40 Hz. Thirty seconds below 58.40 Hz and two seconds below 58.00 Hz. Please note that these time limitations are cumulative during the entire service-life of a generator.

If a unit is removed from the transmission system by the on-site GOP and cannot continue operation on a self-supporting basis the GOP should shut down the Plant in an organized manner in preparation for restart. Such operation should be continued until a request to re-synchronize the generating unit to the transmission system can be communicated to and approved by the System Operator. Maintaining generating unit(s) in hot standby mode will reduce the time required to restore the electrical system to normal operation.

On-site generating unit(s) operator should make regular attempts to restore communications with the System Operator to convey the status of their generating unit(s) and always follow their Black Start Plans. This should include attempts to contact the Balancing Authority, Transmission Operator and/or Reliability Coordinator.
Chart 2 – ERCOT Interconnection Generator Frequency Operating Guideline

Notes:

1. Nuclear generating plants are expected to stay on line at a sustainable, stable output level as long as possible. Under no circumstances should this Reliability Guideline be interpreted as requiring nuclear generating plants to operate in a manner that will violate their regulatory requirements, endanger public safety or adversely impact the integrity of plant equipment.

2. It is recommended that generating unit(s) calibrate plant frequency equipment on an annual basis.

3. In the event of a conflict between this guideline and the ERCOT governing documents, then the ERCOT governing documents will control.
Western Interconnection

Deadband (Green Zone) – as long as the frequency trend stays reasonably close to 60.00 Hz, no control actions should be taken by generating unit(s). This deadband should be +/- 50 milliHertz (59.95 Hz to 60.05 Hz - See Chart 3 below). This deadband is the “Secondary Control” deadband and should not be confused with governor deadband of the turbine governor.

Selective Response (Yellow Zone) – as the frequency trend moves outside the deadband boundaries but remains within reasonable operational limits it should be corrected by maneuvering generating unit(s) in a gradual manner. For the Western Interconnection, the Selective Response band should be +/- 200 milliHertz (59.80 Hz to 60.20 Hz). The generation ramp rate recommended for Selective Response is roughly one percent of the unit rating per minute. On-site generating unit(s) operator should carefully observe frequency during Selective Response and cease maneuvering their units when frequency enters the deadband.

Full Response (Red Zone) – when the frequency trend exceeds reasonable operational limits all units capable of responding should rapidly maneuver to balance load with generation. Full Response should be triggered when frequency is less than 59.80 Hz or greater than 60.20 Hz. If frequency continues to exceed the Full Response limits, all available generation at the plant should be maneuvered to the appropriate unit operating limits (i.e. fully loaded in the case of low frequency or at minimum load in the case of high frequency). In particular, all available generating capacity at the plant should be deployed to halt frequency decline when the frequency drops below the Full Response limit. On-site generating unit(s) operator should carefully observe frequency during Full Response operation and reduce the ramp rate of their units when frequency reaches the Selective Response region.

Emergency Response – if the frequency trend continues to deteriorate, then emergency measures will be required.

- **High Frequency** – high frequency Emergency Response will consist of maneuvering all available generation to its lowest stable operating point, followed by tripping of selected units.
  - **Low Minimums** – all generation should be maneuvered to its lowest stable minimum load operating point (with auxiliary fuel firing, if required) when frequency increases to 60.50 Hz.
  - **Unit Tripping** – when frequency increases to 60.60 Hz, plants with multiple units should trip generation offline. Generally, smaller units with minimal impacts to transmission should be taken offline first, so that as much capacity as possible remains online. Use operational judgment to minimize any adverse impacts. Subsequent generation should be taken offline as needed. Note that turbine overspeed trips typically engage at 61.20 Hz.

- **Low Frequency** – Emergency Response will consist of loading all available hydro and pumped storage hydro generation, followed by commitment of quick-start generating unit(s) (primarily combustion turbines) and, finally, underfrequency load shedding.
- **Hydro** – all hydro and pumped storage hydro generation should be loaded when frequency declines to 59.70 Hz.

- **Quick-Start** – all quick-start generation resource(s) should be committed when frequency drops below 59.60 Hz.

For information, underfrequency load shed relays start to operate automatically when frequency reaches 59.50 Hz. Roughly 4,200 MW of system load is shed at this point (note that specific frequencies and load percentages vary depending upon specific regional requirements). Additional load is shed as frequency continues to decline. The amount of load actually shed in any particular island is per the May 24, 2011 WECC Off-Nominal Frequency Load Shedding Plan.

It is preferred that online generators that protect for off-nominal frequency operation should have relaying protection that accommodates, at a minimum, underfrequency and overfrequency operation for the time frames specified in the following table:

<table>
<thead>
<tr>
<th>Underfrequency Limit</th>
<th>Overfrequency Limit</th>
<th>Minimum Time</th>
</tr>
</thead>
<tbody>
<tr>
<td>&gt;59.4 Hz</td>
<td>&lt; 60.6 Hz</td>
<td>N/A (continuous operation)</td>
</tr>
<tr>
<td>≤59.4 Hz</td>
<td>≥60.6 Hz</td>
<td>3 minutes</td>
</tr>
<tr>
<td>≤58.4 Hz</td>
<td>≥61.6 Hz</td>
<td>30 seconds</td>
</tr>
<tr>
<td>≤57.8 Hz</td>
<td>≥61.7 Hz</td>
<td>7.5 seconds</td>
</tr>
<tr>
<td>≤57.3 Hz</td>
<td></td>
<td>45 cycles</td>
</tr>
<tr>
<td>≤57.0 Hz</td>
<td></td>
<td>Instantaneous trip</td>
</tr>
</tbody>
</table>

**Note 1:** Minimum Time is the time the generator should stay interconnected and producing power. Also note that these time limitations are cumulative during the entire service-life of a generator.

**Blackout Conditions** – if conditions continue to deteriorate, it will be necessary for the on-site generating unit(s) operator to separate from the synchronized grid in order to protect generating unit equipment. This typically takes place at roughly <58.00 Hz. (Note that this is based on turbine manufacturer’s recommendations that operation below this frequency can result in significant fatigue failure of the turbine blades and may vary with specific turbine design).

While it is desirable to maintain service continuity, it is unacceptable to allow generating unit equipment to suffer major damage that would impede the restoration of service after a major disturbance. However, it is important that units not be prematurely tripped when frequency is declining, since such action will cause system frequency to decline further. It is recommended that unless frequency is declining rapidly, units should remain connected to the system until the operation of automatic underfrequency load shedding relays is completed at roughly 58.30 Hz.

If a unit is removed from the transmission system by the on-site GOP and cannot continue operation on a self-supporting basis the GOP should shut down the Plant in an organized manner in preparation for restart. Such operation should be continued until a request to re-synchronize the generating unit to the
transmission system can be communicated to and approved by the System Operator. Maintaining generating unit(s) in hot standby mode will reduce the time required to restore the electrical system to normal operation.

On-site generating unit(s) operator should make regular attempts to restore communications with the System Operator to convey the status of their generating unit(s) and always follow their Black Start Plans as necessary. This should include attempts to contact the Balancing Authority, Transmission Operator and/or Reliability Coordinator.

**Notes:**

1. Nuclear generating plants are expected to stay on line at a sustainable, stable output level as long as possible. Under no circumstances should this Reliability Guideline be interpreted as requiring nuclear
generating plants to operate in a manner that will violate their regulatory requirements, endanger public
safety or adversely impact the integrity of plant equipment.

2. It is recommended that generating unit(s) calibrate plant frequency equipment on an annual basis.
Quebec Interconnection

Deadband (Green Zone) – as long as the frequency trend stays reasonably close to 60.00 Hz, no control actions should be taken by generating unit(s). This deadband should be +/- 50 milliHertz (59.95 Hz to 60.05 Hz - See Chart 4 below).

Selective Response (Yellow Zone) – as the frequency trend moves outside the deadband boundaries but remains within reasonable operational limits it should be corrected by maneuvering generating unit(s) in a gradual manner. For the Quebec Interconnection, the Selective Response band should be +/- 300 milliHertz (59.70 Hz to 60.3 Hz). The generation ramp rate recommended for Selective Response is roughly one percent of the unit rating per minute. On-site generating unit(s) operator should carefully observe frequency during Selective Response and cease maneuvering their units when frequency enters the deadband.

Full Response (Red Zone) – when the frequency trend exceeds reasonable operational limits all units capable of responding should rapidly maneuver to balance load with generation. Full Response should be triggered when frequency is less than 59.70 Hz or greater than 60.30 Hz. If frequency continues to exceed the Full Response limits, all available generation at the plant should be maneuvered to the appropriate unit operating limits (i.e. fully loaded in the case of low frequency or at minimum load in the case of high frequency). In particular, all available generating capacity at the plant should be deployed to halt frequency decline when the frequency drops below the Full Response limit. On-site generating unit(s) operator should carefully observe frequency during Full Response operation and reduce the ramp rate of their units when frequency reaches the Selective Response region.

Emergency Response – if frequency continues to deteriorate, then emergency measures will be required.

- High Frequency – high frequency Emergency Response will consist of maneuvering all available generation to its lowest stable operating point, followed by tripping of selected units.
  - Low Minimums – all variable hydro generation should be maneuvered to its lowest stable minimum load operating point when increase to 60.30 Hz.
  - Unit Tripping – when frequency increases to 60.50 Hz, plants with multiple units should trip generation offline. Variable hydro generation should be taken offline first and run-of-the-river units second. Use operational judgment to minimize any adverse impacts and to adequately manage hydraulic resource. Subsequent generation should be taken offline as needed. Note that over frequency generation tripping engages roughly at 60.5 Hz.

- Low Frequency – Emergency Response will consist of loading all available hydro and pumped storage hydro generation, followed by commitment of Quick-start generating unit(s) (primarily combustion turbines) and, finally, underfrequency load shedding.
  - Variable Hydro – all variable hydro generation should be loaded when frequency declines to 59.70 Hz.
- **Quick-start** – all Quick-start generation resources should be committed when frequency drops below 59.70 Hz.

- **Run-of-the-river Hydro** – all run-of-the-river hydro generation should be loaded at maximum when frequency drops below 59.60 Hz.

For information, underfrequency load shed relays start to operate automatically when frequency reaches 59.00 Hz. Roughly, 500 MW of load is typically shed at this point (based on peak load conditions). An additional 800 MW of load is typically shed as frequency continues to decline by 500 millihertz thresholds until it reaches the last step at 57.00 Hz.

**Blackout Conditions** – if conditions continue to deteriorate, it will be necessary for the on-site generating unit(s) operator to separate from the synchronized grid in order to protect generating unit equipment.

While it is desirable to maintain service continuity, it is unacceptable to allow generating unit equipment to suffer major damage that would impede the restoration of service after a major disturbance. However, it is important that units not be prematurely tripped when frequency is declining, since such action will cause system frequency to decline further. It is recommended that unless frequency is declining rapidly, units should remain connected to the system until the operation of automatic underfrequency load shedding relays is completed at roughly 57.00 Hz.

If a unit is removed from the transmission system by the on-site GOP and cannot continue operation on a self-supporting basis the GOP should shut down the Plant in an organized manner in preparation for restart. Such operation should be continued until a request to re-synchronize the generating unit to the transmission system can be communicated to and approved by the System Operator.

On-site generating unit(s) operator should make regular attempts to restore communications with the System Operator to convey the status of their generating unit(s) and always follow their Black Start Plans as necessary. This should include attempts to contact the Balancing Authority, Transmission Operator and/or Reliability Coordinator.
Notes

1. It is recommended that generating unit(s) calibrate plant frequency equipment on an annual basis.

Related Documents and Links:

EPRI Power System Dynamics Tutorial

Revision History:

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<thead>
<tr>
<th>Date</th>
<th>Version Number</th>
<th>Reason/Comments</th>
</tr>
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<tr>
<td>11/19/2013</td>
<td>1.0</td>
<td>Initial Version – “Generating Unit Operations During Complete Loss of Communications”</td>
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</table>
Appendix (Training)

Introduction - This appendix outlines suggested additional reading as well as provides a set of tasks the on-site generating unit(s) operator could consider as part of ongoing training and for participation in area restoration drills and seminars. On-site generator unit(s) operator(s) are encouraged to consult with their Balancing Authority in reference to this guideline and training.

Send comments and suggestions to balancing@nerc.com.

Additional Reading - A valuable resource available for training is the *EPRI Power System Dynamics Tutorial*. The tutorial can be downloaded for free at the link above. The parts of the tutorial that deal most directly to frequency control are:

- Section 4
- Section 8
- Section 11.3

Scenario - The tasks that follow are suggested as part of initial “emergency” training for the on-site generating unit(s) operator as well as refresher training during restoration drills. The tasks were developed after reviewing a few actual scenarios where generators found themselves in an island following a disturbance. While communications were still available to the Balancing Authority, the scenario still demonstrates the dynamics that can be observed following a disturbance. Since the most likely situation where an on-site generating unit(s) operator would need to take action and not have communications is following a disturbance or coordinated attack, the situation below is valid for comparison.
The frequency graph from a storm-created island in 2010 shows what took place within about 30 seconds. The storm left approximately 55 MWs of load in the area connected to 45 MWs of generation. This caused frequency to decline to 59Hz, which was the first step of underfrequency load shedding (UFLS) in this area. The UFLS caused frequency to overshoot to approximately 61.5Hz. Unfortunately, 18 MW of hydro generation tripped automatically at 61.5 Hz. This left an insufficient amount of generation in the area that caused a more rapid decline in frequency, which the next step of UFLS was unable to arrest.

The reality is that in some cases as outlined above, there is little for the on-site generating unit(s) operator to do. Knowing and coordinating the UFLS and generator trip setpoints in the area can help generators ride through local disturbances. For islands caused by major events, the islands will be larger and changes in frequency will be slower. The tasks below are intended to help the on-site generating unit(s) operator prepare for such events. It is suggested the tasks should be reviewed annually.

**Tasks**

- Discuss training activities and the guideline with your Balancing Authority.
- Identify your local Load Serving Entity’s Under-Frequency Load Shedding trip points.
- Identify your generator(s) overfrequency trip settings.
- Identify and test the most frequency responsive control modes of your generator(s).
- Identify the ratings of the transmission lines emanating from your station and the plant limitations if one or more lines are out of service.
- List and discuss the symptoms of possible islanding.
- Identify and test possible alternate communication paths with your Balancing Authority, Transmission Operator and Reliability Coordinator (to include communications through other entities).
- If at a multi-unit station, discuss the frequency control strategy to be followed during islanding, restoration or total loss of communications.
- Walk through the steps needed to isolate a generator from the grid while supplying its own auxiliaries.
A. Introduction

1. Title: Physical Security
2. Number: CIP-014-1
3. Purpose: To identify and protect Transmission stations and Transmission substations, and their associated primary control centers, that if rendered inoperable or damaged as a result of a physical attack could result in widespread instability, uncontrolled separation, or Cascading within an Interconnection.

4. Applicability:

4.1. Functional Entities:

4.1.1 Transmission Owner that owns a Transmission station or Transmission substation that meets any of the following criteria:

4.1.1.1 Transmission Facilities operated at 500 kV or higher. For the purpose of this criterion, the collector bus for a generation plant is not considered a Transmission Facility, but is part of the generation interconnection Facility.

4.1.1.2 Transmission Facilities that are operating between 200 kV and 499 kV at a single station or substation, where the station or substation is connected at 200 kV or higher voltages to three or more other Transmission stations or substations and has an "aggregate weighted value" exceeding 3000 according to the table below. The "aggregate weighted value" for a single station or substation is determined by summing the "weight value per line" shown in the table below for each incoming and each outgoing BES Transmission Line that is connected to another Transmission station or substation. For the purpose of this criterion, the collector bus for a generation plant is not considered a Transmission Facility, but is part of the generation interconnection Facility.

<table>
<thead>
<tr>
<th>Voltage Value of a Line</th>
<th>Weight Value per Line</th>
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</thead>
<tbody>
<tr>
<td>less than 200 kV (not applicable)</td>
<td>(not applicable)</td>
</tr>
<tr>
<td>200 kV to 299 kV</td>
<td>700</td>
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<tr>
<td>300 kV to 499 kV</td>
<td>1300</td>
</tr>
<tr>
<td>500 kV and above</td>
<td>0</td>
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</tbody>
</table>

4.1.1.3 Transmission Facilities at a single station or substation location that are identified by its Reliability Coordinator, Planning Coordinator, or
Transmission Planner as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies.

4.1.1.4 Transmission Facilities identified as essential to meeting Nuclear Plant Interface Requirements.

4.1.2 Transmission Operator.

Exemption: Facilities in a “protected area,” as defined in 10 C.F.R. § 73.2, within the scope of a security plan approved or accepted by the Nuclear Regulatory Commission are not subject to this Standard; or, Facilities within the scope of a security plan approved or accepted by the Canadian Nuclear Safety Commission are not subject to this Standard.

5. Effective Dates:

CIP-014-1 is effective the first day of the first calendar quarter that is six months beyond the date that this standard is approved by applicable regulatory authorities, or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. In those jurisdictions where regulatory approval is not required, CIP-014-1 shall become effective on the first day of the first calendar quarter that is six months beyond the date this standard is approved by the NERC Board of Trustees, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

6. Background:

This Reliability Standard addresses the directives from the FERC order issued March 7, 2014, Reliability Standards for Physical Security Measures, 146 FERC ¶ 61,166 (2014), which required NERC to develop a physical security reliability standard(s) to identify and protect facilities that if rendered inoperable or damaged could result in widespread instability, uncontrolled separation, or Cascading within an Interconnection.
B. Requirements and Measures

R1. Each Transmission Owner shall perform an initial risk assessment and subsequent risk assessments of its Transmission stations and Transmission substations (existing and planned to be in service within 24 months) that meet the criteria specified in Applicability Section 4.1.1. The initial and subsequent risk assessments shall consist of a transmission analysis or transmission analyses designed to identify the Transmission station(s) and Transmission substation(s) that if rendered inoperable or damaged could result in widespread instability, uncontrolled separation, or Cascading within an Interconnection. [VRF: High; Time-Horizon: Long-term Planning]

1.1. Subsequent risk assessments shall be performed:

- At least once every 30 calendar months for a Transmission Owner that has identified in its previous risk assessment (as verified according to Requirement R2) one or more Transmission stations or Transmission substations that if rendered inoperable or damaged could result in widespread instability, uncontrolled separation, or Cascading within an Interconnection; or

- At least once every 60 calendar months for a Transmission Owner that has not identified in its previous risk assessment (as verified according to Requirement R2) any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in widespread instability, uncontrolled separation, or Cascading within an Interconnection.

1.2. The Transmission Owner shall identify the primary control center that operationally controls each Transmission station or Transmission substation identified in the Requirement R1 risk assessment.

M1. Examples of acceptable evidence may include, but are not limited to, dated written or electronic documentation of the risk assessment of its Transmission stations and Transmission substations (existing and planned to be in service within 24 months) that meet the criteria in Applicability Section 4.1.1 as specified in Requirement R1. Additionally, examples of acceptable evidence may include, but are not limited to, dated written or electronic documentation of the identification of the primary control center that operationally controls each Transmission station or Transmission substation identified in the Requirement R1 risk assessment as specified in Requirement R1, Part 1.2.

R2. Each Transmission Owner shall have an unaffiliated third party verify the risk assessment performed under Requirement R1. The verification may occur concurrent with or after the risk assessment performed under Requirement R1. [VRF: Medium; Time-Horizon: Long-term Planning]
2.1. Each Transmission Owner shall select an unaffiliated verifying entity that is either:

- A registered Planning Coordinator, Transmission Planner, or Reliability Coordinator; or
- An entity that has transmission planning or analysis experience.

2.2. The unaffiliated third party verification shall verify the Transmission Owner’s risk assessment performed under Requirement R1, which may include recommendations for the addition or deletion of a Transmission station(s) or Transmission substation(s). The Transmission Owner shall ensure the verification is completed within 90 calendar days following the completion of the Requirement R1 risk assessment.

2.3. If the unaffiliated verifying entity recommends that the Transmission Owner add a Transmission station(s) or Transmission substation(s) to, or remove a Transmission station(s) or Transmission substation(s) from, its identification under Requirement R1, the Transmission Owner shall either, within 60 calendar days of completion of the verification, for each recommended addition or removal of a Transmission station or Transmission substation:

- Modify its identification under Requirement R1 consistent with the recommendation; or
- Document the technical basis for not modifying the identification in accordance with the recommendation.

2.4. Each Transmission Owner shall implement procedures, such as the use of non-disclosure agreements, for protecting sensitive or confidential information made available to the unaffiliated third party verifier and to protect or exempt sensitive or confidential information developed pursuant to this Reliability Standard from public disclosure.

M2. Examples of acceptable evidence may include, but are not limited to, dated written or electronic documentation that the Transmission Owner completed an unaffiliated third party verification of the Requirement R1 risk assessment and satisfied all of the applicable provisions of Requirement R2, including, if applicable, documenting the technical basis for not modifying the Requirement R1 identification as specified under Part 2.3. Additionally, examples of evidence may include, but are not limited to, written or electronic documentation of procedures to protect information under Part 2.4.

R3. For a primary control center(s) identified by the Transmission Owner according to Requirement R1, Part 1.2 that a) operationally controls an identified Transmission station or Transmission substation verified according to Requirement R2, and b) is not under the operational control of the Transmission Owner: the Transmission Owner
shall, within seven calendar days following completion of Requirement R2, notify the Transmission Operator that has operational control of the primary control center of such identification and the date of completion of Requirement R2. [VRF: Lower; Time-Horizon: Long-term Planning]

3.1. If a Transmission station or Transmission substation previously identified under Requirement R1 and verified according to Requirement R2 is removed from the identification during a subsequent risk assessment performed according to Requirement R1 or a verification according to Requirement R2, then the Transmission Owner shall, within seven calendar days following the verification or the subsequent risk assessment, notify the Transmission Operator that has operational control of the primary control center of the removal.

M3. Examples of acceptable evidence may include, but are not limited to, dated written or electronic notifications or communications that the Transmission Owner notified each Transmission Operator, as applicable, according to Requirement R3.

R4. Each Transmission Owner that identified a Transmission station, Transmission substation, or a primary control center in Requirement R1 and verified according to Requirement R2, and each Transmission Operator notified by a Transmission Owner according to Requirement R3, shall conduct an evaluation of the potential threats and vulnerabilities of a physical attack to each of their respective Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 and verified according to Requirement R2. The evaluation shall consider the following: [VRF: Medium; Time-Horizon: Operations Planning, Long-term Planning]

4.1. Unique characteristics of the identified and verified Transmission station(s), Transmission substation(s), and primary control center(s);

4.2. Prior history of attack on similar facilities taking into account the frequency, geographic proximity, and severity of past physical security related events; and

4.3. Intelligence or threat warnings received from sources such as law enforcement, the Electric Reliability Organization (ERO), the Electricity Sector Information Sharing and Analysis Center (ES-ISAC), U.S. federal and/or Canadian governmental agencies, or their successors.

M4. Examples of evidence may include, but are not limited to, dated written or electronic documentation that the Transmission Owner or Transmission Operator conducted an evaluation of the potential threats and vulnerabilities of a physical attack to their respective Transmission station(s), Transmission substation(s) and primary control center(s) as specified in Requirement R4.
R5. Each Transmission Owner that identified a Transmission station, Transmission substation, or primary control center in Requirement R1 and verified according to Requirement R2, and each Transmission Operator notified by a Transmission Owner according to Requirement R3, shall develop and implement a documented physical security plan(s) that covers their respective Transmission station(s), Transmission substation(s), and primary control center(s). The physical security plan(s) shall be developed within 120 calendar days following the completion of Requirement R2 and executed according to the timeline specified in the physical security plan(s). The physical security plan(s) shall include the following attributes: [VRF: High; Time-Horizon: Long-term Planning]

5.1. Resiliency or security measures designed collectively to deter, detect, delay, assess, communicate, and respond to potential physical threats and vulnerabilities identified during the evaluation conducted in Requirement R4.

5.2. Law enforcement contact and coordination information.

5.3. A timeline for executing the physical security enhancements and modifications specified in the physical security plan.

5.4. Provisions to evaluate evolving physical threats, and their corresponding security measures, to the Transmission station(s), Transmission substation(s), or primary control center(s).

M5. Examples of evidence may include, but are not limited to, dated written or electronic documentation of its physical security plan(s) that covers their respective identified and verified Transmission station(s), Transmission substation(s), and primary control center(s) as specified in Requirement R5, and additional evidence demonstrating execution of the physical security plan according to the timeline specified in the physical security plan.

R6. Each Transmission Owner that identified a Transmission station, Transmission substation, or primary control center in Requirement R1 and verified according to Requirement R2, and each Transmission Operator notified by a Transmission Owner according to Requirement R3, shall have an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5. The review may occur concurrently with or after completion of the evaluation performed under Requirement R4 and the security plan development under Requirement R5. [VRF: Medium; Time-Horizon: Long-term Planning]

6.1. Each Transmission Owner and Transmission Operator shall select an unaffiliated third party reviewer from the following:

- An entity or organization with electric industry physical security experience and whose review staff has at least one member who holds either a Certified
Protection Professional (CPP) or Physical Security Professional (PSP) certification.

- An entity or organization approved by the ERO.
- A governmental agency with physical security expertise.
- An entity or organization with demonstrated law enforcement, government, or military physical security expertise.

6.2. The Transmission Owner or Transmission Operator, respectively, shall ensure that the unaffiliated third party review is completed within 90 calendar days of completing the security plan(s) developed in Requirement R5. The unaffiliated third party review may, but is not required to, include recommended changes to the evaluation performed under Requirement R4 or the security plan(s) developed under Requirement R5.

6.3. If the unaffiliated third party reviewer recommends changes to the evaluation performed under Requirement R4 or security plan(s) developed under Requirement R5, the Transmission Owner or Transmission Operator shall, within 60 calendar days of the completion of the unaffiliated third party review, for each recommendation:

- Modify its evaluation or security plan(s) consistent with the recommendation; or
- Document the reason(s) for not modifying the evaluation or security plan(s) consistent with the recommendation.

6.4. Each Transmission Owner and Transmission Operator shall implement procedures, such as the use of non-disclosure agreements, for protecting sensitive or confidential information made available to the unaffiliated third party reviewer and to protect or exempt sensitive or confidential information developed pursuant to this Reliability Standard from public disclosure.

M6. Examples of evidence may include, but are not limited to, written or electronic documentation that the Transmission Owner or Transmission Operator had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 as specified in Requirement R6 including, if applicable, documenting the reasons for not modifying the evaluation or security plan(s) in accordance with a recommendation under Part 6.3. Additionally, examples of evidence may include, but are not limited to, written or electronic documentation of procedures to protect information under Part 6.4.
C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

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

1.2. Evidence 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 CEA may ask an entity to provide other evidence during an on-site visit to show that it was compliant for the full time period since the last audit.

The Transmission Owner and Transmission Operator shall keep data or evidence to show compliance, as identified below, unless directed by its Compliance Enforcement Authority (CEA) to retain specific evidence for a longer period of time as part of an investigation.

The responsible entities shall retain documentation as evidence for three years. If a Responsible Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved, or for the time specified above, whichever is longer.

The CEA shall keep the last audit records and all requested and submitted subsequent audit records, subject to the confidentiality provisions of Section 1500 of the Rules of Procedure and the provisions of Section 1.4 below.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audits
Self-Certifications
Spot Checking
Compliance Violation Investigations
Self-Reporting
Complaints Text

1.4. Additional Compliance Information

Confidentiality: To protect the confidentiality and sensitive nature of the evidence for demonstrating compliance with this standard, all evidence will be retained at the Transmission Owner’s and Transmission Operator’s facilities.
## 2. Table of Compliance Elements

<table>
<thead>
<tr>
<th>R #</th>
<th>Time Horizon</th>
<th>VRF</th>
<th>Lower VSL</th>
<th>Moderate VSL</th>
<th>High VSL</th>
<th>Severe VSL</th>
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<tbody>
<tr>
<td>R1</td>
<td>Long-term Planning</td>
<td>High</td>
<td>The Transmission Owner performed an initial risk assessment but did so after the date specified in the implementation plan for performing the initial risk assessment but less than or equal to two calendar months after that date; OR The Transmission Owner that has identified in its previous risk assessment one or more Transmission stations or Transmission substations that if rendered inoperable or damaged could result in widespread damage.</td>
<td>The Transmission Owner performed an initial risk assessment but did so more than two calendar months after the date specified in the implementation plan for performing the initial risk assessment but less than or equal to four calendar months after that date; OR The Transmission Owner that has identified in its previous risk assessment one or more Transmission stations or Transmission substations that if rendered inoperable or damaged could result in widespread damage.</td>
<td>The Transmission Owner performed an initial risk assessment but did so more than four calendar months after the date specified in the implementation plan for performing the initial risk assessment but less than or equal to six calendar months after that date; OR The Transmission Owner that has identified in its previous risk assessment one or more Transmission stations or Transmission substations that if rendered inoperable or damaged could result in widespread damage.</td>
<td>The Transmission Owner performed an initial risk assessment but did so more than six calendar months after the date specified in the implementation plan for performing the initial risk assessment; OR The Transmission Owner failed to perform an initial risk assessment; OR The Transmission Owner that has identified in its previous risk assessment one or more Transmission stations or Transmission substations that if rendered inoperable or damaged could result in widespread damage.</td>
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<td>R #</td>
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<td>Violation Severity Levels (CIP-014-1)</td>
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<td><strong>Lower VSL</strong></td>
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<td>instability, uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk assessment but did so after 30 calendar months but less than or equal to 32 calendar months; OR The Transmission Owner that has not identified in its previous risk assessment any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in widespread instability, uncontrolled separation, or Cascading within an</td>
<td>result in widespread instability, uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk assessment but did so after 32 calendar months but less than or equal to 34 calendar months; OR The Transmission Owner that has not identified in its previous risk assessment any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in widespread instability, uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk assessment but did so after more than 36 calendar months; OR The Transmission Owner that has identified in its previous risk assessment one or more Transmission stations or Transmission substations that if rendered inoperable or damaged could result in widespread instability, uncontrolled separation, or Cascading within an Interconnection</td>
<td>instability, uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk assessment but did so after 34 calendar months but less than or equal to 36 calendar months; OR The Transmission Owner that has not identified in its previous risk assessment any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in widespread instability, uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk assessment but did so after more than 36 calendar months; OR The Transmission Owner that has identified in its previous risk assessment one or more Transmission stations or Transmission substations that if rendered inoperable or damaged could result in widespread instability, uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk assessment but did so after more than 36 calendar months;</td>
<td>Transmission substations that if rendered inoperable or damaged could result in widespread instability, uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk assessment but did so after more than 36 calendar months; OR The Transmission Owner that has identified in its previous risk assessment one or more Transmission stations or Transmission substations that if rendered inoperable or damaged could result in widespread instability, uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk assessment but did so after more than 36 calendar months; OR The Transmission Owner that has identified in its previous risk assessment one or more Transmission stations or Transmission substations that if rendered inoperable or damaged could result in widespread instability, uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk assessment but did so after more than 36 calendar months;</td>
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<td>Violation Severity Levels (CIP-014-1)</td>
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<td>Interconnection performed a subsequent risk assessment but did so after 60 calendar months but less than or equal to 62 calendar months.</td>
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<td><strong>Moderate VSL</strong></td>
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<td></td>
<td>Interconnection performed a subsequent risk assessment but did so after 62 calendar months but less than or equal to 64 calendar months.</td>
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<td></td>
<td><strong>High VSL</strong></td>
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<td>performed a subsequent risk assessment but did so after 64 calendar months but less than or equal to 66 calendar months; OR The Transmission Owner performed a risk assessment but failed to include Part 1.2.</td>
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<td><strong>Severe VSL</strong></td>
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<td>uncontrolled separation, or Cascading within an Interconnection failed to perform a risk assessment; OR The Transmission Owner that has not identified in its previous risk assessment any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in widespread instability, uncontrolled separation, or Cascading within an Interconnection performed a subsequent risk assessment but did so after more than 66 calendar months;</td>
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<td>Lower VSL</td>
<td>Moderate VSL</td>
<td>High VSL</td>
<td>Severe VSL</td>
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<tr>
<td>R2</td>
<td>Long-term Planning</td>
<td>Medium</td>
<td>The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 but did so in more than 90 calendar days but</td>
<td>The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 but did so more than 100 calendar days but</td>
<td>The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 but did so more than 110 calendar days but less than or equal to</td>
<td>The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 but did so more than 120 calendar days</td>
</tr>
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</table>

OR

The Transmission Owner that has not identified in its previous risk assessment any Transmission station and Transmission substations that if rendered inoperable or damaged could result in widespread instability, uncontrolled separation, or Cascading within an Interconnection failed to perform a subsequent risk assessment.
<table>
<thead>
<tr>
<th>R #</th>
<th>Time Horizon</th>
<th>VRF</th>
<th>Violation Severity Levels (CIP-014-1)</th>
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<td>Lower VSL</td>
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<td>less than or equal to 100 calendar days following completion of Requirement R1; OR The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 and modified or documented the technical basis for not modifying its identification under Requirement R1 as required by Part 2.3 but did so more than 60 calendar days and less than or equal to 70 calendar days from completion of the third party verification.</td>
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<td>Moderate VSL</td>
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<td>less than or equal to 110 calendar days following completion of Requirement R1; Or The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 and modified or documented the technical basis for not modifying its identification under Requirement R1 as required by Part 2.3 but did so more than 70 calendar days and less than or equal to 80 calendar days from completion of the third party verification.</td>
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<td>High VSL</td>
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<td>120 calendar days following completion of Requirement R1; OR The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 and modified or documented the technical basis for not modifying its identification under Requirement R1 as required by Part 2.3 but did so more than 80 calendar days from completion of the third party verification; OR The Transmission Owner had an unaffiliated third party verify the risk assessment performed following completion of Requirement R1; OR The Transmission Owner failed to have an unaffiliated third party verify the risk assessment performed under Requirement R1; OR The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R1 but failed to implement procedures for protecting information per Part 2.4.</td>
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### Violation Severity Levels (CIP-014-1)

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<th>R #</th>
<th>Time Horizon</th>
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<td>under Requirement R1 but failed to modify or document the technical basis for not modifying its identification under R1 as required by Part 2.3.</td>
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<td>R3</td>
<td>Long-term Planning</td>
<td>Lower</td>
<td>The Transmission Owner notified the Transmission Operator that operates the primary control center as specified in Requirement R3 but did so more than seven calendar days and less than or equal to nine calendar days following the completion of Requirement R2; OR The Transmission Owner notified the Transmission Operator that operates the primary control center as specified in Requirement R3 but did so more than nine calendar days and less than or equal to 11 calendar days following the completion of Requirement R2; OR The Transmission Owner notified the Transmission Operator that operates the primary control center as specified in Requirement R3 but did so more than 11 calendar days and less than or equal to 13 calendar days following the completion of Requirement R2; OR The Transmission Owner failed to notify the Transmission Operator that it operates a control center as specified in Requirement R3 but did so more than 13 calendar days following the completion of Requirement R2; OR The Transmission Owner notified the Transmission Operator that it operates a control center as specified in Requirement R3 but did so more than 13 calendar days following the completion of Requirement R2; OR The Transmission Owner notified the Transmission Operator that it operates a control center as specified in Requirement R3 but did so more than 13 calendar days following the completion of Requirement R2; OR The Transmission Owner notified the Transmission Operator that it operates a control center as specified in Requirement R3 but did so more than 13 calendar days following the completion of Requirement R2; OR The Transmission Owner notified the Transmission Operator that it operates a control center as specified in Requirement R3 but...</td>
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<td>R #</td>
<td>Time Horizon</td>
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<td>Violation Severity Levels (CIP-014-1)</td>
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<td></td>
<td><strong>Lower VSL</strong></td>
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<td>operates the primary control center of the removal from the identification in Requirement R1 but did so more than seven calendar days and less than or equal to nine calendar days following the verification or the subsequent risk assessment.</td>
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<td><strong>Moderate VSL</strong></td>
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<td>operates the primary control center of the removal from the identification in Requirement R1 but did so more than nine calendar days and less than or equal to 11 calendar days following the verification or the subsequent risk assessment.</td>
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<td><strong>High VSL</strong></td>
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<td>of the removal from the identification in Requirement R1 but did so more than 11 calendar days and less than or equal to 13 calendar days following the verification or the subsequent risk assessment.</td>
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<td><strong>Severe VSL</strong></td>
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<td>center identified in Requirement R1; OR The Transmission Owner notified the Transmission Operator that operates the primary control center of the removal from the identification in Requirement R1 but did so more than 13 calendar days following the verification or the subsequent risk assessment. OR The Transmission Owner failed to notify the Transmission Operator that operates the primary control center of the removal from the identification in Requirement R1;</td>
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<td>R #</td>
<td>Time Horizon</td>
<td>VRF</td>
<td>Lower VSL</td>
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<tr>
<td>R4</td>
<td>Operations Planning, Long-term Planning</td>
<td>Medium</td>
<td>N/A</td>
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<td>R #</td>
<td>Time Horizon</td>
<td>VRF</td>
<td>Violation Severity Levels (CIP-014-1)</td>
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<td>R5</td>
<td>Long-term Planning</td>
<td>High</td>
<td>The Responsible Entity developed and implemented a documented physical security plan(s) that covers each of its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 but did so more than 120 calendar days but less than or equal to 130 calendar days after completing Requirement R2; OR</td>
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<td>R #</td>
<td>Time Horizon</td>
<td>VRF</td>
<td>Violation Severity Levels (CIP-014-1)</td>
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<td><strong>Lower VSL</strong></td>
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<td>The Responsible Entity developed and implemented a documented physical security plan(s) that covers its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 and verified according to Requirement R2 but failed to include one of Parts 5.1 through 5.4 in the plan.</td>
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<td><strong>Moderate VSL</strong></td>
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<td>The Responsible Entity developed and implemented a documented physical security plan(s) that covers its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 and verified according to Requirement R2 but failed to include two of Parts 5.1 through 5.4 in the plan.</td>
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<td>The Responsible Entity developed and implemented a documented physical security plan(s) that covers its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 and verified according to Requirement R2 but failed to include three of Parts 5.1 through 5.4 in the plan.</td>
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<td>The Responsible Entity failed to develop and implement a documented physical security plan(s) that covers its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 and verified according to Requirement R2. OR The Responsible Entity developed and implemented a documented physical security plan(s) that covers its Transmission station(s), Transmission substation(s), and primary control center(s) identified in Requirement R1 and verified according to Requirement R2 but failed to include three of Parts 5.1 through 5.4 in the plan.</td>
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<td>R #</td>
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<tr>
<td>R6</td>
<td>Long-term Planning</td>
<td>Medium</td>
<td>The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 but did so in more than 90 calendar days but less than or equal to 100 calendar days; OR The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 but did so in more than 100 calendar days but less than or equal to 110 calendar days; OR The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 but did so in more than 110 calendar days but less than or equal to 120 calendar days; OR The Responsible Entity failed to have an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 in more than 120 calendar days;</td>
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</table>

center(s) identified in Requirement R1 and verified according to Requirement 2 but failed to include Parts 5.1 through 5.4 in the plan.
<table>
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<tr>
<th>R #</th>
<th>Time Horizon</th>
<th>VRF</th>
<th>Violation Severity Levels (CIP-014-1)</th>
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<td>R4 and the security plan(s) developed under Requirement R5 and modified or documented the reason for not modifying the security plan(s) as specified in Part 6.3 but did so more than 60 calendar days and less than or equal to 70 calendar days following completion of the third party review.</td>
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<td>under Requirement R4 and the security plan(s) developed under Requirement R5 and modified or documented the reason for not modifying the security plan(s) as specified in Part 6.3 but did so more than 70 calendar days and less than or equal to 80 calendar days following completion of the third party review.</td>
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<td>under Requirement R5 and modified or documented the reason for not modifying the security plan(s) as specified in Part 6.3 but did so more than 80 calendar days following completion of the third party review; OR The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 but failed to implement procedures for protecting information per Part 6.3.</td>
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<td>the security plan(s) developed under Requirement R5; OR The Responsible Entity had an unaffiliated third party review the evaluation performed under Requirement R4 and the security plan(s) developed under Requirement R5 but did not document the reason for not modifying the security plan(s) as specified in Part 6.3.</td>
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D. Regional Variances
   None.

E. Interpretations
   None.

F. Associated Documents
   None.

Version History

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<th>Action</th>
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<td>May 13, 2014</td>
<td>Adopted by NERC Board of Trustees</td>
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**Guidelines and Technical Basis**

**Section 4 Applicability**

The purpose of Reliability Standard CIP-014-1 is to protect Transmission stations and Transmission substations, and their associated primary control centers that if rendered inoperable or damaged as a result of a physical attack could result in widespread instability, uncontrolled separation, or Cascading within an Interconnection. To properly include those entities that own or operate such Facilities, the Reliability Standard CIP-014-1 first applies to Transmission Owners that own Transmission Facilities that meet the specific criteria in Applicability Section 4.1.1.1 through 4.1.1.4. The Facilities described in Applicability Section 4.1.1 through 4.1.1.4 mirror those Transmission Facilities that meet the bright line criteria for “Medium Impact” Transmission Facilities under Attachment 1 of Reliability Standard CIP-002-5.1. Each Transmission Owner that owns Transmission Facilities that meet the criteria in Section 4.1.1.1 through 4.1.1.4 is required to perform a risk assessment as specified in Requirement R1 to identify its Transmission stations and Transmission substations, and their associated primary control centers, that if rendered inoperable or damaged as a result of a physical attack could result in widespread instability, uncontrolled separation, or Cascading within an Interconnection. The Standard Drafting Team (SDT) expects this population will be small and that many Transmission Owners that meet the applicability of this standard will not actually identify any such Facilities. Only those Transmission Owners with Transmission stations or Transmission substations identified in the risk assessment (and verified under Requirement R2) have performance obligations under Requirements R3 through R6.

This standard also applies to Transmission Operators. A Transmission Operator’s obligations under the standard, however, are only triggered if the Transmission Operator is notified by an applicable Transmission Owner under Requirement R3 that the Transmission Operator operates a primary control center that operationally controls a Transmission station(s) or Transmission substation(s) identified in the Requirement R1 risk assessment. A primary control center operationally controls a Transmission station or Transmission substation when the control center’s electronic actions can cause direct physical action at the identified Transmission station or Transmission substation, such as opening a breaker, as opposed to a control center that only has information from the Transmission station or Transmission substation and must coordinate direct action through another entity. Only Transmission Operators who are notified that they have primary control centers under this standard have performance obligations under Requirements R4 through R6. In other words, primary control center for purposes of this Standard is the control center that the Transmission Owner or Transmission Operator, respectively, uses as its primary, permanently-manned site to physically operate a Transmission station or Transmission substation that is identified in Requirement R1 and verified in Requirement R2. Control centers that provide back-up capability are not applicable, as they are a form of resiliency and intentionally redundant.

The SDT considered several options for bright line criteria that could be used to determine applicability and provide an initial threshold that defines the set of Transmission stations and Transmission substations that would meet the directives of the FERC order on physical security (*i.e.*, those that could cause widespread instability, uncontrolled separation, or Cascading within...
an Interconnection). The SDT determined that using the criteria for Medium Impact Transmission Facilities in Attachment 1 of CIP-002-5.1 would provide a conservative threshold for defining which Transmission stations and Transmission substations must be included in the risk assessment in Requirement R1 of CIP-014-1. Additionally, the SDT concluded that using the CIP-002-5.1 Medium Impact criteria was appropriate because it has been approved by stakeholders, NERC, and FERC, and its use provides a technically sound basis to determine which Transmission Owners should conduct the risk assessment. As described in CIP-002-5.1, the failure of a Transmission station or Transmission substation that meets the Medium Impact criteria could have the capability to result in exceeding one or more Interconnection Reliability Operating Limits (IROLs). The SDT understands that using this bright line criteria to determine applicability may require some Transmission Owners to perform risk assessments under Requirement R1 that will result in a finding that none of their Transmission stations or Transmission substations would pose a risk of widespread instability, uncontrolled separation, or Cascading within an Interconnection. However, the SDT determined that higher bright lines could not be technically justified to ensure inclusion of all Transmission stations and Transmission substations, and their associated primary control centers that, if rendered inoperable or damaged as a result of a physical attack could result in widespread instability, uncontrolled separation, or Cascading within an Interconnection. Further guidance and technical basis for the bright line criteria for Medium Impact Facilities can be found in the Guidelines and Technical Basis section of CIP-002-5.1.

Additionally, the SDT determined that it was not necessary to include Generator Operators and Generator Owners in the Reliability Standard. First, Transmission stations or Transmission substations interconnecting generation facilities are considered when determining applicability. Transmission Owners will consider those Transmission stations and Transmission substations that include a Transmission station on the high side of the Generator Step-up transformer (GSU) using Applicability Section 4.1.1.1 and 4.1.1.2. As an example, a Transmission station or Transmission substation identified as a Transmission Owner facility that interconnects generation will be subject to the Requirement R1 risk assessment if it operates at 500kV or greater or if it is connected at 200 kV – 499kV to three or more other Transmission stations or Transmission substations and has an "aggregate weighted value" exceeding 3000 according to the table in Applicability Section 4.1.1.2. Second, the Transmission analysis or analyses conducted under Requirement R1 should take into account the impact of the loss of generation connected to applicable Transmission stations or Transmission substations. Additionally, the FERC order does not explicitly mention generation assets and is reasonably understood to focus on the most critical Transmission Facilities. The diagram below shows an example of a station.
Also, the SDT uses the phrase “Transmission stations or Transmission substations” to recognize the existence of both stations and substations. Many entities in industry consider a substation to be a location with physical borders (i.e. fence, wall, etc.) that contains at least an autotransformer. Locations also exist that do not contain autotransformers, and many entities in industry refer to those locations as stations (switching stations or switchyards). Therefore, the SDT chose to use both “station” and “substation” to refer to the locations where groups of Transmission Facilities exist.

On the issue of joint ownership, the SDT recognizes that this issue is not unique to CIP-014-1, and expects that the applicable Transmission Owners and Transmission Operators will develop memorandums of understanding, agreements, Coordinated Functional Registrations, or procedures, etc., to designate responsibilities under CIP-014-1 when joint ownership is at issue, which is similar to what many entities have completed for other Reliability Standards.

The language contained in the applicability section regarding the collector bus is directly copied from CIP-002-5.1, Attachment 1, and has no additional meaning within the CIP-014-1 standard.

**Requirement R1**

The initial risk assessment required under Requirement R1 must be completed on or before the effective date of the standard. Subsequent risk assessments are to be performed at least once every 30 or 60 months depending on the results of the previous risk assessment per Requirement R1, Part 1.1. In performing the risk assessment under Requirement R1, the
Transmission Owner should first identify their population of Transmission stations and Transmission substations that meet the criteria contained in Applicability Section 4.1.1. Requirement R1 then requires the Transmission Owner to perform a risk assessment, consisting of a transmission analysis, to determine which of those Transmission stations and Transmission Substations if rendered inoperable or damaged could result in widespread instability, uncontrolled separation, or Cascading within an Interconnection. The standard does not mandate the specific analytical method for performing the risk assessment. The Transmission Owner has the discretion to choose the specific method that best suites its needs. As an example, an entity may perform a Power Flow analysis and stability analysis at a variety of load levels.

Performing Risk Assessments
The Transmission Owner has the discretion to select a transmission analysis method that fits its facts and system circumstances. To mandate a specific approach is not technically desirable and may lead to results that fail to adequately consider regional, topological, and system circumstances. The following guidance is only an example on how a Transmission Owner may perform a power flow and/or stability analysis to identify those Transmission stations and Transmission substations that if rendered inoperable or damaged as a result of a physical attack could result in widespread instability, uncontrolled separation, or Cascading within an Interconnection. An entity could remove all lines, without regard to the voltage level, to a single Transmission station or Transmission substation and review the simulation results to assess system behavior to determine if Cascading of Transmission Facilities, uncontrolled separation, or voltage or frequency instability is likely to occur over a significant area of the Interconnection. Using engineering judgment, the Transmission Owner (possibly in consultation with regional planning or operation committees and/or ISO/RTO committee input) should develop criteria (e.g. imposing a fault near the removed Transmission station or Transmission substation) to identify a contingency or parameters that result in potential widespread instability, uncontrolled separation, or Cascading within an Interconnection. Regional consultation on these matters is likely to be helpful and informative, given that the inputs for the risk assessment and the attributes of what constitutes widespread instability, uncontrolled separation, or Cascading within an Interconnection will likely vary from region-to-region or from ISO-to-ISO based on topology, system characteristics, and system configurations. Criteria could also include post-contingency facilities loadings above a certain emergency rating or failure of a power flow case to converge. Available special protection systems (SPS), if any, could be applied to determine if the system experiences any additional instability which may result in uncontrolled separation. Example criteria may include:

(a) Thermal overloads beyond facility emergency ratings;
(b) Voltage deviation exceeding ± 10%; or
(c) Cascading outage/voltage collapse; or
(d) Frequency below under-frequency load shed points
Periodicity

A Transmission Owner who identifies one or more Transmission stations or Transmission substations (as verified under Requirement R2) that if rendered inoperable or damaged could result in widespread instability, uncontrolled separation, or Cascading within an Interconnection is required to conduct a risk assessment at least once every 30 months. This period ensures that the risk assessment remains current with projected conditions and configurations in the planned system. This risk assessment, as the initial assessment, must consider applicable planned Transmission stations and Transmission substations to be in service within 24 months. The 30 month timeframe aligns with the 24 month planned to be in service date because the Transmission Owner is provided the flexibility, depending on its planning cycle and the frequency in which it may plan to construct a new Transmission station or Transmission substation to more closely align these dates. The requirement is to conduct the risk assessment at least once every 30 months, so for a Transmission Owner that believes it is better to conduct a risk assessment once every 24 months, because of its planning cycle, it has the flexibility to do so.

Transmission Owners that have not identified any Transmission stations or Transmission substations (as verified under Requirement R2) that if rendered inoperable or damaged could result in widespread instability, uncontrolled separation, or Cascading within an Interconnection are unlikely to see changes to their risk assessment in the Near-Term Planning Horizon. Consequently, a 60 month periodicity for completing a subsequent risk assessment is specified.

Identification of Primary Control Centers

After completing the risk assessment specified in Requirement R1, it is important to additionally identify the primary control center that operationally controls each Transmission station or Transmission substation that if rendered inoperable or damaged could result in widespread instability, uncontrolled separation, or Cascading within an Interconnection. A primary control center “operationally controls” a Transmission station or Transmission substation when the control center’s electronic actions can cause direct physical actions at the identified Transmission station and Transmission substation, such as opening a breaker.

Requirement R2

This requirement specifies verification of the risk assessment performed under Requirement R1 by an entity other than the owner or operator of the Requirement R1 risk assessment.

A verification of the risk assessment by an unaffiliated third party, as specified in Requirement R2, could consist of:

1. Certifying that the Requirement R1 risk assessment considers the Transmission stations and Transmission substations identified in Applicability Section 4.1.1.
2. Review of the model used to conduct the risk assessment to ensure it contains sufficient system topology to identify Transmission stations and Transmission substations that if rendered inoperable or damaged could cause widespread instability, uncontrolled separation, or Cascading within an Interconnection.


This requirement provides the flexibility for a Transmission Owner to select from unaffiliated registered and non-registered entities with transmission planning or analysis experience to perform the verification of the Requirement R1 risk assessment. The term unaffiliated means that the selected verifying entity cannot be a corporate affiliate (i.e., the verifying or third party reviewer cannot be an entity that corporately controls, is controlled by or is under common control with, the Transmission Owner). The verifying entity also cannot be a division of the Transmission Owner that operates as a functional unit.

The prohibition on registered entities using a corporate affiliate to conduct the verification, however, does not prohibit a governmental entity (e.g., a city, a municipality, a U.S. federal power marketing agency, or any other political subdivision of U.S. or Canadian federal, state, or provincial governments) from selecting as the verifying entity another governmental entity within the same political subdivision. For instance, a U.S. federal power marketing agency may select as its verifier another U.S. federal agency to conduct its verification so long as the selected entity has transmission planning or analysis experience. Similarly, a Transmission Owner owned by a Canadian province can use a separate agency of that province to perform the verification. The verifying entity, however, must still be a third party and cannot be a division of the registered entity that operates as a functional unit.

Requirement R2 also provides that the “verification may occur concurrent with or after the risk assessment performed under Requirement R1.” This provision is designed to provide the Transmission Owner the flexibility to work with the verifying entity throughout (i.e., concurrent with) the risk assessment, which for some Transmission Owners may be more efficient and effective. In other words, a Transmission Owner could collaborate with their unaffiliated verifying entity to perform the risk assessment under Requirement R1 such that both Requirement R1 and Requirement R2 are satisfied concurrently. The intent of Requirement R2 is to have an entity other than the owner or operator of the facility to be involved in the risk assessment process and have an opportunity to provide input. Accordingly, Requirement R2 is designed to allow entities the discretion to have a two-step process, where the Transmission Owner performs the risk assessment and subsequently has a third party review that assessment, or a one-step process, where the entity collaborates with a third party to perform the risk assessment.

Characteristics to consider in selecting a third party reviewer could include:

- Registered Entity with applicable planning and reliability functions.
- Experience in power system studies and planning.
- The entity’s understanding of the MOD standards, TPL standards, and facility ratings as they pertain to planning studies.
• The entity’s familiarity with the Interconnection within which the Transmission Owner is located.

With respect to the requirement that Transmission owners develop and implement procedures for protecting confidential and sensitive information, the Transmission Owner could have a method for identifying documents that require confidential treatment. One mechanism for protecting confidential or sensitive information is to prohibit removal of sensitive or confidential information from the Transmission Owner’s site. Transmission Owners could include such a prohibition in a non-disclosure agreement with the verifying entity.

A Technical feasibility study is not required in the Requirement R2 documentation of the technical basis for not modifying the identification in accordance with the recommendation.

On the issue of the difference between a verifier in Requirement R2 and a reviewer in Requirement R6, the SDT indicates that the verifier will confirm that the risk assessment was completed in accordance with Requirement R1, including the number of Transmission stations and substations identified, while the reviewer in Requirement R6 is providing expertise on the manner in which the evaluation of threats was conducted in accordance with Requirement R4, and the physical security plan in accordance with Requirement R5. In the latter situation there is no verification of a technical analysis, rather an application of experience and expertise to provide guidance or recommendations, if needed.

Parts 2.4 and 6.4 require the entities to have procedures to protect the confidentiality of sensitive or confidential information. Those procedures may include the following elements:

1. Control and retention of information on site for third party verifiers/reviewers.
2. Only “need to know” employees, etc., get the information.
3. Marking documents as confidential
4. Securely storing and destroying information when no longer needed.
5. Not releasing information outside the entity without, for example, General Counsel sign-off.

**Requirement R3**

Some Transmission Operators will have obligations under this standard for certain primary control centers. Those obligations, however, are contingent upon a Transmission Owner first completing the risk assessment specified by Requirement R1 and the verification specified by Requirement R2. Requirement R3 is intended to ensure that a Transmission Operator that has operational control of a primary control center identified in Requirement R1 receive notice so that the Transmission Operator may fulfill the rest of the obligations required in Requirements R4 through R6. Since the timing obligations in Requirements R4 through R6 are based upon completion of Requirement R2, the Transmission Owner must also include within the notice the date of completion of Requirement R2. Similarly, the Transmission Owner must notify the Transmission Operator of any removals from identification that result from a subsequent risk
assessment under Requirement R1 or as a result of the verification process under Requirement R2.

**Requirement R4**

This requirement requires owners and operators of facilities identified by the Requirement R1 risk assessment and that are verified under Requirement R2 to conduct an assessment of potential threats and vulnerabilities to those Transmission stations, Transmission substations, and primary control centers using a tailored evaluation process. Threats and vulnerabilities may vary from facility to facility based on any number of factors that include, but are not limited to, location, size, function, existing physical security protections, and attractiveness as a target.

In order to effectively conduct a threat and vulnerability assessment, the asset owner may be the best source to determine specific site vulnerabilities, but current and evolving threats may best be determined by others in the intelligence or law enforcement communities. A number of resources have been identified in the standard, but many others exist and asset owners are not limited to where they may turn for assistance. Additional resources may include state or local fusion centers, U.S. Department of Homeland Security, Federal Bureau of Investigations (FBI), Public Safety Canada, Royal Canadian Mounted Police, and InfraGard chapters coordinated by the FBI.

The Responsible Entity is required to take a number of factors into account in Parts 4.1 to 4.3 in order to make a risk-based evaluation under Requirement R4.

To assist in determining the current threat for a facility, the prior history of attacks on similarly protected facilities should be considered when assessing probability and likelihood of occurrence at the facility in question.

Resources that may be useful in conducting threat and vulnerability assessments include:

- ASIS International General Risk Assessment Guidelines.

**Requirement R5**

This requirement specifies development and implementation of a security plan(s) designed to protect against attacks to the facilities identified in Requirement R1 based on the assessment performed under Requirement R4.

Requirement R5 specifies the following attributes for the physical security plan:
• **Resiliency or security measures designed collectively to deter, detect, delay, assess, communicate, and respond to potential physical threats and vulnerabilities identified during the evaluation conducted in Requirement R4.**

Resiliency may include, among other things:

a. System topology changes,
b. Spare equipment,
c. Construction of a new Transmission station or Transmission substation.

While most security measures will work together to collectively harden the entire site, some may be allocated to protect specific critical components. For example, if protection from gunfire is considered necessary, the entity may only install ballistic protection for critical components, not the entire site.

• **Law enforcement contact and coordination information.**

Examples of such information may be posting 9-1-1 for emergency calls and providing substation safety and familiarization training for local and federal law enforcement, fire department, and Emergency Medical Services.

• **A timeline for executing the physical security enhancements and modifications specified in the physical security plan.**

Entities have the flexibility to prioritize the implementation of the various resiliency or security enhancements and modifications in their security plan according to risk, resources, or other factors. The requirement to include a timeline in the physical security plan for executing the actual physical security enhancements and modifications does not also require that the enhancements and modifications be completed within 120 days. The actual timeline may extend beyond the 120 days, depending on the amount of work to be completed.

• **Provisions to evaluate evolving physical threats, and their corresponding security measures, to the Transmission station(s), Transmission substation(s), or primary control center(s).**

A registered entity's physical security plan should include processes and responsibilities for obtaining and handling alerts, intelligence, and threat warnings from various sources. Some of these sources could include the ERO, ES-ISAC, and US and/or Canadian federal agencies. This information should be used to reevaluate or consider changes in the security plan and corresponding security measures of the security plan found in R5. Incremental changes made to the physical security plan prior to the next required third party review do not require additional third party reviews.

**Requirement R6**

This requirement specifies review by an entity other than the Transmission Owner or Transmission Operator with appropriate expertise for the evaluation performed according to...
Requirement R4 and the security plan(s) developed according to Requirement R5. As with Requirement R2, the term unaffiliated means that the selected third party reviewer cannot be a corporate affiliate (i.e., the third party reviewer cannot be an entity that corporately controls, is controlled by or is under common control with, the Transmission Operator). A third party reviewer also cannot be a division of the Transmission Operator that operates as a functional unit.

As noted in the guidance for Requirement R2, the prohibition on registered entities using a corporate affiliate to conduct the review, however, does not prohibit a governmental entity from selecting as the third party reviewer another governmental entity within the same political subdivision. For instance, a city or municipality may use its local enforcement agency, so long as the local law enforcement agency satisfies the criteria in Requirement R6. The third party reviewer, however, must still be a third party and cannot be a division of the registered entity that operates as a functional unit.

The Responsible Entity can select from several possible entities to perform the review:

- **An entity or organization with electric industry physical security experience and whose review staff has at least one member who holds either a Certified Protection Professional (CPP) or Physical Security Professional (PSP) certification.**

  In selecting CPP and PSP for use in this standard, the SDT believed it was important that if a private entity such as a consulting or security firm was engaged to conduct the third party review, they must tangibly demonstrate competence to conduct the review. This includes electric industry physical security experience and either of the premier security industry certifications sponsored by ASIS International. The ASIS certification program was initiated in 1977, and those that hold the CPP certification are board certified in security management. Those that hold the PSP certification are board certified in physical security.

- **An entity or organization approved by the ERO.**

- **A governmental agency with physical security expertise.**

- **An entity or organization with demonstrated law enforcement, government, or military physical security expertise.**

As with the verification under Requirement R2, Requirement R6 provides that the “review may occur concurrently with or after completion of the evaluation performed under Requirement R4 and the security plan development under Requirement R5.” This provision is designed to provide applicable Transmission Owners and Transmission Operators the flexibility to work with the third party reviewer throughout (i.e., concurrent with) the evaluation performed according to Requirement R4 and the security plan(s) developed according to Requirement R5, which for some Responsible Entities may be more efficient and effective. In other words, a Transmission Owner or Transmission Operator could collaborate with their unaffiliated third party reviewer to perform an evaluation of potential threats and vulnerabilities (Requirement R4) and develop a security plan (Requirement R5) to satisfy Requirements R4 through R6 simultaneously. The
intent of Requirement R6 is to have an entity other than the owner or operator of the facility to be involved in the Requirement R4 evaluation and the development of the Requirement R5 security plans and have an opportunity to provide input on the evaluation and the security plan. Accordingly, Requirement R6 is designed to allow entities the discretion to have a two-step process, where the Transmission Owner performs the evaluation and develops the security plan itself and then has a third party review that assessment, or a one-step process, where the entity collaborates with a third party to perform the evaluation and develop the security plan.
Timeline

CIP-014-1 – Physical Security Process Flow

Notes:
- Days = Calendar Days
- Initial performance of R1 must be complete on or before the effective date of the standard.
- R2 completion is contingent upon whether verification recommends modification.
  If no, R2 is complete upon verification completion in R2.2. If yes, R2 is complete upon performing R2.3.
- R2 can be performed concurrently with R1
- R6 can be performed concurrently with R4 and R5

- 90 Days
  R1 - Risk Assessment

- 90 Days
  R2.2 - Third party verification

- Verification recommends modification?
  YES - 60 Days
  R2.3 - Address verification recommendations and perform modifications or document technical reasons for not modifying

- NO - 7 Days
  R3 - Notice to operators of control centers

- 120 Days from R2 Completion
  R4 - Evaluation of threats and vulnerabilities of physical attack

- 90 Days
  R6.2 - Third party review of evaluation and security plan(s)

- Review recommends modification?
  YES - 60 Days
  R6.3 - Address review recommendations and perform modifications or document reasons for not modifying

- NO

END
**Rationale:**
During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

**Rationale for Requirement R1:**
This requirement meets the FERC directive from paragraph 6 in the order on physical security to perform a risk assessment to identify which facilities if rendered inoperable or damaged could impact an Interconnection through widespread instability, uncontrolled separation, or cascading failures. It also meets the portion of the directive from paragraph 11 for periodic reevaluation by requiring the risk assessment to be performed every 30 months (or 60 months for an entity that has not identified in a previous risk assessment any Transmission stations or Transmission substations that if rendered inoperable or damaged could result in widespread instability, uncontrolled separation, or Cascading within an Interconnection).

After identifying each Transmission station and Transmission substation that meets the criteria in Requirement R1, it is important to additionally identify the primary control center that operationally controls that Transmission station or Transmission substation (i.e., the control center whose electronic actions can cause direct physical actions at the identified Transmission station and Transmission substation, such as opening a breaker, compared to a control center that only has the ability to monitor the Transmission station and Transmission substation and, therefore, must coordinate direct physical action through another entity).

**Rationale for Requirement R2:**
This requirement meets the FERC directive from paragraph 11 in the order on physical security requiring verification by an entity other than the owner or operator of the risk assessment performed under Requirement R1.

This requirement provides the flexibility for a Transmission Owner to select registered and non-registered entities with transmission planning or analysis experience to perform the verification of the Requirement R1 risk assessment. The term “unaffiliated” means that the selected verifying entity cannot be a corporate affiliate (i.e., the verifying entity cannot be an entity that controls, is controlled by, or is under common control with, the Transmission owner). The verifying entity also cannot be a division of the Transmission Owner that operates as a functional unit. The term “unaffiliated” is not intended to prohibit a governmental entity from using another government entity to be a verifier under Requirement R2.

Requirement R2 also provides the Transmission Owner the flexibility to work with the verifying entity throughout the Requirement R1 risk assessment, which for some Transmission Owners may be more efficient and effective. In other words, a Transmission Owner could coordinate with their unaffiliated verifying entity to perform a Requirement R1 risk assessment to satisfy both Requirement R1 and Requirement R2 concurrently.
Planning Coordinator is a functional entity listed in Part 2.1. The Planning Coordinator and Planning Authority are the same entity as shown in the NERC Glossary of Terms Used in NERC Reliability Standards.

Rationale for Requirement R3:
Some Transmission Operators will have obligations under this standard for certain primary control centers. Those obligations, however, are contingent upon a Transmission Owner first identifying which Transmission stations and Transmission substations meet the criteria specified by Requirement R1, as verified according to Requirement R2. This requirement is intended to ensure that a Transmission Operator that has operational control of a primary control center identified in Requirement R1, Part 1.2 of a Transmission station or Transmission substation verified according to Requirement R2 receives notice of such identification so that the Transmission Operator may timely fulfill its resulting obligations under Requirements R4 through R6. Since the timing obligations in Requirements R4 through R6 are based upon completion of Requirement R2, the Transmission Owner must also include notice of the date of completion of Requirement R2. Similarly, the Transmission Owner must notify the Transmission Operator of any removals from identification that result from a subsequent risk assessment under Requirement R1 or the verification process under Requirement R2.

Rationale for Requirement R4:
This requirement meets the FERC directive from paragraph 8 in the order on physical security that the reliability standard must require tailored evaluation of potential threats and vulnerabilities to facilities identified in Requirement R1 and verified according to Requirement R2. Threats and vulnerabilities may vary from facility to facility based on factors such as the facility’s location, size, function, existing protections, and attractiveness of the target. As such, the requirement does not mandate a one-size-fits-all approach but requires entities to account for the unique characteristics of their facilities.
Requirement R4 does not explicitly state when the evaluation of threats and vulnerabilities must occur or be completed. However, Requirement R5 requires that the entity’s security plan(s), which is dependent on the Requirement R4 evaluation, must be completed within 120 calendar days following completion of Requirement R2. Thus, an entity has the flexibility when to complete the Requirement R4 evaluation, provided that it is completed in time to comply with the requirement in Requirement R5 to develop a physical security plan 120 calendar days following completion of Requirement R2.

Rationale for Requirement R5:
This requirement meets the FERC directive from paragraph 9 in the order on physical security requiring the development and implementation of a security plan(s) designed to protect against attacks to the facilities identified in Requirement R1 based on the assessment performed under Requirement R4.
**Rationale for Requirement R6:**

This requirement meets the FERC directive from paragraph 11 in the order on physical security requiring review by an entity other than the owner or operator with appropriate expertise of the evaluation performed according to Requirement R4 and the security plan(s) developed according to Requirement R5.

As with the verification required by Requirement R2, Requirement R6 provides Transmission Owners and Transmission Operators the flexibility to work with the third party reviewer throughout the Requirement R4 evaluation and the development of the Requirement R5 security plan(s). This would allow entities to satisfy their obligations under Requirement R6 concurrent with the satisfaction of their obligations under Requirements R4 and R5.
* FOR INFORMATIONAL PURPOSES ONLY *

Enforcement Dates: Standard CIP-014-1 — Physical Security

United States

<table>
<thead>
<tr>
<th>Standard</th>
<th>Requirement</th>
<th>Enforcement Date</th>
<th>Inactive Date</th>
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This standard has not yet been approved by the applicable regulatory authority.