Agenda
Operating Committee
June 7, 2016 | 1:00–5:00 p.m. (CDT)
June 8, 2016 | 8:00 a.m.–Noon (CDT)

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

Introductions and Chair’s Opening Remarks

NERC Antitrust Compliance Guidelines and Public Announcement

Agenda

1. Administrative - Secretary
   a. Arrangements
      i. Safety Briefing and Identification of Exits (Hyatt Regency Staff)
   b. Announcement of Quorum
   c. Background Information
      i. OC Membership (2015-2017)
      ii. OC Roster*
      iii. OC Organizational Chart
      iv. OC Charter
      v. Parliamentary Procedures*
      vi. Participant Conduct Policy
   d. Future Meetings

<table>
<thead>
<tr>
<th>2016 Meeting Dates</th>
<th>Time</th>
<th>Location</th>
<th>Hotel</th>
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</thead>
<tbody>
<tr>
<td>September 13, 2016</td>
<td>1:00 to 5:00 p.m.</td>
<td>TBD</td>
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<tr>
<td>September 14, 2016</td>
<td>8:00 a.m. to Noon</td>
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<tr>
<td>December 13, 2016</td>
<td>1:00 to 5:00 p.m. (Eastern)</td>
<td>Atlanta, GA</td>
<td>TBD</td>
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<tr>
<td>December 14, 2016</td>
<td>8:00 a.m. to Noon (Eastern)</td>
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<table>
<thead>
<tr>
<th>2017 Meeting Dates</th>
<th>Time</th>
<th>Location</th>
<th>Hotel</th>
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<tbody>
<tr>
<td>March 7, 2017</td>
<td>1:00 to 5:00 p.m.</td>
<td>TBD</td>
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<tr>
<td>March 8, 2017</td>
<td>8:00 a.m. to Noon</td>
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<td>June 6, 2017</td>
<td>1:00 to 5:00 p.m.</td>
<td>TBD</td>
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<tr>
<td>June 7, 2017</td>
<td>8:00 a.m. to Noon</td>
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2. **Consent Agenda – Chair Case**
   
   a. March 8–9, 2016 Draft OC Meeting Minutes*

<table>
<thead>
<tr>
<th><strong>Action:</strong></th>
<th>Approve</th>
<th><strong>Objective:</strong> Approve consent agenda.</th>
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<tbody>
<tr>
<td><strong>Background:</strong></td>
<td>Following posting of the draft meeting minutes, it was suggested that the Section titled “Retirement of BAL-004 (Time Error Correction) be modified as follows:</td>
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### Retirement of BAL-004 (Time Error Correction)

Last Paragraph in that Section: Jerry Rust commented that the RS could develop a guideline given the retirement of BAL-004, however, that guideline cannot be voluntary. Hence, a standard may be needed to make it a mandatory procedure. Robert Blohm suggested that the solution may be to create an inadvertent interchange payback financial settlement procedure. Following further OC discussion, David Zwergel moved to task the RS and ORS to work together to develop a reliability guideline or procedure to implement when, in case there is sufficiently detrimental reliability impact on frequency after BAL-004 is retired. The committee approved the motion.

<table>
<thead>
<tr>
<th><strong>Presentation:</strong></th>
<th><strong>Duration:</strong> 10 minutes</th>
<th><strong>Background Items:</strong> March 8–9, 2016 Draft OC Meeting Minutes</th>
</tr>
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3. **Chair’s Remarks**

   a. Retirement of Pierre Paquet, Hydro Quebec
   
   b. OC 2016 General Election
   
   c. Report on May 4, 2016 Member Representatives Committee Meeting and the May 5, 2016 Board of Trustees Meeting*

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

<table>
<thead>
<tr>
<th><strong>Action:</strong></th>
<th><strong>Objective:</strong> Review and discuss open action items from prior OC meetings.</th>
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<tbody>
<tr>
<td><strong>OC Strategic Plan Goal:</strong></td>
<td>None, this is an administrative item.</td>
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<tr>
<td><strong>Background:</strong></td>
<td>The OC Action Item list will be reviewed near the beginning of each OC meeting, with the intent to reach prompt resolution.</td>
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<table>
<thead>
<tr>
<th><strong>Presentation:</strong></th>
<th><strong>Duration:</strong> 10 minutes</th>
<th><strong>Background Items:</strong> Revised OC Action Item List</th>
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5. **Subcommittee Status Reports**

   a. Operating Reliability Subcommittee* – **Chair Eric Senkowicz**
   
   b. Resources Subcommittee* – **Chair Troy Blalock**
   
   c. Event Analysis Subcommittee* – **Chair Hassan Hamdar**
   
   d. Personnel Subcommittee* – **Chair Lauri Jones**
   
   e. Reliability Assessment Subcommittee – **David Calderon, Engineer, Reliability Assessment**
Post-mortem review of the Short-Term Reliability Assessment on Natural Gas Availability – 
John Moura, Director, Reliability Assessment and System Analysis

Essential Reliability Services Working Group – Co-Chair Todd Lucas

Distributed Energy Resources Task Force – Chair Rich Hydzik

Data Needed to Support Measures 1-4 – Troy Blalock, RS Chair

Reliability Issues Steering Committee Status Report – Vice Chair Linke

Committee Matters

Renewable Integration – John Pespisa, Director, NERC Compliance Program, Southern California Edison

| Action: None | Objective: A look at the renewable picture in California along with an update on Aliso Canyon. |
| OC Strategic Plan Guiding Principle: Maintain high levels of expertise to provide sound conclusions and opinions on operational issues. |
| Action Item Number: None |
| Background: None |
| Presentation: Yes | Duration: 30 minutes | Background Items: None |

Reliability Guideline: Situational Awareness for the System Operator* – Lauri Jones

| Action: None | Objective: Review and discuss a draft Reliability Guideline: Situational Awareness for the System Operator. |
| OC Strategic Plan Guiding Principle: Maintain and enhance reliability through the pursuit of clear NERC Reliability Standards, reliability guidelines, NERC Alerts, interpretations, lessons learned, and other operational compliance clarifications. |
| Action Item Number: 1509-01 |
| Background: At its September 2015 meeting, the OC assigned a task team, chaired by Lauri Jones, with representatives from the ORS and the EAS to develop a strawman guidance document. Ms. Jones will provide an overview of the draft Reliability Guideline: Situational Awareness for the System Operator. |
| Presentation: Yes | Duration: 20 minutes | Background Items: Draft Reliability Guideline: Situational Awareness for the System Operator |

GridEx III Grid Security Exercise – Bill Lawrence, Associate Director, Stakeholder Engagement

| Action: None | Objective: Review and discuss the Grid Security Exercise GridEx III Report and planning for the GridEx IV grid security exercise. |
| OC Strategic Plan Guiding Principle: Maintain high levels of expertise to provide sound conclusions and opinions on operational issues. |
| Action Item Number: None |
**Background:** On November 18-19, 2015 NERC conducted its third biennial grid security and emergency response. A summary of the exercise found that GridEx III showed continued improvement to coordination, communication and emergency response actions on how industry would respond to a cyber or physical attack from previous exercises. The GridEx III report reviewed findings from the scenario to measure attainment of exercise goals, and includes feedback from GridEx III participants.

GridEx III planners designed the large-scale cyber and physical attack scenario to overwhelm even the most prepared participants. The scenario for the distributed play portion of exercise highlighted how essential it was for participants to conduct well-coordinated communications within their own organizations, across the electricity sector, with government and with the public. The Executive Tabletop portion of the exercise included a robust discussion on unity of messaging, the collective effort to protect the grid and the use of extraordinary measures for restoring power.

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

**Notes:**

d. **Revised PJM RTO Reliability Plan** – David Souder, PJM

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<tr>
<th>Action</th>
<th>Objective</th>
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<tbody>
<tr>
<td>Approve</td>
<td>Review, discuss and approve the revised PJM RTO Reliability Plan.</td>
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**OC Strategic Plan Guiding Principle:** Maintain and enhance reliability through the pursuit of clear NERC Reliability Standards, reliability guidelines, NERC Alerts, interpretations, lessons learned, and other operational compliance clarifications.

**Action Item Number:** None

**Background:** On June 1, 2016, PJM included International Transmission Company (ITC) in its reliability area.

On May 26, 2016, the Operating Reliability Subcommittee’s Executive Committee endorsed the revised PJM RTO Reliability Plan for OC review.

**Presentation:** Yes  
**Duration:** 10 minutes  
**Background Items:** Revised PJM RTO Reliability Plan.

**Notes:**

e. **Roundtable Discussion – EPA Clean Power Plan and Its Potential Impacts on BES Reliability** – Richard McCall, Director, Environmental and Transmission Compliance, North Carolina Electric Membership Corporation

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<th>Action</th>
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<tbody>
<tr>
<td>None</td>
<td>Review and discuss the EPA Clean Power Plan and its potential impacts on BES reliability.</td>
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**OC Strategic Plan Guiding Principle:** Maintain high levels of expertise to provide sound conclusions and opinions on operational issues.

**Action Item Number:** None

**Background:** Richard McCall will led the OC in a discussion of the proposed EPA Clean Power Plan and its potential impacts on BES reliability. In a similar presentation to the ORS, Mr. McCall provided an overview of the EPA’s Clean Power Plan (CPP). EPA issued the proposed CPP rule in June 2014 to reduce carbon emissions from existing fossil-fueled electric generating units. The CPP rulemaking received over
4.3 million comments. The final CPP was signed on August 3, 2015 and was published in the Federal Register on October 23, 2015. Full compliance with the CPP is set for 2030. The CPP relied on three basic tenets or building blocks: 1) heat rate improvement of coal-fired plants, 2) re-dispatch of natural gas combined cycle power plants and 3) increased use of new renewable energy. State Implementation Plans (SIPs) must be submitted by September 6, 2016, however, states can request an extension to September 2018. The EPA has up to one year to approve a SIP. If a SIP is not approved, the EPA can impose upon the state that it follow the Federal Plan. The EPA plans to finalize the Federal Plan in the summer of 2016.

Using data based on North Carolina’s generation fleet, Mr. McCall illustrated the impact to North Carolina of implementing the EPA CPP. He also compared North Carolina’s final 2030 rate-based goals to other states. He noted that there are many entities that have studied the reliability impacts of implementing the EPA CPP and informed the ORS of a FERC staff white paper on *Guidance Principles for Clean Power Plan Modeling* (Docket No. AD16-14-000). Potential reliability impacts of implementing the CPP include: 1) early retirement of generating units, 2) changing resource mix and unit dispatch and 3) unit cycling due to environmental constraints.

**Presentation:**

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

**Notes:**

f. CPS 1 Data and BAAL Exceedances Information* – Troy Blalock, RS Chair

**Action:** None  
**Objective:** Review and discuss a letter from Chair Case to balancing authorities and Regional Entities.

**OC Strategic Plan Guiding Principle:** Maintain and enhance reliability through the pursuit of clear NERC Reliability Standards, reliability guidelines, NERC Alerts, interpretations, lessons learned, and other operational compliance clarifications.

**Action Item Number:** 1603-08

**Background:** Today, Balancing Authorities (BAs) submit CPS 1 %, CPS 2 % and rolling 12 month CPS 1 % values monthly through Regional internet portals for compliance which is then aggregated and provided to NERC. This NERC aggregated data is sent to the NERC Resources Subcommittee (RS) to monitor and provide analysis of individual BA performance as it pertains to Interconnection reliability.

With the pending implementation of BAL-001-2, July 1, 2016, CPS data will no longer be required to be provided unless a compliance violation has occurred. However, the NERC Operating Committee (OC) is requesting the same CPS 1 % data and additionally, BAAL exceedances to be provided to allow the NERC RS to continue to monitor and analyze individual BA performance as the performance Standards and requirements change and also to assist BAs as needed. This data request is not to be considered compliance related but is very important and needed to assist the industry and support and monitor Interconnection performance.

Due to the fact this is not compliance data, a new process has been developed for BAs to provide this information on a secured NERC SharePoint website referred to as the balancing authority submittal site (BASS). Secure ID information is required to access the BASS site and access will be limited to a BA only seeing its information.
<table>
<thead>
<tr>
<th>Presentation:</th>
<th>Duration: 15 minutes</th>
<th>Background Items: CPS1 and BAAL Exceedance Information Letter</th>
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<td>Notes:</td>
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### g. NERC’s Comments in Response to FERC Notice of Inquiry (Primary Frequency Response) – Dr. James Merlo, Vice President, Reliability Risk Management

**Action:** None  
**Objective:** Review and discuss NERC’s Comments in Response to the FERC Primary Frequency Response Notice of Inquiry.

**OC Strategic Plan Guiding Principle:** Maintain high levels of expertise to provide sound conclusions and opinions on operational issues.

**Action Item Number:** 1512-01

**Background:** On February 18, 2016, FERC issued RM16-6-000, a Notice of Inquiry on Primary Frequency Response. On April 25, 2016, NERC filed its Comments in Response to the FERC NOI. Dr. Merlo will provide an overview of NERC’s comments.

<table>
<thead>
<tr>
<th>Presentation:</th>
<th>Duration: 20 minutes</th>
<th>Background Items: Notice of Inquiry and NERC's Comments in Response to FERC Notice of Inquiry</th>
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<td>Notes:</td>
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### h. Review of Proposed Planning Committee Charter Changes* – Secretary Kezele

**Action:** None  
**Objective:** Review and discuss proposed changes to the Planning Committee Charter. The OC will consider whether similar changes are needed for its Charter.

**OC Strategic Plan Guiding Principle:** This is an administrative item.

**Action Item Number:** None

**Background:** The Planning Committee’s Charter changes focus primarily on the layout and organization of the document, while limiting changes to the content (unless absolutely necessary). Guidance that was too prescriptive for inclusion in the Charter update was instead included in an Addendum (which will not require Board approval). There are a total of three attachments:
1. PC Charter – Updated (DRAFT)
2. PC Charter Summary of Changes
3. PC Charter Addendum

| Presentation: | Duration: 15 minutes | Background Items:  
|--------------|---------------------|-------------------------------------------------------------|
|              |                     | 1. Draft PC Charter (Updated)  
|              |                     | 2. PC Charter Summary of Changes  
|              |                     | 3. PC Charter – Addendum |

**Notes:**

### i. Archive the NERC Backup Control Center – A Reference Document* – Eric Senkowitz, ORS Chair

**Action:** Approve  
**Objective:** Review, discuss and approve archival of the NERC Backup Control Center – A Reference Document, dated July 1993.
OC Strategic Plan Guiding Principle: Maintain and enhance reliability through the pursuit of clear NERC Reliability Standards, reliability guidelines, NERC Alerts, interpretations, lessons learned, and other operational compliance clarifications.

Action Item Number: None

Background: The ORS formed a task team to consider the disposition of the NERC Backup Control Center – A Reference Document. The task team’s recommendation is to retire or archive the guideline, as it has become quite dated since it was issued. As written, the document provides a guide to utilities to assess and justify the addition of a backup capability to their main control center. The task team feels that, since 1993, business continuity has taken a much more prominent place in daily operations and justification of a backup control center is no longer an issue for registered entities. Further, the task team believes that the current standard EOP-008 (Loss of Control Center Functionality) adequately covers the appropriate requirements. Therefore, the ORS approved a motion to recommend to the Operating Committee the archival of the Backup Control Center Reference Document.

Presentation: No
Duration: 10 minutes
Background Items: NERC Backup Control Center – A Reference Document

Notes:

j. Dynamic Transfer Reference Document, Version 3* – Troy Blalock, RS Chair

Action: Approve

OC Strategic Plan Guiding Principle: Maintain and enhance reliability through the pursuit of clear NERC Reliability Standards, reliability guidelines, NERC Alerts, interpretations, lessons learned, and other operational compliance clarifications.

Action Item Number: None

Background: The OC approved Version 2 of the Dynamic Transfer Reference Guidelines in June 2010. The Resources Subcommittee completed a review of the document and made some revisions, which are reflected in the attached red-line of Version 3.

Presentation: No
Duration: 10 minutes
Background Items: Red-line of Version 3 of the Dynamic Transfer Reference Document

Notes:

k. Time Monitoring Reference Document, Version 4* – Troy Blalock, RS Chair

Action: Approve

OC Strategic Plan Guiding Principle: Maintain and enhance reliability through the pursuit of clear NERC Reliability Standards, reliability guidelines, NERC Alerts, interpretations, lessons learned, and other operational compliance clarifications.

Action Item Number: 1603-07

Background: At its March 2016 meeting, the OC charged the Resources Subcommittee and the Operating Reliability Subcommittee to work together to develop a reliability guideline or procedure to implement in case there is sufficiently detrimental reliability impact on frequency after BAL-004 is retired.

Presentation: Yes
Duration: 20 minutes
Background Items: Time Monitoring Reference Document, Version 4
### Notes:

I. Eastern Interconnection Unaccounted Inadvertent Interchange* – Troy Blalock, RS Chair

<table>
<thead>
<tr>
<th>Action: None</th>
<th>Objective: Review and discuss the results of an inquiry of Eastern Interconnection balancing authorities to participate in an unaccounted for Inadvertent Interchange true-up.</th>
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</table>

**OC Strategic Plan Guiding Principle:** Maintain high levels of expertise to provide sound conclusions and opinions on operational issues.

**Action Item Number:** None

**Background:** The unaccounted for Inadvertent Interchange true-up is the result of Inadvertent Interchange in the Eastern Interconnection accumulating to a non-zero amount. This happened due to a number of errors that have occurred over many years and, at this point, can no longer be traced back to their origins. The unaccounted for Inadvertent balances are the following:

- **On-Peak:** 45,410 MWHrs
- **Off-Peak:** -100,647 MWHrs
- **Total:** -55,239 MWHrs

In order to achieve a Interconnection net zero Inadvertent balance, the Resources Subcommittee is asking BAs if they would like to participate in an Inadvertent true-up. The true-up will consist of allocating Inadvertent amongst the participating BAs in the opposite direction of the above balances. The unaccounted for Inadvertent balances will be spread among the interested BAs based on their individual biases.

Example: To take the On-Peak Inadvertent to zero, a true-up by -45,410 MWHrs is required. The -45,410 MWhrs would be allocated based on a voluntary basis.

BA XYZ has an On-Peak Inadvertent balance of 150 MWHrs. They choose to participate in the true-up for the Eastern Interconnect for On-Peak only and want to limit the Inadvertent amount they take to -150 MWHrs, if available. In the true-up process BA XYZ’s portion of the balance was -125 MWHrs. This would result in BA XYZ’s On-Peak net Inadvertent balance being 25 MWHrs.

Each BA has the opportunity to participate in the true-up to a MWh amount specified in the BA participation survey.

Allocations will be made on individual biases and not exceeding the values listed in the survey per the BA. The RS will communicate further information once the surveys have been received.

### Presentation:

- **Yes**
- **Duration:** 15 minutes

| Background Items: Eastern Interconnection Unaccounted for Inadvertent Survey Letter |

**m. 2013-08-09 Boulder R450/R550 and Rathdrum A502 Event – Rich Hydzik, Transmission Operations Engineer, Avista Corp**
Action: None  
Objective: Mr. Hydzik will review an event that resulted in a simultaneous breaker failure in a double bus double breaker substation.

**OC Strategic Plan Guiding Principle:** Continually strive for excellence in event analysis (EA), emerging cause code trending, and information sharing.

**Action Item Number:** None

**Background:** This event resulted in a change to lightning protection practices in a relatively low lighting frequency area.

**Presentation:** Yes  
**Duration:** 35 minutes  
**Background Items:** None

**Notes:**

n. Functional Model Advisory Group* – **Lacey Ourso, Standards Developer**

Action: None  
Objective: To review and discuss proposed revisions to the Functional Model, and provide the Functional Model Advisory Group with feedback (comments and proposed revisions, if any).

Please note that the FMAG is only seeking comments regarding the proposed substantive changes to the Functional Entity sections of the FM. There are a number of “introductory” or “general information” sections contained in the FM (i.e., Forward, Introduction, Purpose, Guiding Principles of the FM, Clarification Service, and Revision Summary). The FMAG has not updated these sections yet, but will do so prior to finalizing the successor version. The FMAG requests that the standing committee members please focus their review only the substance of the proposed revisions to the technical content in the “Functional Entity” sections (starting with pg. 10 of the attached document). All formatting and other non-substantive issues should be ignored for the purpose of this review.

**OC Strategic Plan Guiding Principle:** Maintain and enhance reliability through the pursuit of clear NERC Reliability Standards, reliability guidelines, NERC Alerts, interpretations, lessons learned, and other operational compliance clarifications.

**Action Item Number:** 1603-03

**Background:** The FMAG is in the process of revising the Functional Model (FM) and its companion document, the Functional Model Technical Document (FMTD). The purpose of the project, as outlined in the FMAG Scope document is to revise the FM and FMTD to, “ensure the model correctly reflects the industry today and evaluates and incorporates new and emergent reliability related tasks.” Under the Scope document, the FMAG reports to the Standards Committee (SC), but is required to, “present draft revisions to the [FM] and its associated [FMTD] to the NERC CIPC, OC, and PC to establish consensus of the technical content.”
2016 FMAG project:
The FMAG was asked by the SC to undertake a review of the FM and FMTD, and make the necessary revisions to ensure that the model is up to date, and reflects the current industry today. The FMAG began the revision work in December of 2015 – focusing first on the revisions needed to the FM. The team has completed its initial review and revisions to the FM. The FMAG is now providing the draft revisions to the standing committees in order to obtain their feedback (comments and proposed revisions, if any) regarding the revisions. The main focus of this stage of the project is to obtain any and all feedback from the standing committees regarding the direction and proposed changes that the FMAG would like to move forward with. The FMAG is scheduled to meet the week after the standing committee meetings (June 15-17) for the purpose of incorporating the feedback and proposed revisions of the OC, PC, and CIPC committee members. Then, the proposed revisions to the FM will be posted for industry comment. Once the FMAG is satisfied with the direction of the FM revisions, the team will then make any necessary alignment revisions to the supporting document (the FMTD). At the September 2016 standing committee meetings, the FMAG will provide the final revisions to the FM and FMTD for the committee members for the purpose of “obtaining consensus.”

The FMAG is seeking input and feedback of the committee members at the June meeting so that the team can incorporate the feedback. This is the time to voice any concerns, objections or support (hopefully) related to the substantive revisions. In contrast, at the September meeting, the FMAG will be near completion of its planned work and the project, and will be asking for a yes/no confirmation that there is general agreement (or “consensus”) among the committee members in support of the revisions. The FMAG will not be seeking feedback, input or comments at that time. It is important to note that to the extent no comments or objection are raised to the proposed revisions at the June meeting, then the FMAG will assume that the committee members will not later raise objection to those very same revisions at the September meetings (once the documents have been finalized).

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<tr>
<th>Presentation:</th>
<th>Duration: 20 minutes</th>
<th>Background Item: Red-line of Functional Model</th>
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Notes:

*Background materials included.*
Antitrust Compliance Guidelines

I. General

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

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

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

II. Prohibited Activities

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

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

III. Activities That Are Permitted

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

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

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

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

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

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

<table>
<thead>
<tr>
<th>Role</th>
<th>Name</th>
<th>Organization</th>
<th>Address</th>
<th>Phone</th>
<th>Fax</th>
<th>Email</th>
</tr>
</thead>
<tbody>
<tr>
<td>Chair</td>
<td>James S Case</td>
<td>Entergy Services, Inc.</td>
<td>5201 W. Barraque Street, Pine Bluff, Arkansas 71602</td>
<td>(501) 228-2828</td>
<td>(870) 541-3964 Fx</td>
<td><a href="mailto:jcase@entergy.com">jcase@entergy.com</a></td>
</tr>
<tr>
<td>Vice Chair</td>
<td>Lloyd A Linke</td>
<td>Western Area Power Administration</td>
<td>1330 41st Street, PO Box 790, Watertown, South Dakota 57201</td>
<td>605 882-7500</td>
<td>(605)-880-4434 Fx</td>
<td><a href="mailto:lloyd@wapa.gov">lloyd@wapa.gov</a></td>
</tr>
<tr>
<td>Secretary</td>
<td>Larry J Kezele</td>
<td>North American Electric Reliability Corporation</td>
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<td>Role</td>
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<td>RE-WECC President</td>
<td>Jerry Rust</td>
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<td>Electricity Marketer</td>
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<td>Address</td>
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<tr>
<td>Large end-use electricity customer</td>
<td>To Be Named</td>
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<tr>
<td>Large end-use electricity customer</td>
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</table>
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 “kills” the motion. Useful for disposing of a badly chosen motion that cannot be adopted or rejected without undesirable consequences.</td>
</tr>
<tr>
<td>Request a review of procedure</td>
<td>Point of order</td>
<td>No</td>
<td>Second not required. The Chair or secretary shall review the parliamentary procedure used during the discussion of the Motion.</td>
</tr>
</tbody>
</table>

Notes on Motions

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

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

Revisions. Technically, revisions to the main motion are accomplished by the Amend procedure. However, immediately after making the motion, and before it is announced by the Chair, another member may ask that the motion be revised. If the original “motion -maker” agrees to the revision, then the revised motion will be the one debated. The original “seconder” need not be consulted, because the original “motion-maker” plus the “reviser” constitute a motion and a second.
Meeting Minutes
Operating Committee
March 8–9, 2016

Hyatt Regency Louisville
Louisville, Kentucky

A regular meeting of the NERC Operating Committee (OC) was held on March 8–9, 2016, in Louisville, Kentucky. 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 Case 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 Case welcomed the OC to Louisville and noted that the OC has another full agenda of material to consider and debate. He drew the OC’s attention to the following agenda items:

1. ERS Working Group Status Report
2. NERC Frequency Response Action Plan and FERC Notice of Inquiry regarding Primary Frequency Response
3. OC and Subcommittee 2016 Work Plans
4. Retirement of BAL-004 (Time Error Correction)

Consent Agenda
By consent, the committee approved the minutes of the December 15–16, 2015 meeting.

Chair’s Remarks
Chair Case welcomed the following new members to the Operating Committee: 1) Michelle Rheault – Manitoba Hydro (Federal/Provincial Sector), Mark Ennis – Alabama Municipal Electric Authority (Transmission Dependent Utility Sector) and Robert Blohm – Keen Resources (Small End-Use Electricity Customer Sector).
He also provided a brief overview of the February 10, 2016 Member Representatives Committee meeting and the February 11, 2016 Board of Trustees meeting. The OC’s report to the Board of Trustees was included in the agenda packet for this meeting.

**NERC White Paper – On FERC NOPR – Proposal to Revise Standard Generator Interconnection Agreements**

Ryan Quint, Senior Engineer, System Analysis, provided a summary of the NERC White Paper On FERC Notice of Proposed Rulemaking (Docket No. RM16-1-000) *Proposal to Revise Standard Generator Interconnection Agreements*. The white paper addresses the supply of reactive power, within a power factor range, for non-synchronous generation, removal of the exemption to supply reactive power from non-synchronous generation, and minimum output level for reactive capability (*Presentation 7.m*). The white paper also addressed:

1. Removing system impact study requirements
2. Voltage control versus power factor control
3. Dynamic versus reactive capability
4. Primary frequency response
5. Voltage ride through capability
6. Solar PV considerations

NERC filed its Comments in Response to the NOPR on Reactive Power Requirements for Non-Synchronous Generation on January 27, 2016. The NERC White Paper was an attachment to that filing.

**IEEE 1547 Revision Update**

Mr. Quint also briefed the committee on an IEEE effort to revise Standard 1547 (Standard for Interconnecting Distributed Resources with Electric Power Systems) (*Presentation 7.r*). IEEE 1547 establishes criteria and requirements for interconnection of distributed resources (DR) with electric power systems (EPS). The purpose of this standard is to provide requirements relevant to the performance, operation, testing, safety considerations, and maintenance of the interconnection.

NERC is engaging primarily in revisions to Clause 4.2: Response to Area EPS abnormal conditions which should address:

1. Voltage Ride-Through
2. Dynamic Voltage Support
3. Frequency Ride-Through
4. Frequency Response Capabilities, such as frequency droop characteristic and governor deadband settings
OC Action Item Review
Chair Case reviewed the list of action items and reported that several have been completed or are on the agenda for this meeting. The revised action item list is attached as Exhibit E.

Operating Reliability Subcommittee (ORS) Status Report
ORS Chair Eric Senkowicz summarized the subcommittee’s status report, which was included in the OC agenda packet. He highlighted the subcommittee’s work 1) with the IDC Tools Association on the Parallel Flow Visualization project, 2) on refinement of its 2016 Work Plan and 3) on the continued need for the Data Exchange and Telecommunications Working Groups. He reported that on February 1, 2016 the PJM Reliability Coordinator became the Eastern Interconnection time monitor and the Geomagnetic Disturbance monitor.

Resources Subcommittee (RS) Status Report
RS Chair Troy Blalock provided an overview of subcommittee activities, including:

1. Balancing Authority ACE Limit (CPS 1, CPS 2, and DCS) compliance reports, which is a separate topic on the OC’s agenda.
2. Support of BAL-003-1 implementation.
3. The RS Eastern Interconnection Inadvertent Interchange survey, which determined that there is 47236 MWHr On-Peak and -99131 MWHr Off-Peak for a total of -51895 MWHr of accumulated inadvertent. The RS discussed several options to reduce or eliminate the accumulated Inadvertent Interchange. Due to the overall negative imbalance and the related impact to BAs, the RS approved a motion to create a pseudo BA with equal and opposite values to record the imbalance at this time.

The OC discussed the accumulated Inadvertent Interchange identified above and suggested that the RS reconsider the options available to reducing or eliminating the balances.

Event Analysis Subcommittee (EAS) Status Report
EAS Chair Hassan Hamdar noted that the EAS and NERC have not posted any Lessons Learned since the OC’s last meeting. He reported that the subcommittee’s Trends Working Group is beginning an effort to review all previous Lessons Learned to identify event patterns or trends. Chair Hamdar also reported that the subcommittee is working with the North American Transmission Forum to develop a joint Lessons Learned.

Personnel Subcommittee (PS) Status Report
Lauri Jones, chair of the PS, noted that the subcommittee is continuing to review and approve Continuing Education courses and to review and approve NERC Approved Continuing Education Providers. The subcommittee is beginning a major project to clean-up the Continuing Education Training Manual. She provided the schedules for the 2016 Continuing Education Provider Workshops and a summary of the continuing education hours provided to those that participated in GridEx III (Presentation 5.d).
Reliability Issues Steering Committee (RISC)
Vice Chair Lloyd Linke reported that the RISC has not met since the OC’s last meeting. He introduced Peter Brandien, the incoming RISC chair. Mr. Brandien stated that the 2016 Reliability Leadership Summit is scheduled to be held in late June. The RISC will also be reviewing the list of 14 reliability risks and, by way of a survey, determine the continued relevancy of the identified risks. Chair Case suggested the OC meet by conference call in May to discuss RISC’s preliminary results prior to the Summit.

Development Status of Situation Awareness Reliability Guideline
Lauri Jones, chair of a task team to develop a reliability guideline that addresses system operator situation awareness, reported that the team is actively addressing this OC assignment. She expects to present a draft of the reliability guideline to the OC at its June 2016 meeting.

Functional Model Advisory Group (FMAG)
Jerry Rust, co-chair of the FMAG, noted that the purpose of the Functional Model (FM) is to provide a framework for the development of reliability standards and to describe each function and relationships between entities responsible for performing tasks required for each function (Presentation 7.q). The purpose of the FMWG is to maintain the FM to ensure it correctly reflects the industry and to evaluate and incorporate new and emergent reliability-related tasks. The FMWG reports to the Standards Committee and advises and consults with the Planning, the Operating and the Critical Infrastructure Protection Committees. The FMWG Project for 2016 will review recent NERC initiatives (e.g. Risk-Based Registration initiative) and standard development projects to identify any changes or updates to the FM language. Mr. Rust also reviewed the 2016 FMWG Project timeline, which indicates that proposed revisions to the FM would be presented to the OC at its June 2016 meeting.

Performance Analysis Subcommittee (PAS) Status Report
PAS Chair Melinda Montgomery briefed the OC on recent PAS activities (Presentation 7.b), which included a review of the timeline for the development of the 2016 State of Reliability Report. The timeline calls for the OC to meet by conference call on May 3, 2016 to review and accept the 2016 SOR report. Ms. Montgomery also asked the OC to identify members to review and comment on the draft SOR report. OC volunteers to review the draft SOR report are Doug Peterchuck, Stuart Goza, Tom Leeming, John Stephens, David Souder, Rocky Williamson, and Chair Case.

Essential Reliability Services Working Group (ERSWG)
Todd Lucas reported that the ERSTF Framework report and the ERSTF Abstract report was accepted by the NERC Board of Trustees on December 7, 2015 (Presentation 7.a). The Framework Report presents three broad areas for further analysis: Frequency Response, Voltage Support and System Modelling. In addition, NERC developed three ERS Videos that address load ramping, voltage, and frequency. The videos are posted at ERS Videos. The NERC Board also endorsed the concept of transitioning the ERSTF to the ERS Working Group. A Distributed Energy Resources Task Force (DERTF), chaired by Rich Hydzik, will report to the ERSWG. Members of the DERTF have also been involved with the IEEE 1547 project described above. The 2016 Deliverables for the ERSWG include 1) a whitepaper on the methodology for the ERS Measures Sufficiency Guidelines and the final DERTF report.
Following a brief discussion, Stuart Goza moved to approve the ERSWG scope, the DERTF scope, and the ERSWG Work Plan. The committee approved the motion. Chair Case asked that the future status reports of the ERSWG and the DERTF be added to the “Subcommittees” section of the OC agenda.

**OC and Subcommittee Work Plans**

Chair Case reviewed the 2016 Operating Committee Work Plan and the Work Plans of its Subcommittees. Following a review of the work plans, Chair Case tasked Keith Carman, Lloyd Linke, Jerry Rust, and Todd Lucas with reviewing and updating the OC strategic plan. Chair Case asked Mr. Rust to lead this effort and he further asked that a revision to the existing strategic plan be available for OC review at the September 2016 OC meeting.

**NERC Action Plan to Address Frequency Response and FERC Notice of Inquiry (Primary Frequency Response)**

Dr. James Merlo, Senior Director, Reliability Risk Management, provided an overview of *NERC’s Alignment of Efforts to Maintain Adequate Frequency Response* (*Presentation 7.f*). Upcoming advancements include the FERC Notice of Inquiry on Primary Frequency Response, the monitoring of the four ERS frequency response measures, NERC assessment on variable energy resources in the Eastern Interconnection and the ERSWG development of sufficiency guidelines. Dr. Merlo noted that the NERC frequency response initiative consists of many moving parts in various states of completeness. The moving parts or internal programs include:

1. Frequency Response Annual Analysis
2. Regulatory Actions (e.g. an Industry Stakeholder group is developing comments on the FERC NOI)
3. NERC issued an Advisory Alert on governor response in January 2015
4. Implementation of BAL-003-1 continues to be a work in progress. The BA Submittal Site (BASS) has been set up for BAs to submit their data.
5. New measures to be included and considered for the 2016 State of Reliability report
6. The Long-Term Reliability Assessment indicates an upward trend in asynchronous resources and retirements of conventional generation, potentially decreasing the overall system inertia and frequency response capability
7. The ERSWG has four measures relative to frequency for balancing authorities and Interconnections
8. The Resources Subcommittee and the Operating Committee developed a guideline for generator owners on governor response and DCS control strategies for thermal plants

Dr. Merlo noted that FERC NOI on Primary Frequency Response seeks input on whether and what action is needed 1) to amend the *pro forma* Large and Small Generator Interconnection Agreements to require that each generating unit operate with the governor in service and responsive to frequency when the unit is on line, 2) to assess the performance of existing resources to determine whether to impose primary frequency
response requirements on existing resources and 3) to determine the requirements related to procuring and compensating primary frequency response. He also noted that with a rapidly changing resources mix, ensuring adequate frequency support is a risk to BPS reliability. Finally, he suggested that the OC and its Resources Subcommittee modify the Reliability Guideline: Primary Frequency Control to include asynchronous resources.

Adjourn and Reconvene
The committee adjourned at 4:26 p.m. EST and reconvened the following morning at 8:02 a.m. EST.

Reliability Assessment Subcommittee (RAS)
Amir Najafzadeh, Engineer II, provided an overview of RAS activities (Presentation 5.e). Mr. Najafzadeh specifically addressed the OC’s response to recommendations from NERC’s 2015 Long-Term Reliability Assessment. The recommendations identified by the OC task team included:

1. Need to better account for Distributed Energy Resources
2. Need to better evaluate impacts of storage: The Resources Subcommittee to develop a report for consideration of application of real power energy storage
3. Need to better assess fuel, operations and other risks: Operating Reliability Subcommittee to develop a reliability guideline for managing increased dependency on natural gas
4. Need for consistency between planning and operations for models: PC and OC should review existing guidelines and technical documents that address modeling and should revise as needed

In response to OC member questions, Mr. Najafzadeh stated that the RAS has decided to continue, for the time being, the development of the Summer and Winter Pre-Season Assessments, although the reports will be issued in a foreshortened format. The OC reiterated its desire to have adequate time to thoroughly review and comment on the list of potential special assessment topics. The first special assessment will address gas/electric dependency.

Archive the Interconnected Operations Services Reference Document
Chair Case noted that the OC approved the Interconnected Operations Services Reference Document in March 2002. The content of the reference document has been superseded by the work of the Integration of Variable Generation Task Force and the ERS Task Force. Following a brief discussion, Jerry Rust moved to archive the Interconnected Operations Services Reference Document, approved by the OC in March 2002. The committee approved the motion.

Archive the Available Transfer Capability Definitions and Determination Reference Document
Chair Case noted that the OC approved the Available Transfer Capability Definitions and Determination Reference Document in June 1996. The content of the reference document has been superseded by the development of the MOD reliability standards and FERC Orders. Following a brief discussion, Jerry Rust moved to archive the Available Transfer Capability Definitions and Determination Reference Document, approved by the OC in June 1996. The committee approved the motion.
Balancing Authority ACE Limit (BAAL) Compliance (CPS1, CPS2, and DCS) Reports
RS chair Troy Blalock noted that BAL-001-2 (Real Power Balancing Control Performance) becomes effective on July 1, 2016 and that Requirement R2 of the new reliability standard states: Each Balancing Authority shall operate such that its clock-minute average of Reporting ACE does not exceed its clock-minute Balancing Authority ACE Limit (BAAL) for more than 30 consecutive clock-minutes, calculated in accordance with Attachment 2, for the applicable Interconnection in which the Balancing Authority operates (Presentation 7.e). Furthermore, Measure M2 states: Each Balancing Authority shall provide evidence, upon request, such as dated calculation output from spreadsheets, system logs, software programs, or other evidence (either in hard copy or electronic format) to demonstrate compliance with Requirement R2.

Chair Blalock highlighted sections of the RS scope wherein it is stated that the functions of the RS include reviewing BA control performance (i.e. CPS and DCS) on a periodic basis and to address technical issues related to automatic generation control, time error correction, operating reserve and frequency response. He noted that the RS needs continued access to compliance data to fulfil the responsibilities outlined in its scope. It was noted that while the standard may not require the submission of data on a regular basis, a Section 1600 data request could be developed. However, the timeframe for developing and vetting a Section 1600 data request is fairly cumbersome. It was also noted that the Regional Entities could be asked to collect the requested data on a voluntary basis. Following further discussion, Chair Case tasked Chair Blalock with drafting a letter to the balancing authorities to request the needed data on a voluntary basis. Gerry Beckerle moved that Chair Case write a letter to the balancing authorities to submit BAL compliance data (e.g. CPS1, CPS2, DCS and BAAL) on a voluntary basis. The committee approved the motion.

Review of 2015 Long-Term Reliability Assessment to Identify Recommendations for Development of Operational Guidelines
At the December 2015 OC meeting, David Calderon, Engineer of Reliability Performance Analysis, briefed the committee on the recommendations identified in the 2015 Long-Term Reliability Assessment. Following that briefing, Chair Case tasked Sammy Roberts (chair), Leonard Kula and Kevin Conway with reviewing the 2015 LTRA to identify the need to develop potential operational guidelines. Sammy Roberts provided an overview of the task team’s recommendations, which were contained in a letter attached to the OC agenda packet (Presentation 7.h). The four recommendations the task team focused on were:

1. DER Planning, Forecasting, Visibility, Lessons Learned
2. Real Power Energy Storage Application
3. Managing Increased Dependency on Natural Gas – Fuel Planning, BA/TOP – Gas Pipeline Coordination, Contingency Planning
4. Dynamic and Static System Modeling Accuracy

The OC recommended the following assignments for each of the above identified recommendations:

1. Recommendation 1 be assigned to the DERTF
2. Recommendation 2 be assigned to the RS to write reliability guideline
3. Recommendation 3 be assigned to the ORS, although it was noted that will be a difficult assignment that has already been attempted by various entities

4. Recommendation 4 be assigned to the DERTF

**Retirement of BAL-004 (Time Error Correction)**

Terry Bilke briefed the OC on a *Recommended Procedural Approach for Time and Average Frequency Control upon Retirement of BAL-004* ([Presentation 7.k](#)). He stated that, while the industry overwhelmingly supported the retirement of BAL-004 as a reliability standard, the commenters were evenly split on whether the practice of time error correction (TEC) should continue in some other form. Mr. Bilke noted that TECs anchor average frequency at 60 Hz and they provide an early warning of a chronic or major error in a balancing authority’s ACE. The retirement of BAL-004 along with the retirement of its companion NAESB business practice will likely result in a drift in average frequency and time error. He recommended that the OC direct the RS to work with the ORS to add a simple manual TEC procedure in the NERC Operating Manual. He also asked the RS and ORS consider changes within the new procedure that could reduce the number and impact of TECs. Those changes include:

1. Widen the TEC window to +/- 30 seconds similar to Europe
2. Clock-day TECs with a smaller +/- 0.01 Hz offset similar to Europe
3. Evaluate implementing payback approach used in NERC prior to 2000 that helped manage inadvertent balances and also reduced the number of TECs

Jerry Rust commented that the RS could develop a guideline given the retirement of BAL-004, however, that guideline cannot be voluntary. Hence, a standard may be needed to make it a mandatory procedure. Robert Blohm suggested that the solution may be to create an inadvertent interchange payback procedure. Following further OC discussion, David Zwergel moved to task the RS and ORS to work together to develop a reliability guideline or procedure to implement when BAL-004 is retired. The committee approved the motion.

**Emergency Service Response – A Restoration Disaster**

Devan Hoke, SERC, provide a detailed Lessons Learned Case Study of the events which took place due to a lack of situational awareness and how a failure to properly troubleshoot led to a restoration disaster ([Presentation 7.n](#)). The objectives of Mr. Hoke’s presentation were to 1) describe the necessity of maintaining situational awareness, 2) list human error precursors that can set the stage for power outages, equipment damage or risk to human life, 3) give a real-life example of how yielding to time pressure and outside influences can lead to disaster and 4) discuss the importance of clear and accurate communication.

Following his opening remarks, Mr. Hoke provided a very detailed overview of the sequence of events which took place following the control center’s receipt of an alarm indicating a trip out of a high tension circuit switcher. In the end, a 20 MVA transformer failed catastrophically, and the burning oil was visible for miles. The first responder was not injured even though he was very near the transformer when it failed. The customer sustained an extended outage which cost approximately $500,000, while the replacement transformer cost approximately $250,000 to replace.
Lessons Learned include 1) incomplete communication, 2) failure to properly analyze situation, 3) available station prints and relay instructions were not utilized, 4) multiple players, 5) did not resolve conflict, 6) time pressure, 7) other possible cause of the outage were not considered, and 8) first responder was unfamiliar with the station.

Walkthrough of the OC Website
Sandy Shiflett provided a demonstration of navigating through the OC and its subcommittee websites. During her demonstration she received positive feedback where improvements could possibly be made. For example, it was suggested that the OC’s main web page be split into two sections with the upper section showing only active OC sub-groups (e.g. Operating Reliability Subcommittee), while the lower portion would show the inactive OC sub-groups (e.g. IDC Working Group and the Real-time Application of PMUs to Improve Reliability Task Force). It was also suggested that the June 2004 version of the Operating Manual be shown on the OC website.

North American Transmission Forum (NATF)
Kevin Berent, NATF, highlighted the programs and services currently being provided by NATF to its members (Presentation 7.p). Examples include: Reviews, Assistance and Training; Practices and Initiatives; and Knowledge Management. He noted that more than 5,000 subject matter experts participate in NATF working groups, committees and programs. The Forum, located at www.NATF.net, has a Public Documents section which contains resources and presentations for public use.

Project 2007-06.2 (Phase 2 of System Protection Coordination)
Darrel Richardson, Senior Standards Developer, provided an overview of Project 2007-06.2 (Presentation 7.o). Project 2007-06.2 is intended to address FERC directives and the requirements of PRC-001-1.1(iii). The drafting team is considering what belongs in PRC-001 and believes that some of the requirements are ambiguous and duplicative and are not measureable. The drafting team proposes the development of a new reliability standard, PER-006-1, which would be applicable to Generator Operators that have “plant personnel who are responsible for the real-time control of a generator and receive direction from the Generator Operator’s Reliability Coordinator, Balancing Authority, Transmission Operator, or centrally located dispatch center.” PER-006-1 is proposed to contain one requirement which states: Each Generator Operator shall provide training to plant personnel identified in Applicability Section 4.1.1.1 that are responsible for Real-time control of its generating Facility on the operational functionality of Protection Systems and Remedial Action Schemes that affect output of its generating Facility. Mr. Richardson stated that PER-006-1 would be posted for public comment in mid-March 2016. Also posted for public comment would be the revised definitions of Operational Planning Analysis and Real-time Assessment.

Next Meeting
The next meeting of the Operating Committee will be on June 7–8, 2016 in St. Louis, Missouri.
Adjourn
There being no further business before the Operating Committee, Chair Case adjourned the meeting on Wednesday, March 9, 2016 at 11:23 a.m. EST.

Larry Kezele
Larry Kezele
Secretary
Operating Committee Report

Action
Information

Operating Committee’s (OC) Major Accomplishments for 2016 (Year-to-date)

1. Reliability Guidelines – The OC is working to develop reliability guidelines addressing:
   a. Calculating and Using Reporting Area Control Error (ACE) in Tie Line Bias Control Program
   b. Inadvertent Interchange
   c. Situational Awareness
   d. Real Power Energy Storage Applications
   e. A revision to the Reliability Guideline: Primary Frequency Control to include asynchronous generation
   f. The retirement of BAL-004 (Time Error Correction)

2. OC Strategic Plan – At its March 2016 meeting, the OC formed a task team to review and revise its 2015-2019 Strategic Plan.

3. OC and Subcommittee Work Plans – The OC Executive Committee and the leadership of its subcommittees met in early February to draft the 2016 Work Plans. At the March 2016 OC meeting, the OC continued to review and refine these Work Plans.

4. Essential Reliability Services Working Group (ERSWG) – The OC reviewed and accepted the ERSWG scope, the Distributed Energy Resources Task Force scope, and the ERSWG work plan.

OC’s Major Initiatives for 2016

1. OC Strategic Plan – The OC will review and revise its 2015-2019 Strategic Plan.


3. Resources Subcommittee (RS) – The RS will review and revise several reliability guidelines, reference documents and training guides under its purview.


5. Essential Reliability Services Working Group (ERSWG) and the Distributed Energy Resources Task Force (DERTF) – The OC is providing leadership to the ERSWG and the DERTF. The DERTF expects to complete its report to the ERSWG and the OC by year end 2016. The ERSWG is studying the sufficiency of the proposed measures. The OC’s Resources Subcommittee will play a key role in the further development of the frequency response measures.
March 2016 Meeting Summary:
The following is a summary of the OC’s March 2016 meeting, which highlights the latest activities of the OC and its associated subcommittees in support of the NERC or OC mission and corporate goals. The March 2016 OC Meeting Minutes are posted on the NERC website.

1. Reliability Issues Steering Committee (RISC) – The RISC has not met since the OC’s December 2015 meeting. Peter Brandien, the incoming RISC chair, stated that the 2016 Reliability Leadership Summit is scheduled to be held in late June (Update: at the time of this report the Reliability Summit has been postponed until early 2017). The RISC will also be reviewing the list of 14 reliability risks and, by way of a survey, determining the continued relevancy of the identified risks. Chair Case suggested the OC meet by conference call in May to discuss RISC’s preliminary results prior to the Summit.

2. Functional Model Advisory Group (FMAG) – The purpose of the Functional Model (FM) is to provide a framework for the development of reliability standards and to describe each function and relationships between entities responsible for performing tasks required for each function. The purpose of the FMAG is to maintain the FM to ensure it correctly reflects the industry and to evaluate and incorporate new and emergent reliability-related tasks. The FMAG reports to the Standards Committee and advises and consults with the Planning, the Operating and the Critical Infrastructure Protection Committees. The FMAG Project for 2016 will review recent NERC initiatives (e.g., Risk-Based Registration initiative) and standard development projects to identify any changes or updates to the FM language. Proposed revisions to the FM would be presented to the OC at its June 2016 meeting.

3. NERC Action Plan to Address Frequency Response and FERC Notice of Inquiry (Primary Frequency Response) – Dr. James Merlo provided an overview of NERC’s Alignment of Efforts to Maintain Adequate Frequency Response. Upcoming advancements include the FERC Notice of Inquiry on Primary Frequency Response, the monitoring of the four ERS frequency response measures, NERC assessment on variable energy resources in the Eastern Interconnection and the ERSWG development of sufficiency guidelines. Dr. Merlo noted that the NERC frequency response initiative consists of many moving parts in various states of completeness. The moving parts or internal programs include:
   a. Frequency Response Annual Analysis
   b. Regulatory Actions (e.g., an Industry Stakeholder group is developing comments on the FERC NOI)
   c. NERC issued an Advisory Alert on governor response in January 2015
   d. Implementation of BAL-003-1 continues to be a work in progress. The BA Submittal Site (BASS) has been set up for BAs to submit their data
   e. New measures to be included and considered for the 2016 State of Reliability report
   f. The Long-Term Reliability Assessment indicates an upward trend in asynchronous resources and retirements of conventional generation, potentially decreasing the overall system inertia and frequency response capability
   g. The ERSWG has four measures relative to frequency for balancing authorities and Interconnections
   h. The RS and the OC developed a guideline for generator owners on governor response and DCS control strategies for thermal plants
Dr. Merlo noted that the FERC NOI on Primary Frequency Response seeks input on whether and what action is needed: i.) to amend the *pro forma* Large and Small Generator Interconnection Agreements to require that each generating unit operate with the governor in service and responsive to frequency when the unit is on line, ii.) to assess the performance of existing resources to determine whether to impose primary frequency response requirements on existing resources and iii.) to determine the requirements related to procuring and compensating primary frequency response. He also noted that with a rapidly changing resource mix, ensuring adequate frequency support is a risk to BPS reliability.

4. **Time Monitoring and Geomagnetic Disturbance Reference Documents** – The OC approved revisions to the *Time Monitoring Reference Document* and the *Geomagnetic Disturbance Reference Document* at its December 2015 meeting (see Current Reference Documents). The PJM Reliability Coordinator replaced the NYISO RC as the Eastern Interconnection Time Monitor on February 1, 2016. The PJM RC also became the Eastern Interconnection GMD Monitor on February 1, 2016.


6. **Retirement of BAL-004 (Time Error Correction)** – Terry Bilke briefed the OC on a *Recommended Procedural Approach for Time and Average Frequency Control upon Retirement of BAL-004*. He stated that, while the industry overwhelmingly supported the retirement of BAL-004 as a Reliability Standard, the commenters were evenly split on whether the practice of time error correction (TEC) should continue in some other form. Mr. Bilke noted that TECs anchor average frequency at 60 Hz and provide an early warning of a chronic or major error in a balancing authority’s ACE. The retirement of BAL-004 along with the retirement of its companion NAESB business practice will likely result in a drift in average frequency and time error. He recommended that the OC direct the RS to work with the Operating Reliability Subcommittee to add a simple manual TEC procedure in the NERC Operating Manual. He also asked the RS and ORS consider changes within the new procedure that could reduce the number and impact of TECs. Those changes include:

   a. Widen the TEC window to +/- 30 seconds similar to Europe
   b. Clock-day TECs with a smaller +/- 0.01 Hz offset similar to Europe
   c. Evaluate implementing payback approach used in NERC prior to 2000 that helped manage inadvertent balances and also reduced the number of TECs

Following Mr. Bilke’s presentation, the OC approved a motion to task the RS and ORS to work together to develop a reliability guideline or procedure to implement when BAL-004 is retired.

7. **Event Analysis Subcommittee Lessons Learned Presentation: Emergency Service Response – A Restoration Disaster** – Devan Hoke, SERC, provided a detailed Lessons Learned Case Study of the events which took place due to a lack of situational awareness and how a failure to properly troubleshoot led to a restoration disaster. The objectives of Mr. Hoke’s presentation were to 1) describe the necessity of maintaining situational awareness, 2) list human error precursors that can set the stage for power outages, equipment damage or
risk to human life, 3) give a real-life example of how yielding to time pressure and outside influences can lead to disaster and 4) discuss the importance of clear and accurate communication. Following his opening remarks, Mr. Hoke provided a very detailed overview of the sequence of events which took place following the control center’s receipt of an alarm indicating a trip out of a high tension circuit switcher. In the end, a 20 MVA transformer failed catastrophically. The first responder was not injured even though he was very near the transformer when it failed. The customer sustained an extended outage which cost approximately $500,000, while the replacement transformer cost approximately $250,000 to replace. Lessons Learned include 1) incomplete communication, 2) failure to properly analyze situation, 3) available station prints and relay instructions were not utilized, 4) multiple players, 5) did not resolve conflict, 6) time pressure, 7) other possible causes of the outage were not considered, and 8) first responder was unfamiliar with the station.
**December 2012 Meeting Action Items**

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<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>1212-21</td>
<td>BARC SDT (Jerry Rust and Gerry Beckerle)</td>
<td>BARC Final Report of Field Trial – lay out the analysis – lessons learned from field trial structure and testing</td>
<td>Dec 2013 Sept 2016</td>
<td>Need information from Drafting Team Facilitator. BARC SDT provided an overview of the field trial at the June 2014 and September 2014 meetings. SDT developed a Preliminary Report. Board approved BAL-001-2 and it was filed at FERC on 4/2/14. The OC expects the field trial to remain in place until its FERC approved compliance enforcement date, after which a final field trial report will be developed and presented to the OC. December 15 – BAL-001-2 becomes effective on July 1, 2016. SDT provided an overview of the Field Trial.</td>
<td>Final Report Due following the Enforcement Date. In Progress Action due in September 2016 to review report</td>
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<tr>
<td>OC meeting and item number</td>
<td>Assignment</td>
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<tr>
<td>1406-08</td>
<td>Resources Subcommittee</td>
<td>Establishment of a data repository by NERC for the generator survey data</td>
<td>September Meeting</td>
<td>NERC staff to address. December 2014 – No progress to date. March 2015 – No progress to date. June 2015 – No progress to date. September 2015 – The Balancing Authority Submittal Site is being tested by the Resource Subcommittee. December 2015 – Generator survey data to be stored in a Modelling Database. March 2015 – This topic held over to the June 2016 OC meeting.</td>
<td>In Progress James to provide status at March OC Meeting. James to provide status at the June OC meeting.</td>
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**September 2015 Meeting Action Items**

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<tr>
<th>OC meeting and item number</th>
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<th>Status</th>
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<tbody>
<tr>
<td>1509-01</td>
<td>Lauri Jones with input from the ORS and EAS</td>
<td>Develop a strawman guidance document for discussion at the December 2015 OC meeting.</td>
<td>December 2015</td>
<td>September 2015 – Appointed a task group of Lauri Jones and representatives of the ORS and the EAS to develop a strawman guidance document for discussion at the December 2015 OC meeting reference the definition and understanding of SA in relation to system operators. December 2015 – The OC further discussed the scope of this project during its review of the PS status report and as part of the OC Work Plan Brainstorming Exercise.</td>
<td>In Progress Short update in the March meeting 2016 Place on June OC meeting agenda</td>
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March 2016 – Lauri Jones provided a brief status report. She expects to complete the Reliability Guideline: Situation Awareness for discussion at the June 2016 OC meeting.

### December 2015 Meeting Action Items

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<thead>
<tr>
<th>OC meeting and item number</th>
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<th>Due Date</th>
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<th>Status</th>
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</table>
| 1512-01                    | James Merlo| NERC to develop a plan to address existing generation fleet and FERC LGIA and SGIA. | March 2016  
April 2016 | March 2016 – This topic will be addressed in NERC’s comments to the FERC NOI on Primary Frequency Response.  
NERC Comments filed at FERC on April 25, 2016. | In Progress |
| 1512-02                    | James Merlo| NERC to develop a plan to gather the data to support the frequency measures identified in the ERSTF Framework Report. | March 2016  
December 2016 | OC will need to assign specific guidance for RS to plan the ERS work in 2016.  
March 2016 – The newly formed ERS Working Group is developing “sufficiency” measures for the four frequency measure. | In Progress |
| 1512-03                    | Chair Case | Assign OC reviewers of the 2016 State of Reliability Report. | March 2016 | December 2015 – Assign volunteers to review. In April OC will conduct a conference call and WebEx to review and accept.  
March 2016 – Volunteers to review the draft 2106 SOR Report include: Doug Peterchuck, Stuart Goza, Tom Leeming, John Stephens, David Souder, Rocky Williamson, and Chair Case. The OC will vote by email ballot by COB on May 3 to accept the 2016 SOR report. | Complete |
<p>| 1512-04                    | Project 2010-14.2.1 STD and RS | Develop an Inadvertent Interchange Guideline. | September 2016 | BAL-006 requirement goes away and what is the replacement to gather data? Jerry Rust update in March meeting. | In Progress |</p>
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<tr>
<td>1603-01</td>
<td>Chair Case</td>
<td>OC to meeting by conference call in May to discuss RISC going forward</td>
<td>June 2016</td>
<td>Vice Chair to meet with RISC on April 22 to further define this activity.</td>
<td>In Progress</td>
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<td>OC to provide review of the 14 identified risks with comments and relative priorities.</td>
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<tr>
<td>1603-02</td>
<td>Chair Case</td>
<td>Entergy to provide an overview of its operation with two primary transmission control centers</td>
<td>December 2016</td>
<td></td>
<td>In Progress</td>
</tr>
<tr>
<td>1603-03</td>
<td>Jerry Rust and Lacey Ourso</td>
<td>Develop proposed revisions to the Functional Model for OC acceptance</td>
<td>June 2016</td>
<td>March 2016 – The Functional Model Working Group is working on a project to identify required revisions to the Functional Model. The expectation is that the FMAG will present a FM revision to the OC at its June 2016 meeting.</td>
<td>In Progress</td>
</tr>
<tr>
<td>1603-04</td>
<td>Larry Kezele</td>
<td>Add ERSWG and DERTF status reports to the “Subcommittee” section of future OC agendas.</td>
<td>On-going</td>
<td></td>
<td>In Progress</td>
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**March 2016 Meeting Action Items**

**OC meeting and item number** | **Assignment** | **Description**                                                                 | **Due Date**       | **Progress**                                                                 | **Status**       |
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<tbody>
<tr>
<td>1512-05</td>
<td>Project 2010-14.2.1 STD and RS</td>
<td>Develop a Reporting ACE Guideline.</td>
<td>September 2016</td>
<td>Jerry Rust update please.</td>
<td>In Progress</td>
</tr>
<tr>
<td>1512-09</td>
<td>RAS</td>
<td>Coordination with Reliability Assessment Subcommittee on the development of Topic-Based Reliability Assessments. Include RAS Status Report on quarterly OC agendas.</td>
<td>March 2016</td>
<td>Have an RAS update quarterly to review lists of current RA topics.</td>
<td>In Progress</td>
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**NERC Operating Committee Action Items**

**Page 4 of 6**
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<tr>
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<tbody>
<tr>
<td>1603-05</td>
<td>Keith Carman, Lloyd Linke, Jerry Rust (chair) and Todd Lucas</td>
<td>Review and update the OC strategic plan</td>
<td>September 2016</td>
<td>In Progress</td>
</tr>
<tr>
<td>1603-06</td>
<td>Resources Subcommittee</td>
<td>Modify the Reliability Guideline: Primary Frequency Control to address asynchronous resources</td>
<td>December 2016</td>
<td>In Progress</td>
</tr>
<tr>
<td>1603-07</td>
<td>Resources Subcommittee and Operating Reliability Subcommittee</td>
<td>Develop a reliability guideline or procedure to implement when BAL-004 is retired.</td>
<td>December 2016</td>
<td>In Progress</td>
</tr>
<tr>
<td>1603-08</td>
<td>Resources Subcommittee</td>
<td>Draft a letter, for Chair Case’s signature, to balancing authorities to submit BAL compliance data (e.g. CPS1, CPS2, DCS and BAAL) on a voluntary basis.</td>
<td>June 2016</td>
<td>In Progress</td>
</tr>
<tr>
<td>1603-10</td>
<td>Larry Kezele</td>
<td>Post the Operating Manual dated June 15, 2004 to the OC website.</td>
<td>June 2016</td>
<td>In Progress</td>
</tr>
<tr>
<td>1603-11</td>
<td>RS</td>
<td>2015 LTRA OC Task Team Recommendation 2 (Real Power Energy Storage Application) – The RS to draft a reliability guideline addressing this recommendation</td>
<td>December 2016</td>
<td>In Progress</td>
</tr>
<tr>
<td>1603-12</td>
<td>ORS</td>
<td>2015 LTRA Task Team Recommendation 3 (Managing Increased Dependency on Natural Gas – Fuel Planning, BA/TOP – Gas Pipeline Coordination, Contingency Planning).</td>
<td>December 2016</td>
<td>In Progress</td>
</tr>
<tr>
<td>Action Item</td>
<td>Responsible Party</td>
<td>Description</td>
<td>Due Date</td>
<td>Status</td>
</tr>
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<tr>
<td>1603-13</td>
<td>DERTF</td>
<td>2015 LTRA Task Team Recommendation 1 (DER Planning, Forecasting, Visibility, Lessons Learned) and Recommendation 4 (Dynamic and Static System Modelling Accuracy).</td>
<td>December 2016</td>
<td>In Progress</td>
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<tr>
<td>1603-14</td>
<td>OC Leadership</td>
<td>Mid-year check of the status of the OC and Subcommittee Work Plan efforts</td>
<td>September 2016</td>
<td>In Progress</td>
</tr>
</tbody>
</table>
NERC Operating Committee
Sub-group Status Report

Group: Operating Reliability Subcommittee

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.

Last Meeting: May 3-4, 2016  Location: Atlanta, GA (NERC)
Duration: 1 Day

Next Meeting: Sept. 7-8, 2016  Location: Montreal, PQ, Canada
Duration: 1 Day

Chair: Eric Senkowicz – FRCC RC
Vice-Chair: Dave Devereaux – IESO

2016 Initiatives/ Deliverables:
GOAL: We are focusing on regular review, update, and communication of Guidance Documents and Reference Guides within our area of responsibility. We also continue to prepare for implementation of the PFV field trial.

Pending OC Approval Items:
• Archive the *NERC Backup Control Center (Approved July 1993)*” document

ORS recommends the OC archive the *NERC Backup Control Center (Approved July 1993)* Document. ORS feels that, since 1993, business continuity has taken a much more prominent place in daily operations and justification of a backup control center is no longer an issue for registered entities. Further, the task team believes that the current standard EOP-008 (Loss of Control Center Functionality) adequately covers the appropriate requirements.

• Recommend approval of PJM Reliability Plan (assuming ORS Exec approval).
Key issues for OC Resolution:

- Future of Reliability Plans with transition to new IRO /TOP standards in 2017. With no standards requirement what value does OC see in ORS and OC awareness of Regional Reliability Plans

- ORS is reviewing the issue of distributed generation and its role and impact on entity system restoration plans. ORS is seeking input from the OC to ensure the issue is coordinated with the ERSWG and what the role of ORS should be

Key Issues for OC Information:

- ORS has been working with the IDC Tools Association (IDC Tools Association dissolved as of April 1, 2016, with functions moved to the EIDSN Steering Committee) to develop metrics that test the effectiveness of the Parallel Flow Visualization (PFV) project so that they can be incorporated into the field trial of the project. The PFV Project is intended to improve the data quality used by the IDC during curtailment of transactions and may eventually result in changes to both NERC Reliability Standards and NAESB Business Practices. ORS has directed the IDC Working Group to proceed with a change order incorporating the agreed to metrics. ORS continues to receive updates from the EIDSN Steering Committee regarding the PFV field trial.

- At the last OC meeting, ORS reported an approved exception to IDC practices for the transaction known as the Manitoba Hydro Energy Board Export External Asynchronous Resource (EAR). The impacts of the Export EAR can be accounted for in MISO market flow and in lieu of an e-Tag until June 2017. By that date, ORS has requested that MISO provide a software solution that ensures tag priority is maintained during the conversion to market flow. ORS continues to work on the issue of tag exceptions. The group will develop a proposed ORS guideline to ensure a consistent approach is applied for any future exception requests.

- NERC ORS members continue to work with the PS on developing a Situation Awareness guideline/ definition / reference document. The current draft includes “operational aspects” and is supported by ORS.

Current Initiatives/ Deliverables:

- 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. This project has become an ORS priority, with expected completion by year-end 2016.
• Determine the need for the DEWG and TWG under NERC ORS.
• ORS has reviewed and discussed the 2017 OC work plan and will be working items in the plan as prioritized by the OC
• ORS is reviewing the *Electric system restoration reference* document and plans to bring the OC a recommendation on the document in September.
• ORS has established a sub-team to look at developing a Gas/ Electric coordination guideline as requested by the OC – content and scope is TBD. ORS plans to bring a strawman outline to the OC in September or November
• NERC ORS RC representatives have volunteered to work with NERC’s E-ISAC group on the planning activities for GridEx 4 to be held in 2017.

### 2016 ORS Work Plan:

<table>
<thead>
<tr>
<th>Description</th>
<th>Status</th>
<th>Due</th>
</tr>
</thead>
<tbody>
<tr>
<td>Develop metrics for PFV field trial</td>
<td>In Progress</td>
<td>Q3 2016</td>
</tr>
<tr>
<td>Review “NERC Backup Control Center (Approved July 1993)” document and determine next steps (retire/ archive/ reduce and retain as guideline)</td>
<td>In Progress</td>
<td>Q4 2016</td>
</tr>
<tr>
<td>Review “Electric system restoration reference document” document and determine next steps (retire/ archive/ reduce and retain as guideline)</td>
<td>In Progress</td>
<td>Q4 2016</td>
</tr>
<tr>
<td>Support the development of the PS/EAS Situation Awareness Guideline</td>
<td>In Progress</td>
<td>?</td>
</tr>
<tr>
<td>Continue development of Net Actual / Net Scheduled Interchange Tool</td>
<td>In Progress</td>
<td>Q4 2016</td>
</tr>
<tr>
<td>Determine the need to have the NERC TWG and DEWG and recommend to the OC in Q2 2016</td>
<td>In Progress</td>
<td>Q4 2016</td>
</tr>
<tr>
<td>Develop the scope for a guideline for managing increased dependency on natural gas. Should we offer our vision of a straw man?</td>
<td>Discussion in progress</td>
<td>?</td>
</tr>
<tr>
<td>Agenda Item 5.a</td>
<td>OC Meeting</td>
<td>June 7-8, 2016</td>
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<tr>
<td>Update Time Monitor</td>
<td>Reference Guide</td>
<td>Completed 12/15</td>
</tr>
<tr>
<td>Request OC approval</td>
<td>of Time Monitor for</td>
<td>Completed 12/15</td>
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<tr>
<td>2017</td>
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<tr>
<td>Request OC approval</td>
<td>of Loss of Real-time</td>
<td>Completed 12/15</td>
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<td>Reliability Tools</td>
<td>Capability/Loss of Equipment</td>
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<td>Significantly Affecting ICCP</td>
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<td>Data Reliability Guideline</td>
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<td>Transition initiation</td>
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<td>GMD notifications</td>
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<td>Transition Time</td>
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<td>Complete -</td>
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<td>Frequency Monitor</td>
<td>Reporting</td>
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<tr>
<td>GridEx III Aftter Action</td>
<td>Report</td>
<td>Follow-on Work</td>
</tr>
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</table>

**Recurring Deliverables of Group**
- 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.
- Review the use of Proxy Flowgates.
- Review TLR 5 events as requested.
- Review of EEA events.
- Develop comments on Adequate Level of Reliability metrics.
- Provide coordination between the IDC Association and the Operating Committee.

**NERC Program’s Oversight Responsibility for the Group**
- Provide oversight of information technology tools and services that facilitate operational reliability coordination.
- Provide oversight and guidance on aspects of Interchange Scheduling, including Dynamic Transfers, as it applies to impacts on reliable operations.

**NERC Document (Non-Reliability Standard) Responsibility for the Group**
- Guideline for Approving Regional and Reliability Coordinator Reliability Plans
- Time Monitoring Reference Document
- GMD Reference Document
NERC Operating Committee
Sub-group Status Report

Group: Resources Subcommittee

Purpose: Status Update

Last Meeting: April 20-21, 2016  Location: Austin, TX
Duration: 1½ days

Next Meeting: July 27-28, 2016  Location: San Francisco, CA
Duration: 1½ days

Chair: Troy Blalock, SCE&G  Vice-Chair: John Tolo, Tucson Electric

Pending OC Approval Items:
- Dynamic Transfer Reference Document
- Time Monitoring Reference Document

Key issues for OC Resolution:
- None

Key Issues for OC Information
- The RS approved a Resolution of Appreciation for Sydney Niemeyer, a member of the NERC RS since 2004. The RS thanked him for his representation of ERCOT, support and development of NERC Standard BAL-003-1 and tireless effort to support those trying to improve governor response. Sydney is retiring from NRG after 44 years in our industry.
- The RS Frequency Working Group selected M-4 (formerly ALR1-12) and BAL-003-1 frequency events for January, February and March for the Eastern, ERCOT and Quebec Interconnections and for January and February 2016 for the Western Interconnection. The selected events and forms are posted on the BASS site. Tony Nguyen with BC Hydro is the new FWG Chair. The FWG will be supporting NERC in conducting industry training seminars for FRS Forms 1 and Forms 2.
- The RS sent out a Survey on May 12, 2016 to the Eastern Interconnection BA’s. In order to achieve Interconnection net zero inadvertent balance, the Resources Subcommittee is asking BAs if they would like to participate in an inadvertent true-up. The true-up will consist of allocating Inadvertent amongst the participating BAs in the opposite direction of the above balances. The unaccounted for inadvertent balances will be spread among the interested BAs based on their individual biases.
- The RS Reserve Working Group did not meet during the past subcommittee meeting.
• The RS is reviewed guidelines and provided “draft” comments presented by the Chair of the Standard Drafting BAL-005 and BAL-006 related to Inadvertent Interchange and ACE. Conference calls are being set up to discuss between members of the RS and Drafting Team.
• The RS is working with NERC staff and DERTF/ERSWG to work with industry to collect data relative to Measures 1-3.
• The RS sent out a letter 5/20/2016 under the NERC OC Chair on maintaining submittals of CPS1 and BAAL data to continue to allow the RS to monitor the performance of the Interconnections and implementation of BAL-001-2. The data is planned to be submitted on the NERC SharePoint BASS site.
• Bob Cummings reported the Reliability Guideline: Primary Frequency Control should be amended to include sections addressing asynchronous resources such as battery storage, roof-top solar, and wind powered generation. He anticipates developing a revised guideline for RS consideration in July 2016.
• The RS discussed and, by email ballot, approved the Time Monitoring Reference Document with one dissenting vote. Terry Bilke, MISO, also worked with Chair of the BAL-004 drafting team, David Lemmons, NERC ORS and NERC legal. The NERC RS submits the revised reference document to the OC for final approval.
• The RS discussed and provided comments to NERC in regards to the FERC Notice of Inquiry: Essential Reliability Services and the Evolving Bulk-Power System – Primary Frequency Response.
• The RS reviewed the Dynamic Transfer Reference Guideline and voted to approve the document and to recommend NERC OC approval.
• The RS reviewed and discussed the ACE Diversity Interchange Guideline. The RS still continues to provide revisions to the document.
• The RS has been challenged in the two past meetings by the lack of Interconnection Performance data due to the fact of NERC termination of contract with CERTS with the anticipation of NERC staff picking up this work. To date this has not occurred.
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 7, 2016  **Location:** Louisville, KY
**Duration:** 1 Day

**Next Meeting:** June 6, 2016  **Location:** St. Louis, MO
**Duration:** 1 Day

**Bi-Weekly Conference Calls on Wednesdays from 1100 to 1200 (EDT)**

**Chair:** Hassan Hamdar – FRCC

**Vice-Chair:** Rich Hydzik – Avista Corporation

**Pending OC Approval Items:**
- None at this time

**Key issues for OC Resolution:**
- None at this time

**Key Issues for OC Information:**
- Lessons learned summary of additions since last OC meeting.
- 4th Annual Monitoring and Situational Awareness Technical Conference is tentatively planned for September 20th & 21st.

**Current Initiatives/ Deliverables:**
- EAS is conducting outreach to drive lessons learned submittals through not only the ERO EA Process but through other occurrences or near occurrences experienced by entities.
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:

- Collaboration meetings with North American Transmission Forum and is being discussed.
- Collaboration with North American Generator Forum has begun with a review of four lessons learned and brainstorming on how collaboration may best serve both parties.
- The EAS is coordinating with the Personnel Subcommittee (PS).
  - Liaisons have been established between the two sub-committees
  - Leadership calls are set up prior to OC meetings
  - EAS has many representatives on the Situation Awareness Task Force (SATF) that is being led by the PS Chair
- Participation on Essential Reliability Services Working Group (ERSWG) as directed by the OC.
  - EAS has two representatives on the ERSWG
  - 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
NERC Operating Committee
Sub-group Status Report

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

Last Meeting: February 9-10, 2016
Next Meeting: June 7-9, 2016
Location: Sarasota, FL (Joint PCGC)
Location: St. Louis, MO

Chair: Lauri Jones
Vice-Chair: Rocky Williamson

Pending OC Approval Items: None
Key Issues for OC Resolution: None
Key Issues for OC Information: None

Current Initiatives / Deliverables

- Program criteria re-evaluation and solicitation of industry input for next version of the manual.

Continuing Education Program Statistics

<table>
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<tr>
<th></th>
<th>1Q</th>
<th>2Q</th>
<th>3Q</th>
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<tr>
<td>Courses Approved</td>
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<td>Active Provider Accounts</td>
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<tr>
<td>System Operator Renewals</td>
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PS Work Plan

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<tr>
<th>Description</th>
<th>Status</th>
<th>Due</th>
</tr>
</thead>
<tbody>
<tr>
<td>Develop a PS Action Plan in alignment with the OC Strategic Plan</td>
<td>Complete</td>
<td></td>
</tr>
<tr>
<td>Roll out of the CE Program Manual, v. 4.3</td>
<td>Complete</td>
<td>Q1 2015</td>
</tr>
<tr>
<td>Draft revision CE Program Manual, v. 4.4 Update in December including draft</td>
<td>In Progress</td>
<td>Q2 2017</td>
</tr>
<tr>
<td>manual out for comment.</td>
<td></td>
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<tr>
<td>Support testing and implementation of the updated SOCCED provider interface</td>
<td>In Progress</td>
<td>Q3 2016</td>
</tr>
<tr>
<td>Implement a multi-reviewer process for questionable course submissions.</td>
<td>In Progress</td>
<td>Q2 2017</td>
</tr>
<tr>
<td>Target a reduction in course submission errors and support best practices</td>
<td>On going</td>
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<tr>
<td>instructional methods</td>
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<tr>
<td>Work with EAS and ORS to develop a draft situational awareness guideline for</td>
<td>In Progress</td>
<td>Q2 2017</td>
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<tr>
<td>System Operators</td>
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</tr>
<tr>
<td>Recruiting new members for the CERP</td>
<td>On going</td>
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</table>

External Requests to Group:
Recruiring Deliverables of Group
- The review and approval of Continuing Education courses.
- The review and approval of NERC Approved Continuing Education Providers.
- Audits of Continuing Education courses.
- Stay abreast of industry initiatives regarding training programs.

NERC Program's Oversight Responsibility for the Group
- Oversight of the Continuing Education Program

NERC Document (Non-Reliability Standard) Responsibility for the Group
- Quarterly CE Program Report to PCGC and OC
- CE Program Administrative Manual
- Guide to Writing Learning Objectives
- Provider Application and Renewal User Guide
- Provider SOCCED Course Generation and Renewal User Guide
- Provider User Guide for Completing an ILA Form
Reliability Guideline
Situational Awareness for the System Operator

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; the Operating Committee (OC), the 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 and Security Guidelines. Guidelines establish voluntary codes of practice for consideration and use by BES users, owners, and operators. They are developed by technical committees and include the collective experience, expertise and judgment of the industry. 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 and use of guideline practices is strictly voluntary, the review, revision, and development of a program using these practices is highly encouraged to promote and achieve the highest levels of reliability for the BES.

Purpose
The objective of this reliability guideline is to provide information on Situational Awareness (SA) and its applicability to real-time operation of the electric industry.
System Operators must be on the same page when operating the BES. The following questions may be asked:
- What is the current status of the system?
- What has been done so far?
- What are they doing now?
- How will that affect my tasks?
- How does what I’m doing affect them?
- What will they do next?

Organizations that have a process in place for assessing and increasing the effectiveness of the situation awareness of their operators (whatever their function) will likely provide their operators the best information and therefore improve their ability to make better informed decisions.

This Reliability Guideline provides a global recognition of the importance for the System Operator to maintain situational awareness while operating the Bulk Electric System reliably. It is meant to assist TOP, BA, RC, GOP or other operating entities to use as they deem appropriate with the primary goal of supporting BES reliability.
Situational Awareness

The BES operates in a dynamic environment and its physical properties are constantly changing. Therefore, situational awareness is a necessity to maintain reliability, anticipate events and properly respond when or before they occur. The guideline approaches situational awareness in three levels: perception, comprehension and projection.


Theory

Perception

Level 1 Perception

The system operator needs to accurately perceive relevant information about the BES (e.g. procedures, resources, clearances, alarms, and tool status) as well as weather, emergency information, and other pertinent elements.

Comprehension

Level 2 - Comprehension

Comprehension of the situation is based on a synthesis of perceived information. Comprehension goes beyond simply perceiving information that is presented to include an understanding of the significance of those elements Endsley M.R. (1995) Toward a Theory of Situational Awareness in Dynamics Systems. Human Factors 37 (1), p.37

Projection

Level 3 - Projection

Projection is the ability to anticipate the future conditions, based on the perception and comprehension of information at least in the near term in order to make informed decisions.

Together the 3 levels of SA help operators understand the current state of their environment and adapt their behavior as necessary to make effective and efficient decisions (see graphic). In the best of situations the follow occurs:

1. The condition is quickly identified
2. The impact to operations is understood
3. Relevant data to address the issue is easily available and thoroughly reviewed
4. Corrective action recommendations take into account possible negative impacts to the BES
5. Corrective action can be implemented quickly with available resources.
6. Information is captured and used to mitigate potential future problems.


**BES System Operator roles:**

To maintain reliability of the BES the following support functions are examples of key roles impacting situational awareness of personnel performing real-time operations functions; (i.e. Training; IT/EMS; Real-time Operations Engineering; SCADA; Operations Management; Transmission Planning). The intent of this guideline only addresses the SA of the personnel performing real time functions and assumes that the support functions above are available.

The high level SA descriptions below, outlined by functional entity, provide industry examples, but are not all-inclusive of real time applications of SA.
Reliability Coordinator

To maintain adequate situational awareness a Reliability Coordinator operator at the console should be able to:

- Monitor the current frequency within the RC’s Area
- Monitor the current status and capabilities (online, offline, output and dispatch availability) of the generators within the RC’s Area.
- Monitor the availability of generating operating reserves in real time
- Monitoring resources (Generator Operators and Load-Serving Entities) and developing plans to take action to ensure balance in real time up to and including directing the shedding of load to maintain balance of generation to load within the RC Area
- Coordinate a generation dispatch plan for the RC Area to meet forecasted load for the next 24 hours including any generating operating reserve requirements
- Re-assess generation dispatch plans within the RC Area based on the loss of generating resources in real-time
- Monitor the current status (open or closed) and real and reactive power flows on the BES tie-lines and facilities within the RC’s Area
- Monitor the current voltage profile across the RC’s Area.
- Monitor and adjust interchange in accordance with the applicable congestion management processes.
- Monitor and direct actions as necessary so that instability, uncontrolled separation, or cascading outages will not occur as a result of the most severe single contingency or specifically identified multiple outages within the RC’s Area.
- Coordinate with the neighboring RC(s) so that instability, uncontrolled separation, or cascading outages will not occur as a result of the most severe single contingency or specifically identified multiple outages.
- Identify any actual or potential BES facility overloads within the RC’s Area
- Develop, coordinate, monitor and maintain a transmission facility outage plan and coordinated generation dispatch plan that supports reliable operation of the TOPs and BAs within the RC’s Area for the next 24 hours
- Adjust planned transmission facility outages across the RC Area plan based on current transmission system conditions and any unplanned element losses (generation or transmission) that could affect the reliability of the current plan
- Assess and be prepared to implement as required, the RCs mitigation strategies for unplanned events ranging from voltage coordination to full transmission system restoration.
- Monitor weather forecasts and identify potential impacts to RC Area reliability for the next 24 hours
- Maintain effective and routine communications with its BAs, TOPs and neighboring RC(s). Distribute Interconnection wide information as necessary to preserve BES reliability (ie. GMD, cyber and physical attacks)
- Monitor current and forecasted generation levels compared to loads and declare Energy Emergencies Alerts if load cannot be served
Balancing Authority
To maintain adequate situational awareness a Balancing Authority operator at the console should be able to:

- Monitor the current status (open or closed) and real and reactive power flows on the BES tie-lines of the BA’s Area including interchange power transfers with other BAs
- Monitor the current frequency within the BA’s Area
- Monitor the current status and capabilities (online, offline, output and dispatch availability) of the generators within the BA’s Area.
- Monitor the availability of generating operating reserves in real time
- Monitoring resources (Generator Operators and Load-Serving Entities) and developing plans to take action to ensure balance in real time up to and including the shedding of load to maintain balance of generation to load within the BA Area
- Maintain a generation dispatch plan to serve forecasted load for the next 24 hours including regulating reserves and any generating operating reserve requirements
- Maintain a dispatch plan that includes the capability to mitigate the loss of the BAs largest generating resource
- Understand generation limitations due to transmission system configurations, maintenance outages or unplanned line outages
- Monitor weather forecasts and identify potential impacts to generation dispatch plan for the next 24 hours
- Adjust generation dispatch plan based on current generation dispatch plan or loss of generating resources in real-time
- Monitor current and forecasted generation levels compared to loads and declare Energy Emergencies Alerts if load cannot be served
Transmission Operator

To maintain adequate situational awareness a Transmission Operator system operator, at the console, should be able to:

- Monitor the current status (open or closed) and real and reactive power flows on the BES tie-lines and facilities within the TOP’s Area
- Monitor and adjust the current voltage profile across the TOP’s Area using available BES reactive resources
- Monitor and adjust interchange in accordance with the applicable congestion management processes.
- Monitor and adjust the TOP’s interconnected facilities so that instability, uncontrolled separation, or cascading outages will not occur as a result of the most severe single contingency or specifically identified multiple outages.
- Coordinate with the TOP’s RC and neighboring TOPs so that instability, uncontrolled separation, or cascading outages will not occur as a result of the most severe single contingency or specifically identified multiple outages.
- Identify any actual or potential BES facility overloads within the TOP’s Area
- Monitor and maintain BES facility line flows and voltages within IROLs, SOLs and facility ratings using available generation dispatch, re-dispatch or load shedding as necessary
- Identify and maintain a transmission facility outage plan of the TOP’s Area that maintains reliable operation of the BES for the next 24 hours
- Identify, coordinate and monitor as appropriate, the generation dispatch plan of BAs and GOPs connected to the TOP transmission system, over the next 24 hours
- Adjust planned transmission facility outage plan based on current transmission system conditions and any unplanned element losses (generation or transmission) that could affect the reliability of the current plan
- Assess and be prepared to implement as required, the TOPs mitigation strategies for unplanned events ranging from voltage coordination to full transmission system restoration.
- Monitor weather forecasts and identify potential impacts to transmission facility outage plan for the next 24 hours. This includes the pre-positioning of personnel and equipment to deal with identified threats to the TOP Area reliability
Generator Operator
To maintain adequate situational awareness as it pertains to BES reliability, a Generator Operator system operator at the console should be able to:

- Dispatch generation based on an agreed upon schedule
- Be aware of any unit or availability limitations on real and reactive power outputs or other system imposed requirements and provide feedback to host BA and TOP accordingly (ie. AVR, System stabilizers, RASs, Blackstart resources).
- Monitor the current status of the generating unit(s) online and adjust real and reactive power outputs based on the needs/direction of the host BA and/or TOP.
- Maintain a generation dispatch plan for the next 24 hours including identification of any generator limitations
- Maintain effective and routine communications with host BA and TOP. Be prepared to coordinate actions after a system events as required (ie. Unit tripping offline, expected load shedding, transmission system failure and restoration, blackstart initiation).
- Monitor availability of required fuel for the next 24 hour dispatch plan
- Monitor weather forecasts and identify potential impacts to generator(s) dispatch plan or generator preparation for the next 24 hours
References:


Summary of the Various Definitions of Situation Awareness


Appendix
PJM Reliability Plan

PJM RTO Reliability Plan

[Map of PJM RTO Reliability Plan area]
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Introduction

The North American Electric Reliability Corporation (NERC) requires every Region, sub-region, or interregional coordinating group to establish a Reliability Coordinator to provide the reliability assessment and emergency operations coordination for the Balancing Authorities and Transmission Operators within the Regions and across the Regional boundaries.

PJM Interconnection, LLC (PJM) serves as the Reliability Coordinator (RC) for its transmission-owning members. PJM is responsible for regional system reliability, which includes responsibility for both the Bulk Electric System, and lower voltage facilities that have been turned over to PJM for operational control. The PJM functions associated with the reliability of the Bulk Electric System include review and approval of planned facility transmission line outages and generation outages based upon current and projected system conditions, monitoring of real time loading information and calculating post-contingency loadings on the transmission system, administering loading relief procedures, re-dispatch of generation, and ordering curtailment of transactions and/or load. PJM operates a single Balancing Authority (BA) in its footprint and is also responsible for system control performance. PJM reliability procedures and policies are consistent with NERC and Regional Reliability Organization (RRO) Standards. PJM operates in multiple NERC RROs and recognizes each RRO’s policies and standards.

This plan supersedes the previous PJM RTO Plan. This plan is provided to document the entry of the following systems into the PJM BA as follows:

- **East Kentucky Power Cooperative**
  (NCR01225) Effective date: June 1, 2013

- **International Transmission Company (ITC)**
  (NCRXXXXX) Effective date: June 1, 2016
A. Responsibilities -- Authorization

1. Authority to Act - PJM is responsible for the reliable operation of the Bulk Electric System within its Reliability Coordination Area in accordance with NERC Standards, Regional policies and standards. PJM’s authority to act is derived from a set of agreements that all PJM members have executed (See Appendix A). PJM has clear decision-making authority to act and to direct actions to be taken by its members within its Reliability Coordination Area to preserve the integrity and reliability of the Bulk Electric System.

1.1. PJM has a Wide Area view of its Reliability Coordination Area and neighboring areas that have an impact on PJM’s area. PJM has the operating tools, processes and procedures, including the authority, to prevent or mitigate emergency operating situations in both next-day analysis and during real-time conditions per the NERC Standards and Regional policies and standards, as well as the governing documents listed in Appendix A of this document.

1.2. PJM has clear decision-making authority to act and to direct actions to be taken by its members within its Reliability Coordination Area to preserve the integrity and reliability of the Bulk Electric System. PJM’s responsibilities and authorities, as well as its members’ responsibilities, are clearly defined in the governing documents.

1.3. PJM has not delegated any of its Reliability Coordinator responsibilities.

2. Independence - PJM will act in the best interest of insuring reliability for its Reliability Coordination Area and the Eastern Interconnection before that of any other entity. This expectation is clearly identified in the governing documents (see Appendix A).

3. PJM Directives Compliance - Per the governing documents (see Appendix A), the PJM local control centers shall carry out required emergency actions as directed by PJM, including the shedding of firm load if required, unless such actions would violate safety, equipment, regulatory, or statutory requirements.
B. Responsibilities – Delegation of Tasks

1. PJM has not delegated any Reliability Coordination tasks.
C. Common Tasks for Next-Day and Current-Day Operations

This section documents how PJM conducts current-day and next-day reliability analysis for its Reliability Coordination Area.

1. Determination of Interconnection Reliability Operating Limits (IROLs) – PJM determines IROLs based on local, regional and inter-regional studies including seasonal assessments and ad hoc studies. The majority of the PJM IROLs are voltage stability interfaces.

During real time operations, PJM calculates the actual flow for the reactive interface IROLs using Transmission Limit Calculator (TLC). TLC uses a state estimator snapshot, calculates a voltage collapse transfer limit, and establishes an operating limit based on a back off from the calculated collapse point. These limits are calculated approximately every 5 minutes using the current system topology and posted to the PJM website in close to real time.

2. Operation to prevent the likelihood of a SOL or IROL violation in another area of the Interconnection and operation when there is a difference in limits - PJM, through the Joint Operating Agreement with other Reliability Coordinator neighbors, coordinates operations to prevent the likelihood of a SOL or IROL in another area. These agreements include data exchange, Available Transfer Capability coordination, and Outage Coordination and are listed in Appendix B.

Local control centers in the PJM Reliability Coordination Area are required to follow directives provided by PJM and operate to NERC Standards to prevent the likelihood that a disturbance, action, or non-action in its Reliability Coordination Area will result in a SOL or IROL violation in another area of the Interconnection. When there is a difference in derived limits, PJM utilizes the most conservative limit until the difference is resolved.

3. Operation under known and studied conditions and re-position without delay and no longer than 30 minutes – PJM ensures that entities within its Reliability Coordination Area always operate under known and studied conditions and that they return their systems to a secure operating state following contingency events within approved timelines, regardless of the number of contingency events that occur or the status of their monitoring, operating and analysis tools. PJM also ensures its local control centers re-position the system to be within all IROLs following contingencies within 30 minutes.

On a daily basis, PJM conducts next-day security analysis utilizing planned outages, forecasted loads, generation commitment, and expected net interchange. The analyses include contingency analysis and voltage stability analysis on key interfaces. These analyses model peak conditions for the day and are conducted utilizing first contingency (n-1) analysis.Results and mitigation are documented in the Next-Day Security Analysis
Report and distributed to PJM staff and neighboring Reliability Coordinators. The Next-Day Security Analysis Report is also e-mailed to the PJM local control centers and neighbors. Mitigation plans are formed as needed for potential violations determined in the next day security analysis.

In real time, PJM relies on its telemetry and real-time analysis tools to monitor the real time system conditions to identify potential IROL and SOL problems. PJM’s operational philosophy is to operate on a pre-contingency basis; that is, to mitigate a simulated overload condition before it occurs.

4. PJM provides transmission service within the PJM Reliability Coordination area. PJM communicates IROLs within its wide-area view and provides updates as needed via reports, morning conference calls, and the ALL-CALL system and real-time via voice and messaging.

5. PJM process for issuing directives – PJM uses a number of communications tools for issuing/receiving of directives. The primary communications means is the PJM All-Call System (All-Call) which is a dedicated telephone-based system which sends the directive / message to all control centers simultaneously and confirms response. In addition, PJM will issue follow the verbal message with Emergency Procedures messages on its website through a specific application that runs within its Data Viewer tool and as well direct phone contact as necessary.
D. Next Day Operations

This section documents how PJM conducts next-day reliability analysis for its Reliability Coordination Area.

1. Reliability Analysis and System Studies - PJM conducts next-day reliability analyses for its Area to ensure that the Bulk Power System can be operated reliably in normal and post contingency conditions.

On a daily basis, PJM conducts next-day security analysis utilizing known outages, forecasted loads, generation commitment and dispatch, and expected net interchange using the study capability in the PJM EMS. Base case flows on all monitored facilities compared against the normal rating. Post-contingency flows for all monitored facilities are compared against their emergency rating for all contingencies. Voltage stability analysis is conducted on key critical interfaces to determine a flow limit.

Mitigation plans are formed as needed for potential violations determined in the next day security analysis. Mitigation is of the form of additional generation commitment, system reconfiguration, generation redispatch, use of NERC TLR or other local flow mitigation procedures.

2. Information Sharing –Generation Owners and Transmission Owners in the PJM Reliability Coordination Area and neighboring Reliability Coordinator areas provide to PJM all information required for system studies, such as critical facility status, load, generation, Operating Reserve projections, and known interchange transactions.

The entities in the PJM Reliability Coordination Area provide generation and transmission facility statuses to the PJM outage scheduling application (eDART), forecasted loads, operating reserves, and known interchange transactions via e-tags. PJM shares this information via an SDX file every ten minutes. For entities outside PJM, SDX files are downloaded and loaded into appropriate systems.

3. Sharing of Study Results - When conditions warrant or upon request, PJM shares the results of its system studies with the entities within its Reliability Coordination Area and/or with other Reliability Coordinators. Study results for the next day shall be available no later than 15:00 Eastern Prevailing Time, unless circumstances warrant otherwise.

A Next-Day Security Analysis Report is distributed to PJM and member operations staff and neighboring Reliability Coordinators via e-mail. PJM holds daily conference calls with MISO, and others, as necessary, as part of this process.
E. Current-Day Operations

This section documents how PJM conducts current-day reliability analysis for its Reliability Coordination Area.

1. PJM uses a suite of real time network analysis tools to continuously monitor all Bulk Power System facilities, including sub-transmission information as needed, within the PJM Reliability Coordination Area and adjacent areas, as necessary, to ensure that, at any time, PJM is able to determine any potential SOL and IROL violations within its Reliability Coordination Area.

PJM utilizes a state estimator and real-time contingency analysis as the primary tool to monitor facilities. The state estimator model includes all BES as well as facilities, generally 69 kV and above, in the PJM Reliability Coordination Area. The model also has extensive representation of neighboring facilities in order to provide an effective wide-area view. This model is updated quarterly and may be updated on demand for emergencies.

Real Time Contingency Analysis (RTCA) is performed on contingencies utilizing the state estimator model approximately every 1-2 minutes. Contingencies include all PJM Reliability Coordination Area equipment which has been turned over to PJM for operational control, and neighboring contingencies that would impact PJM Reliability Coordination Area facilities.

In order to continuously monitor its reactive interfaces, PJM uses a real time calculation tool named Transmission Limit Calculator (TLC). TLC takes a state estimator snapshot and calculates a voltage collapse equivalent flow for the interface, based on current real time telemetry and topology. A back off flow is established to prevent an actual voltage collapse as the limit, and PJM operates to maintain flows below the limit.

SCADA alarming is utilized to alert PJM of any actual low or high voltages or facilities loaded beyond their normal or emergency limits.

In addition to the above applications, PJM utilizes a dynamically updated transmission overview display to maintain a wide area view. All transmission facilities 500 kV and above are depicted on the overview with flows (MW and MVAR), indication of facilities out of service, high and low voltage warning and alarming. For more detailed monitoring, bus level one-line diagrams are utilized for station level monitoring and information. The one-line diagrams are populated with the real time telemetered information as well as the state estimated solution.

1.1. PJM notifies neighboring Reliability Coordinators of operational concerns (e.g. declining voltages, excessive reactive flows, or an IROL violation) that it identifies within the neighboring Reliability Coordination Area via direct phone calls, conference calls, NERC hotline calls, and/or RCIS messages. PJM has joint operating
agreements with neighboring Reliability Coordinators that are listed in Appendix B. PJM directs actions to provide emergency assistance to all Reliability Coordination neighbors, during declared emergencies, which is required to mitigate the operational concern to the extent that the same entities are taking in kind steps and the assistance would be effective.

2. PJM maintains awareness of the status of all current critical facilities whose failure, degradation or disconnection could result in an SOL or IROL violation within its Reliability Coordination Area via State Estimator, RTCA, SCADA alarming, and transmission displays. PJM is aware of the status of any facilities that may be required to assist Reliability Coordination Area restoration objectives via these same displays and tools.

3. PJM is continuously aware of conditions within its Reliability Coordination Area, and includes real time information in its reliability assessments via automatic updates to the state estimator, TLC, and transmission displays. PJM monitors its Reliability Coordination Area parameters, including the following:

3.1. Current status of Bulk Power System elements (transmission or generation including critical auxiliaries) such as Automatic Voltage Regulators, Special Protection Systems, and system loading are monitored by state estimator, RTCA, SCADA Alarming, and transmission displays. PJM members are required to report to PJM when Automatic Voltage Regulators are not in-service or status changes of Special Protection Systems.

3.2. Current pre-contingency element conditions (voltage, thermal, or stability) are monitored by state estimator, SCADA Alarming, TLC, and transmission displays.

3.3. Current post- contingency element conditions (voltage, thermal, or stability) are monitored by RTCA, TLC, and transmission displays.

3.4. System real reserves are monitored versus what is required in EMS. Reactive reserves versus what is required are monitored via monitoring adequacy of calculated post-contingent steady state voltages versus voltage limits, voltage stability interfaces against limits, and reactive reserves versus required for defined zones. Reactive Reserve Checks are made as needed when reactive reserves in real-time indicate that they are lower than expected.

3.5. Capacity and energy adequacy conditions are determined Day Ahead (DA) and monitored real time in accordance with our Market Processes to maintain the required levels of reserves.

3.6. Current ACE and System Frequency are displayed in a trend chart to the PJM Generation Dispatcher as part of the BAAL field test. PJM is participating in the NERC BAAL field test and adheres to this system control requirement.
3.7. Current local procedures, such as operating procedures, are monitored and coordinated with local control centers and implementation documented in the PJM logs. TLR procedures in effect are monitored via the NERC Interchange Distribution Calculator, and also documented on the PJM logs.

3.8. Generation dispatching is performed for the PJM balancing authority area by the PJM Generation Dispatcher using the Security Constrained Economic Dispatch (SCED) application, which is a single economic constraint controlled dispatch for the entire PJM RTO area.

3.9. Planned transmission or generation outages are reported to PJM via the eDART application. The eDart application tickets, once approved and implemented, automatically update the EMS model.

3.10. Contingency Events are monitored by state estimator, RTCA, SCADA Alarming, and transmission displays. Local control centers report Contingency Events on non-monitored facilities to PJM.

4. PJM monitors Bulk Power System parameters that may have significant impacts upon its Reliability Coordination Area and neighboring Reliability Coordination areas with respect to:

4.1. PJM maintains awareness of all Interchange Transactions that wheel-through, source, or sink in its Reliability Coordination Area via NERC E-tags and NERC IDC displays. Interchange Transaction information is made available to all Reliability Coordinators via NERC E-tags. PJM monitors internal transactions in its market area via the PJM ExSchedules application.

4.2. PJM evaluates and assesses any additional Interchange Transactions that would violate IROL or SOLs by using the NERC IDC as a look-ahead tool. As flows approach their IROL or SOLs, PJM evaluates the incremental loading next-hour transactions would have on the SOLs or IROLs and determines if action needs to be taken to prevent and SOL or IROL violation. PJM has the authority to direct all actions necessary and may utilize all resources to address a potential or actual IROL violation up to and including load shedding. PJM has EMS displays, including the reactive interface limits screen that is designed so the operators can watch and monitor specific IROL limits.

4.3. PJM monitors Operating Reserves versus each Regional requirement to ensure the required amount of Operating Reserves is provided and available as required to meet NERC Control Standards via EMS and meet the Regional obligation. If necessary, PJM will commit additional reserves including obtaining assistance from neighbors as needed.

4.4. PJM identifies the cause of potential or actual SOL or IROL violations via analysis of state estimator results, RTCA results, SCADA Alarming of outages, TLC results, transmission displays of changes, and Interchange Transaction impacts. PJM will initiate control actions
including transmission reconfiguration, generation redispatch, or emergency procedures to relieve the potential or actual IROL violation without delay, and no longer than 30 minutes. PJM is authorized to direct utilization of all resources, including load shedding, to address a potential or actual IROL violation. PJM will not solely rely on the NERC TLR procedure to mitigate an IROL violation.

4.5. PJM complies with the start and end times for time error corrections as communicated by the Time Monitor. PJM communicates Geo-Magnetic Disturbance forecast information to local control centers and Generation Operators via the All-Call System and the Emergency Procedures webpage. PJM will assist in development of any required response plan and may move to conservative operating mode to mitigate impacts as needed.

4.6. PJM participates in NERC Hotline discussions, assists in the assessment of reliability of the Regions and the overall interconnected system, and coordinates actions in anticipated or actual emergency situations. PJM will disseminate this information via the All-Call system or individual phone calls.

4.7. PJM monitors system frequency and ACE via trend graph. Since PJM is participating in the NERC Balancing Standard Field Test, if the BAAL is outside of the acceptable range, then the PJM Regulation will be manually adjusted, if necessary, to utilize the support resources for frequency mitigation. PJM will utilize all resources, including firm load shedding, to relieve the emergent condition.

4.8. PJM coordinates with other Reliability Coordinators and its Generation Operators and local control centers, as needed, on the development and implementation of action plans to mitigate potential or actual SOL, IROL, BAAL or DCS violations. PJM coordinates pending generation and transmission maintenance outages with other Reliability Coordinators and its Generation Operators and local control centers, as needed and within code of conduct requirements, real time via telephone and next-day, per the PJM outage scheduling process.

4.9. PJM will assist or request assistance as the Balancing Authority Operator for the RTO from neighboring Reliability Coordinators via the Energy Emergency Alert (EEA) notification process and will conference parties together as appropriate.

4.10. PJM monitors its ACE to identify the sources of problems contributing to frequency, time error, or inadvertent interchange and directs corrective actions per 4.7 above.

4.11. The local control centers within PJM’s Reliability Area inform PJM of all changes in status of Special Protection Systems (SPS) including any degradation or potential failure to operate as expected by the
local control center. PJM factors these SPS changes into its reliability analyses and updates its’ contingency definitions as appropriate.

5. PJM issues alerts, as appropriate, to local control centers via the All-Call system, individual phone calls, when it foresees a transmission problem (such as an SOL or IROL violation, loss of reactive reserves, etc.) within its Reliability Area that requires notification. PJM issues alerts, as appropriate, to all Reliability Coordinators via the Reliability Coordinator Information System when it foresees a transmission problem (such as an SOL or IROL violation, loss of reactive reserves, etc.) within its Reliability Area that requires notification.

6. PJM confirms reliability assessment results via analyzing results of state estimator/RTCA, and discussions with local control centers and neighboring Reliability Coordinators. PJM identifies options to mitigate potential or actual SOL or IROL violations via examining existing operating procedures, system knowledge, and power flow analysis to identify and implement only those actions as necessary as to always act in the best interests of the interconnection.
F. Emergency Operations

1. PJM utilizes PJM Manual M-13, Emergency Operations, to direct its Members to return the transmission system to within IROL or SOL limits as soon as possible, but no longer than 30 minutes. This procedure includes the actions (e.g. reconfiguration, re-dispatch or load shedding) that PJM will direct until relief requested by the TLR process is achieved.

2. PJM utilizes PJM Manual M-13, Emergency Operations, when it determines that IROL violations are imminent. PJM Emergency Operations documents the processes and procedures that PJM follows when directing the re-dispatch of generation, reconfiguring transmission, managing Interchange Transactions, or reducing system demand to mitigate the IROL violation to return the system to a reliable state. PJM coordinates its alert and emergency procedures with other Reliability Coordinators via joint operating agreements listed in Section H.

3. PJM directs actions in the event the loading of transmission facilities progresses to or is projected to progress to a SOL or IROL violation.
   3.1 PJM directs reconfiguration and re-dispatch within its market area as needed to prevent or relieve SOL or IROL violations. PJM will not rely on or wait for NERC TLR to relieve IROL violations. PJM will implement NERC TLR if doing so will provide additional relief. PJM will adhere to the NERC TLR congestion report instructions including curtailing transactions and re-dispatching for market flow.
   3.2 PJM utilizes market-to-market re-dispatch for its market area for reciprocally coordinated flowgates with MISO per the Congestion Management Process (see Appendix B). PJM also coordinates flowgate limits and monitors flows on facilities within TVA, Duke, Progress Energy and other RC areas in order to maintain reliable operation.
   3.3 PJM uses market re-dispatch, in conjunction with NERC TLR per the NERC IDC congestion relief report.
   3.4 PJM complies with the provisions of the NERC TLR by curtailing Interchange Transactions and re-dispatching for market flow per the NERC IDC congestion relief report.
   3.5 PJM will direct reconfiguration, re-dispatch for market areas, and NERC TLR reductions to relieve facilities as necessary. PJM will not rely on NERC TLR as an emergency action.

4. PJM monitors its ACE, and directs action to assist in maintaining system frequency to return within L10 or BAAL limits as appropriate.

5. PJM utilizes PJM Manual M-13, Emergency Operations, to mitigate an energy emergency within its Reliability Coordination Area. PJM will provide
assistance to other Reliability Coordinators per its respective joint operating agreement listed in Appendix B.

6. PJM utilizes PJM Manual M-13, Emergency Operations, when it, or a Reserve-Sharing Group, or a Load-Serving Entity within its Reliability Coordination Area is experiencing a potential or actual Energy Emergency. PJM Emergency Operations document the processes and procedures that PJM uses to mitigate the emergency condition, including a request for emergency assistance if required.

7. PJM also drills at least annually with its members on Emergency procedures.
G. System Restoration

1. Knowledge of PJM Transmission Owner Restoration Plans - PJM is aware of each transmission owner Restoration Plan and has a written copy of each plan. During system restoration, PJM monitors restoration progress and acts to coordinate any needed assistance. PJM may direct the restoration activities, depending on system conditions.

2. PJM Restoration Plan – The PJM Restoration Procedures are contained in PJM Manual M-36, System Restoration. PJM takes action to restore normal operations once an operating emergency has been mitigated in accordance with its Restoration Plan. This Restoration Plan is drilled at least annually.

3. Dissemination of Information - PJM serves as the primary contact for disseminating information regarding restoration to neighboring Reliability Coordinators and members not immediately involved in restoration.

PJM approves, communicates and coordinates the re-synchronizing of major system islands or synchronizing points so as not to cause a burden on member or adjacent Reliability Coordination Areas.
H. Coordination Agreements and Data Sharing

1. Coordination Agreements:
   See Appendix B

2. Data Sharing - PJM determines the data requirements to support its reliability coordination tasks and requests such data from members or adjacent Reliability Coordinators. PJM provides for data exchange with local control centers and adjacent Reliability Coordinators via a secure network. PJM members provide data to PJM via ICCP. PJM provides data to entities outside PJM via direct links and ISN.
I. Facility

PJM performs the Reliability Coordinator function at the PJM Headquarters in Valley Forge, PA along with the PJM Milford control center in Milford Township, PA. The Valley Forge and Milford offices have the necessary voice and data communication links to appropriate entities within PJM to perform their responsibilities. These communication facilities are staffed and available to act in addressing a real-time emergency condition.

1. Adequate Communication Links - PJM maintains satellite phones, cellular phones, and redundant, diversely routed telecommunications circuits. There is also a video link between the Valley Forge and Milford Control Rooms.

2. Multi-directional Capabilities – PJM has multi-directional communications capabilities with its members, and with neighboring Reliability Coordinators, for both voice and data exchange to meet reliability needs of the Interconnection.

3. Real-time Monitoring - PJM has detailed real-time monitoring capability of its Reliability Coordination Area and all first tier companies surrounding the PJM Reliability Coordination Area to ensure that potential or actual System Operating Limit of Interconnection Reliability Operating Limit violations are identified.

3.1 PJM monitors BES elements (generators, transmission lines, buses, transformers, breakers, etc.) that could result in SOL or IROL violations within its Reliability Coordination Area. PJM monitors both real and reactive power system flows, and operating reserves, and the status of the Bulk Power System elements that are, or could be, critical to SOLs and IROls and system restoration requirements within its Reliability Coordination Area.

4. Study and Analysis Tools

4.1 PJM has adequate analysis tools, including state estimation, pre-and post-contingency analysis capabilities (thermal, stability, and voltage), and wide-area overview displays. PJM has detailed monitoring capability of the PJM Reliability Area and sufficient monitoring capability of the surrounding Reliability Areas to ensure potential reliability violations are identified. PJM continuously monitors key transmission facilities in its area in conjunction with the Members monitoring of local facilities and issues.

PJM ensures that SOL and IROL monitoring and derivations continue if the main monitoring system is unavailable. PJM has backup facilities that shall be exercised if the main monitoring system is unavailable.

The systems utilized by PJM include:

- State Estimator and Contingency Analysis
- Status and Analog Alarming
Overview Displays of PJM Transmission System via Wallboard
- One line diagrams for entire PJM Transmission System
- Transmission Limit Calculator
- Voltage Stability Analysis (VSA)
- Transient Stability Analysis (TSA)
- ExSchedules
- Security Constrained Economic Dispatch (SCED)
- Dispatcher Management Tool (DMT)

PJM utilizes these tools, which provide information that is easily understood and interpreted by the PJM operating personnel. The alarm management is designed to classify alarms in priority for heightened awareness of critical alarms.

4.2 PJM controls its Reliability Coordinator analysis tools, including approvals for planned maintenance. PJM has procedures in place to mitigate the effects of analysis tool outages.
J. Staffing

1. Staff Adequately Trained and NERC Certified – The 24 x 7 PJM shift operations team is composed as follows:

- 1 Shift supervisor*
- 2 Generation dispatchers*
- 3 to 4 Transmission dispatchers*
- 1 or 2 Master Coordinators

In addition, one or more Reliability Engineers* are on shift from 5:00 AM to 12:00 midnight, 7 days per week.

*All people in these positions possess the NERC Reliability Coordinator certification¹.

- Positions that have the primary responsibility, either directly or through communications with others, for the real-time operation of the interconnected Bulk Electric System.
- Positions directly responsible for complying with NERC and RRO Standards.

Each week, one of the shift teams is assigned to training. The training program consists of a set curriculum which includes tests that each person must successfully complete. At a minimum, each person must complete a minimum of 32 hours per year of training and drills using realistic simulations of system emergencies, in addition to other training required to maintain qualified operation personnel.

2. Comprehensive Understanding - PJM operating personnel have an extensive understanding of the transmission system within the PJM Reliability Coordination Area, including the operating staff, operating practices and procedures, restoration priorities and objectives, outage plans, equipment capabilities, and operational restrictions.

PJM operating personnel place particular attention on SOLs and IROLs and inter-tie facility limits. PJM ensures that protocols are in place to allow PJM operating personnel to have the best available information at all times.

PJM’s System Operators are trained to perform their duties, both at entry level and in continuous training status. Successful completion of both written and simulator tests are required for each progression step in the control room job family. A Learning Management System is used to track the status of each operator’s progress. In addition to the above training, PJM conducts other training sessions that PJM System Operators are expected to complete.

3. Standards of Conduct - PJM is independent of the merchant function. PJM does not pass transmission information or data to any wholesale merchant function or retail merchant function that is not made available simultaneously
to all such wholesale merchant functions. An officer of PJM has signed the NERC Reliability Coordinators Standards of Conduct. Every PJM employee, not just the operating staff, has completed training on PJM’s Standards of Conduct. Refresher training on PJM’s Standards of Conduct is conducted every year. Training records are maintained.
**APPENDIX A – PJM Governing Documents**

PJM Operating Agreement

PJM Transmission Tariff

**APPENDIX B – Agreements with External Entities**

Joint Operating Agreement between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C.

Joint Reliability Coordination Agreement among and between PJM Interconnection, L.L.C., and Tennessee Valley Authority

Midwest Independent Transmission System Operator, Inc., PJM Interconnection, L.L.C., and Tennessee Valley Authority
Congestion Management Process

Joint Operating Agreement between New York Independent System Operator, LLC and PJM Interconnection, L.L.C.
See PJM Website link: [http://pjm.com/~media/documents/agreements/nyiso-joa.ashx](http://pjm.com/~media/documents/agreements/nyiso-joa.ashx)

Joint Operating Agreement between VACAR South and PJM Interconnection, L.L.C.
See PJM Website link
APPENDIX C: PJM Reliability Area Map
May 19, 2016

To: Balancing Authorities and Regional Entities
From: NERC Operating Committee Chair, NERC Resources Subcommittee Chair

RE: CPS 1 Data and BAAL Exceedances Information

Today, Balancing Authorities (BAs) submit CPS 1 %, CPS 2 % and rolling 12 month CPS 1 % values monthly through Regional internet portals for compliance which is then aggregated and provided to NERC. This NERC aggregated data is sent to the NERC Resources Subcommittee (RS) to monitor and provide analysis of individual BA performance as it pertains to Interconnection reliability.

With the pending implementation of BAL-001-2, July 1, 2016, CPS data will no longer be required to be provided unless a compliance violation has occurred. However, the NERC Operating Committee (OC) is requesting the same CPS 1 % data and additionally, BAAL exceedances (as shown below) to be provided to allow the NERC RS to continue to monitor and analyze individual BA performance as the performance Standards and requirements change and also to assist BAs as needed. This data request is not to be considered compliance related but is very important and needed to assist the industry and support and monitor Interconnection performance.

Due to the fact this is not compliance data, a new process has been developed for BAs to provide this information on a secured NERC SharePoint website referred to as the balancing authority submittal site (BASS). Secure ID information is required to access the BASS site and access will be limited to a BA only seeing its information. Information will be sent to you later from NERC in regards accessing the site to supply the below requested information.

The monthly information will be asked to be provided quarterly as follows by the 15th day of October (July-Sept), January (Oct – Dec), May (Jan-March) and finally July (April-June) as follows:

- CPS 1 % monthly
- CPS 1 % rolling 12 month

BAAL exceedances in total minutes for the month in the following categories:

- 10-15 (including 10 min but less than 15 min)
- 15-20 (including 15 min but less than 20 min)
- 20 min and greater (including 20 min and all minutes over)
On behalf of the NERC OC and NERC RS your support is greatly appreciated. This data will allow us to continue our important work in assisting the industry, evaluating interconnection reliability related to control performance, and providing FERC with the analysis they requested. If you have any questions please contact your NERC RS representative or the NERC RS Chair, Troy Blalock (via email) or at 803 217-2040.

Sincerely,

James Case

James Case
NERC Operating Committee Chair
NERC’s Planning Committee Charter

Approved by NERC’s Board of Trustees
August 2016
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Preface

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

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

The North American BPS is divided into eight Regional Entity (RE) boundaries. The highlighted areas denote overlap as some load-serving entities participate in one Region while associated transmission owners/operators participate in another.

<table>
<thead>
<tr>
<th>RE</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>FRCC</td>
<td>Florida Reliability Coordinating Council</td>
</tr>
<tr>
<td>MRO</td>
<td>Midwest Reliability Organization</td>
</tr>
<tr>
<td>NPCC</td>
<td>Northeast Power Coordinating Council</td>
</tr>
<tr>
<td>RF</td>
<td>ReliabilityFirst</td>
</tr>
<tr>
<td>SERC</td>
<td>SERC Reliability Corporation</td>
</tr>
<tr>
<td>SPP RE</td>
<td>Southwest Power Pool Regional Entity</td>
</tr>
<tr>
<td>Texas RE</td>
<td>Texas Reliability Entity</td>
</tr>
<tr>
<td>WECC</td>
<td>Western Electricity Coordinating Council</td>
</tr>
</tbody>
</table>
Section 1: Purpose and Functions

Purpose
The Planning Committee (PC) proactively supports the NERC and Electric Reliability Organization (ERO) enterprise mission, vision, and relevant NERC program areas by carrying out a broad array of functions and responsibilities focused on the reliable planning and assessment of interconnected bulk power systems (BPS).

Function
The PC is a general forum for aggregating ideas and interests regarding the reliable planning and assessment of the interconnected North American BPS. The committee provides NERC (stakeholders, Board of Trustees, and staff) with technical advice, recommendations, and the collective and diverse opinions on matters related to BPS planning, reliability, and adequacy to promote informed decisions.

The PC supports the priorities of the NERC ERO enterprise, providing a technical foundation for reliability issues, including:

- **Reliability Assessments** – Review reliability assessments for technical accuracy and endorse to the NERC’s Board of Trustees for approval. Additional guidance on committee review and endorsement of PC deliverables is provided in Appendix 3.
- **Emerging Issues and Reliability Concerns** – Identify and Assess emerging issues within the electric industry and address other reliability concerns, as assigned by NERC’s Board of Trustees.
- **Technical Planning Analyses** – Develop technical analyses, model validation, and key reliability areas, resulting in technically accurate and comprehensive reports addressing these areas (i.e., FDVIR, variable generation, smart grid, etc.). Provide recommendations to facilitate the mitigation of the identified reliability risks. Provide oversight, guidance, and direction to address key planning-related issues.
- **Standards Input** – Provide technical expertise and feedback to Standard Authorization Requests (SARs) that have planning-related impacts. Provide technical input to support the development of key reliability planning-related standards. Coordinate effectively with the Standards Committee to maintain alignment PC-related efforts, and provide reliability risk information for prioritization of SARs and new Reliability Standards.
- **Metrics** – Provide direction, technical oversight, and feedback on the NERC Adequate Level of Reliability (ALR) metrics.
- **Event Analysis** – Support disturbance reporting and event analysis activities, providing lessons-learned and other insights to promote industry awareness and enhance BPS reliability.
- **NERC Alerts** – Support the review and deployment of requests for industry actions and informational responses.
- **Guidelines and Technical Reports** – Develop guidelines, white papers, technical reports and reference documents to address emerging issues and industry concerns related to system planning.
- **Compliance Input** – Provide technical expertise and feedback on the potential impact of emerging issues on the development of NERC’s annual compliance program.
- **Reliability Guidelines** – Issue reliability guidelines in accordance with the process described in Appendix 3.

The PC will develop and maintain a Strategic Plan and an associated Work Plan to address the functions described above. As changes emerge, the PC will revisit its Strategic Plan to ensure alignment is maintained with the NERC Electric Reliability Organization (ERO) enterprise. As changes to the PC Strategic Plan become necessary, the PC will advise the BOT of changes in strategies and priorities being considered.
Section 2: Membership

Goals
The PC membership includes subject matter experts (SMEs) from across the industry with technical knowledge and experience in the area of interconnected systems planning reliability and reliability assessment.

Expectations
PC voting members are expected to:

- Bring the applicable subject matter expertise to the PC;
- Attend and participate in all PC meetings;
- Express their opinions as well as the opinions of their represented sector at committee meetings;
- Discuss and debate interests rather than positions;
- Complete committee assignments; and
- 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.

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

Selection
Except for 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.

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.

Members may not represent more than one committee sector.

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

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 as specified in Appendix 2. In this case, no more than two additional Canadian voting members may be selected from the same sector.

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

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: (i) If two members are simultaneously selected to a sector that did not have any existing members, in order to stagger their terms, one member will be assigned a one-year term and the second member will be assigned a two-year term using a fair and unbiased method. (ii) If a member replaces a departed member between elections, the new member will assume the remaining term of the departed member. (iii) If a member is selected to fill a vacant member position between elections, his/her term will end when the term for that vacant position ends.

Resignations, Vacancies, and Nonparticipation
Members who resign will be replaced for the time remaining in the member’s term. Members and officers will be selected or replaced pursuant to Section 4, and executive committee members will be replaced pursuant to Section 6.

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.

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.

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

Proxies
A member of the committee is authorized to designate a proxy. A member of the committee may give a proxy only to a person who:

- meets the member’s eligibility requirements and is not affiliated with the same organization as another committee member, or
- is not another committee member, unless that committee member would represent the proxy’s sector instead of his/her own sector at the meeting. (Additional guidance is provided see Section 4 and Appendix 1)

To permit time to determine a proxy’s eligibility, proxies must be submitted to the secretary in writing at least one week prior to the meeting (electronic transmittal is acceptable). Any proxy submitted after that time will be accepted at the chairman’s discretion, provided that the chairman believes the proxy meets the eligibility requirements.
Section 3: Meetings

Unless stated otherwise, the Planning Committee will follow Robert’s Rules of Order, Newly Revised. Additional information on meeting procedures is provided in Appendix 2.

Quorum
A quorum requires two-thirds of voting members.

Voting
Voting may be conducted during regularly scheduled in-person meetings, via electronic mail (email), or through scheduled a conference call. All actions by the committee shall be approved upon receipt of the affirmative vote of two-thirds of the members present and voting at a meeting at which quorum is present. The chair and vice chair may vote. Additional voting guidelines are in Appendix 2.

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.

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

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

Action without a Meeting
The committee may act by mail or electronic (email) ballot without a regularly scheduled meeting. Two-thirds of the members are required to approve any action. The committee 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 committee members with a written notice (letter or email) 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 committee (letter, or email) 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 from the committee members with the committee minutes.
Section 4: Officers

Selection
At its 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.

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

Representation
The newly selected chair and vice chair shall not be from the same sector. The chair and vice chair, upon assuming such positions, shall cease to act as members of the sectors that elected them as members to the committee and shall thereafter be responsible for acting in the best interests of the members as a whole.

Board Approval
Pending approval by the board, the newly elected officers will assume their duties. The secretary will submit the names of the elected officers to the chair of the NERC Board of Trustees for approval at their next regular meeting.

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

a. The chair opens the floor for nominations.
b. After hearing no further nominations, the chair closes the nominating process.
c. If the committee nominates one person, that person is automatically selected as the next chair.
d. If the committee nominates two or more persons, then the secretary will distribute paper ballots for the members to mark their preference.
e. The secretary will collect the ballots. If the committee nominates three or more candidates, then the winner will be selected using the Instant Runoff Process. (Explained in Robert’s Rules of Order.)
Section 5: Subgroups

The PC may appoint technical subcommittees, task forces, and working groups as needed. The PC is responsible for directing the work of these subgroups and for their work products. Committee subgroups will be tied to the PC Strategic Plan and generally be structured as follows:

<table>
<thead>
<tr>
<th>Committee Subgroups</th>
<th>Scope</th>
<th>Duration</th>
<th>Approvals</th>
<th>Leadership</th>
</tr>
</thead>
<tbody>
<tr>
<td>Subcommittee</td>
<td>Oversee broad processes</td>
<td>Long-term</td>
<td>Consensus seeking; vote as specified by charter</td>
<td>Nominated by subcommittee; Approved by PC Leadership</td>
</tr>
<tr>
<td></td>
<td>Manage cyclical deliverables</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Working Group</td>
<td>Oversee specific data systems</td>
<td>Long-term</td>
<td>Consensus seeking; non-voting</td>
<td>Nominated by working group, parent subcommittee, or direct appointment by the NERC Technical Committees; approved by PC Leadership</td>
</tr>
<tr>
<td></td>
<td>Support specific initiatives</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Support parent subcommittee</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Task Force</td>
<td>Support specific initiatives</td>
<td>Short-term</td>
<td>Consensus seeking; non-voting</td>
<td>Nominated by task force, parent subcommittee, or direct appointment by the NERC Technical Committees; approved by PC Leadership</td>
</tr>
<tr>
<td></td>
<td>Support parent subcommittee</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
Section 6: Executive Committee

Authorization
The PC Executive Committee is authorized to act between regular meetings of the Planning Committee. However, the executive committee may not reverse the Planning Committee’s decisions.

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

Election Process
1. The chair opens the floor for nominations.
2. If the committee members nominate four or fewer candidates, then those candidates are automatically elected.
3. If the committee members nominate more than four candidates, then the secretary will distribute paper ballots for the members to list their top four candidates.
4. The four candidates who receive the most votes will be elected, provided that no two candidates may be from the same sector.

Terms
The executive committee will be replaced every two years, with the chair and vice chair replaced at the a June meeting and the at-large members replaced at the September meeting.
## Appendix 1 – Committee Members

### Report Template Formatting

<table>
<thead>
<tr>
<th>Name</th>
<th>Definition</th>
<th>Members</th>
<th>Votes</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Voting Members</strong></td>
<td></td>
<td></td>
<td></td>
</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>
<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>
<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>
<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>
<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>
<td>2</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>
<td>2</td>
</tr>
</tbody>
</table>
7. **Electricity marketer**

This sector includes any entity that is engaged in the activity of buying and selling of wholesale electric power in North America on a physical or financial basis. This sector also includes organizations that represent the interests of such entities.

<table>
<thead>
<tr>
<th>Number of Members</th>
<th>Proportional Voting</th>
</tr>
</thead>
<tbody>
<tr>
<td>2</td>
<td>X</td>
</tr>
</tbody>
</table>

8. **Large end-use electricity customer**

This sector includes any entity in North America with at least one service delivery taken at 50 kV or higher (radial supply or facilities dedicated to serve customers) that is not purchased for resale; and any single end-use customer with an average aggregated service load (not purchased for resale) of at least 50,000 MWh annually, excluding cogeneration or other back feed to the serving utility. This sector also includes organizations that represent the interests of such entities.

<table>
<thead>
<tr>
<th>Number of Members</th>
<th>Proportional Voting</th>
</tr>
</thead>
<tbody>
<tr>
<td>2</td>
<td>X</td>
</tr>
</tbody>
</table>

9. **Small end-use electricity customer**

This sector includes any person or entity within North America that takes service below 50 kV; and any single end-use customer with an average aggregated service load (not purchased for resale) of less than 50,000 MWh annually, excluding cogeneration or other back feed to the serving utility. This sector also includes organizations (including state consumer advocates) that represent the interests of such entities.

<table>
<thead>
<tr>
<th>Number of Members</th>
<th>Proportional Voting</th>
</tr>
</thead>
<tbody>
<tr>
<td>2</td>
<td>X</td>
</tr>
</tbody>
</table>

10. **Independent system operator/regional transmission organization**

This sector includes any entity authorized by the Commission to function as an independent transmission system operator, a regional transmission organization, or a similar organization; comparable entities in Canada and Mexico; and the Electric Reliability Council of Texas or its successor. This sector also includes organizations that represent the interests of such entities.

<table>
<thead>
<tr>
<th>Number of Members</th>
<th>Proportional Voting</th>
</tr>
</thead>
<tbody>
<tr>
<td>2</td>
<td>X</td>
</tr>
</tbody>
</table>

11. **Regional Entity**

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.

<table>
<thead>
<tr>
<th>RE</th>
<th>Number of Members</th>
<th>Proportional Voting</th>
</tr>
</thead>
<tbody>
<tr>
<td>FRCC</td>
<td>1</td>
<td>X</td>
</tr>
<tr>
<td>RFC</td>
<td>1</td>
<td>X</td>
</tr>
<tr>
<td>TRE</td>
<td>1</td>
<td>X</td>
</tr>
<tr>
<td>MRO</td>
<td>1</td>
<td>X</td>
</tr>
<tr>
<td>NPCC</td>
<td>1</td>
<td>X</td>
</tr>
<tr>
<td>SERC</td>
<td>1</td>
<td>X</td>
</tr>
<tr>
<td>SPP</td>
<td>1</td>
<td>X</td>
</tr>
<tr>
<td>WECC</td>
<td>1</td>
<td>X</td>
</tr>
</tbody>
</table>

12. **State government**

(See Government representatives below)

<table>
<thead>
<tr>
<th>Number of Members</th>
<th>Proportional Voting</th>
</tr>
</thead>
<tbody>
<tr>
<td>2</td>
<td>X</td>
</tr>
</tbody>
</table>

**Officers**

Chair and Vice Chair

<table>
<thead>
<tr>
<th>Number of Members</th>
<th>Proportional Voting</th>
</tr>
</thead>
<tbody>
<tr>
<td>2</td>
<td>X</td>
</tr>
</tbody>
</table>

**Total Members**

<table>
<thead>
<tr>
<th>Number of Members</th>
<th>Proportional Voting</th>
</tr>
</thead>
<tbody>
<tr>
<td>34</td>
<td></td>
</tr>
<tr>
<td>26</td>
<td></td>
</tr>
</tbody>
</table>
Appendix 2 – Meeting and Voting Procedures

Voting Procedures for Motions

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

Voting Procedures for Motions

1. General guidelines:
   a. Meeting minutes are a record of what the committee did, not what its members said.
   b. Minutes should list discussion points where appropriate, but should usually not attribute comments to individuals. It is acceptable to cite the chair’s directions, summaries, and assignments.
   c. Do not list the person who seconds a motion.
   d. Do not record (or even ask for) abstentions.
2. Minority Opinions - All committee members are afforded the opportunity to provide alternative views on an issue. The meeting minutes will provide an exhibit to record minority opinions. The chair shall report both the majority and any minority views in presenting results to the Board of Trustees.
3. Personal Statements - The minutes will also provide an exhibit to record personal statements.
Appendix 3 - Committee Review, Endorsement and Approval

Approval of Section 1600 Data or Information Request
A report requested by the PC that accompanies or recommends a Rules of Procedure (ROP) Section 1600 - Data or Information Request will follow the process outlined below:

1. This Section 1600 request, with draft supporting documentation, will be provided to the PC at a regular meeting.
2. The draft data request and supporting documentation will be considered for approval to post for comments at the PC regular meeting.
3. A committee subgroup will review and develop responses to comments on the draft report and provide a final draft report, including all required documentation for the final data request, to the PC at a regular meeting.
4. The final draft of the 1600 request – with responses to all comments and any modifications made to the request based on these comments – will be provided to the NERC’s Board of Trustees.

Reliability Guidelines Review and Approval Process
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.¹

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

1. New/updated draft guideline approved for industry posting. The Planning Committee 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.
2. Post draft guideline for industry comment. The draft guideline is posted for industry-wide comment for forty-five (45) days. If the draft guideline is an update, a redline version against the previous version must also be posted.
3. Post industry comments and responses. After the public comment period, the Planning Committee 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.
4. New/updated guideline approval and posting. A new or updated guideline which considers the comments received, is approved by the Planning Committee and posted as “Approved” on the NERC Web site. Updates must include a revision history and a redline version against the previous version.
5. Guideline updates. After posting a new or updated guideline, the Planning Committee will continue to accept comments from the industry via a Web-based forum where commenters may post their comments.
   a. Each quarter, the Planning Committee will review the comments received. At any time, the Planning Committee may decide to update the guideline based on the comments received or on changes in the industry that necessitate an update.
   b. Updating an existing guideline will require that a draft updated guideline be approved by the Planning Committee in step 1 and proceed to steps 2 and 3 until it is approved by the Planning Committee in step 4.

¹ 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.
The table below summarizes proposed updates to the PC Charter.

<table>
<thead>
<tr>
<th>Proposed Change</th>
<th>Driver</th>
<th>Section (Posted)</th>
<th>Section (New)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Updated with current NERC template and formatting</td>
<td>Consistency with other NERC documents; organizational enhancement</td>
<td>All</td>
<td>All</td>
</tr>
<tr>
<td>Combined “Section 1-Purposed and Section 2-General Overview and Functions”</td>
<td>Organizational enhancement</td>
<td>Section 1-Purpose and Functions</td>
<td>Section 1-Purpose; Section 2-General Overview and Functions</td>
</tr>
<tr>
<td>Clarified “Reliability Assessments” Function</td>
<td>Provide clarity and consistency on PC review role for Reliability Assessments</td>
<td>Section 2-General Overview and Functions</td>
<td>Section 1-Purpose and Functions</td>
</tr>
<tr>
<td>Added Function of developing Reliability Guidelines</td>
<td>Provide clarity on PC role in developing Reliability Guidelines</td>
<td>Section 2-General Overview and Functions</td>
<td>Section 1-Purpose and Functions</td>
</tr>
<tr>
<td>Combined “Officers” Section with “Officer Selection Process” Appendix</td>
<td>Organizational enhancement</td>
<td>Section 5 – Officers</td>
<td>Section 4: Officers</td>
</tr>
<tr>
<td>Updated Appendix – Report/Reliability Guideline Approval Process</td>
<td>Provide more clarity on the process of endorsement, acceptance, and approval of various PC deliverables; Organizational enhancement</td>
<td>Appendix 4 – Officer Selection Process</td>
<td>Appendix 3 – Committee Review, Endorsement and Approval</td>
</tr>
<tr>
<td>Updated/Renamed “Subcommittees” Section to “Subgroups” Section; added table for guidance on subgroup development and operation</td>
<td>Organizational enhancement</td>
<td>Section 6 – Subcommittees</td>
<td>Section 5 – Subgroups</td>
</tr>
<tr>
<td>Renamed Appendix “Meeting Procedures” as “Meeting and Voting Procedures”</td>
<td>Organizational enhancement</td>
<td>Appendix 2 – Meeting Procedures</td>
<td>Appendix 2 – Meeting and Voting Procedures</td>
</tr>
</tbody>
</table>

**Agenda Item 7.h.2**
OC Meeting
June 7-8, 2016
PC Charter Addendum
Supplemental Process Guidance

Background
The intent of this addendum is to provide additional clarity to existing Planning Committee (PC) processes and the subgroup structure.

Guidance on PC Reviews
Deliverables with deadlines set by NERC's Board will be developed based on a timeline developed by the Planning Committee to allow for adequate review, without compromising desired approval from the NERC's Board.

The PC recognizes the need for flexibility in the review and approval process defined above. As such, these are provided as guidelines to be followed by the committee and its subgroups.

Requests for exceptions may be brought to the PC at its regular meetings or to the PC Executive Committee, if the exception cannot wait for a PC meeting. In all cases, a final report may be considered for endorsement if the PC decides to act sooner.

Report Endorsement and Acceptance
The committee will abide by the following parameters regarding endorsement or acceptance of committee deliverables. In general, the committee will seek endorsement of all deliverables (technical documents, white papers, etc.).

Endorsement: committee has adequately reviewed the deliverable and supports the content and development process, endorsing any recommendations. A full committee vote resulting in a quorum is required for endorsement. Report endorsements will be made with committee recognition that the deliverable is subject to further modifications by the NERC Executive Management and/or the NERC Board of Trustees. Changes subsequent to committee endorsement will be presented out to the PC in a timely manner.

Acceptance: committee has adequately reviewed the deliverable and supports the content and development process, but does not formally endorse any recommendations. A full committee vote resulting in a quorum is required for report acceptance.

If consensus via a vote resulting in a quorum is not reached, PC leadership will move for a motion for acceptance of a deliverable. The following deliverables require endorsement:

- Long-Term Reliability Assessments
- Special Reliability Assessments
- State of Reliability Reports

PC Work Plan
The PC will develop and maintain a Work Plan to track the progress of committee-related deliverables. The Work Plan will be updated and posted on a quarterly-basis to provide the status of all PC subgroup initiatives.

Timelines
Deliverables submitted by either a committee subgroup or NERC staff for endorsement will make the report available to the PC at least 10 business days prior to the scheduled vote for endorsement.
NERC BACKUP CONTROL CENTER

A Reference Document

EPRI Project RP2473-68
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Appendixes

Appendix A — Bibliography
Appendix B — Utility Questionnaire
1. Introduction

This reference document is intended to aid control center managers in scoping, justifying, and planning a backup control center (BUCC). Since control centers differ in their functions and responsibilities, each utility must decide which functions are critical and need to be performed when operating from an alternate location. To aid a utility in justifying and designing its BUCC, key issues to be considered in planning a BUCC are provided. Common issues, such as control center threats and their resultant impacts, are discussed in general terms. Alternative BUCC solutions that are related to a utility’s specific responsibilities within its control area are discussed using prototype situations to further guide a utility based on its own operating requirements.

The information contained in this reference document was obtained both from a search of current literature on backup control centers and from a survey of utility personnel with expertise in the planning and use of backup control centers. Appendix A contains a bibliography of current literature used as reference material. Appendix B contains a copy of the questionnaire used in the utility survey.

Individuals from the following utilities were contacted during the survey process and they provided the bulk of the information included in this document.

- American Electric Power Corporation
- Baltimore Gas & Electric
- Bonneville Power Administration
- Boston Edison Company
- Delmarva Power & Light Company
- Detroit Edison Company
- Entergy Services, Inc.
- Florida Power & Light Company
- General Public Utilities
- Michigan Electric Power Coordination Center
- New England Power Exchange
- New York Power Pool
- Ontario Hydro
- Orange & Rockland Utilities, Inc.
- Pacific Gas & Electric Company
- PJM Interconnection Association
- Pennsylvania Power & Light Company
- Public Service Electric & Gas Company
- Southern California Edison Company
- Tucson Electric Power Company
- Union Electric Company
2. Criteria for Critical BUCC Functional Capabilities

NERC Guide III, G. Recommendation 5 states that the standards of Guide I should be considered when developing the plan to continue operation. The standards of Guide I address the functions of generation control, voltage control, time and frequency control, interchange scheduling, and inadvertent interchange management. In addition, utilities require either manual or automated control of critical substation devices; logging of significant power system events; and, as appropriate, hourly interchange accounting. These functions to the extent they are operating responsibilities of the primary control center provide the minimum set of recommended functional capabilities for a BUCC.

In addition, a BUCC may also be required to support other corporate or power pool responsibilities that are normally performed by the primary control center. For example, power pool accounting or corporate-wide access to historical data may be required.

3. Threat Assessment for the Primary Control Center

Most utilities that have already implemented BUCCs did not perform a quantitative threat assessment. These utilities considered the consequences of a control center loss and the resultant concern for power system security as sufficient justification for implementing a BUCC. This type of qualitative justification is most prevalent among utilities that are located in areas prone to natural disasters.

The objective of performing a threat assessment is to determine the range of control center outages that need to be considered when planning for a BUCC. Brief outages (less than two hours) are not normally considered in a threat assessment, since their incremental impact to operations is small. A quantitative methodology for threat assessment and for BUCC cost justification involves the following steps:

(a) Determine the likelihood of losing a control center
(b) Quantify the consequences for different disaster scenarios
(c) Prepare a risk analysis using probabilities and cost consequences

3.1 Control Center Threats

When performing a threat assessment, the following types of events that could disable a control center should be considered:

(a) Natural disasters, such as hurricanes, earthquakes, tornados, floods, and other weather caused conditions. The frequency and severity of these natural disasters can be forecasted by using historical data.
(b) Accidents, such as fire, internal environmental problems, flooding, chemical spills, plane crash, explosion, loss of communications, and other catastrophic events. The frequency of accidental events may be obtained from insurance carriers or other industry experts.
(c) Sabotage, such as bomb threats, software viruses, and other malicious actions. The frequency of these events can be grossly estimated from the use of historical data and from information from other studies.
The overall annual frequency of control center loss is the total of the individual frequency for each of the above three classifications. Based on a utility’s location, the frequency of occurrence for each of these classifications could differ by a few orders of magnitude.

### 3.2 Impact on Control Center Operation

The above threats can result in various impacts to control center operation. The severity of these impacts can range from a forced evacuation of a few minutes up to the complete rebuilding of the control center facility. A comprehensive plan for justifying a BUCC should consider a full range of potential disaster durations, the following ranges of outage durations are appropriate:

(a) Short term — up to 48 hours  
(b) Intermediate term — up to two weeks  
(c) Long term — over two weeks

Please note, the number of classifications and the outage durations for the classifications can be tailored to the actual circumstances of a particular utility.

The following types of impacts to control center operations should be considered during the threat assessment process:

(a) Impacts that normally result in short-term outages:  
   (1) required evacuation of the control center  
   (2) loss of communications  
   (3) loss of EMS/SCADA system  
   (4) loss of critical data  
   (5) loss of control center support facilities, such as air conditioning, power, and water

(b) Impacts that may result in intermediate-term outages:  
   (1) damage to private microwave system  
   (2) severe damage to EMS/SCADA system  
   (3) damage to the control center facility

(c) Widespread damage to the control center facility could result in a long-term outage lasting many months

The cost consequences of these outages both with and without a BUCC can then be used in justifying the need for a BUCC.

### 3.3 Worst-Case Scenario

The cost consequences of a control center outage depend upon the state of the power system at the time the disaster occurs. A worst-case scenario would be a disaster that not only caused the loss of the control center facility, but also caused widespread outages in the electrical network. This would result in not only increasing the recovery time for the power system disturbance, but would most likely result in extended hours and deteriorating working conditions for both operating staff and field crews. This could lead to accidents, inaccurate records, and potentially unstable operating conditions. Because the costs associated with this type of worst case scenario would be almost impossible to determine, this document considers only the loss of the control center under normal power system conditions.
4. **Justification for a Backup Control Center**

As stated before, a utility can take one of two approaches for justifying a BUCC: a qualitative justification that discusses the costs of a control center loss and benefits of a BUCC in general terms, and a quantitative risk analysis that develops a complete cost justification for a BUCC. While gathering information for this document, it became apparent that most utilities with a BUCC performed a qualitative analysis to justify a “bare bones” backup facility.

4.1 **Qualitative Justification**

A qualitative justification is usually based on an opportunistic occurrence where the incremental cost to add a BUCC is small, such as the procurement of an EMS or the installation of a SCADA system at a remote regional control center. Where the threat of natural disasters and/or sabotage are significantly greater, a more sophisticated BUCC facility is more readily justified because of management’s concern for power system security or by other outside pressures.

Qualitative justifications should be based on NERC Guide III.G. criterion that control centers have plans and backup capability to avoid placing burdens on neighboring control areas. The cost of implementing these plans, including any cost to transfer control to an adjacent control area, purchase regulating service, or to operate the system in a conservative manner to assure system security, should be compared to the cost of implementing a BUCC.

4.2 **Quantitative Risk Analysis**

When performing a quantitative risk analysis, the following issues need to be considered:

(a) The change in average daily production cost with and without a BUCC
(b) Loss of revenue from potential interchange transactions
(c) Cost of additional staffing to support manual operations from critical locations for an extended period of time
(d) Effects on power system security based on potential loss of equipment due to lack of network security software
(e) Costs for training operators to work under emergency conditions from a backup facility for an extended period of time

The cost for each of the above items will be affected by the functional capabilities implemented in the BUCC. Different risk scenarios can then be used to evaluate the appropriate level of BUCC functionality. In disaster planning, the amount of resources worth investing in emergency facilities is evaluated using risk analysis. In this content:

\[ \text{Risk} = \text{Consequences} \times \text{Frequency} \]

In justifying a BUCC, the consequence is the cost difference between operating with and without a BUCC. This cost difference must take into account the different yearly probabilities and estimated outage durations. The frequency is the expected frequency of loss of the primary control center as discussed in Section 3.1. Risk can then be quantified as an Expected Annual Cost (EAC). The expected useful life of the BUCC must be used with the EAC in calculating the present worth of the BUCC. The
dollar amount worth spending on a BUCC is equal to its present worth. Clearly, this is not a precise analysis method.

4.3 Scope of the BUCC

The cost justification of expensive disaster recovery facilities is made difficult by the extremely low historical frequency of control center disasters. The low probability of an individual utility experiencing a disaster tends to justify only low budgets for a BUCC. This has led utilities to use manned backup facilities with only radio and telephone communications to monitor and control the power system during a control center disaster or outage. This method provided an initial low cost solution; but, in the long term, it was expensive to develop and maintain an adequate set of manual operating procedures. An increasing risk associated with a BUCC that relies on manual operating procedures is the inability of system operators to manage the complexities of a power system over an extended period of time without automated tools. For this reason, a manual control-oriented BUCC should only be considered as an adequate backup for short-term outages (up to 48 hours), and should not be used for protection against disasters that render the primary control center unusable for several days or more.

5. Alternative Solutions for Backup Control Centers

This section discusses alternative BUCC solutions in terms of control center prototypes that are used to represent a range of utility operating responsibilities in a control area. These prototypes are then used to discuss the metering and communications requirements that are necessary to support the critical BUCC functions as described in Section 1. Later sections discuss alternative BUCC solutions based on these prototypes.

<table>
<thead>
<tr>
<th>Prototype</th>
<th>Control Area Responsibilities</th>
<th>Control Center (CC) Configuration</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Primary control center performs complete control area dispatch</td>
<td>Single primary control center</td>
</tr>
<tr>
<td>2</td>
<td>Primary control center performs complete control area dispatch</td>
<td>Primary control center with subordinate control centers</td>
</tr>
<tr>
<td>3</td>
<td>Primary control center performs AGC but does not directly control generating units</td>
<td>Primary control center with subordinate control centers</td>
</tr>
<tr>
<td>4</td>
<td>Control center does not perform AGC but sends control signals to generating units</td>
<td>Single control center</td>
</tr>
<tr>
<td>5</td>
<td>Control center does not perform AGC but sends control signals to generating units</td>
<td>Control center with subordinate controls centers</td>
</tr>
<tr>
<td>6</td>
<td>Control center has no involvement in AGC</td>
<td>May or may not have subordinate control centers</td>
</tr>
</tbody>
</table>
5.1 BUCC Metering and Communication Requirements

Regardless of the level of sophistication of the BUCC, the most important considerations when implementing a BUCC is the availability of both voice and data communication facilities. Providing adequate communications is the major portion of the cost for a BUCC. It is essential for system operators at the BUCC to have voice communications with operating personnel that they normally communicate with from the primary control center. If the BUCC is to include data monitoring and supervisory control, these communications facilities must also include data channels to remote terminal units located at key substations. Data channels may also be required to send control signals to generating plants or subordinate control centers as appropriate. The following table provides the metering and communication requirements for each of the BUCC prototypes.

<table>
<thead>
<tr>
<th>BUCC Metering &amp; Communication Requirements</th>
<th>Prototypes</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>1</td>
</tr>
<tr>
<td>1. Instantaneous tie-line MW and Mvar telemetry</td>
<td>✓</td>
</tr>
<tr>
<td>2. Instantaneous generating unit MW telemetry</td>
<td>✓</td>
</tr>
<tr>
<td>3. MWh accumulator readings for all tie lines and generating units</td>
<td>✓</td>
</tr>
<tr>
<td>4. SCADA for generating units</td>
<td>✓</td>
</tr>
<tr>
<td>5. SCADA for unmanned, critical substations</td>
<td>✓</td>
</tr>
<tr>
<td>6. System frequency and time error measurements</td>
<td>✓</td>
</tr>
<tr>
<td>7. Data links to send generation control signals to subordinate centers</td>
<td>–</td>
</tr>
<tr>
<td>8. Voice communications to manned power plants</td>
<td>✓</td>
</tr>
<tr>
<td>9. Voice communications to manned, critical substations</td>
<td>✓</td>
</tr>
<tr>
<td>10. Voice Communications to subordinate control centers</td>
<td>–</td>
</tr>
<tr>
<td>11. Voice communications to higher-level control center</td>
<td>–</td>
</tr>
<tr>
<td>12. Voice communications to neighboring control centers</td>
<td>✓</td>
</tr>
</tbody>
</table>
5.2 BUCC Alternative Solutions

The BUCC alternatives available to an electric utility range from a basic “war room” equipped with system maps, diagrams, telephones, radios, and manual procedure documents to a full-function replica of the primary control center complete with most, if not all, application software used for control of the power system. As the level of sophistication of the BUCC facility increases, so in general, does its initial implementation cost. However, the ongoing support cost of a BUCC is normally inversely proportional to its degree of sophistication due to the costs associated with developing, maintaining, and teaching the skills and procedures required to support the manual operation of the power system. The following sections list the configuration alternatives for implementing a BUCC at utilities with and without subordinate control centers.

5.2.1 Utilities Without Subordinate Control Centers (Prototypes 1, 4 and possibly 6)

These utilities are at a disadvantage in that there is no obvious location, such as a divisional control center, to assume the backup control functions if the primary control center is disabled. The solution is to select an existing facility, such as a previous control center site or an office facility, that has access to the communications facilities and thus can be provided with the data necessary to perform the required BUCC functions. The selected facility should be sufficiently removed from the primary control center in order to isolate it from the same threats that may render the primary control center inoperable.

The following types of alternative configurations can be deployed at the BUCC depending upon the level of functionality required:

(a) A remote facility with a complete backup EMS/SCADA system (either a single or dual processor). This configuration provides full functionality at the BUCC, but also requires a large amount of telemetry and data to support it. The use of a retired EMS or SCADA system to perform as the BUCC is a way to reduce the initial implementation cost; however, the long-term maintenance costs are usually high due to a lack of spare parts, inadequate documentation, and cumbersome software/database maintenance tools.

If the BUCC is an exact duplicate or a subset of the primary control center, then the BUCC could also be used as a remote maintenance site for troubleshooting hardware, as an additional source for critical spare parts, and as a remote test site for newly developed or modified software.

(b) A remote facility with reduced functionality using one or more workstations and/or personal computers. This configuration provides the most functional flexibility and ease of expansion. Advancements in networking and distributed systems/database technologies have allowed utilities to implement a basic set of SCADA/AGC functions on microprocessor-based platforms that can be easily expanded in the future via third-party software products that run under standard operating systems, such as UNIX and DOS. Custom operating procedures and software/database maintenance tools must be developed to support this type of BUCC configuration.

(c) A remote facility with minimum requirements that is used for manual dispatch. A utility must determine if adequate system regulation can be maintained using manual
generation control. As mentioned above, manual operation from a BUCC should only be considered as a backup strategy for short-term emergencies. Specific plans and procedures should be in place for establishing an adequate backup facility if a longer-term outage occurs at the primary control center. This may be accomplished either by an agreement with a neighboring utility to provide backup control area capability or by acquiring backup equipment and communications at the BUCC under emergency conditions. If a neighboring utility is to provide adequate system regulation, then tie line MW telemetry must be made available to it.

5.2.2 Utilities with Subordinate Control Centers (Prototypes 2, 3, 5 & possibly 6)

These utilities may use any of the BUCC configurations described in the previous section and also have access to the facilities of the subordinate control centers. Once again, the communications system is key to the functionality of the BUCC. If one or more of the subordinate control centers has access to all of the data available to the primary control center, it is possible to duplicate the functionality of the primary control center by locating the BUCC at the subordinate control center. Otherwise, the functionality of the BUCC will be limited to the data available at the subordinate control center site.

In addition to the configurations described in Section 5.2.1, the BUCC control system at a subordinate control center may also take the following forms:

(a) A stand-alone system (either single or dual processor) that utilizes the subordinate control center’s communication facilities. This configuration minimizes the impact of any BUCC activities on the existing computer system.

(b) Use of the redundant portion of the existing subordinate control center computer system to perform the BUCC functions. In this configuration, special backup software that is normally deactivated can be initialized on the redundant processor of the existing system whenever there is a need for the BUCC. If there is an extended outage of the primary control center, this configuration can provide an interim solution that will allow sufficient time to procure additional hardware to implement the BUCC functions on a separate system and, if necessary, expand the overall functionality of the BUCC.

5.2.3 Other Alternatives

Many utilities, regardless of their prototype categories, include a development system or a stand-alone operator training simulator in their EMS/SCADA system configuration. Each of these systems can be a potential BUCC if located at a remote site. The only resources they lack are sufficient communication interfaces to remote facilities for performing the required monitoring and control actions. For an incremental investment either of these systems can be expanded to include the necessary communications interface equipment.

Another alternative is the use of a high performance workstation that is normally used as a remote console. Under emergency conditions, the workstation can be reconfigured and enhanced with SCADA and AGC capabilities to perform a minimum set of BUCC functions, assuming sufficient data and voice communication access to critical remote facilities is available.
6. Training and Maintenance Costs

In addition to any leased communication costs, there are two main elements to the recurring cost of a backup control center; training and maintenance.

6.1 Training Costs

Training will consist of classroom training in the procedures to evacuate the primary control center, activate and occupy the BUCC, operate from the BUCC, and validate and reactivate the primary control center once the emergency condition has cleared. The amount of required training will increase in proportion to the degree the tools and procedures used in the BUCC are different than those used in the primary control center.

In general, if time is already allocated for an ongoing operator training program, the BUCC training should have a relatively small incremental cost associated with it. Otherwise, it will be necessary to bring operators in for training at special times and may involve overtime costs, as well as the cost for developing the training materials.

In addition to classroom training, there is the need for periodic drills to practice transfer procedures from the primary to the backup control center. Since most utilities staff both the primary and backup control centers during drills, the cost will be the overtime costs for a second shift of operators. These drills are normally conducted at a periodicity that ranges from quarterly to yearly. The duration of the drills normally range from an hour to a maximum of 24 hours.

6.2 Maintenance Costs

Three aspects of BUCC maintenance are hardware, software, and database/display updates. The degree of difficulty of all three areas is related to the configuration of the BUCC compared with that of the primary control center.

Even if the BUCC is based on entirely manual operations, (i.e., does not have any computers or other control equipment), there will still be some maintenance cost. This cost will be to maintain adequate communication circuits, written evacuation and startup procedures, log sheets, system diagrams, substation diagrams, relaying diagrams, operating procedures, and other textual material normally stored in a computer system.

If the BUCC is an exact duplicate or a subset of the primary control center, the incremental maintenance costs associated with the BUCC should be relatively small. Depending on whether the utility performs self-maintenance or contracts out hardware maintenance, the incremental hardware maintenance cost will either be negligible or a function of the additional hardware to be maintained. The software, database, and display maintenance can be accomplished as part of the primary control center maintenance and simply involves transporting the changes to the BUCC site and loading them into the BUCC. This can also be accomplished via a data link if the two centers are interconnected.

If the BUCC is the functional equivalent of the primary control center, but uses different hardware and software, such as the system previously used at the primary control center, all three elements of the maintenance costs will escalate and may approach those of the primary control center. The hardware maintenance will require unique training, test equipment, and spare parts. All software
changes and database and display edits performed at the primary control center will have to be repeated at the BUCC.

In addition to the above cases, there are various configuration alternatives that impact the maintenance costs. For example, the use of a BUCC with reduced functionality that is configured with PCs and workstations rather than minicomputers will reduce both hardware and overall system maintenance costs. Maintenance also depends on whether the BUCC has any other functions when the primary control center is operational. If the BUCC is normally used for other purposes, the incremental maintenance cost for its use as a BUCC will be very small. Similarly, if the BUCC is co-located with an existing control system that requires an on-site maintenance staff, the cost of BUCC maintenance will be reduced significantly.

In addition to the BUCC maintenance costs, a utility should also consider an annual budget for software upgrades both to enhance economic operation and overall power system security and to maintain a level of “open system” standards that are compatible with those implemented on the primary control system. This level of compatibility will allow both systems to evolve together as the responsibilities and interface requirements for the control center change over time.

7. Conclusion

The following conclusions regarding the planning of a backup facility were drawn from the survey of utilities with existing BUCCs:

(1) The most critical issue, based on both initial and recurring costs, in implementing a backup control center is its access to both voice and data communication facilities. It is for this reason that the majority of backup control centers are currently located at regional control centers or other utility locations that have access to a company-wide communications network. Installing the BUCC at a regional control center also has the advantage of an on-site maintenance staff and already existing support facilities for an on-line control system. For those utilities without regional control centers, a remote facility that houses an operator training simulator, a software development system, or a high-performance workstation may be a good candidate for a BUCC if sufficient communication facilities are available.

(2) Most backup control systems are implemented as an opportunistic addition to a larger procurement, such as a replacement EMS or a regional SCADA system. However, utilities that do not have a BUCC can use advances in communications networking and control system platforms to reduce its cost for implementing a BUCC. Microprocessor-based technologies, the industry-wide migration to de facto software standards (e.g., UNIX, TCP/IP, SQL) and high-level languages, and the ability to network diverse computer systems have driven down both the hardware and software costs for implementing a backup control system while improving the available processing power for a reduced function backup facility.
(3) The scope of the BUCC should not only satisfy the minimum requirements as described in Section 2, but should also have sufficient functionality to cover most long-term disasters. On average, backup control systems have been designed to support emergency operations for up to a six-month period. For severe control center outages that extend beyond the six-month period, the six months will allow sufficient time to enhance the backup control system into a redundant, fully functional primary control system.
Appendix A

Bibliography


Appendix B

Utility Questionnaire

Introduction

This survey is being conducted by Macro Corporation under the sponsorship of the NERC Operating Reliability Subcommittee and EPRI within the framework of EPRI Project RP2473-68. The survey responses will be used in the study collectively and no reference will be made to the name of the organization nor the source of specific information. However, a list of the organizations responding to the questionnaire will be included in the study report. If you do not wish the name of your organization to appear in the list, please check the box below.

☐ Do not use the organization name in the report.

Objectives

The objective of the study is to prepare a reference document for utility use in scoping, justifying, and planning a backup control center.

The objective of this survey is to obtain sufficient information about current knowledge of and experience with backup control center planning and implementation. This information will be used to define general control center prototypes based on operational responsibility and specific planning elements to be incorporated into the reference document.

Method Of Response

After you have had time to review the survey you will be contacted by Macro to arrange a telephone interview during which we will receive your responses verbally. If you prefer, you may respond in writing and we will call you only if we require further clarification of your answer.

1. Organization Data

1.1 Organization Name

1.2 Discuss Your Operating Responsibilities

a. Involved in generation control
b. Calculates ACE
c. Receives generation control signals from higher level control center
d. Sends signals to units
e. Sends signals to lower level control center

1.3 Control Center Location
2. Control System Data

2.1 SCADA or EMS
2.2 Manufacturer and Installation Date
2.3 Functions
    Consider the following:
    a. SCADA — RTUs (#)
       — Data Links (#)
    b. Automatic Dispatching System (AGC, ED, ITS, RM, and PC)
    c. Generation Scheduling (LF, UC, and ITE)
    d. Power System Analysis (SE, BLDF, SSSA, PF, VS, SCD, and SENH)
    e. Information Storage and Retrieval (PDSR, Energy ACC, and DDC)
    f. Other—Specify

2.4 User Interface
    a. Consoles — Local
       — Remote
    b. Mapboard
    c. Trend Recorders
    d. Other — Specify

3. Backup Control Center

3.1 Do you have a plan to continue operation in the event the control center becomes inoperable?
    YES — Go to 3.4  NO — Continue

3.2 Explain the lack of a plan. Was it a conscious decision or default? Is there a plan to reconsider?

3.3 If it was a conscious decision, explain the basis for the decision.

3.4 Do you have a Backup Control Center (BUCC)?
    YES — Go to 3.7  NO — Continue

3.5 Have you ever considered implementing a BUCC? Please explain why you have not considered one or why you decided against one.

3.6 Have you ever been in a situation where you would have used a BUCC if you had one? Please elaborate.

3.7 Did you perform a requirements or justification study before implementing the BUCC? If yes, please summarize the study and its results.

3.8 Discuss the types of emergencies that would force you to use a BUCC. What are the minimum and maximum durations you would expect to occupy the BUCC due to any single emergency or disaster? Discuss the range of backup plans you may have based on the severity of the incident.
3.9 What was the justification for the BUCC? Consider economic, political, emotional, results of a management audit, or other.

3.10 Were the costs and benefits quantified? If so, please discuss the methods used to quantify both.

3.11 What range of outage durations of the main control center was the BUCC designed to support? Consider:
   a. Short Term — Up to 48 hours
   b. Intermediate Term — Up to two weeks
   c. Long Term — Over two weeks

What plans do you have if the outage exceeds the planned duration?

3.12 Where is the BUCC located with respect to the main control center? Are the BUCC site and facilities used for any other purpose when the BUCC is not in use? If yes, please elaborate.

3.13 What facilities are provided at the BUCC? Consider the following:
   a. Computers — Host Minicomputers, workstation(s), PC(s), calculators, and analog equipment
   b. Consoles — Local and/or remote
   c. Mapboard, trend recorders, etc.
   d. Local meters
   e. Maps, one-line diagrams, log sheets, operating instructions, system documentation, and the like

3.14 What communications are available at the BUCC? Consider the following:
   a. Data from RTUs? Data links? Other?
   b. Dedicated voice channels to power plants, other control centers, other company facilities, and other places.
   c. Dial-up voice channels
   d. Radio channels

3.15 What functions are available at the BUCC? For each function performed at the main control center, estimate the percent that is available at the BUCC? (For example x% of the RTU data available at the main control center is available at the BUCC.)

3.16 For those functions not available at the BUCC, how are they performed when the main control center is down? For example, the transmission coordination and monitoring functions that are normally performed at the main control center are parceled out to the divisional control centers when the main control center is down.
3.17 Discuss the method used to procure the BUCC. Was it implemented as a standalone project or as part of another project? Provide an estimate of the cost of the BUCC including procurement cost, project staffing, communications, training, facilities, and all other related costs.

3.18 Do you have written procedures for the following events?

a. Evacuation of the main control center
b. Occupation and activation of the BUCC
c. Functional verification and reactivation of the main control center

3.19 Do you perform system drills periodically where the BUCC is activated and used to control the electric power system? What is the frequency and duration of these drills?

3.20 Have you ever activated and used the BUCC because of a real problem at the main control center? If yes, please elaborate.

3.21 Discuss the impact of the BUCC on the following:

a. Staffing
b. Training
c. Documentation
d. Hardware Maintenance
e. Database and Software upgrades
f. Operation and Maintenance Budget

3.22 Discuss future plans for a BUCC or upgrading the existing BUCC.
Dynamic Transfer Reference Document
Version 3
May 2016
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Preface

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

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

The Regional boundaries in this map are approximate. The highlighted area between SPP and SERC denotes overlap as some load-serving entities participate in one Region while associated transmission owners/operators participate in another.

<table>
<thead>
<tr>
<th>FRCC</th>
<th>Florida Reliability Coordinating Council</th>
</tr>
</thead>
<tbody>
<tr>
<td>MRO</td>
<td>Midwest Reliability Organization</td>
</tr>
<tr>
<td>NPCC</td>
<td>Northeast Power Coordinating Council</td>
</tr>
<tr>
<td>RF</td>
<td>ReliabilityFirst</td>
</tr>
<tr>
<td>SERC</td>
<td>SERC Reliability Corporation</td>
</tr>
<tr>
<td>SPP-RE</td>
<td>Southwest Power Pool Regional Entity</td>
</tr>
<tr>
<td>TRE</td>
<td>Texas Reliability Entity</td>
</tr>
<tr>
<td>WECC</td>
<td>Western Electricity Coordinating Council</td>
</tr>
</tbody>
</table>

NERC | Dynamic Transfer Reference Guidelines – Version 2 | June 2010
Chapter 1 - Overview

Purpose
The purpose of this document is to provide guidance and encourage consistency in the industry on the responsibilities, requirements, and expectations placed upon parties involved in establishing a dynamic transfer. It is not within the scope of this reference document to require any organization to modify any existing dynamic transfers.

Terms

Attaining BA — A BA bringing generation or load into its effective control boundaries through dynamic transfer from the Native BA.

Dynamic Transfer Signal — The electronic signal used to implement a pseudo-tie or dynamic schedule using either a metered value or a calculated value.

Integration in the terms for dynamic schedule and pseudo-tie above means the value could be mathematically calculated or determined mechanically with a metering device.

Native BA — A BA from which a portion of its physically interconnected generation and/or load is assigned from its effective control boundaries through dynamic transfer to the attaining BA.
Chapter 2 – Dynamic Schedule versus Pseudo-tie Fundamentals

The key difference between pseudo-ties and dynamic schedules is often viewed only as a system control issue. Discussions are typically limited to how the transfer is implemented in each BA’s ACE equations and in the associated energy accounting process. Pseudo-ties are accounted for by all parties as actual interchange and dynamic schedules are accounted for as scheduled interchange. However, there are other factors that must be considered when determining which type of dynamic transfer should be utilized for a given situation. The descriptions provided in this document are based on practical experience where dynamic transfers have been successfully implemented.

From a simple perspective, a dynamic schedule is a means of achieving a time-varying exchange of power where a traditional block scheduling is not sufficient. Examples might be the partial or complete exchange of regulating obligations (see Appendix B — Supplemental Regulation Service as a Dynamic Schedule), the temporary provision of power under a reserve sharing agreement, or the exchange of power to serve a real-time demand signal.

On the other hand, pseudo-ties are used (typically but not exclusively) to represent interconnections between two BAs at a generator or load similar to a physical tie line. These load/generators, however, are at locations where no other physical connection exists between the load/generation and the power system network of the responsible, Attaining BA’s traditional control boundaries defined by its physical tie lines. In the instance of a pseudo-tie, the operational and procedural responsibility¹ for a load/generation is key. In addition to system control responsibility that is traditionally considered, the responsibilities related to a pseudo-tie extend to such requirements as Disturbance Control Standard (DCS) recovery, load shedding, transmission and ancillary services, load forecasting, etc. associated with the load/generation.

Although both pseudo-ties and dynamic schedules involve time-varying quantities, unlike for a pseudo-tie, a dynamic schedule has no specific load/generation for which the attaining BA is operationally or procedurally responsible.

The choice of a pseudo-tie versus dynamic schedule can be adapted to suit any implementation between the native and attaining BAs – as long as both BAs agree which one is responsible for each of the obligations associated with the load/generation. For example, a pseudo-tie would typically be used to represent a generator owned by an attaining BA that is located within the physical tie line boundary of a native BA. However, a dynamic schedule implementation can be used in each BA’s ACE equation as long as responsibility for obligations such as recovery during a DCS event are clearly understood and accepted by both BAs.

¹ Procedural responsibility refers to which Balancing Authority Area’s and/or which Reliability Region’s requirements will apply to the generator or load.
Chapter 3 - Dynamic Transfer Implementation Considerations

Dynamic transfers can be used for, but not limited to the following scenarios:

- Transfer all, or a portion of, actual output of a specific generator(s) to another BA in real-time,
- Enable resources in one BA to provide the real-time power requirements for a load physically located in another BA, or
- Enable generators, loads, or both in one BA to supply one or more interconnected operations services to generators, loads, or both in another BA, or
- Provide a mechanism for reserve sharing, or
- Provide supplemental regulation.

The particular dynamic transfer method to be utilized for a specific operating arrangement may be dependent on some or all of the following:

- Desired service(s) to be provided,
- The capability to capture the dynamic transfer in system models,
- Responsibility for forecasting load,
- Responsibility for providing unit commitment and maintenance information, and
- EMS capability.

Each BA is obligated to fulfill its commitment to the Interconnection and not burden other BA(s) in the Interconnection. The use of a dynamic transfer does not in any way diminish this responsibility.

- Before implementing the dynamic transfer, all parties to the dynamic transfer must agree on all implementation issues.
- Any errors resulting from an improperly implemented or operated dynamic transfer (including inadvertent interchange accumulations) must be resolved between the involved parties.
- Dynamic transfers must NOT include any control offsets that are not explicitly compliant with the requirements set forth in the NERC reliability standards (e.g., unilateral inadvertent payback, Western Interconnection automatic time error control, etc.).
- Applicable tariff requirements of all involved, or affected, transmission providers and BA(s) must be met (this includes proper handling and accounting for energy losses).
- If the dynamic transfer includes a pre-arranged calculated assistance (or distribution of responsibility) between the native BA and the attaining BA for recovery from the loss of generation, then both BAs are responsible for ensuring that their respective DCS compliance reporting requirements are met in accordance with NERC Standard BAL-002-0 — Disturbance Control Performance.
- The projected use of the transmission system for a dynamic transfer shall be modeled in the base case power flow study cases. Such modeling must be done for the dynamic transfer at each end of its range, and for as many other points within its range as required to ensure that the dynamic transfer will not cause reliability problems in real time.

From a system modeling perspective, the assignment of load or generation into the control response of another BA must be appropriately captured in the reliability analysis tools. It is the obligation of each BA involved in the
dynamic transfer to ensure that the dynamic transfer of load or generation is coordinated with their Reliability Coordinator so that the method of dynamic transfer can be considered in the system modeling of the generation or load affected, and necessary data provision requirements are met.

- To assure proper resource application, it is the responsibility of the attaining BA dynamically transferring load into its effective boundaries through pseudo-ties to ensure that load forecasts and subsequent BA reporting reflect the load incorporated within its BA boundaries. Conversely, when a dynamic schedule is used to serve load within another BA area, the BA where the load is electrically connected (native BA) must include that load in its BA load forecast and any subsequent reporting as needed.

- It is the responsibility of both the native BA and attaining BA to model any generation or load serving dynamic transfers in their respective, power flow models and security applications. This modeling is required to ensure that both affected BAs study the generation or load regardless of the control boundary designations. This modeling also is necessary to ensure that each BA can see the impact of the dynamic transfer on their systems.

- Dynamic transfers must not affect reliability adversely. If the reliability impact of a dynamic transfer that has been implemented as a pseudo-tie cannot be addressed adequately without modeling it in the IDC or other applicable security analysis system models that use scheduled values, then the dynamic transfer must be performed via a dynamic schedule.

- For both Pseudo-Ties and Dynamic Schedules — The BAs shall adjust the control logic that determines their frequency bias setting to account for the frequency bias characteristics of the loads and/or resources being assigned between BAs.

  - Frequency Bias Setting — Once the ERO reviews the data submitted in FRS Form 1 and FRS Form 2 for all Balancing Authorities, the ERO will use FRS Form 1 data to post the following information for each Balancing Authority for the upcoming year:
    - Frequency Bias Setting
    - Frequency Response Obligation (FRO)

  Once the data listed above is fully posted, the ERO will announce the three-day implementation period for changing the Frequency Bias Setting if it differs from that shown in the timeline below.

A BA using a fixed Frequency Bias Setting sets its Frequency Bias Setting to the greater of (in absolute value):

- Any number the BA chooses between 100% and 125% of its Frequency Response Measure as calculated on FRS Form 1
- Interconnection Minimum as determined by the ERO

For purposes of calculating the minimum Frequency Bias Setting, a Balancing Authority participating in a Frequency Response Sharing Group will need to calculate its stand-alone Frequency Response Measure using FRS Form 1 and FRS Form 2 to determine its minimum Frequency Bias Setting.

A Balancing Authority providing Overlap Regulation will report the historic peak demand and generation of its combined BAs’ areas on FRS Form 1 as described in Requirement R4.

There are occasions when changes are needed to Bias Settings outside of the normal schedule. Examples are footprint changes between Balancing Authorities and major changes in load or generation or the formation of new Balancing Authorities. In such cases the changing Balancing Authorities will work with their Regions, NERC
Chapter 3 – Dynamic Transfer Implementation Considerations

and the Resources Subcommittee to confirm appropriate changes to Bias Settings, FRO, CPS limits and inadvertent interchange balances.

If there is no net change to the Interconnection total Bias, the Balancing Authorities involved will agree on a date to implement their respective change in Bias Settings. The Balancing Authorities and ERO will also agree to the allocation of FRO such that the sum remains the same.

If there is a net change to the Interconnection total Bias, this will cause a change in CPS2 limits and FRO for other Balancing Authorities in the Interconnection. In this case, the ERO will notify the impacted Balancing Authorities of their respective changes and provide an implementation window for making the Bias Setting changes.

The native, attaining, and intermediate BAs must carefully coordinate many aspects related to dynamic transfers. Failure to do so may result in the creation of reliability problems for the Interconnection, may create after-the-fact energy accounting and billing problems, and may cause violations of industry standards. Below is a list of items that the affected BAs should consider prior to implementing a new dynamic transfer:

- Control offsets are compliant with applicable industry standards
- Tariff requirements are met
- DCS reporting requirements have been addressed
- Transmission service has been considered
- Need for inclusion in reliability tools has been addressed
- Transferred loads and/or generation are accounted for in energy dispatch
- Transferred loads and/or generation are still included in relevant security analysis tools
- Frequency Bias impacts have been addressed
- Contingency plans for loss of dynamic transfer signal have been addressed
- Contingency plans for network problems that prohibit the dynamic transfer
- Other industry compliance issues have been addressed
- Energy accounting practices are consistent, including losses
- Ancillary service provision has been addressed
- Impact on spinning reserve requirements have been addressed
- Impact on under-frequency load shedding relays have been addressed

Table 1 describes and outlines the obligations associated with the typical historical application of pseudo-ties and dynamic schedules related to many of the topics addressed above. In practical application, however, both the native and attaining BAs can agree to exchange the obligations from that shown in the Table 1.

<table>
<thead>
<tr>
<th>BA’s Obligation/modeling</th>
<th>Pseudo tie</th>
<th>Dynamic schedule</th>
</tr>
</thead>
<tbody>
<tr>
<td>Generation planning and reporting and outage coordination</td>
<td>Attaining BA</td>
<td>Typically, native BA but may be re-assigned (wholly or a portion) to the attaining BA</td>
</tr>
</tbody>
</table>

Table 1: Assignment of BA Obligations

Deleted: Each BA is required to review its Frequency Bias Setting on an annual periodicity. The BA may change its Frequency Bias Setting, and the method used to determine the setting, whenever any of the factors used to determine the current bias value change. Each BA, upon request from NERC, will report its Frequency Bias Setting, and the method for determining the setting.

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Table 1 - Assignment of BA Obligations

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Table 1: Assignment of BA Obligations

<table>
<thead>
<tr>
<th>BA’s Obligation/modeling</th>
<th>Pseudo tie</th>
<th>Dynamic schedule</th>
</tr>
</thead>
<tbody>
<tr>
<td>CPS and DCS recovery/reporting and RMS</td>
<td>Attaining BA</td>
<td>Attaining and/or native BA (depending on agreements)</td>
</tr>
<tr>
<td>Operational responsibility</td>
<td>Attaining BA</td>
<td>Native BA</td>
</tr>
<tr>
<td>BA services FERC OATT Schedules 3–6 and other ancillary services as required</td>
<td>Attaining BA</td>
<td>Native BA</td>
</tr>
<tr>
<td>Ancillary services associated with transmission FERC OATT Schedules 1–2 and other ancillary services as required</td>
<td>Attaining/native BA (as agreed)</td>
<td>Attaining/Native BA (as agreed)</td>
</tr>
<tr>
<td>ACE frequency bias calc/setting</td>
<td>The native and attaining BA(s) shall adjust the control logic that determines their frequency bias setting to account for the frequency bias characteristics of the loads and/or resources being assigned between BA(s) by the pseudo-tie</td>
<td>The attaining BA should include the load from its dynamic schedule as a part of its forecast load to set frequency bias requirement. The native BA should change its load used to set frequency bias setting by the same amount in the opposite direction.</td>
</tr>
<tr>
<td>Load forecasting and reporting</td>
<td>Attaining BA</td>
<td>Native BA</td>
</tr>
<tr>
<td>Manual load shedding during an Energy Emergency Alert (EEA)</td>
<td>Attaining BA</td>
<td>Native BA</td>
</tr>
</tbody>
</table>

Note: This table contains the typical BA obligations that have been utilized throughout the industry for pseudo-ties and dynamic schedules. However, for any specific dynamic transfer implementation, both the native and attaining BAs can agree to exchange the obligations from that shown in the Table 1.
Chapter 4 - Dynamic Schedule

A dynamic schedule is implemented as an interchange transaction that is modified in real-time to transfer time-varying amounts of power between BAs. A dynamic schedule typically does not change a BA’s operational responsibility; that is, the native BA continues to exercise operational control over, and provides basic BA services to, the dynamically scheduled resources.

Dynamic schedules are to be accounted for as interchange schedules by the source, sink, and contract intermediary BA(s), both in their respective ACE equations, and throughout all of their energy accounting processes. Requirement to incorporate into the contract intermediary BA’s ACE is subject to regional procedures.

All dynamic schedules used for supplemental regulation or to assign the control of generation, loads, or resources from one BA to another must meet the following requirements:

1. Telemetry
   Appropriate telemetry must be in place and incorporated by all affected BA(s) in accordance with all NERC reliability standards, in particular the Disturbance Control Performance standard.

2. Transmission Service
   Prior to implementation of the dynamic schedule of load or generation, all applicable NERC interchange reliability standards need to be met, including ancillary services and provision of losses.
   
   If transmission service between the source and sink BA(s) is curtailed then the allowable range of the magnitude of the schedules between them, including dynamic schedules, may have to be curtailed accordingly. All BAs involved in a dynamic schedule curtailment must also adjust the dynamic schedule signal input to their respective ACE equations to a common value. The value used must be equal to or less than the curtailed dynamic schedule tag. Since dynamic schedule tags are generally not used as dynamic transfer signals for ACE, this adjustment may require manual entry or other revision to a telemetered or calculated value used by the ACE.

3. System Modeling
   When a dynamic schedule is used to serve load within another BA area, the BA where the load is electrically connected (native BA) must include that load in its BA load forecast for both energy dispatch and security analysis and any subsequent reporting as needed. This is necessary because the system models must adequately capture the projected demand on the system (load forecast), and the projected supply (provided by the electronic tagging system).

4. Dynamic Schedule Coordination and Scheduling
   Implementation of a dynamic schedule must be through the use of an interchange transaction between BA(s). As such, all dynamic schedules shall be implemented in accordance with NERC interchange standards.
   
   Energy exchanged between the source, sink, and intermediary BA(s) as a dynamic schedule is the metered or calculated (obtained by the integration of the dynamic schedule signal) energy for the loads and/or resources. Agreements must be in place with the applicable transmission providers to address the physical or financial provision of transmission losses.
   
   The native BA must ensure that agreements are in place defining the responsibility for providing applicable ancillary/interconnected operations services.
If the power flows associated with the dynamic schedule are expected to be bi-directional, two separate dynamic schedules are required (each schedule to be implemented as unidirectional following the “gen-to-load” direction convention). This expectation is a result of the fact that transmission service would be required for the dynamic schedules and most often import and export transmission services are provided as separate reservations.

5. Contingency Response

Before implementation of the dynamic schedule, the involved BAs shall agree on a plan:

- To operate during a loss of the dynamic schedule telemetry signal such that all involved BAs are using the same value (including periods of time when the interconnection between them is unavailable). The BA(s) may agree to hold the last known good value, use an average load profile value, or have one party provide the other with a manual override value at some acceptable frequency of update.

- To serve the load during system conditions which prevent delivery of the dynamic schedule from the generation to the load.

- To redispach the generation that had served the dynamically scheduled load prior to the system conditions which prevent delivery from the generation to the load.

6. Compliance with NERC Reliability Standards

The implementation of a dynamic schedule may confer upon the attaining BA additional responsibilities for compliance with NERC reliability standards for the load or generation that has been transferred.
Chapter 5 – Pseudo-Tie

Pseudo-ties are often employed to assign generators, loads, or both from the BA to which they are physically connected into a BA that has effective operational control of them. Thus, pseudo-ties often provide for change of BA operational responsibility from the native to the attaining BA and at the same time make the attaining BA provider of BA services. In practice, pseudo-ties may be implemented based upon metered or calculated values. All BAs involved account for the power exchange and associated transmission losses as actual interchange between the BAs, both in their ACE equations and throughout all of their energy accounting processes. All pseudo-ties used to assign generation, loads, or resources from the native BA to the attaining BA must meet the following requirements:

1. Telemetry
   Prior to implementation of the pseudo-tie transfer of load or generation, all applicable NERC reliability standards need to be met, including:
   • common metering points
   • adequate communications infrastructure
   The requirement for common metering points and adequate communications infrastructure does not imply specific ownership of telemetry devices.

2. Transmission Service
   Prior to implementation of the pseudo-tie transfer of load or generation, each involved BA shall ensure that the dynamic transfer is implemented such that the tariff requirements of the applicable transmission provider(s), including applicable ancillary services and provision of losses, are met.
   If transmission service between the native and attaining BA(s) is curtailed, then the allowable range of the magnitude of the pseudo-ties between them must be limited accordingly to these constraints.
   Agreements must be in place with the applicable transmission providers to address the physical and/or financial provision of transmission losses.

3. System Modeling
   The attaining BA dynamically transferring load into its effective boundaries through a pseudo-tie shall ensure that load forecasts used for energy dispatch and subsequent BA reporting reflect the load incorporated within its BA boundaries. The native BA would continue to consider this load in load forecasts used for security analysis.
   If the reliability impact of the pseudo-tie cannot be accurately captured in the IDC and/or any other security analysis system models of the reliability entities impacted by the dynamic transfer, then the dynamic transfer must be implemented as a dynamic schedule.

4. Pseudo-Ties Coordination and Scheduling
   Subsequent to moving load or resources into an attaining BA through pseudo-tie transfers, all interchange transactions or other energy transfers to the loads or from the resources must be coordinated among the attaining intermediary and native BAs in accordance with the NERC reliability standards.
   • The attaining BA assumes responsibility for BA services required by the assigned loads and/or resources. The attaining BA assumes all regulation, contingency reserves, and other BA responsibilities for the loads and/or resources in question.
5. Contingency Response

Before implementation of the pseudo-tie transfer, the involved BAs shall agree on a plan:

- To operate during a loss of the pseudo-tie transfer telemetry signal such that all involved BAs are using the same value (including periods of time when the interconnection between them is unavailable). The BA(s) may agree to hold the last known good value, use an average load profile value, or have one party provide the other with a manual override value at some acceptable frequency of update.

- To serve the load during system conditions which prevent delivery of the pseudo-tie transfer from the generation to the load.

- To redispatch the generation that had served the pseudo-tie transfer load prior to the system conditions which prevent delivery from the generation to the load.

6. Compliance with NERC Operating Standards

The implementation of a pseudo-tie transfers may confer upon the attaining BA additional responsibilities for compliance with NERC reliability standards for the load or generation that has been transferred.
Appendix A – ACE Equation Implications of Dynamic Transfers

\[
ACE = \left\{ \left[ \text{Net Actual Interchange} \right] - \left[ \text{Net Schedule Interchange} \right] \right\} - 10F_b \left( F_A - F_s \right) - IME
\]

(1)

\[
ACE = \left\{ [N_A] - [N_S] \right\} - 10F_b \left( F_A - F_s \right) - IME
\]

(2)

\[
ACE = \left\{ \left( N_A + (N_{APTGE} - N_{APTGI} - N_{APTLE} + N_{APTLI} + N_{ARSE} - N_{ARSI}) \right) \right\}
\]

\[
- \left\{ \left( N_S + \left( - N_{SDSGE} + N_{SDSGI} + N_{SDSLE} - N_{SDSLI} - N_{SRS} + N_{SRSI} \right) \right) \right\}
\]

\[
- 10F_b \left( F_A - F_s \right) - IME
\]

(3)

where:

Net Actual Interchange (NIA)

Affected by pseudo-ties/AGC interchanges

\[
N_A = \left( \text{SUM of Tie Lines} \right) + \left( \text{SUM of Pseudo-Ties} \right)
\]

\[
N_A = (N_{Li}) + (N_{APTGE} - N_{APTGI} - N_{APTLE} + N_{APTLI} + N_{ARSE} - N_{ARSI})
\]

where:

\[
N_{Li} = \text{Net sum of tie line flows}
\]

\[
N_{APTGE} = \text{sum of AGC interchange generation external to the attaining BA.}
\]

\[
N_{APTGI} = \text{sum of AGC interchange generation internal to the BA (native BA).}
\]

\[
N_{APTLE} = \text{sum of AGC interchange load external to the BA (attaining BA).}
\]

\[
N_{APTLI} = \text{sum of AGC interchange load internal to the BA (native BA).}
\]

\[
N_{ARSE} = \text{supplemental regulation service external to the BA (BA purchasing the supplemental regulation service) via pseudo-tie. See Appendix C.}
\]

\[
N_{ARSI} = \text{Supplemental regulation service internal to the BA (BA selling the supplemental regulation service) via pseudo-tie. See Appendix C.}
\]

and where values for all generation and load terms are assumed to be positive quantities.
Appendix A – ACE Equation Implications of Dynamic Transfers

Net Scheduled Interchange (NIS)
Affected by dynamic schedules and supplemental regulation services.

\[ N_{IS} = (\text{SUM of non-dynamically scheduled transactions}) + (\text{SUM of Dynamic Schedules}) \]
\[ N_{IS} = (N_{Is}) + (-N_{ISDSGE} + N_{ISDSGI} + N_{ISDSLE} - N_{ISERSE} + N_{ISERSI}) \]

where:
- \( N_{Is} \) = Net sum of non-dynamically scheduled transactions,
- \( N_{ISDSGE} \) = Sum of dynamically scheduled generation external to the attaining BA,
- \( N_{ISDSGI} \) = Sum of dynamically scheduled generation internal to the native BA,
- \( N_{ISDSLE} \) = Sum of dynamically scheduled load external to the attaining BA,
- \( N_{ISERSE} \) = Sum of dynamically scheduled load internal to the native BA,
- \( N_{ISERSE} \) = Supplemental regulation service external to the BA (BA purchasing the supplemental regulation service). See Appendix B,
- \( N_{ISERSI} \) = Supplemental regulation service internal to the BA (BA selling the supplemental regulation service). See Appendix B, and

where values for all generation and load terms are assumed to be positive quantities.

Terms Unaffected by Dynamic Transfers
- \( F_B \) = BA Frequency Bias
- \( F_A \) = Actual Frequency
- \( F_S \) = Scheduled Frequency
- \( I_{MRE} \) = Meter Error Correction

The following sections show which specific component should be used by each involved BA to reflect each type of dynamic transfer in its ACE equation.
**Application of Pseudo-ties in ACE by BA(s)**

(A→B) BA(s) A and B are Adjacent BA(s).

(A→C→B) BA C is an Intermediate BA.

(A→C) BA(s) A and C are Adjacent BA(s).

(A→B→C) BA B is an Intermediate BA.

<table>
<thead>
<tr>
<th>Table A-1</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
</tr>
<tr>
<td>P1 Generator From A to B Path A→B</td>
</tr>
<tr>
<td>P2 Generator From A to B Path A→C→B</td>
</tr>
<tr>
<td>P3 Generator From A to C Path A→C</td>
</tr>
<tr>
<td>P4 Generator From A to C Path A→B→C</td>
</tr>
<tr>
<td>P5 Load From A to B Path A→B</td>
</tr>
<tr>
<td>P6 Load From A to B Path A→C→B</td>
</tr>
<tr>
<td>P7 Load From A to C Path A→C</td>
</tr>
<tr>
<td>P8 Load From A to C Path A→B→C</td>
</tr>
</tbody>
</table>

**Application of Dynamic Schedules in ACE by BA(s)**
Appendix A – ACE Equation Implications of Dynamic Transfers

(A  B) BA(s) A and B are Adjacent BA(s).
(A  C  B) BA C is an Intermediary BA.
(A  C) BA(s) A and C are Adjacent BA(s).
(A  B  C) BA B is an Intermediary BA.

Table A-2

<table>
<thead>
<tr>
<th></th>
<th>BA A</th>
<th>BA B</th>
<th>BA C</th>
</tr>
</thead>
<tbody>
<tr>
<td>S1</td>
<td>Generator output From A to B Path A  B</td>
<td>A  B</td>
<td>NISDSGI</td>
</tr>
<tr>
<td>S2</td>
<td>Generator output From A to B Path A  C  B</td>
<td>A  C</td>
<td>NISDSGI</td>
</tr>
<tr>
<td></td>
<td></td>
<td>C  B</td>
<td></td>
</tr>
<tr>
<td>S3</td>
<td>Generator output From A to C Path A  C</td>
<td>A  C</td>
<td>NISDSGI</td>
</tr>
<tr>
<td>S4</td>
<td>Generator output From A to C Path A  B  C</td>
<td>A  B</td>
<td>NISDSGI</td>
</tr>
<tr>
<td></td>
<td></td>
<td>B  C</td>
<td></td>
</tr>
<tr>
<td>S5</td>
<td>Serve a Load In B from A Path A  B</td>
<td>A  B</td>
<td>NISDSLI</td>
</tr>
<tr>
<td>S6</td>
<td>Serve a Load In B from A Path A  C  B</td>
<td>A  C</td>
<td>NISDSLI</td>
</tr>
<tr>
<td></td>
<td></td>
<td>C  B</td>
<td></td>
</tr>
<tr>
<td>S7</td>
<td>Serve a Load In C from A Path A  C</td>
<td>A  C</td>
<td>NISDSLI</td>
</tr>
<tr>
<td>S8</td>
<td>Serve a Load In C from A Path A  B  C</td>
<td>A  B</td>
<td>NISDSLI</td>
</tr>
</tbody>
</table>

Numeric Examples
Appendix A – ACE Equation Implications of Dynamic Transfers

In these examples, BA West will become the attaining BA for load Y and generator Z. Similarly, BA East will become the attaining BA for load X and generator W.

Assume:
- Net sum of tie flows = 0,
- Net sum of non-dynamically scheduled transactions = 0,
- $F_S = F_A$, and
- $I_{ME} = 0$
Using Dynamic Schedules
Using Table A-2, rows S1 and S5, to obtain the correct net scheduled interchange terms for the dynamic schedules, the ACE equation for BA West becomes:

\[
ACE_{BA\ West} = NI_A - NI_S = NI_A - (NI_A - (NI_S - NI_{SDGE} + NI_{SDGI} + NI_{SDLE} - NI_{SDL}))
\]

\[
= NI_A - (NI_A - Gen\ Z + Gen\ W + Load\ Y - Load\ X)
\]

Substituting the values in the example as positive quantities, the equation becomes:

\[
ACE_{BA\ West} = 0 - (0 - 200 + 100 + 75 - 50)
\]

\[
= 0 - (-75) = 75
\]

Using Pseudo-Ties
Using Table A-1, rows P1 and P5, to obtain the correct net actual interchange terms for the pseudo-ties, the ACE equation becomes:

\[
ACE_{BA\ West} = NI_A - NI_S = (NI_A + Gen\ Z - Gen\ W - Load\ Y + Load\ X) - NI_S
\]

Substituting the values in the example as positive quantities, the equation becomes:

\[
ACE_{BA\ West} = (0 + 200 - 100 - 75 + 50) - 0
\]

\[
= 75
\]

Using both Dynamic Schedules and Pseudo-ties
Assume that the generation will be modeled as dynamic schedules and the loads as pseudo-ties. Using Table A-2, Row S1 and Table A-1, Row P5 to obtain the correct Net Scheduled Interchange and Net Actual Interchange terms for the dynamic transfers, the ACE equation for BA West becomes:

\[
ACE_{BA\ West} = NI_A - NI_S = (NI_A - Load\ Y + Load\ X) - (NI_S - Gen\ Z + Gen\ W)
\]

Substituting the values in the example as positive quantities, the equation becomes:

\[
ACE_{BA\ West} = (0 - 75 + 50) - (0 - 200 + 100)
\]

\[
= (-25) - (-100)
\]

\[
= -25 + 100 = 75
\]

Note: In all cases the ACE value is the same regardless of the dynamic transfer method(s) used.
Appendix B – Supplemental Regulations Service as a Dynamic Schedule

Supplemental regulation service is when one BA provides part of the regulation requirements of another BA. The BA(s) implement a dynamic schedule incorporating the calculated portion of the ACE signal that has been agreed upon between them. This is accomplished by adding another component to the scheduled interchange component of the ACE equation for both BA(s). Care should be taken to maintain the proper sign convention to ensure proper control, with the BA purchasing regulation service subtracting the supplemental regulation service from the scheduling component of their ACE while the BA providing the service adds it to the scheduling component of their ACE.

If the supplemental regulation service includes a calculated assistance between the native BA and the attaining BA for recovery from the loss of generation, then both BA(s) are responsible for assuring that DCS compliance reporting requirements are met in accordance with NERC Standard BAL-002 — Disturbance Control Performance.

ACE equation modifications required for supplemental regulation service:

ACE Equation Modifications

Typically:

\[ ACE = (N_{IA} - N_{IS}) - 10F_b (F_A - F_S) - IME \]

where:

- \( N_{IA} \): Net Actual Interchange
- \( N_{IS} \): Net Scheduled Interchange
- \( F_b \): BA Frequency Bias
- \( F_A \): Actual Frequency
- \( F_S \): Scheduled Frequency
- \( IME \): Meter Error Correction

For a DYNAMIC SCHEDULE the \( N_{IA} \) remains unchanged, but to implement supplemental regulation service, the \( N_{IS} \) term becomes:

\[ N_{IS} = N_I - N_{SDGE} + N_{SDGI} + N_{SDLE} - N_{SDSL} - N_{SRSE} + N_{SRSI} \]

where:

- \( N_I \): Net sum of non-dynamically scheduled transactions
- \( N_{SDGE} \): sum of dynamically scheduled generation external to the BA (attaining BA)
- \( N_{SDGI} \): sum of dynamically scheduled generation internal to the BA (native BA)
- \( N_{SDLE} \): sum of dynamically scheduled load external to the BA (attaining BA)
- \( N_{SDSL} \): sum of dynamically scheduled load internal to the BA (native BA)
- \( N_{SRSE} \): Supplemental regulation service external to the BA (BA purchasing the supplemental regulation service)
- \( N_{SRSI} \): Supplemental regulation service internal to the BA (BA selling the supplemental regulation service)

and where supplemental regulation service for an overgeneration condition is assumed to be negative and for undergeneration it is positive to achieve the desired effect via \( N_{IS} \) on ACE as described in the “NAESB WEQ Area Control Error (ACE) Equation Special Cases Standards - WEQBS – 003-000”
Supplemental Regulation as Dynamic Schedule - Numeric Example

Assume: Net sum of tie flows = 0,
Net sum of non-dynamically scheduled transactions = 20 Mw from BA-West to BA-East,
\( F_S = F_A \),
and \( I_{BA} = 0 \)

In this example, BA-West will become the BA purchasing 15 Mw of supplemental regulation. Similarly, BA-East will become the BA selling 15 Mw of supplemental regulation.

Using the correct net scheduled interchange terms for supplemental regulation as a dynamic schedule, the ACE equation for BA-West becomes:

\[
ACE_{BA-West} = NI_A - NI_S
\]
\[
= NI_A - (NI - NI_{DSGE} + NI_{DSGI} + NI_{DSGL} - NI_{DSLE} - NI_{SRE} + NI_{SRU})
\]

simplifying for applicable terms for this example yields,
\[
= NI_A - (NI - NI_{SRE})
\]

Since purchaser BA-West is in an undergenerating condition in this example, the Supplemental Regulation term is positive and substitution in the equation becomes:

\[
ACE_{BA-West} = 0 - (20 - 15)
\]
\[
= 0 - (5) = -5
\]

Similarly, the ACE equation for BA-East becomes:

\[
ACE_{BA-East} = NI_A - NI_S
\]
\[
= NI_A - (NI - NI_{DSGE} + NI_{DSGI} + NI_{DSGL} - NI_{DSLE} - NI_{SRE} + NI_{SRU})
\]

simplifying for applicable terms for this example yields,
\[
= NI_A - (NI + NI_{SRU})
\]
Again since purchaser BA-West is in an undergenerating condition in this example, the Supplemental Regulation term is positive and substitution in the equation becomes:

\[ \text{ACE}_{BA\text{East}} = 0 - (-20 + 15) \]
\[ = 0 - (-5) = 5 \]
Appendix C - Supplemental Regulation Service as a Pseudo-Tie

Supplemental regulation service is when one BA provides all or part of the regulation requirements of another BA. The BA(s) implement a pseudo-tie incorporating the calculated portion of the ACE signal that has been agreed upon between them. This is accomplished by adding another component to the actual interchange component of the ACE equation for both BA(s). Care should be taken to maintain the proper sign convention to ensure proper control.

If the supplemental regulation service includes a calculated assistance between the native BA and the attaining BA for recovery from the loss of generation, then both BA(s) are responsible for assuring that DCS compliance reporting requirements are met in accordance with NERC Standard BAL-002 — Disturbance Control Performance.

ACE equation modifications required for supplemental regulation service:

**ACE Equation Modifications**

Typically:

\[
\text{ACE} = (\text{NI}_A - \text{NI}_S) - 10F_b (\text{F}_A - \text{F}_S) - IME
\]

where:

- \(\text{NI}_A\) = Net Actual Interchange
- \(\text{NI}_S\) = Net Scheduled Interchange
- \(F_b\) = BA Frequency Bias
- \(F_A\) = Actual Frequency
- \(F_S\) = Scheduled Frequency
- \(IME\) = Meter Error Correction

For a PSEUDO-TIE with supplemental regulation, the \(\text{NI}_S\) remains unchanged, but the \(\text{NI}_A\) term becomes:

\[
\text{NI}_A = \text{NI}_a + (\text{NI}_APTGE - \text{NI}_APTGI - \text{NI}_APTLE + \text{NI}_APTLI + \text{NIARSE} - \text{NIARSI})
\]

where:

- \(\text{NI}_a\) = Net sum of tie line flows
- \(\text{NI}_APTGE\) = sum of AGC interchange generation external to the attaining BA.
- \(\text{NI}_APTGI\) = sum of AGC interchange generation internal to the BA (native BA).
- \(\text{NI}_APTLE\) = sum of AGC interchange load external to the BA (attaining BA).
- \(\text{NI}_APTLI\) = sum of AGC interchange load internal to the BA (native BA).
- \(\text{NIARSE}\) = supplemental regulation service external to the BA (BA purchasing the supplemental regulation service) via pseudo-tie.
- \(\text{NIARSI}\) = supplemental regulation service internal to the BA (BA selling the supplemental regulation service) via pseudo-tie.

As with dynamic schedules, for both the purchasing and selling BAs, supplemental service being provided to alleviate overgeneration has a negative sign, while supplemental service being provided to alleviate undergeneration has a positive sign.
Appendix C – Supplemental Regulation Service as a Pseudo-Tie

Supplemental Regulation as Pseudo-Tie - Numeric Example

In this example, BA-West will become the BA purchasing 15 Mw of supplemental regulation. Similarly, BA-East will become the BA selling 15 Mw of supplemental regulation.

Using the correct net actual interchange terms for supplemental regulation as a pseudo-tie, the ACE equation for BA-West becomes:

\[ \text{ACE BA-West} = NIA - NIS = (NI_a + NIAPTGE - NIAPTGI - NIAPTLI + NARSE - NARSI) - NIS \]

simplifying for applicable terms for this example yields,

\[ \text{ACE BA-West} = (NI_a + NARSE) - NIS \]

Since purchaser BA-West is in an undergenerating condition in this example, the Supplemental Regulation term is positive and substitution in the equation becomes:

\[ \text{ACE BA-West} = (0 + 15) - 20 = 15 - 20 = -5 \]

Similarly, the ACE equation for BA-East becomes:

\[ \text{ACE BA-East} = NIA - NIS = (NI_a + NIAPTGE - NIAPTGI - NIAPTLI + NARSE - NARSI) - NIS \]

simplifying for applicable terms for this example yields,

\[ \text{ACE BA-East} = (NI_a - NARSI) - NIS \]

Assume: Net sum of tie flows = 0,
Net sum of non-dynamically scheduled transactions = 20 Mw from BA-West to BA-East,
\( f_s = f_a \),
and \( f_{IM} = 0 \)

In this example, BA-West will become the BA purchasing 15 Mw of supplemental regulation. Similarly, BA-East will become the BA selling 15 Mw of supplemental regulation.

Using the correct net actual interchange terms for supplemental regulation as a pseudo-tie, the ACE equation for BA-West becomes:

\[ \text{ACE BA-West} = NIA - NIS = (NI_a + NIAPTGE - NIAPTGI - NIAPTLI + NARSE - NARSI) - NIS \]

simplifying for applicable terms for this example yields,

\[ \text{ACE BA-West} = (NI_a + NARSE) - NIS \]

Since purchaser BA-West is in an undergenerating condition in this example, the Supplemental Regulation term is positive and substitution in the equation becomes:

\[ \text{ACE BA-West} = (0 + 15) - 20 = 15 - 20 = -5 \]

Similarly, the ACE equation for BA-East becomes:

\[ \text{ACE BA-East} = NIA - NIS = (NI_a + NIAPTGE - NIAPTGI - NIAPTLI + NARSE - NARSI) - NIS \]

simplifying for applicable terms for this example yields,

\[ \text{ACE BA-East} = (NI_a - NARSI) - NIS \]
Again since purchaser BA-West is in an undergenerating condition in this example, the Supplemental Regulation term is positive and substitution in the equation becomes:

\[
ACE_{BA-East} = (0 - 15) - (-20) = -15 + 20 = 5
\]
**Revision History**

<table>
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<tr>
<th>Version</th>
<th>Date</th>
<th>Action</th>
<th>Change Tracking</th>
</tr>
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<tr>
<td>3</td>
<td>May 10, 2016</td>
<td>Replaced the Frequency Bias Setting section in Chapter 3 to reflect the Frequency Bias methodology used in BAI-003-1</td>
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Time Monitoring Reference Document

Introduction

This procedure outlines responsibilities of Reliability Coordinators serving as time monitors in the North American Interconnections. Changes to this reference document will be at the direction of the NERC Operating Committee (OC) with the participation of the NERC Resources Subcommittee (RS) and the Operating Reliability Subcommittee (ORS).

This document applies to current and future frequency or time related procedural responsibilities assigned to the time monitor.

Designation of Time Monitor

There will be one time monitor within each Interconnection. NERC ORS will nominate a time monitor for each Interconnection. The ORS will notify the NERC OC at its December meeting of the designated time monitors for the next two time monitor terms.

The term of each time monitor shall be one (1) year. With the exception of the Eastern Interconnection, the time monitor term shall be automatically renewed unless requested otherwise by providing a minimum of six (6) months notice to the NERC ORS. The Eastern Interconnection time monitor will rotate on an annual basis as outlined below. Should an existing or future time monitor no longer be willing or able to fulfill its responsibilities, the NERC OC will direct the NERC ORS to nominate a replacement and communicate the transition plan.

The NERC RS will report to the NERC OC and ORS any frequency or time error issues that may have been caused or aggravated by the time monitor or Time Error Correction (TEC) practices.

If a time monitor fails to fulfill its responsibilities, the NERC ORS will work with the time monitor to resolve the problem. The NERC ORS will submit a report to the NERC OC either identifying corrective measures taken or provide a recommendation for a new time monitor.

Responsibilities of the Time Monitor

The time monitor will start and stop a TEC as outlined in Attachment A of this reference.

The time monitor will terminate any TEC believed to be negatively impacting reliability. Requests for termination may come from any Balancing Authority operator to its respective Reliability Coordinator, who will notify the respective Interconnection’s time monitor.

The time monitor will provide accumulated Time Error following each TEC or at least monthly to the Balancing Authorities within its Interconnection. The Eastern Interconnection time monitor will provide
accumulated Time Error following each TEC or at least monthly via a posting to the Reliability Coordinator Information System.

**Time Monitor Transition**
The current time monitor will contact the next scheduled time monitor no later than October 1st to begin coordinating the transition that will occur on February 1st of the following year. This coordination should include such things as local procedure currently in use, data requirements, and communications. In the event unusual operating issues prevent the designated Eastern Interconnection time monitor from fulfilling its responsibilities, the previous time monitor should maintain the capability to perform the time monitor duties.

**References**
Each time monitor’s local procedure is available on an as needed basis. Contact the current time monitor for additional information or a copy of their local procedure.

**Interconnection Time Monitors**
Each Interconnection has identified the following Reliability Coordinator as its time monitor:

1. ERCOT Interconnection – ERCOT Reliability Coordinator
2. Québec Interconnection – Hydro-Québec TransÉnergie Reliability Coordinator
3. Eastern Interconnection – The Reliability Coordinators in the Eastern Interconnection will rotate the time monitor responsibilities on an annual basis as follows:
   a. PJM – February 1, 2016 through January 31, 2017
   b. FRCC – February 1, 2017 through January 31, 2018
   c. ISO-NE – February 1, 2018 through January 31, 2019
   d. SaskPower – February 1, 2019 through January 31, 2020
   e. Southeastern – February 1, 2020 through January 31, 2021
   f. TVA – February 1, 2021 through January 31, 2022
   g. MISO – February 1, 2022 through January 31, 2023
   h. IESO (Ontario) – February 1, 2023 through January 31, 2024
   i. NBP (New Brunswick Power) – February 1, 2024 through January 31, 2025
   j. VACAR-South – February 1, 2025 through January 31, 2026
   k. SPP – February 1, 2026 through January 31, 2027
   l. NYISO – February 1, 2027 through January 31, 2028
4. WECC Interconnection – Peak Reliability Reliability Coordinator
Attachment A

Introduction

Interconnection frequency is normally scheduled at 60.00 Hz. Since control is imperfect, frequency will average slightly above or below 60.00 Hz, resulting in electric clocks developing an error relative to true time. When the error exceeds pre-set limits, corrective action is taken by adjusting the Interconnection's scheduled frequency. This practice is termed Time Error Correction (TEC). This control anchors long term average frequency at 60.00 Hz.

Each Balancing Authority is expected to participate in Interconnection Time Error Correction procedures unless it is operating asynchronously to its Interconnection or is experiencing a Reliability problem that would be aggravated by the correction.

Single Balancing Authority Interconnections or Balancing Authorities operating asynchronously may establish their own time error control bands and time correction methodology, but should notify the NERC Resources Subcommittee (RS) of the bands utilized of such as well as subsequent changes.

Interconnections may choose to follow alternative procedures. If so, those procedures should be shared with the RS and approved by the NERC Operating Committee.

General Practices

1. **Time error correction notice and commencement.** Time Error Corrections are conducted following the process below.

2. **Time Error Initiation.** Time error corrections start and end on the hour or half-hour with notice by the time monitor generally given at least one hour before the TEC is scheduled to start.

3. **Time Error Correction labeling.** Time error correction notifications are labeled on a monthly basis using an Interconnection approach (e.g. A-Z, AA-AZ, BA-BZ,...).

4. **Time correction offset.** The Balancing Authority may participate in a Time Error Correction by either of the following two methods:
   a. **Frequency offset (Preferred Approach).** The Balancing Authority may offset its frequency schedule by 0.02 Hz (or other smaller offset designated by the time monitor1), leaving the Frequency Bias Setting normal, or
   b. **Schedule offset.** If the frequency schedule cannot be offset, the Balancing Authority may offset its net Interchange Schedule (MW) by an amount equal to the computed bias contribution times the desired frequency offset.

5. **Request for Termination or Halt of Scheduled Time Error Correction.** Any Reliability Coordinator in an Interconnection may request the termination of a TEC or the initiation of a future TEC. A Balancing Authority that has a reliability concern with the execution of a time error correction should notify their

---

1 Alternative procedures would be approved by the Interconnection or the NERC Operating Committee prior to implementation.
Reliability Coordinator to request a termination of the TEC. A Reliability Coordinator requesting a termination or halt of a TEC is asked to forward the reasons for requesting the termination to the chairs of the Resources Subcommittee and Operating Reliability Subcommittee.

6. **INTERCONNECTION time error notification.** The Interconnection time monitor is expected to either publicly post time error or issue a time error notice on the first day of each month. The time error notices should be accurate to 0.01 second and are sent to the other Reliability Coordinators and Balancing Authorities within the Interconnection to assure uniform calibration of time standards.

**General Time Error Correction Practice**

The normal TEC process is outlined in the table below. Unless local Interconnection procedures prevail, TECs will last 42 hours unless terminated by a Reliability Coordinator for Reliability concerns. Corrections for fast time should not be initiated such that they would run during the morning load ramp.

<table>
<thead>
<tr>
<th>Time</th>
<th>General Time Error Initiation (Seconds)</th>
<th>Scheduled Freq – Hz</th>
</tr>
</thead>
<tbody>
<tr>
<td>Slow</td>
<td>−30 East, TBD West, −30 ERCOT, NA Quebec</td>
<td>60.02</td>
</tr>
<tr>
<td>Fast</td>
<td>+30 East, TBD West, +30 ERCOT, NA Quebec</td>
<td>59.98</td>
</tr>
</tbody>
</table>

**Clock Day (24 Hour) Correction Process**

An Interconnection may elect to utilize a smaller clock-day offset to control time. The time monitor may initiate a clock-day correction beginning at 0000 Central Time. Clock day corrections use a smaller frequency offset, such as 60.005 Hz and 59.995 Hz. The notification used to initiate the clock day correction will include the desired offset.

**Unilateral Correction Process**

A Balancing Authority may perform a limited unilateral correction of Time Error. Such correction may only occur whenever the Balancing Authority’s Inadvertent Interchange Balance and Time Error have the same sign. The unilateral payback must end when Time Error or the accumulation of Inadvertent Interchange has been corrected to zero, or if a Time Error Correction is initiated.

The unilateral correction is limited to 10% of the Balancing Authority Bias or 50 MW, whichever is less. If implemented as an Interchange Schedule, the unilateral correction may be rounded up to the next whole MW. To ensure coordination, the Balancing Authority performing a unilateral correction needs to notify their Reliability Coordinator prior to implementation.

---

2 The 4 hour duration is intended to reduce the likelihood of errors. A 4 hour correction would reduce a 30 second time error to approximately 25 seconds.

3 Avoiding TEC initiation for fast time during the morning load ramp reduces the likelihood of low frequency excursions during schedule changes and can preclude a TEC where load increase would naturally reduce fast time.

4 This approach would need to be approved by the NERC OC prior to adoption. An Interconnection can choose not to adopt this approach.

5 This approach would need to be approved by the NERC OC prior to adoption. An Interconnection can choose not to adopt this approach.
Eastern Interconnection Regional Managers  
NERC Operating Committee Leadership  
Resources Subcommittee  
Eastern Interconnection Resources Subcommittee Survey Contacts

**Eastern Interconnect Inadvertent Imbalance – Options for payback**

The NERC Operating Committee has approved the Resources Subcommittee (RS) to seek volunteers from the Eastern Interconnection Balancing Authorities (BAs) to participate in an unaccounted for Inadvertent true-up.

The unaccounted for Inadvertent true-up is the result of Inadvertent Interchange in the Eastern Interconnection accumulating to a non-zero amount. This happened due to a number of errors that have occurred over many years and, at this point, can no longer be traced back to their origins.

The unaccounted for Inadvertent balances are the following:

- **On-Peak**: 45,410
- **Off-Peak**: -100,647
- **Total**: -55,239

In order to achieve a Interconnection net zero Inadvertent balance, we are asking BAs if they would like to participate in an Inadvertent true-up. The true-up will consist of allocating Inadvertent amongst the participating BAs in the opposite direction of the above balances. The unaccounted for Inadvertent balances will be spread among the interested BAs based on their individual biases.

**Example:** To take the On-Peak Inadvertent to zero we will need to true-up by -45,410 MWs. The -45,410 MWhs would be allocated based on a voluntary basis.

BA XYZ has an On-Peak Inadvertent balance of 150 MWs. They choose to participate in the true-up for the Eastern Interconnect for On-Peak only and want to limit the Inadvertent amount they take to -150 MWs, if available. In the true-up process BA XYZ’s portion of the balance was -125 MWs. This would result in BA XYZ’s On-Peak net Inadvertent balance being 25 MWs.

Each BA has the opportunity to participate in the true-up to a MWh amount specified in the BA participation survey.
Allocations will be made on individual biases and not exceeding the values listed in the survey per the BA. The RS will communicate further information once the surveys have been received.

After discussion with your BA’s management, please complete the BA participation survey no later than May 31, 2016.

Sincerely,

Troy Blalock
Troy Blalock
Resources Subcommittee Chairman

Enclosure
cc: Larry Kezele, Chris Scheetz, NERC
Reliability Functional Model
Function Definitions and Functional Entities

Version 5

Prepared by the Functional Model Advisory Group
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Part 1: Foreword

This document replaces version 4 of the NERC Reliability Functional Model that the NERC Standing Committees approved in September 2008.

Historically, Control Areas were established by vertically integrated utilities to operate their individual power systems in a secure and reliable manner and provide for their customers’ electricity needs. The traditional Control Area operator balanced its load with its generation, implemented Interchange Schedules with other Control Areas, and ensured transmission reliability.

As utilities began to provide transmission service to other entities, the Control Area also began to perform the function of Transmission Service Provider through tariffs or other arrangements. NERC’s Operating Policies reflected this traditional electric utility industry structure, and ascribed virtually every reliability function to the Control Area.

Beginning in the early 1990s with the advent of open transmission access and restructuring of the electric utility industry to facilitate the operation of wholesale power markets, the functions performed by Control Areas began to change to reflect the newly emerging industry structure. These changes occurred because:

1. Some utilities were separating their transmission from their merchant functions (functional unbundling), and even selling off their generation;
2. Some states and provinces were instituting “customer choice” options for selecting energy providers; and,
3. The developing power markets were requiring wide-area transmission reliability assessment and dispatch solutions, which were beyond the capability of many Control Areas to perform.

As a result, the NERC Operating Policies in place at that time, which centered on Control Area operations, were beginning to lose their focus, and become more difficult to apply and enforce.

The NERC Operating Committee formed the Control Area Criteria Task Force (CACTF) in 1999 to address this problem. The task force began by listing all the tasks required for maintaining electric system reliability and then organizing these tasks into basic groups that it called “functions.” Ultimately, the Task Force decided to build a “Functional Model.” This involved breaking down the previous reliability functions more finely, such that all organizations involved in ensuring reliability—whether they are traditional, vertically integrated control areas, regional transmission organizations, independent system operators, independent transmission companies or so on—can identify those functions they perform, and register with NERC as one or more of the functional entities. Initially the Model dealt with operating functions, but it was subsequently expanded in Version 2 to incorporate planning-related functions. This Functional Model Framework provides guidance to NERC standards drafting teams to write reliability standards in terms of the functional entities who perform the reliability functions.

Part 2: Introduction

The NERC Reliability Functional Model provides the framework for the development and applicability of NERC’s Reliability Standards as follows:

- The Model describes a set of Functions that are performed to ensure the reliability of the Bulk Electric System. Each Function consists of a set of related reliability Tasks. The Model assigns each Function to a functional entity, that is, the entity that performs the Function. The Model also describes the interrelationships between that functional entity and other functional entities (that perform other Functions).

- NERC’s Standards Development Teams develop Reliability Standards that assign each reliability requirement within a standard to a functional entity (that is defined in the Model and NERC’s Glossary). This is possible because a given standard requirement will typically be related to a Task within a Function. A standard requirement will be very specific, whereas a Task in the Model will be more general in nature.

- NERC’s compliance processes require specific organizations to register as the entities responsible for complying with standards requirements assigned to the applicable entities.

- The Model’s Functions and functional entities also provide for consistency and compatibility among different Reliability Standards.

The Model is a guideline for the development of standards and their applicability. The Model is not a Standard and does not have compliance requirements. Standards developers are not required to include all tasks envisioned in the model, nor are the developers precluded from developing Reliability Standards that address functions not described in the model. Where conflicts or inconsistency exist, the Reliability Standards requirements take precedence over the Model.

The Model is independent of any particular organization or market structure. An organization may perform more than one Function.

The Functional Model describes a functional entity envisioned to ensure that all of the Tasks related to its Function are performed. The Model, while using the term “functional entity”, is a guideline and cannot prescribe responsibility. It is NERC’s compliance processes, backed by regulatory authority, that specify the manner in which, a functional entity is “legally responsible” for meeting the standards requirements assigned to that functional entity.

The work performed to meet the requirements may be self-performed or performed by others.

**Functional Model maintenance.** The Functional Model is maintained by the Functional Model Working Group (FMWG) under the direction of the NERC Standards Committee, with technical content in the Model and accompanying technical document approved by the Standing Committees (OC, PC and CIPC).

**Technical discussions.** The companion document, “Functional Model – Technical Discussions,” provides additional details on the Functions themselves, how organizations can “roll up” those Functions they wish to perform, and how organizations as “functional entities” interrelate.

The following terms are used in the Functional Model and do not appear in the NERC Glossary.
**Functional Entity.** The term used in the Functional Model which applies to a class of entity that carries out the Tasks within a Function.

**Function.** A set of related reliability Tasks.

**Task.** One of the elements that make up a Function in the Functional Model.

**Customer.** The term applies to a customer for transmission, capacity or energy services (a Purchasing-Selling Entity, Generator Owner, Load-Serving Entity, or End-use Customer).

**End-use Customer.** The party served by a Load-Serving Entity (energy) and Distribution Provider (wire service).

**Purpose of the Functional Model**

The purpose of the NERC Reliability Functional Model is to:

1. Provide a framework for Reliability Standards developed through the NERC standards development process that will apply to certain Tasks defined in the Functional Model.
2. Describe in general terms each Function and the relationships between the entities that are responsible for performing the Tasks within the Functions. The framework for developing the Function definitions is:
   a. The Functions are independent of the organization structure performing the functions, and
   b. The Functions provide flexibility to accommodate the range of presently conceivable organization structures, as well as accommodate alternative tools, procedures and processes.
## Functional Model Diagram

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<thead>
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<th>Function Name</th>
<th>Functional Entity</th>
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<td>Balancing Authority</td>
</tr>
<tr>
<td>Compliance Enforcement</td>
<td>Compliance Enforcement Authority</td>
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<td>Distribution</td>
<td>Distribution Provider</td>
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<tr>
<td>Generator Operations</td>
<td>Generator Operator</td>
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<td>Generator Ownership</td>
<td>Generator Owner</td>
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<tr>
<td>Interchange</td>
<td>Interchange Coordinator</td>
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<tr>
<td>Load-Serving</td>
<td>Load-Serving Entity</td>
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<tr>
<td>Market Operations</td>
<td>Market Operator (Resource Integrator)</td>
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<tr>
<td>Operating Reliability</td>
<td>Reliability Coordinator</td>
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<td>Purchasing-Selling</td>
<td>Purchasing-Selling Entity</td>
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<tr>
<td>Reliability Assurance</td>
<td>Reliability Assurer</td>
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<td>Resource Planning</td>
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<td>Standards Development</td>
<td>Standards Developer</td>
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<td>Transmission Operations</td>
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<tr>
<td>Transmission Service</td>
<td>Transmission Service Provider</td>
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</tbody>
</table>
Guiding Principles of the Functional Model

As explained in the Introduction, the Model provides the framework on which the NERC Reliability Standards are developed and applied. To ensure that this framework remains viable, the Model itself is governed by a set of “guiding principles” that define a Function’s Tasks and establish the relationships between the functional entities which are responsible for meeting the requirements in the NERC Reliability Standards that correspond to these Tasks. These principles serve as a guideline to those revising or interpreting the Model.

For further details, refer to the Technical Discussions section in the Functional Model Technical Document.

1. The Model must be complete. That is, it must include all reliability Tasks and interrelationships between entities performing them. This helps ensure that any reliability requirement arising in a Reliability Standard will generally be related to a Task in the Model and therefore be assignable to a particular functional entity.

2. The Model must group these Tasks into a set of Functions, such that:
   - There are enough Functions (and corresponding functional entities) to accommodate the full range of organization structures and responsibilities within the industry, and
   - The number of Functions is developed based on logical grouping of the Tasks and kept low as reasonably possible.
   - In particular, where a number of organizations that perform a given Function form a single group, the Model recognizes this as a business arrangement among organizations, not a new Function and corresponding new functional entity. That is, the fundamental reliability Tasks, and hence the Function, remain the same - all that has changed is how the Function is performed. Examples of such groups are a reserve sharing group (a collection of entities that are Balancing Authorities), or a planned resource sharing group.

3. The Model is structured to ensure there are no gaps or overlaps in the performance of operation Tasks in the operating timeframe anywhere in the Bulk Electric System. This is achieved in part by associating an “area” of purview for each functional entity. Areas are defined in terms of the individual transmission, generator and customer equipment assets that collectively constitute the Bulk Electric System. For example, each Bulk Electric System asset has one Reliability Coordinator, one Balancing Authority, and one Transmission Operator. Regarding overlaps for planning, as described in the Technical Document, it is not always possible to achieve this in the case of planning Functions, where there may be overlapping levels of responsibility for given assets. Questions regarding relationships between the areas of different functional entities, such as whether one type of area must be totally within another type of area, will be defined in Reliability Standards or the Rules of Procedure, not the Model.

4. Tasks describe what is to be done, not how it is to be done.

5. The Model is a guideline that describes reliability Tasks and interrelationships between the entities that perform them - it is not prescriptive. In particular, the Model does not address requirements for registering or becoming certified as a functional entity, or the delegation or splitting of responsibility for meeting standards requirements.
Clarification Service

The Functional Model is a reference tool that links functional entities with associated reliability-related functions and respective Tasks. Drafting teams use the Functional Model to help them determine which functional entity should be required to comply with each requirement in a reliability standard.

From time to time questions of clarification and interpretation arise. The FMWG is following the process described below for handling requests for clarification of the Functional Model. This process, which has been approved by the Standards Committee, is accessible to all drafting teams as well as any other interested stakeholders. If a drafting team needs help in understanding Tasks that make up a Function and/or in determining which functional entities should be responsible for particular standards requirements, the drafting team’s coordinator will send an e-mail to the NERC Staff assigned as the FMWG facilitator with a request for clarification.

1. The NERC Staff assigned as the FMWG facilitator will convene a conference call/meeting of available members of the FMWG to review the question(s) and provide a clarification.
   - If the question(s) need more detailed discussion with the drafting team, the two coordinators will organize a conference call/meeting with available members of the FMWG and available members of the drafting team to discuss the issues in more detail.

2. Each FMWG request for clarification and the associated response will be posted on the NERC Functional Model Web Page under a Frequently Asked Questions section.
   - If the questions result in changes to the model, the changes will be added to a change summary table used to develop the next updated version of the Functional Model document.
Part 3: Functions and Functional Entities

This section defines the functions and associated Tasks that are necessary to plan and operate the Bulk Electric System in a reliable manner. This section also characterizes the Functional Entities that perform these Tasks, and provides examples of the inter-relationships that take place between entities to ensure reliability. As standards are developed, the Model may be revised to add and remove Tasks under specific Functions to aid in the development of standards. Relationships between Functional Entities in the Model are reciprocal. Where a one-to-one relationship exists, the Model will include the reciprocal relationship specifically; and where a one-to-many relationship exists, the reciprocal relationships are implied.

Functional Model Diagram
Part 3: Functions and Functional Entities

**Deleted:** Standards Development and Standards Developer

**Deleted:** Standards Development

**Deleted:** Tasks

**Deleted:** Develop and maintain a standards development process.

Develop Reliability Standards for the planning and operation of the Bulk Electric System.
The functional entity that develops and maintains Reliability Standards to ensure the reliability of the Bulk Electric System.

The Model addresses Reliability Standards created at NERC using the NERC Reliability Standards Development Procedure and Regional Standards that are created through an open Regional process and approved by NERC for enforcement. The Functional Model is intended to serve as the framework for the development and application of these Reliability Standards.

Receives request for Reliability Standards through the public process.

Sends Reliability Standards to the Compliance Enforcement Authority.
Develop, maintain and implement a compliance enforcement process.
Evaluate and document compliance.
1. **Reliability Assurance and Reliability Assurer**

**Reliability Assurance**

**Tasks**

1. Develop and maintain Reliability Standards that apply to Bulk Power System owners, operators, and users and that enable the Reliability Assurer to measure the reliability performance of Bulk Power System owners, operators, and users; and to hold them accountable for Reliable Operation of the Bulk Power Systems.

2. Develop and implement a compliance and enforcement program to promote the reliability of the Bulk Power System by enforcing compliance with approved Reliability Standards in those regions of North America in which the Reliability Assurer has been given enforcement authority.

3. Develop and maintain a program for identifying and registering those entities that are responsible for compliance with the governmental-approved Reliability Standards.

4. Provide for certification of all entities with primary reliability responsibilities requiring certification.

5. Provide a mechanism to ensure system operators are provided the education and training necessary to obtain the essential knowledge and skills and are therefore qualified to operate the BES.

6. Provide reliability readiness evaluation and improvement, and formation of sector forums if necessary for reliability.

7. Develop a reliability assessment and performance analysis program that conducts reviews and assessments of the overall reliability of the interconnected BPS, including:
   - Review, assess, and report on the overall electric generation and transmission reliability (adequacy and operating reliability) of the interconnected Bulk Power Systems, both existing and as planned.
   - Assess and report on the key issues, risks, and uncertainties that affect or have the potential to affect the reliability of existing and future electric supply and transmission.
   - Review, analyze, and report on Regional Entity self-assessments of electric supply and bulk power transmission reliability, including reliability issues of specific regional concern.
   - Identify, analyze, and project trends in electric customer demand, supply, and transmission and their impacts on Bulk Power System reliability.
   - Investigate, assess, and report on the potential impacts of new and evolving electricity market practices, new or proposed regulatory procedures, and new or proposed legislation (e.g. environmental requirements) on the adequacy and operating reliability of the Bulk Power Systems.

8. Provide leadership, coordination, technical expertise, and assistance to the industry in responding to a major event.

9. Provide the education and training necessary for Bulk Power System personnel and regulators to obtain the essential knowledge necessary to understand and operate the BES.

10. Through the use of appropriate functional entities and available tools, monitor present conditions on
Part 3: Functions and Functional Entities

the Bulk Power System and provide leadership coordination, technical expertise, and assistance to the industry in responding to events as necessary.

11. Coordinate electric industry activities to promote Critical Infrastructure protection of the Bulk Power System in North America by taking a leadership role in Critical Infrastructure protection of the electricity sector so as to reduce vulnerability and improve mitigation and protection of the electricity sector’s Critical Infrastructure.

Deleted: <#>Coordinate reliability assurance among adjacent Reliability Assurers through the development of necessary protocols and processes. ¶
Coordinating the activities related to maintaining critical infrastructure protection. ¶
Establishing reliability assurance processes and documentation related to planning and operations within the Reliability Assurer’s area including such things as a regional reliability plan or a Reliability Coordinator plan. ¶
Identify and address gaps in reliability processes and responsibilities. ¶
Reliability Assurer

Definition
Subject to oversight by the Federal Energy Regulatory Commission and governmental authorities in Canada, assure the reliability of the Bulk Power System in North America by developing and enforcing Reliability Standards; annually assessing seasonal and long-term reliability; monitoring the Bulk Power System through system awareness; and, educating, training, and certifying industry personnel.

Relationships with Other Functional Entities


3. Obtain the information necessary to complete registration from the appropriate functional entities, including: Reliability Coordinators, Balancing Authorities, Transmission Operators, Transmission Owners, Generator Operators, Generator Owners, Transmission Service Providers, Planning Coordinators, Transmission Planners, Resource Planners, and Distribution Providers.

Deleted: The functional entity that monitors and evaluates the activities related to planning and operations, and coordinates activities of functional entities to secure the reliability of the Bulk Electric System within a Reliability Assurer area and adjacent areas.

Planning Reliability and Planning Coordinator

Planning Reliability

Tasks

1. Establish data requirements necessary to develop power system models for analysis within the Planning Coordinator area.
2. Collect and validate information from Transmission Planners, such as modeling data, to perform a Transmission assessment of the Planning Coordinator area.
3. Assess the performance of the Transmission System, with the Loads, resources, and proposed projects included in the Transmission Planner’s Planning Assessment (including any Corrective Action Plan(s)).
4. Coordinate with adjoining Planning Coordinators to develop interconnection models with appropriate Loads, resources, and System topology.
5. Evaluate and report on the performance of the consolidated Transmission assessments.

Planning Coordinator

Definition

The responsible entity that coordinates and integrates transmission facilities and service plans, resource plans, and Protection Systems.

Introduction to the Planning Coordinator

By its very nature, BES planning involves multiple entities. Since all electric systems within an integrated network are electrically connected, whatever one system does can affect the other systems. The Planning Coordinator is responsible for coordinating the assessment of the BES within its Planning Coordinator area. While the area under the purview of a Planning Coordinator may include as few as one Transmission Planner, the Planning Coordinator’s scope of activities is intended to span a broader area that may include BES assets of multiple Transmission Planners. All BES Facilities should be assigned to a Transmission Planner and to a Planning Coordinator, so that there are no gaps in the assessment of the BES. Planning Coordinators work through a variety of processes to conduct facilitated, coordinated, joint, centralized, or regional planning activities to the extent that all portions of the interconnected BES are completely coordinated for planning activities.

Relationships with Other Functional Entities

1. Establish power system modeling data requirements in conjunction with interconnected Transmission Planners and other Planning Coordinators.
2. Collect data for power system modeling and assessments from the Transmission Planner.
3. Determine transfer capability with neighboring Planning Coordinators.
4. Exchange information on Contingencies, criteria, System Operating Limits (SOLs), Remedial Action

\[2\] Definition of Planning Authority from the NERC Glossary of Terms (as of May 15, 2016). In the Glossary, Planning Coordinator and Planning Authority are defined interchangeably.
Part 3: Functions and Functional Entities

Schemes (RAS), automatic Load-shedding schemes, and plans with the Reliability Coordinator and other Planning Coordinators.

5. Assess the performance of the Transmission system, in coordination with Transmission Planners.
   a. 
   b. 
   c. 
   d. 

6. Collect and review reports on Transmission, loads and resources from Transmission Planners.

7. Facilitate the integration of the respective plans of the Transmission Planners within the Planning Coordinator area, and adjacent Planning Coordinator areas, as appropriate.
   a. Review the integrated plan with respect to established reliability needs considering the impact on and by adjoining systems.
   b. In coordination with the Transmission Planners, facilitate the development of alternative solutions for plans that do not meet those reliability performance criteria.
Transmission Planning and Transmission Planner

Transmission Planning

Tasks

1. **Develop and maintain** methodologies, criteria and tools for the analysis and simulation of the Transmission Systems.

2. **Develop, acquire and validate** information required for Transmission assessments including:
   a. Transmission Facility characteristics and Ratings.
   b. Demand and Electrical Energy forecasts, capacity resources, and Demand-Side Management (DSM) programs.
   c. Generator unit performance characteristics and capabilities.
   d. Commitments for firm Transmission Interchange.
   e. Load forecasts and generation dispatch scenarios.

3. **Develop and maintain** power system models (steady state, dynamics, and short circuit) necessary for the assessment of Transmission System performance for identified scenarios.

4. **Exchange information with other** Transmission Planners and the Planning Coordinator to achieve an interconnected model.

5. **Assess** the performance of the Transmission System with the anticipated topology and scenarios of Loads and resources.

6. 

7. 

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Deleted: and develop, in cooperation with adjacent and overlapping Transmission Planners,

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Deleted: In the evaluation and development of transmission expansion plans related to resource adequacy plans

Deleted: Define, consolidate and collect or d

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Deleted: Coordinate with adjacent and overlapping

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Deleted: s and resource and transmission expansion plans take into account modifications made to adjacent and overlapping Transmission Planner areas

Deleted: Evaluate, develop, document, and report on expansion plans for the Transmission Planner area.

Deleted: whether the integrated plan meets reliability needs, and, if not, report on potential network conditions or configurations that do not meet performance requirements and provide potential alternative solutions to meet performance requirements

Deleted: Evaluate the plans that are in response to long-term (generally one year and beyond) customer requests for transmission service. Evaluate and plan for all requests required to integrate new (End-use Customer, generation, and transmission) facilities into the Bulk Electric System.

Determine transfer capability values (generally one year and beyond) as appropriate.

Monitor, evaluate and report on transmission expansion plan and resource plan implementation.

Coordinate projects requiring transmission outages that can impact reliability and firm transactions.

Notify Generation Owners, Resource Planners, Transmission Planners and Transmission Owners of any planned transmission changes that may impact their facilities.

Deleted: Define system protection and control needs and requirements, including special protection systems (remedial action schemes), to meet reliability needs.
Transmission Planner

Definition
The entity that develops a long-term (generally one year and beyond) plan for the reliability (adequacy) of the interconnected bulk electric transmission systems within its portion of the Planning Authority area.\(^3\)

Introduction to the Transmission Planner
The Transmission Planner is responsible for assessing the long term (generally one year and beyond) transmission system performance within its Transmission Planner area. By its very nature, BES planning involves multiple entities. Since all electric systems within an integrated network are electrically connected, changes planned in one part of the system can affect the other parts of the system. Transmission Planners coordinate their plans with the adjoining Transmission Planners to assess impact on or by those plans. The area under the purview of a Transmission Planner may include one or more Resource Planner areas. All BES Facilities should be under the purview of at least one Transmission Planner.

Relationships with Other Functional Entities
1. Coordinate and collect data (steady state, dynamics, and short circuit) for power system modeling from Load-Serving Entities, Generator Owners, Distribution Providers, Resource Planners, Transmission Owners, Transmission Service Providers, and other Transmission Planners.

2. Collect information including:
   b. Demand and Electrical Energy forecasts, capacity resources, and Demand-Side Management programs from Load-Serving Entities, and Resource Planners.
   c. Generator unit performance characteristics and capabilities from Generator Owners.
   d. Commitments for firm Transmission Interchange from Transmission Service Providers.


6. Notify other Transmission Planners, Transmission Owners, Transmission Operators and other entities that may be impacted by any planned BES changes.

7. Coordinate with Distribution Providers, Transmission Owners, Generator Owners and Load-Serving Entities in the evaluation and plans for all requests required to integrate new (end-use customer, generation, and Transmission) Facilities into the BES.

8. Submit and coordinate the plans for the interconnection of Facilities to the BES within its Transmission

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\(^3\) Definition of Transmission Planner from the NERC Glossary of Terms (as of May 15, 2016).

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Planner area with other Transmission Planners and the Planning Coordinator, as appropriate.


10. Coordinate with Transmission Owners and Generator Owners to define system protection and control needs and requirements, including Remedial Action Schemes to meet reliability needs.

11. Receive maintenance schedules and construction plans from Transmission Operator or Transmission Owner for input into and evaluation of BES expansion plans.
Resource Planning and Resource Planner

Resource Planning

Tasks

1. **Acquire or develop the tools needed to evaluate long-term resource adequacy for a specific set of Loads.**

2. **Acquire or develop the data and information required for performing periodic resource adequacy assessments.**

3. Determine the reliability criteria used as the basis for assessing long-term resource Adequacy, considering generation capacity from resources inside and outside of its area.

4. Perform periodic resource Adequacy assessments and document the results.

5. Evaluate future Report on resource alternatives. Adequacy

6. Create and periodically update a long-term resource plan.
Part 3: Functions and Functional Entities

**Resource Planner**

**Definition**
The entity that develops a long-term (generally one year and beyond) plan for the resource adequacy of specific loads (customer demand and energy requirements) within a Planning Authority area.4

**Relationships with Other Functional Entities**

1. Collect data and information required for performing periodic resource Adequacy assessments from one or more of the following entities as necessary: Load-Serving Entity, Generator Owner, Generator Operator, Transmission Planner, Planning Coordinator, and Transmission Service Provider.
2. Provide long-term resource plan information to the Transmission Planner for power system modeling and Planning Assessments.
3. Receive information from the Transmission Planners regarding submitted resource plan deliverability.
4. Provide resource plan recommendations to the affiliated Generator Owner and Load-Serving Entity.
5. Coordinate with Transmission Planners and Transmission Service Providers on resource plans.
6. 
7. Assess alternative plans with Transmission Planners to identify potential alternative solutions to meet resource Adequacy requirements.

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4 Definition of Resource Planner from the NERC Glossary of Terms (as of May 15, 2016).
Reliability Operations and Reliability Coordinator

Reliability Operations

Tasks

1. Monitor all reliability-related parameters within the reliability area, including generation dispatch and maintenance plans for generation and Transmission.
2. Identify, communicate, and direct actions if necessary to relieve reliability threats and limit violations in the reliability area.
3. Develop Interconnection Reliability Operating Limits (to protect from instability and Cascading).
4. Assist in determining Interconnected Operations Services (IOS) requirements for:
   a. balancing generation and load\(^5\), and
   b. reliability of Transmission.
5. Perform reliability analysis (actual and Contingency) for the reliability area.
6. Direct revisions to Transmission maintenance plans as permitted by Agreements.
7. Direct revisions to generation maintenance plans as permitted by Agreements.
8. Direct implementation of emergency\(^6\) procedures including load shedding.
9. Direct and coordinate restoration of any combination of generation, Transmission or distribution components.
10. Curtail Confirmed Interchange that adversely impacts reliability.
11. Provide appropriate security protections for cyber assets and physical assets, and their related support systems and data.
12. Communicate to appropriate authorities and relevant functional entities of an actual or suspected attack on cyber assets and/or physical assets.

\(^5\) The Glossary definition of "Load" is not appropriate because the Glossary definition refers to end-use customer or end-use device; the Glossary definition does not incorporate the concept of quantity.

\(^6\) The Glossary definition is not appropriate because the definition is limited in application to the BES. In this context, the RC may encounter an emergency situation that is broader than the circumstances described in the Glossary definition.
Reliability Coordinator

Definition
The entity that is the highest level of authority who is responsible for the Reliable Operation of the Bulk Electric System, has the Wide Area view of the Bulk Electric System, and has the operating tools, processes and procedures, including the authority to prevent or mitigate emergency operating situations in both next-day analysis and real-time operations. The Reliability Coordinator has the purview that is broad enough to enable the calculation of Interconnection Reliability Operating Limits, which may be based on the operating parameters of transmission systems beyond any Transmission Operator’s vision.7

Introduction to the Reliability Coordinator
The Reliability Coordinator maintains the Real-time operating reliability of its Reliability Coordinator Area and in coordination with its neighboring Reliability Coordinator’s Wide Area view. Wide Area view means the entire Reliability Coordinator area as well as the critical flow and status information from adjacent Reliability Coordinator Areas as determined by detailed system studies to allow the calculation of Interconnected Reliability Operating Limits.8 The Wide Area view includes situational awareness of its neighboring Reliability Coordinator Areas. The RC has the authority to direct other functional entities to take certain actions to ensure that its Reliability Coordinator Area operates reliably. Its scope includes both:

1. Transmission operations. With respect to transmission operations, the Reliability Coordinator and Transmission Operator have similar roles, but different scopes. The Transmission Operator directly maintains reliability for its Transmission Operator Area. However, the Reliability Coordinator also maintains reliability, in concert with the other Reliability Coordinators, for the Interconnection as a whole. Thus, the Reliability Coordinator needs a Wide Area view that reaches beyond its boundaries to enable it to operate within Interconnection Reliability Operating Limits. The Transmission Operator may or may not have this Wide Area view, but the Reliability Coordinator does have it. The Reliability Coordinator may direct a Transmission Operator within its Reliability Coordinator Area to take whatever action is necessary to ensure that Interconnection Reliability Operating Limits are not exceeded.

2. Balancing operations. The Reliability Coordinator ensures that the generation-demand balance is maintained within its Reliability Coordinator Area, which, in turn, ensures that the Interconnection frequency remains within acceptable limits. The Balancing Authority has the responsibility for generation-demand-interchange balance in the Balancing Authority Area. The Reliability Coordinator may direct a Balancing Authority within its Reliability Coordinator Area to take whatever action is necessary to ensure that this balance does not adversely impact reliability.

Relationships with Other Functional Entities

Ahead of Time

1. Coordinate with other Reliability Coordinators, Transmission Planners, and Transmission Service Providers on transmission system9 limitations.

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7 Definition of Reliability Coordinator from the NERC Glossary of Terms (as of May 15, 2016).
8 Definition of “Wide-area” from the NERC Glossary of Terms (as of May 1, 2016).
9 Not appropriate to use the NERC Glossary definition in this context because may not always include a combination of generation, transmission, and distribution.
Part 3: Functions and Functional Entities

2. Receive facility\textsuperscript{10} and operational data from Generator Operators, Distribution Providers, Load-Serving Entities, Transmission Owners, Generator Owners, and Transmission Operators.

3. Receive generation dispatch from Balancing Authorities and issue dispatch adjustments to Balancing Authorities to prevent exceeding limits within the Reliability Coordinator Area (if not resolved through market mechanisms).

4. Receive integrated operational plans from Balancing Authorities for reliability analysis of Reliability Coordinator Area.

5. Develop Interconnection Reliability Operating Limits (IROLs), and provide them to those functional entities with a reliability-related need.


8. Receive final approval or denial of Arranged Interchange from Interchange Coordinator.


10. Develops operating agreements or procedures with Transmission Owners.

14. Coordinate with Transmission Operators on restoration plans (\textit{i.e.}, any combination of generation, Transmission or distribution components), contingency\textsuperscript{11} plans and Interconnected Operations Services (IOS).

Real Time

15. Coordinate reliability processes and actions with and among other Reliability Coordinators.


17. Issue reliability alerts to Generator Operators, Transmission Operators, Transmission Service Providers, Balancing Authorities, Interchange Coordinators, Regional Entities and NERC.


19. Specify reliability-related requirements to Balancing Authorities.

20. Receive verification of Emergency procedures from Balancing Authorities.

21. Receive notification of Confirmed Interchange changes from Balancing Authorities.

\textsuperscript{10} Glossary definition not appropriate because definition is limited in application to BES Elements. In this context, the intent is to have broader application to include non-BES elements (\textit{e.g.}, industrial equipment).

\textsuperscript{11} Glossary definition not appropriate because application in this context is not limited to power system contingency (\textit{i.e.}, N-1 event); in this context, intended to have broader meaning.
22. Order re-dispatch of generation by Balancing Authorities.
23. Direct use of flow control devices by Transmission Operators.
24. Respond to requests from Transmission Operators to assist in mitigating equipment overloads.
Balancing and Balancing Authority

Balancing

Tasks

1. Control any of the following combinations within a Balancing Authority Area:
   a. Demand and resource
   b. Demand and Confirmed Interchange
   c. Generation and Confirmed Interchange
   d. Generation, Demand, and Confirmed Interchange

2. Calculate Area Control Error (ACE) within the reliability area.

3. Operate in the Balancing Authority Area to maintain Demand and resource balance.

4. Review generation commitments, dispatch, and Demand forecasts.

5. Formulate an operational plan (e.g., generation commitment, outages) for reliability evaluation.

6. Approve Arranged Interchange from Damping ability perspective.

7. Implement Confirmed Interchange.

8. Operate the Balancing Authority Area to contribute to Interconnection frequency.


10. Provide balancing and energy accounting (including hourly checkout of Confirmed Arranged Interchange, Implemented Interchange and actual Interchange), and administer inadvertent energy paybacks.


13. Implement Emergency procedures.

14. Provide appropriate security protections for cyber assets and physical assets, and their related support systems and data.

15. Communicate to appropriate authorities and relevant functional entities of an actual or suspected attack on cyber assets and/or physical assets.

*Glossary term not appropriate in this context because the definition is too broad.*
Balancing Authority

**Definition**
The responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports interconnection frequency in real time.\(^{13}\)

**Relationships with Other Functional Entities**

**Ahead of Time**

1. Receive generator Facility plans from Generator Operators within the Balancing Authority Area.
2. Receive operational data from Generator Operators within the Balancing Authority Area.
3. Receive operating and availability status of generating units from Generator Operators within the Balancing Authority Area.
4. Receive reliability evaluations from the Reliability Coordinator.
5. Compile Demand forecasts from Load-Serving Entities.
6. Develop Agreements with adjacent Balancing Authorities for ACE calculation parameters.
7. Submit integrated operational plans to the Reliability Coordinator for reliability evaluation and provides balancing information to the Reliability Coordinator for monitoring.
9. Send approval or denial of Arranged Interchange based on meeting Ramping requirements to Interchange Coordinators.
10. Receive notice of final approval or denial of Arranged Interchange becoming Confirmed Interchange from the Interchange Coordinator.
11. Implement generator commitment and dispatch schedules from the Load-Serving Entities who have arranged for resources within the Balancing Authority Area.
12. Acquires Interconnected Operations Services (IOS) from Generator Operator.
13. Receive dispatch adjustments from Reliability Coordinators to prevent exceeding limits.
14. Receives generator information from Generator Owners including unit maintenance schedules and retirement plans.
15. Receive reports on frequency regulating equipment from Generator Operators within the Balancing Authority Area.
16. Receive information from Load-Serving Entities on self-provided Interconnected Operations Services (IOS).
17. Coordinate restoration plans (i.e., any combination of generation, Transmission or other system).\(^{13}\)

\(^{13}\) Definition of Balancing Authority from the NERC Glossary of Terms (as of May 15, 2016).

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Part 3: Functions and Functional Entities

distribution components) with the Transmission Operator.

20. Provide resource dispatch to Reliability Coordinators.

Real Time

21. Coordinate use of Interruptible Demand with Load-Serving Entities.
22. Receive loss allocation from Transmission Service Providers (for repayment with in-kind losses).
23. Receive Real-time operating information from the Transmission Operator, adjacent Balancing Authorities and Generator Operators.
24. Receive operating information from Generator Operators.
25. Provide Real-time operational information for Reliability Coordinator monitoring.
26. Receive reliability alerts from Reliability Coordinator.
27. Comply with reliability-related requirements (e.g., reactive requirements, location of operating reserves) specified by Reliability Coordinator.
28. Verify implementation of Emergency procedures to Reliability Coordinator.

29. Inform Reliability Coordinator and Interchange Coordinators of Confirmed Interchange changes (e.g., due to Demand or resource interruptions) involving its Balancing Authority Area.

30. Receive Confirmed Interchange revisions (including Curtailments) from Interchange Coordinators.
31. Direct resources (Generator Operators and Load-Serving Entities) to take action to ensure balance in Real-time.

32. Request Transmission Operator (or Distribution Provider) to reduce voltage to lower Demand or shed Load if needed to ensure balance within its Balancing Authority Area.
33. Direct Generator Operators to implement re-dispatch for congestion management as directed by the Reliability Coordinator.
34. Implements corrective actions and Emergency procedures as directed by the Reliability Coordinator.
35. Implement restoration plans (i.e., any combination of generation, Transmission or distribution components) as directed by the Transmission Operator.
36. Direct Transmission Operator to implement flow control devices.

After the hour

38. Confirm Implemented Interchange with Confirmed Interchange provided by the Interchange Coordinators after the hour for "checkout."

39. Confirm Implemented Interchange and Confirmed Interchange with adjacent Balancing Authorities after the hour for "checkout."

40. Request record of individual Confirmed Interchange from Interchange Coordinator.
Market Operations and Market Operator (Resource Integrator)

Market Operations

Tasks

1. The market operations function, its tasks, and the interrelationships with other entities are included in the Functional Model only as an interface point of reliability functions with commercial functions.
Market Operator (Resource Integrator)

**Definition**
The market entity whose interrelationships with other entities are included in the Functional Model only as an interface point of reliability functions with commercial functions.

**Relationships with Other Functional Entities**
Market operator tasks and relationships are specific to a particular market design and will depend on the market structure over which the market operator presides.
Transmission Operations and Transmission Operator

Transmission Operations

Tasks
1. Monitor and provide telemetry (as needed) of all reliability-related parameters within the reliability area.
2. Monitor the status of, and deploy, facilities\textsuperscript{14} classed as Transmission assets, which may include the Transmission lines connecting a generating plant to the Transmission system, associated protective relaying systems and Remedial Action Schemes.
3. Develop System limitations (e.g., System Operating Limits) and operate within those limits.
4. Develop and implement Emergency procedures.
5. Develop and implement System restoration plans.
6. Operate within established Interconnection Reliability Operating Limits,\textsuperscript{15}
8. Adjust Real Power, Reactive Power and voltage to maintain reliability,\textsuperscript{16}
9. Determine the available Transmission capability that supports the Reliable Operation of the Transmission Operator Area.
10. Perform switching operation of Transmission Facilities,\textsuperscript{17}
11. Provide appropriate security protections for cyber assets and physical assets, and their related support systems and data.
12. Communicate to appropriate authorities and relevant functional entities of an actual or suspected attack on cyber assets and/or physical assets.

Transmission Operator

Definition
The entity responsible for the reliability of its "local" transmission system, and that operates or directs the operations of the transmission Facilities.\textsuperscript{18}

Introduction to the Transmission Operator
The Transmission Operator is responsible for the Real-time operating reliability of the Transmission assets under its purview, which is referred to as the Transmission Operator Area. The Transmission Operator has the authority to take certain actions to ensure that its Transmission Operator Area operates reliably.

\begin{itemize}
  \item The Glossary definition of “Facility” is not appropriate because the definition is limited in application to BES Elements. In this context, the intent is to have broader application to include responsibilities for non-BES elements.
  \item Definition of Transmission Operator from the NERC Glossary of Terms (as of May 15, 2016).
\end{itemize}
Part 3: Functions and Functional Entities

The Transmission Operator and Reliability Coordinator have similar roles with respect to the reliability of the Transmission System, but have different responsibilities. The Transmission Operator shares a role in monitoring the Transmission System with the Reliability Coordinator, and in addition, has the operational responsibility for the Transmission System area under its purview. The Transmission Operator can calculate System Operating Limits, but does not necessarily have the wider-area view of the Reliability Coordinator, necessary to calculate Interconnection Reliability Operating Limits.

Relationships with Other Functional Entities

**Ahead of Time**

2.Receive maintenance requirements and construction plans and schedules from the Transmission Owners and Generation Owners.
3. Receive Interconnection Reliability Operating Limits as established by the Reliability Coordinator.
4. Receive reliability evaluations from the Reliability Coordinator.
5. Develop agreements (Operating Plans, procedures, and processes) with adjacent Transmission Operators.
6. Define Total Transfer Capabilities and System Operating Limits based on facility information provided by the Transmission Owners and Generation Owners and assistance from Reliability Coordinator.
7. Arrange for Interconnected Operations Services (IOS) from Generator Operators (e.g., voltage schedules, VAR Demand schedule).
8. Develop contingency plans, and monitors operations of the Transmission facilities within the Transmission Operator Area control and as directed by the Reliability Coordinator.
9. Provide facility and operating information to the Reliability Coordinator.
10. Provide to the Transmission Planner information on the capability to Curtail (reduce) and shed Load during Emergencies.
12. Receive operating and availability status of generating units from Generator Operators including status of automatic voltage regulators and power system stabilizers.
13. Receive operational data from Generator Operators.
14. Develop operating agreements or procedures with Transmission Owners.

**Real Time**

15. Coordinate Load shedding with, or as directed by, the Reliability Coordinator.
16. Provide Real-time operations information to the Reliability Coordinator and Balancing Authority.
17. Notify Generator Operators of Transmission System problems (e.g., voltage limitations or equipment overloads that may affect generator operations).

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18. Request Reliability Coordinator to assist in mitigating equipment overloads. (e.g., re-dispatch, transmission loading relief).

19. Deploy reactive resources from Transmission Owners and Distribution Providers to maintain acceptable voltage profiles.

20. Direct Distribution Providers to shed load if needed to ensure reliability within the Transmission Operator Area.

21. Implement flow control device operations for those ties under the Transmission Operator’s purview as directed by the Balancing Authorities or Reliability Coordinator.

22. Receive reliability alerts from Reliability Coordinator.

23. Direct Balancing Authorities and Distribution Providers to implement system restoration plans.

24. Receive Real-time operating information from Generator Operators.
Interchange and Interchange Coordinator

Interchange

Tasks

1. Receive completed Request for Interchange (RFI) (i.e., valid source and sink, Transmission arrangements).
2. Transition RFI to Arranged Interchange.
3. Forward Arranged Interchange to entities for approval, change, or denial.
4. Collect approvals and denials of requested Arranged Interchange.
5. Communicate status of an Arranged Interchange that becomes Confirmed Interchange or otherwise.
6. Communicate Confirmed Interchange information to the appropriate reliability assessment tools (e.g., the interchange distribution calculator in the Eastern Interconnection).
7. Submit Arranged Interchange for Curtailments and re-dispatch implementation requests.
8. Maintain record of an individual Confirmed Interchange.
9. Provide appropriate security protections for cyber assets and physical assets, and their related support systems and data.
10. Communicate to appropriate authorities and relevant functional entities of an actual or suspected attack on cyber assets and/or physical assets.
Interchange Coordinator

Definition

The responsible entity that authorizes implementation of valid and balanced Interchange Schedules between Balancing Authority Areas, and ensures communication of Interchange information for reliability assessment purposes.\(^{17}\)

Relationships with Other Functional Entities

Ahead of Time

1. Receive Requests for Interchange from Generation Owner, Purchasing-Selling Entity, and Load-Serving Entity.
2. Submit Arranged Interchange to become Confirmed Interchange to the Balancing Authorities and Transmission Service Providers for approvals.
3. Receive approval or denial from Transmission Service Providers of Transmission arrangement(s) for Arranged Interchange.
4. Receive approval or denial from Balancing Authorities of the ability to meet Ramping requirements for submitted Arranged Interchange.
5. Receives approval from Generation Owners, Purchase-Selling Entities, or Load-Serving Entities for any revised Arranged Interchange.
6. Communicate final approval or denial of a request for an Arranged Interchange to become Confirmed Interchange to the Reliability Coordinator, Balancing Authorities, Transmission Service Providers, Generation Owners, Purchasing-Selling Entities, and Load-Serving Entities for implementation.

Real Time

7. Receive Reliability alerts from the Reliability Coordinators.
8. Receive Curtailments and re-dispatch implementation requests from Reliability Coordinators and submits Arranged Interchange.
9. Receive information on Confirmed Interchange interruptions from the Balancing Authorities and communicates the Confirmed Interchange status to Balancing Authorities, Transmission Service Providers, Reliability Coordinators, Generation Owners, and Purchasing-Selling Entities, and Load-Serving Entities.

After the hour

11. Provide a record of individual Confirmed Interchange to requesting Balancing Authorities.
12. Coordinate Confirmed Interchange with Balancing Authorities after the hour for "checkout."

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\(^{17}\) Definition of Interchange Authority from the NERC Glossary of Terms (as of May 15, 2016). The Glossary uses the term "Interchange Authority" whereas the Functional Model uses the term "Interchange Coordinator."
Transmission Service and Transmission Service Provider

Transmission Service

Tasks

1. Receive Transmission Service requests and process each request for service according to the requirements of the tariff.
   a. Maintain commercial interface for receiving and confirming requests for Transmission Service according to the requirements of the tariff (e.g., OASIS).
2. Determine and post available transfer capability values.
3. Approve or deny Transmission Service requests.
4. Approve or deny Arranged Interchange from Transmission Service arrangement perspective.
5. Allocate Transmission losses (MWs or funds) among Balancing Authority Areas.
6. Acquire Ancillary reliability-related Services to support Transmission Service.
7. Update information that is relevant to a long-term Transmission Service arrangement.
Transmission Service Provider

Definition
The entity that administers the transmission tariff and provides Transmission Service to Transmission Customers under applicable Transmission Service agreements.

Relationships with Other Functional Entities

Ahead of Time
1. Receive the methodology to determine available transfer capacity from the Transmission Operator.
2. Receive Total Transfer Capabilities, System Operating Limits and Interconnection Reliability Operating Limits from the Transmission Planner and Transmission Operator, and coordinates available transfer capacity with these entities and other Transmission Service Providers.
3. 
4. Receive Transmission expansion plans identified by the Transmission Planner(s) to help determine ability to accommodate long-term Transmission Service requests.
5. Arrange for providers of Ancillary Services, and notify the Transmission Operator and Balancing Authority.
6. Accept or decline Transmission Service requests from Purchasing-Selling Entities, Generator Owners, and Load-Serving Entities.
7. 
8. Develop Agreements or procedures with Transmission Owners.
10. Send approval or denial of Arranged Interchange to Interchange Coordinator based on meeting Transmission Service arrangements.
11. Receive notice of final approval or denial of Arranged Interchange becoming Confirmed Interchange from Interchange Coordinator.

Real Time
13. Receive Confirmed Interchange revisions (including Curtailments) from the Interchange Coordinators.
14. Receive Confirmed Interchange Interruption status from Interchange Coordinator.
15. Receive reliability alerts from Reliability Coordinator.
16. Provide loss allocation to Balancing Authorities.
17. Notify the Transmission Operator and Balancing Authority of changes to Ancillary Services.

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18 Definition of Transmission Service Provider from the NERC Glossary of Terms (as of May 15, 2016).

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Transmission Ownership and Transmission Owner

Transmission Ownership

Tasks
1. Develop interconnection agreements.
2. Establish ratings of transmission facilities.
4. Design and install owned facilities classified as transmission and obtain associated rights-of-way.
5. Design and authorize maintenance of transmission protective relaying systems and remedial action schemes.
6. Provide appropriate security protections for cyber assets and physical assets, and their related support systems and data.
7. Communicate to appropriate authorities and relevant functional entities of an actual or suspected attack on cyber assets and/or physical assets.

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\[\text{19 Glossary definition of “Facilities” is not appropriate because the definition is limited in application to BES Elements. In this context, the intent is to have broader application for non-BES elements.}\]
Transmission Owner

Definition
The entity that owns and maintains transmission facilities.

Relationships with Other Functional Entities
1. Coordinate with Transmission Planners, the Planning Coordinator, and other Transmission Owners desiring to connect with the Transmission system under the purview of the Transmission Owner.
2. Receive approved Transmission expansion plans from the Transmission Planner.
3. Develop agreements or procedures with the Transmission Service Providers.
4. Develop operating agreements or procedures with the Transmission Operators, Reliability Coordinators, and Distribution Providers.
5. Develop agreements with adjacent Transmission Owners for joint Transmission facilities.
6. Provide Transmission expansion plans and changes to the Planning Coordinator and Transmission Planners.
9. Coordinate and develop interconnection agreements with the Distribution Providers, Generation Owners, and Load Serving Entities desiring to connect with the Transmission system under the purview of the Transmission Owner.
10. Provide reactive resources to Transmission Operators.
11. Revise Transmission maintenance plans as requested by the Reliability Coordinator.

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Distribution and Distribution Provider

Distribution

Tasks

1. Provide and operate electrical delivery Facilities between the Transmission System and the end-use customer or distribution-connected energy resource.
2. Identify and characterize its connected Load and energy resources.
3. Implement voltage reduction.
4. Design and maintain protective relaying systems, under-frequency Load shedding systems, under-voltage Load shedding systems, and Remedial Action Schemes that interface with the Transmission System.
5. Provide and implement Load-shed capability.
6. Maintain voltage and power factor within specified limits at the interconnection point.
7. Provide appropriate security protections for cyber assets and physical assets, and their related support systems and data.
8. Communicate to appropriate authorities and relevant functional entities of an actual or suspected attack on cyber assets and/or physical assets.
**Distribution Provider**

**Definition**
The functional entity that provides and operates the “wires” between the transmission system and the end-use customer. For those end-use customers who are served at transmission voltages, the Transmission Owner also serves as the Distribution Provider. Thus, the Distribution Provider is not defined by a specific voltage, but rather as performing the distribution function at any voltage.

**Introduction to the Distribution Provider**
The Distribution Provider delivers electrical energy from the Transmission System to the end-use customer. The Distribution Provider provides the switches and re-closers that could be used to shed load for emergency action.

**Relationships with Other Functional Entities**

**Ahead of Time**
1. Coordinate with Transmission Planners on interconnected load and energy resources to support transmission analysis.
2. Coordinate system restoration plans with Transmission Operator.
3. Coordinates with end-use customers, distributed energy resources, and Load-Serving Entities to identify new facility connection needs.
4. Develop interconnection agreements with Transmission Owners on a facility basis.
5. Provide operational data to Transmission Operator.
6. Coordinate with Load-Serving Entities to identify critical loads that are to be precluded from load shedding where avoidable.
7. Provide protective relaying systems, under-frequency load shedding systems, under-voltage load shedding systems, and Remedial Action Schemes as defined by the Transmission Planner and Planning Coordinator.

**Real Time**
8. Obtain voltage and power factor requirements from the Transmission Operator.
9. Implement voltage reduction and shed load as directed by the Transmission Operator or Balancing Authority.
10. Implement system restoration plans as coordinated by the Transmission Operator.
11. Direct load-serving entities to communicate requests for voluntary load curtailment.

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21 Definition of Distribution Provider from the NERC Glossary of Terms (as of May 15, 2016).

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Part 3: Functions and Functional Entities

Generator Operation and Generator Operator

Generator Operation

Tasks

1. Formulate daily generation plan.
2. Report operating and availability status of generator Facility{ies} and related equipment, such as automatic voltage regulator equipment, power system stabilizer equipment and frequency regulating equipment.
3. Operate generator Facility{ies} to provide Real Power and Reactive Power or Interconnected Operations Services in accordance with contracts or arrangements.
4. Monitor the status of generator Facility{ies}.
5. Support Interconnection frequency and voltage.
6. Provide appropriate security protections for cyber assets and physical assets, and their related support systems and data.
7. Communicate to appropriate authorities and relevant functional entities of an actual or suspected attack on cyber assets and/or physical assets.
Generator Operator

Definition
The entity that operates generating unit(s) and performs the functions of supplying energy and Interconnected Operations Services.22

Relationships with Other Functional Entities

Ahead of Time
1. Provide generation commitment plans to the Balancing Authority.
2. Provide Balancing Authority and Transmission Operators with requested amount of Interconnected Operations Services (IOS).
3. Provide availability and operating status of generator Facility(ies), Balancing Authority and Transmission Operators for reliability analysis.
4. Report status of automatic voltage regulating equipment and power system stabilizer equipment to Transmission Operators.
5. Report on frequency regulating equipment to Balancing Authority.
6. Provide operational data to Reliability Coordinator, Balancing Authority and Transmission Operator.
7. 
8. Receive notice from Purchasing-Selling Entity if Arranged Interchange approved or denied.
9. Receive reliability alerts from Reliability Coordinator.

Real Time
11. Provide Real-time operating information to the Transmission Operators and the required Balancing Authority.
12. Adjust Real Power and Reactive Power as directed by the Balancing Authority and Transmission Operators.

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22 Definition of Generator Operator from the NERC Glossary of Terms (as of May 15, 2016).
Generator Ownership and Generator Owner

Generator Ownership

Tasks

1. Establishes generator facility ratings, limits, and operating requirements.
2. Designs, and authorizes maintenance of the generator protective relaying systems, protective relaying systems on the Transmission lines connecting the generator to the Transmission System, and Remedial Action Schemes (RAS) related to the generator.
3. Performs or authorizes maintenance of generator facilities.
4. Provides verified generator facility performance characteristics / data.
5. Provide appropriate security protections for cyber assets and physical assets, and their related support systems and data.
6. Communicate to appropriate authorities and relevant functional entities of an actual or suspected attack on cyber assets and/or physical assets.
Generator Owner

**Definition**
The entity that owns and maintains generating Facility(ies). 23

**Relationships with Other Functional Entities**

**Ahead of Time**
1. Provide generator Facility(ies) information to the Transmission Operator, Reliability Coordinator, Balancing Authority, Transmission Planner, and Resource Planner.
3. Develop interconnection Agreement(s) with Transmission Owner on a Facility basis.
4. Receive approval or denial of Transmission Service request from Transmission Service Provider.
5. Provide Interconnected Operations Services to Purchasing-Selling Entity pursuant to agreement.
6. Revise the generation maintenance plans as requested by the Balancing Authority, Transmission Operator, and Reliability Coordinator.
7. Submit Request for Interchange to the Interchange Coordinator.
8. Submit approval for original or revised Arranged Interchange to the Interchange Coordinator.
9. Receive communication that Arranged Interchange has become Confirmed Interchange from the Interchange Coordinator.

**Real-time**

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23 Definition of Generator Owner from the NERC Glossary of Terms (as of May 15, 2016).
10. Receive Confirmed Interchange Interruptions status from the Interchange Coordinator.

11. Receive Confirmed Interchange revisions (including Curtailments) from the Interchange Coordinator.
Part 3: Functions and Functional Entities

Purchasing-Selling and Purchasing-Selling Entity

**Purchasing-Selling**

**Tasks**

1. Purchase and sell energy or capacity.
2. Arrange for Transmission Service that is required to implement an Interchange Transaction.
3. Request implementation of Arranged Interchange.
Part 3: Functions and Functional Entities

**Purchasing-Selling Entity**

**Definition**
The entity that purchases or sells, and takes title to, energy, capacity, and Interconnected Operations Services. Purchase-Selling Entities may be affiliated or unaffiliated merchants and may or may not own generating facilities.24

**Relationships with Other Functional Entities**

**Ahead of Time**
1. Arrange for energy and capacity from Generator Owners.
2. Arrange for Transmission Service from Transmission Service Providers and makes arrangements for self-provided Interconnected Operations Services with Generator Owners or Load-Serving Entities.
3. Submit Requests For Interchange to Interchange Coordinators.
4. Submit approval for original or revised Arranged Interchange to Interchange Coordinator.
5. 
6. Receive communication that Arranged Interchange has become Confirmed Interchange from the Interchange Coordinator.
7. Receive Demand profiles and forecasts from Load-Serving Entities.

**Real Time**
8. Receive notice of Confirmed Interchange Interruptions from Interchange Coordinator.
9. Receive notice of Confirmed Interchange revisions (including Curtailments) from Interchange Coordinator.
10. Notify Interchange Coordinators of Confirmed Interchange and Implemented Interchange cancellations or terminations.
11. Receive notice of Confirmed Interchange Curtailments from Interchange Coordinator.

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24 Definition of Purchasing-Selling Entity from the NERC Glossary of Terms (as of May 15, 2016).
Load-Serving and Load-Serving Entity

Load-Serving

Tasks

1. Collect individual load\textsuperscript{25} profiles and characteristics.
2. Identify capability for and communicate requests for voluntary load Curtailment.
3. \textbf{Identify and communicate} critical customer Loads that are to be excluded from the Load shedding systems.
4. Identify the resources needed for self-provided Interconnected Operations Services (IOS).
5. Develop overall load profiles and forecasts of end-user energy requirements.
6. Acquire necessary Transmission Service, and \textbf{provide for Interconnected Operations Services}.
7. \textbf{Arrange for Interchange},
8. Manage resource portfolios to meet Demand and energy delivery requirements.

* Keep lowercase because:
Load-Serving Entity

Definition
Secures energy and Transmission Service (and Interconnected Operations Services) to serve the electrical demand and energy requirements of its end use customers.²⁶

Relationships with Other Functional Entities

Ahead of Time
1. Submit load data as needed to the appropriate entity (e.g., Balancing Authorities, and Resource Planners, and Transmission Service Provider) in accordance with applicable tariffs, interconnection agreements or other arrangements.
2. Coordinate with Distribution Provider to identify critical Loads that are to be excluded from Load shedding.
3. Provide information regarding self-provided Interconnected Operations Services (IOS) to the Balancing Authority.
5. Arrange for Transmission Service from Transmission Service Providers and makes arrangements for Ancillary Services with Generator Owners or Load-Serving Entities.
6. Submit Requests For Interchange to Interchange Coordinator.
7. Submit approval for original or revised Arranged Interchange to Interchange Coordinator.
8. Receive communication that Arranged Interchange has become Confirmed Interchange from the Interchange Coordinator.
9. Notify Generator Operators if Arranged Interchange requests are approved or denied.
10. Coordinate with Distribution Provider on identifying new Facility interconnection needs.

Real Time
12. Communicate requests for voluntary load Curtailment to end-use customers as directed by the Reliability Coordinator, Balancing Authority, Transmission Operator, and Distribution Provider.
13. Receive notice of Confirmed Interchange revisions (including Curtailments) from Interchange Coordinator.
14. Receive notice of Confirmed Interchange Interruptions from Interchange Coordinator.

²⁶ Definition of Load-Serving Entity from the NERC Glossary of Terms (as of May 15, 2016).
Chapter 4 - Revision Summary

NOTE ADDED: This section needs to be re-written to the changes made in Version 6, including:
- The reasons for developing Version 6, including the Risk-Based Registration changes, Alignment of Terms changes, and consideration of issues that may impact the Model
- Each of these aspects should be in a separate paragraph, describing the change and the associated change, if any, in the Model.
- Some suggestions follow:

Risk-Based Registration changes.
On December 14, 2014, NERC petitioned FERC to approve a number of revisions to the ROP respecting the Risk-based Registration Initiative. In particular, NERC proposed:
- the removal of three functional registration categories (Purchasing-Selling Entities, Interchange Authorities, and Load-Serving Entities),
- the risk-based application of sub-set lists of Reliability Standards, as warranted and supported by technical and risk consideration review and analysis, for entities (including Underfrequency Load Shedding-Only Distribution Providers).

NERC’s petition noted: “While three entities [PSE, IA, LSE] are proposed for removal from the Registry Criteria, as users, owners and operators of the Bulk-Power System, these entities … will continue to exist and will continue to perform in the markets or operate under open access transmission tariffs, as applicable”.

The removal of these three functional registration categories was approved in FERC Orders dated March 19, 2015 and October 15, 2015.

The FMAG was tasked with determining whether these registration changes had implications for the Functional Model.

Resolution
Version 5 made it clear that the Model deals with reliability tasks and relationships, and not associated registration and compliance aspects. Version 6 of the Model has retained these three functional entities, recognizing that the reliability-related tasks and functional entities that perform them continue to exist, as noted above in NERC’s petition, regardless of whether NERC Registration is required under ROP Appendix 5B.

Likewise, the creation of sub-set lists of standards requirements, in effect a sub-category of a functional entity, for registration and compliance purposes is not a concern for the Model. A similar conclusion was reached in Version 5 with the creation of Joint Registration Organizations.

A number of registration and compliance-related references in the Model and Technical Document that were introduced in earlier versions of the Model have been removed. For example, references to “responsible for” were changed to “performed by”.27

Alignment of Terms changes.
Version 6 clarifies the distinction in the Model between defined terms and terms intended to have a generic meaning:
- Terms that are intended to have the meaning given in the NERC Glossary have their first letters

27 However, such references to registration appearing in the NERC Glossary definitions of functional entities were retained, for consistency between the Glossary and the Model.
capitalized, as in “Transmitter”.

- Terms that are intended to a generic meaning are in lower case, as in “transmitter”.

This distinction recognizes that Glossary definitions relate to BES facilities, whereas the Model allows for those situations in which non-BES facilities may impact BES reliability.

In addition, Version 6 has defined terms that have applicability only within the Model. These terms are defined in the Introduction.

*** TO BE RESOLVED BY FMAG:
- Review all instances of ‘reliability-related services’ in the Model, to determine which should be retained versus replaced by IOS
- Did the FMAG agree to a global replace to add “Typical” in front of “Relationships with Other Functional Entities”? Does the suggested footer on each page adequately cover this point? Adding “Typical” was discussed only in connection with LSE, but the template should be the same for all functional entities.

Consideration of issues that may impact the Model.

There are indications of instances in which the Model has been used inappropriately by standards drafting teams, by taking the Model’s Tasks and Relationships with Other Functional Entities to be prescriptive and authoritative. Version 6 includes a footer on each page to emphasize that the Model’s Tasks and relationships are typical and illustrative, and not prescriptive.
Evaluate the plans that are in response to long-term (generally one year and beyond) customer requests for transmission service.

Review transmission facility plans required to integrate new (End-use Customer, generation, and transmission) facilities into the Bulk Electric System.

Review and determine transfer capability (generally one year and beyond) as appropriate.

Monitor and evaluate transmission expansion plan and resource plan implementation.

Coordinate projects requiring transmission outages that can impact reliability and firm transactions.

so that system models and resource and transmission expansion plans take into account modifications made to adjacent Planning Coordinator areas.

1. Develop and maintain transmission and resource (demand and capacity) system models to evaluate transmission system performance and resource adequacy.

2. within a Planning Coordinator area and coordinates those plans with adjoining Planning Coordinator areas.

may include extended coordination with integrated Planning Coordinators’ plans for adjoining areas beyond individual system plans. By its very nature, Bulk Electric System planning involves multiple entities. Since all electric systems within an integrated network are electrically connected, whatever one system does can affect the other systems.

network areas with little or no ties to others’ areas, such as interconnections,

Transmission Planners, Reliability Coordinator, Transmission Owner, Transmission Operator, Transmission Service Provider, and

1.
Coordinates with Resource Planners and other Transmission Planners on Bulk Electric System expansion plans.

Coordinates with Resource Planners and other Transmission Planners on Bulk Electric System expansion plans.

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