Agenda
Reliability and Security Technical Committee

Virtual Meeting via WebEx

December 15, 2020 | 1:00–4:00 p.m. Eastern

Attendee WebEx Link: Join Meeting

Call to Order

NERC Antitrust Compliance Guidelines and Public Announcement

Introductions and Chair's Remarks

1. **Administrative items**
    a. Arrangements
    b. Announcement of Quorum
    c. Reliability and Security Technical Committee (RSTC) Membership 2020-2023*
        i. RSTC Roster
        ii. RSTC Organization
        iii. RSTC Charter
        iv. Governance Management*
        v. Participant Conduct Policy

Consent Agenda

2. **Minutes - Approve**
    a. September 15, 2020 RSTC Meeting*
    b. October 14, 2020 RSTC Meeting*

Regular Agenda

3. **Remarks and Reports**
    a. Remarks – Greg Ford, RSTC Chair
        i. Subcommittee Reports and RSTC Work Plan*
    b. Report of November 5, 2020 Member Representatives Committee (MRC) Meeting and Board Meeting – Chair Ford

4. **Reliability Guideline: Gas and Electrical Operational Coordination Considerations* – Accept to Post Document for 45-day Comment Period** – *Chris Pilong, RTOS Chair*

    The Reliability Guideline: Gas and Electrical Operational Coordination Considerations was revised by the Real Time Operating Subcommittee and the Electric Gas Working Group. These two groups are seeking acceptance to post the document for a 45-day public comment period.

5. **Battery Energy Storage Systems (BESS) and Hybrid Power Plant Modeling and Performance Guideline – Accept to Post Document for 45-day Comment Period –** *Jeff Billo, IRPWG Vice Chair*

   Interconnection queues across North America are seeing a rapid influx of requests for battery energy storage systems (BESSs) and are experiencing a rapid increase in penetration levels. Similarly, BESSs are most commonly being coupled with inverter-based generating resources such as wind and solar photovoltaic (PV). The IRPWG is requesting that the draft guideline be accepted to post for a 45-day industry comment period.

6. **Security Guideline for the Electricity Sector: Assessing and Reducing Risk* – Accept to Post Document for 45-day Comment Period –** *Brent Sessions, Chair SWG*

   The purpose of this Guideline is to help organizations determine their current security and compliance posture and develop an improvement plan for addressing any gaps that are identified. The tool for that analysis maps requirements of the CIP Reliability Standards to the National Institute of Standards and Technology (NIST) Cybersecurity Framework (hereafter referred to as "the framework"), and it can help a responsible entity identify areas that may require further action. The SWG is requesting that the RSTC accept this guideline for a 45-day industry comment period.

7. **Resources Subcommittee (RS) Documents – Accept to Post Document for 45-day Comment Period** – *Greg Park, Chair RS*

   a. Reliability Guideline: ACE Diversity Interchange* is a 3-year review of an existing, posted document. A redline was included in the agenda package.

   b. Reliability Guideline: Operating Reserve Management is also a 3 year review of an existing, posted document. A redline was included in the agenda package.

   c. Balancing and Frequency Control Reference Document is also a 3 year review of an existing, posted document. A redline was included in the agenda package.

8. **Reliability Guideline: Generating Unit Winter Weather Readiness – Current Industry Practices – Version 3 – Approve** – *Vinit Gupta, EAS Chair*

   The Event Analysis Subcommittee updated the Reliability Guideline and posted it for a 45-day comment period. They have responded to the comments received and are seeking RSTC approval of the final document.

9. **Reliability Assessments Subcommittee (RAS) Scope* and Probabilistic Assessments Working Group (PAWG) Scope* – Approve –** *Lewis De La Rosa, RAS Chair*

   The RAS and PAWG revised their scope documents as part of the RSTC transition planning activities. A redline for each is included in the agenda package. The RAS and PAWG are seeking approval of the scope documents.

10. Supply Chain Working Group (SCWG) Guideline and Scope - Approve – *Tony Eddleman, SCWG Chair*

a. Guideline for the Electricity Sector: Supply Chain Procurement Language*

This guideline was posted for a 45-day industry comment period and conforming revisions were made. The response to comments received is included in the agenda package for this item. The SCWG is seeking approval of the guideline.

b. Supply Chain Working Group Scope Document*

The SCWG revised their scope document as part of the RSTC transition planning activities. A redline is include in the agenda package. The SCWG is seeking approval of the scope document.

11. EMP Task Force (EMPTF) Scope and Work Plan* - Approve – *Aaron Shaw, Chair EMPTF*

The EMPTF sponsor, leadership, and NERC Staff revised and enhanced the previous version of the draft scope for the EMPTF. They also developed a draft work plan for 2021. They are seeking approval of both the EMPTF Scope document and 2021 Work Plan.

12. Real Time Operating Subcommittee (RTOS) Scope* - Approve – *Chris Pilong, RTOS Chair*

The RTOS sponsor, leadership, and NERC Staff revised, updated, and enhanced the previous version of the Operating reliability Subcommittee (ORS) scope document. They are seeking approval of the updated RTOS Scope document.

13. GMD Data Collection Program Update – Information - *Donna Pratt and Ian Grant, GMDTF*

14. Chair's Closing Remarks and Adjournment

*Background materials included.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

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.

In all cases, a final report may be considered for approval, endorsement, or acceptance if the RSTC, as outlined above, decides to act sooner.

Possible Actions for other Deliverables

1. **Approve:**

   The RSTC has reviewed the deliverable and supports the content and development process, including any recommendations.

2. **Accept:**

   The RSTC has reviewed the deliverable and supports the development process used to complete the deliverable.

3. **Remand:**

   The RSTC remands the deliverable to the originating subcommittee, refer it to another group, or direct other action by the RSTC or one of its subcommittees or groups.

4. **Endorse:**

   The RSTC agrees with the content of the document or action, and recommends the deliverable for the approving authority to act on. This includes deliverables that are provided to the RSTC by other NERC committees. RSTC endorsements will be made with recognition that the deliverable is subject to further modifications by NERC Executive Management and/or the NERC Board. Changes made to the deliverable subsequent to RSTC endorsement will be presented to the RSTC in a timely manner. If the RSTC does not agree with the deliverable or its recommendations, it may decline endorsement. It is recognized that this does not prevent an approval authority from further action.

RSTC Meetings – Governance Management

Chair will state the governance management of the meeting as follows:

- For each topic, the Chair will state the primary motion, ask for first/second, speaker will present, committee then has discussion.
- **At the conclusion of the discussion,** a secondary motion can be offered, the Chair will ask for first/second, discussion/debate; the Chair will then call for a vote.
- If the secondary motion does not receive a second or is voted down, the Chair will go back and restate the primary motion. At this point, the following actions may proceed:
  - Debate on that primary motion again;
  - Another secondary motion can be offered;
  - Motion could be offered to postpone, table, etc. Management of next action will follow the first two bullets.

The Chair is able to initiate a motion to end a debate.

Motions can encompass accepting minor revisions as provided during the discussions and reflected in the words of the motion.

Guiding principle is one thing at a time.

DRAFT Meeting Minutes
Reliability and Security Technical Committee

September 15, 2020

Virtual via WebEx

A regular meeting of the NERC Reliability and Security Technical Committee (RSTC) was held on September 15, 2020, via webinar. The meeting agenda is affixed as **Exhibit A**. The meeting presentations are posted in a separate file at RSTC presentations.

RSTC Chair Greg Ford convened the meeting at 1:00 p.m. Eastern on Tuesday, September 15, 2020 and led introductions of RSTC members, observers and NERC Staff.

Chair Ford called the meeting to order, and thanked everyone for attending. Tina Buzzard, NERC Staff, reviewed the procedures for the meeting, read the Antitrust Compliance Guidelines and Public meeting notice, and confirmed quorum for the RSTC.

Meeting Highlights

1. Chair Ford appointed new Resources Subcommittee Leadership Greg Park (Northwest Power Pool) as Chair and Rodney O'Bryant (Southern Co) as vice chair.
2. Chair Ford appointed new Performance Analysis Subcommittee Leadership Brantley Tillis (Duke Energy) as chair and David Penney (Texas RE) as vice chair.
3. The RSTC approved the Reliability Guideline: DER Data Collection for Modeling in Transmission Planning Studies.
4. The RSTC approved the RSTC Notional Work Flow Process document .
5. The RSTC approved the Subgroup Organization Proposal and announced the RSTC Executive Committee appointed Sponsors for 12 subgroups.
6. The RSTC endorsed *Compliance Implementation Guidance: PRC-019-2* for Submittal to the ERO.

Introductions and Chair's Remarks

Chair Ford provided the following remarks:

1. We continue to face the challenges with working remotely and social distancing and we are continuing to figure out this "new normal" so thank you for attending our second virtual RSTC meeting.
2. The agenda is packed with a number of approval items of significant importance to industry; depending on how the timing plays out to complete those actions there is the possibility we may need to divert some non-action topics to next meeting.

Consent Agenda

Chair Ford reviewed the Consent Agenda and asked RSTC members if they concurred with the items on it. A request was made to remove items 4a, 4b, 5a, 5b and 6a from the Consent Agenda and the request was granted. Brian Evans-Mongeon made a motion to approve the remainder of the consent agenda. The motion passed without dissent.

Regular Agenda

Remarks and Reports

- Remarks – Greg Ford, RSTC Chair

    a. Subcommittee Reports and RSTC Work Plan
    Chair Ford referenced the materials contained in the advance agenda package.

    b. Possible Misunderstandings of the Term "Load Loss" White Paper
    Chair Ford requested for Review Team volunteers – Chris Shepherd, Edison Elizeh, Carl Turner, Todd Lucas, and Wes Yeomans volunteered to review the document. Stephen Crutchfield will coordinate the review process.

- Report of August 20, 2020 Member Representatives Committee (MRC) Meeting and Board Meeting

    Chair Ford summarized the August 20, 2020 MRC and Board of Trustees meetings to include the election of a new Canadian Board of Trustee Jane Allen, who was elected to fill the vacated seat of Dave Goulding, the MRC's approval of the NERC Bylaws amendments, approval by the NERC Board of Trustees of the NERC and Regional Entity 2021 Business Plans and Budgets and associated assessments, and the acceptance of the E-ISAC Long-Term Strategic Plan.

- Appoint New Resources Subcommittee Leadership

    Chair Ford appointed Greg Park (Northwest Power Pool) as Chair and Rodney O'Bryant (Southern Co) as vice chair.

- Appoint New Performance Analysis Subcommittee Leadership

    Chair Ford appointed Brantley Tillis (Duke Energy) as chair and David Penney (Texas RE) as vice chair.

RSTC Transition Plan – Discussion and Action – Chair Ford

- Subgroup Organization Proposal - Chair Ford reviewed the slides that were included in the agenda package. A request was made to table action on this agenda item until discussion of SITES Scope, Notional Work Flow Process and Integrating Security Topics into RSTC Technical Groups.
- Security Integration and Technology Enablement Subcommittee (SITES) Scope - Marc Child reviewed the draft SITES Scope. Several RSTC members expressed concerns with the scope including potential overlap with other subgroups, and need to include operations and planning aspects to the scope.
- RSTC Notional Work Flow Process document - Kayla Messamore reviewed the document and highlighted the coordination between RSTC and RISC in identifying and mitigating risks to reliability and security of the grid. A clarification was requested to add the Risk Registry information from the RISC Framework to the work flow process document.

Greg Stone made a motion to endorse the organization information as presented (agenda item 9a) and conceptually endorse the SITES scope (agenda item 9ai) and ask SITES to revise their scope and develop a work plan for approval at the December RSTC meeting.

Brian Evans-Mongeon made a friendly amendment to the motion to approve the proposed organization (agenda item 9a) and table SITES scope (agenda item 9ai) until the December RSTC meeting. The amendment was accepted. The vote for the amended motion was called with 22 in favor and 6 were opposed. The amended motion carries.

Christine Hasha made a motion to approve the RSTC notional work flow process document with the corrections/edits as discussed. The motion carried without dissent.

- Subgroup Sponsors – Chair Ford reviewed the sponsor appointments that were made by the Executive Committee:
  - Real-Time Operations Subcommittee (RTOS) - Todd Lucas
  - Performance Analysis Subcommittee (PAS) - Jeff Harrison
  - Event Analysis Subcommittee (EAS) - Patrick Doyle
  - Resources Subcommittee (RS) - Rich Hydzik
  - Inverter-based Performance WG (IRPWG) - Jodirah Green
  - Security WG (SWG) - Christine Hasha
  - EMP Task Force (EMPTF) - Brian Evans-Mongeon
  - System Planning Impacts from DER WG (SPIDERWG) – Wayne Guttormson
  - Electric-Gas Working Group (EGWG) – Venona Greaff
  - System Protection and Control WG (SPCWG) – Allen Schriver
  - Reliability Assessment Subcommittee (RAS) – Kayla Messamore
  - Security Integration and Technology Enablement Subcommittee (SITES) – Marc Child
- Integrating Security Topics into RSTC Technical Groups - Ryan Quint provided an overview of the draft concepts for integrating security into the RSTC subgroups.

  Brian Evans-Mongeon made a motion to table this topic until our next conference call. The motion passed without dissent.

Chair's Closing Remarks
Chair Ford thanked everyone for their participation. He noted that all discussions are appreciated and helpful for the actions taken by the committee today, and recognized that the structure for the December meeting will be to conduct the meeting over two afternoons to ensure the ability for the Committee to review and address each item.

There being no further business before the RSTC, Chair Ford adjourned the meeting at 4:05 p.m. Eastern.

Next Meeting

The RSTC will meet at a time to be determined before the December 15 and 16, 2020 meeting to discuss consent agenda items not approved today.

Stephen Crutchfield

Stephen Crutchfield
Secretary

DRAFT Meeting Minutes
Reliability and Security Technical Committee

October 14, 2020

Virtual via WebEx

A regular meeting of the NERC Reliability and Security Technical Committee (RSTC) was held on October 14, 2020, via webinar. The meeting agenda is affixed as **Exhibit A**.

RSTC Chair Greg Ford convened the meeting at 1:00 p.m. Eastern on Wednesday, October 14, 2020 and led introductions of RSTC members, Observers and NERC Staff.

Chair Ford called the meeting to order, and thanked everyone for attending. Tina Buzzard, NERC Staff, reviewed the procedures for the meeting, read the Antitrust Compliance Guidelines and Public meeting notice, and confirmed quorum for the RSTC.

Meeting Highlights

1. Accepted the Concept Paper: Integrating Security Topics into RSTC Technical Groups
2. E025-2 - Unit Verification and Modeling to the Standards Committee
3. Endorsed the submittal of the SAR for Revisions to PRC-023-4 – Transmission Relay Loadability to the Standards Committee
4. Accepted for posting Reliability Guideline: Model Verification of Aggregate DER Models Used in Planning Studies for a 45-day industry comment period.
5. Approved the White Paper on Assessment of DER Impacts on NERC Reliability Standard TPL-001.

Introductions and Chair’s Remarks

Chair Ford called on Nina Jenkins- Johnston, NERC Legal, to review the meeting governance guidelines (listed below) with the hope of streamlining discussion of agenda items.

- For each topic that requires an action (approve, endorse, accept or remand), Chair Ford will state the primary motion, ask for first/second, speaker will present, committee then has discussion.
- At the conclusion of the discussion, a secondary motion can be offered, Chair Ford will ask for first/second, discussion/debate; Chair Ford will then call for a vote.
- If the secondary motion does not receive a second or is voted down, Chair Ford will go back and restate the primary motion. At this point, the following actions may proceed:
  - Debate on that primary motion again;
  - Another secondary motion can be offered;
  - Motion could be offered to postpone, table, etc. Management of next action will follow the first two bullets.

Chair Ford may initiate a motion to end debate. Motions can encompass accepting minor revisions as provided during the discussions and reflected in the words of the motion. Guiding principle is to address one action at a time.

Regular Agenda

Remarks - Greg Ford, RSTC Chair - Chair Ford noted the agenda covers consent agenda items that were not addressed during the September 15, 2020 meeting. Chair Ford provided an update on the sponsor trainings, stated they were going very well, and looked forward to future trainings.

Two requests were made to include the governance management procedures in future packages for the Committee, as well as to send out the full list of sponsors to the Committee, both will be addressed accordingly.

Concept Paper: Integrating Security Topics into RSTC Technical Groups* – Accept - Ryan Quint, NERC Staff

This concept paper is intended to support efforts of the RSTC to incorporate cyber and physical security considerations within the scope of every RSTC technical group. Seeking RSTC to accept the concepts paper for each subgroup to consider ways to integrate security into their scope.

Chair Ford stated the primary motion: *Motion to accept the Concept Paper: Integrating Security Topics into RSTC Technical Groups.*

Made by: Marc Child

Mr. Quint discussed the concept paper and the intent of it. He also hit the highlights for various groups pertaining to cyber and physical security.

A suggestion was made to have all subgroups provide this type of report to the committee annually or periodically. Chair Ford agreed noting we can leverage our sponsors for this going forward.

Chair Ford called for a vote on the motion, the motion carried without dissent.

SAR for Revisions to MOD-025-2 - Unit Verification and Modeling*– Endorse – Shawn Patterson, PPMVTF Chair

The PPMVTF has prepared a draft SAR that aligns with the previously approved white paper findings and is seeking RSTC endorsement to submit the SAR to the Standards Committee.

Chair Ford stated the primary motion: *Motion is to endorse the submittal of the **SAR for Revisions to MOD-025-2 - Unit Verification and Modeling** to the Standards Committee.*

Made by: Carl Turner

Mr. Patterson summarized the PPMVTF created a white paper which the RSTC approved. The recommendation of the white paper was to develop the SAR which we are bringing today. Purpose is to verify models by staged testing to demonstrate real and reactive power. PPMVTF has received feedback since this standard went into effect. Consensus is the standard is not sufficient as-is and should be modified based on the SAR.

Greg Stone made secondary motion to endorse the SAR with the following item removed:

> "Ensure that data provided by the applicable Generator Owners and Transmission Owners is analyzed and used appropriately by Transmission Planners and Planning Coordinators"

After brief discussion, Chair Ford called a vote on the second motion: remove item 5 from the scope items in MOD-025-2 SAR.

In favor: 8

Opposed: 13

Motion fails to carry. Fall back to original motion:

In favor: 19

Opposed: 6

The motion carries.

SAR for Revisions to PRC-023-4 – Transmission Relay Loadability*– Endorse – Jeff Iler, Chair SPCWG
The SPCS developed a PRC-023-4 SAR and requested NERC Planning Committee review in December 2018. The SAR was revised based on the comments received and is seeking endorsement to submit the SAR to the Standards Committee.

Chair Ford stated the primary motion: *Motion is to endorse the submittal of the **SAR for Revisions to PRC-023-4 – Transmission Relay Loadability** to the Standards Committee.*

Made by: Marc Child

Second: Carl Turner

Jeff Iler gave a brief background on the SAR. Requirement R2, in PRC-023-4, requires applicable functional entities to set their Out of Step Blocking (OOSB) elements to allow tripping for faults during the loading conditions prescribed by Requirement R1. A requirement to allow tripping in a Standard whose intent is to block tripping, has led to some entities disabling their OOSB relays. Disabling of these relays could lead to tripping during stable power swings causing an increased reliability risk. OOSB relays provide increased security by preventing relays from tripping for stable power swings. Preventing the tripping of transmission lines during these types of disturbances increases the reliability of the BES. The SAR recommends removing Requirement R2 because it has been interpreted to restrict the setting of OOSB elements making compliance with PRC-026 more difficult.

The SAR also recommends removing Attachment A exclusion 2.3. This exclusion is no longer needed and that exclusion has contributed to the confusion surrounding R2. Attachment A exclusion 2.3 has been interpreted as being in conflict with R2.

No discussion. Chair Ford called for the vote:

In favor: 25

Opposed: 2

The motion carries.

Reliability Guideline: Gas and Electrical Operational Coordination Considerations* – Accept to Post Document for 45-day Comment Period – Chris Pilong, ORS Chair

Chair Ford stated the primary motion: *Motion is to accept posting the **Reliability Guideline: Gas and Electrical Operational Coordination Considerations** for a 45-day public comment period.*

Made by: Jeff Harrison

Chris Pilong provided a summary of the development and revision of the Reliability Guideline. There were a few grammatical corrections and some improvement areas made to the guideline. The Reliability Guideline: Gas and Electrical Operational Coordination Considerations was revised by the Operating reliability Subcommittee and endorsed at its September 2020 meeting. They are seeking acceptance to post the document for a 45-day public comment period.

Brian Evans-Mongeon made a motion to table this item and ask the RTOS to coordinate with the EGWG to bring back a revised document for posting.

Chair Ford called for a vote:

In favor: 18

Opposed: 4

The motion carries. The RTOS will seek input from the EGWG.

Reliability Guideline: Model Verification of Aggregate DER Models Used in Planning Studies* – Accept to Post Document for 45-day Comment Period – Kun Zhu, SPIDERWG Chair

Chair Ford state the primary motion: *Motion is to accept posting **Reliability Guideline: Model Verification of Aggregate DER Models Used in Planning Studies** for a 45-day industry comment period.*

Made by: Carl turner

Second: Jody Green

Kun Zhu provided a summary of this agenda item to post a new Reliability Guideline. This guideline provides TPs and PCs with tools and techniques can be adapted for their specific systems to verify that the aggregate DER models created are a suitable representation of these resources in planning assessments. SPIDERWG asks the RSTC to accept posting this Reliability Guideline: Model Verification of Aggregate DER Models used in Planning Studies for a 45 day industry commenting period as per the approval process for Reliability Guidelines.

After discussion by the committee members, it was recommended a clean copy be posted to which NERC staff agreed.

Chair Ford called for vote:

In favor: 20

Opposed: 0

The motion carries.

White Paper on Assessment of DER Impacts on NERC Reliability Standard TPL-001* – Approve – Kun Zhu, SPIDERWG Chair

Chair Ford state the primary motion: *Motion to approve the* ***White Paper on Assessment of DER Impacts on NERC Reliability Standard TPL-001.***

Made by: Cesar Panait

Second: Brian Evans-Mongeon

Mr. Zhu provided an overview of the White Paper. The intent of the white paper is to highlight potential gaps or areas for improvement within TPL-001 along with some potential solutions such that a SAR or an implementation guide can be developed, as needed, to address various issues by a SDT. SPIDERWG asks the RSTC to approve the white paper.

After discussion by Committee members, Mr. Evans-Mongeon motioned to table this and have it considered at the same time that the second white paper (addressing DER impact on other standards) is presented to the RSTC.

Mr. Turner seconded the motion.

After further discussion, Mr. Evans-Mongeon and Mr. Turner agreed to withdraw their motion to table.

Chair Ford re-stated the original motion.

Mr. Evans-Mongeon motioned to approve the white paper and submit guidance to the SPIDERWG to consider developing a SAR that addresses the recommendations in the white paper as well as the future white paper on assessment of DER impacts on NERC reliability standards.

Mr. Turner seconded.

Vice Chair Zwergel called for a vote (Chair Ford had to step away)

In favor: 16

Secondary motion fails. Back to the primary motion.

Chair Ford called for vote on original motion:

In favor: 18

Opposed: 5

The motion carries.

SITES Scope and Work Plan – Update

Chair Ford appointed David Zwergel as the Chair and Benny Naas as the Vice Chair of this group, and noted that Marc Child is the sponsor. Chair Ford called on Vice Chair Zwergel to provide an update on the SITES Scope document review and to make the request for volunteers to assist in the revision of the Scope.

Ms. Messamore, Ms. Hasha, and Messrs. Turner, Schriver, Evans-Mongeon, and Shepherd volunteered. Vice Chair Zwergel stated he will coordinate with NERC staff to schedule the first meeting of the group.

Chair's Closing Remarks and Adjournment

Chair Ford thanked the members of the Committee and respective NERC staff for the assistance in the implementation of the new governance management process, and stated he felt the meeting went well, was streamlined, and allowed for the proper discussions and management of actions.

There was a request to consider amending the new governance management to allow the presentation first prior to requesting the action motion, Chair Ford stated the Executive Committee would take the request under advisement.

Finally, Chair Ford updated that the registration will open on October 15 for Lead Planners and Planners for the E-ISAC GridEx VI. E-ISAC members can register at eisac.com. GridEx VI will be held November 16-17, 2021.

There being no further business before the RSTC, Chair Ford adjourned the meeting at 3:05 p.m. Eastern.

Next Meeting

The next regular meeting of the RSTC is December 15 and 16, 2020 and will be held virtually via WebEx.

Stephen Crutchfield

Stephen Crutchfield
Secretary

System Planning Impacts of Distributed Energy Resources Working Group (SPIDERWG)

Website: SPIDERWG
Hierarchy: Reports to RSTC

Chair: Kun Zhu (September 2019)
Vice-Chair: Bill Quaintance (July 2018)

NERC Lead: Ryan Quint, JP Skeath
Scope Approved: December 2018

#	Task Description	Risk Profile(s)	Strategic Focus Area(s)	Target Completion	Requested Action	Status
Modeling Subgroup *(Co-Leads: Irina Green, CAISO; Mohab Elnashar, IESO)*						
M1	**DER Modeling Survey** *Perform industry survey of SPIDERWG members regarding use of DER planning models in BPS studies, dynamic load models and DER modeling guidelines.*	1, 2	2, 3	Q4-2020	No	Survey results complete; white paper being created to capture key takeaways from survey. To be presented to RSTC at appropriate time.
M6	**Modeling Distributed Energy Storage and Multiple Types of DERs** *SPIDERWG will dig into technical considerations of modeling distributed energy storage, specifically distributed battery energy storage (D-BESS). The group will also consider how to model multiple types of DERs, including D-BESS and distributed solar PV (D-PV). Lastly, the group will focus on forecasting and dispatch assumptions for D-BESS. SPIDERWG will determine the level of guidance or reference materials needed once discussions begin. Task to be coordinated with Studies sub-group.*	1, 2	2, 3	Q3-2021	Yes	New work task, getting underway. *(High priority task for SPIDERWG)*
Verification Subgroup *(Co-Leads: Michael Lombardi, NPCC; Mike Tabrizi, DNV-GL)*						
V1	**Reliability Guideline: DER Performance and Model Verification** *Reliability Guideline covering aggregate DER model verification, including recommended measurement practices, executing model verification activities, model benchmarking, relation to MOD-033 activities, and conversion of data sources for verification.*	1, 2	2, 3	Q1-2021	Yes	Posting for industry comment period in Q4 2021. *(High priority task for SPIDERWG)*
V2	**Reliability Guideline: DER Forecasting Practices and Relationship to DER Modeling for Reliability Studies** *Guidance providing how forecasting practices are linked to DER modeling for reliability studies. DER forecasting practices are important for accurately representing the correct amount and type of DER, particularly at an aggregate level representation for BPS studies.*	1, 2	2, 3	Q2-2021	Yes	On track; early stages of development.
Studies Subgroup *(Co-Leads: Pengwei Du, ERCOT; Mohab Elnashar, IESO)*						
S1	**Reliability Guideline: Bulk Power System Planning under Increasing Penetration of Distributed Energy Resources** *Reliability Guideline providing recommended practices for performing planning studies considering the impacts of aggregate DER behavior – study approaches, analyzing BPS performance criteria incorporating DER models into studies, developing study assumptions, etc.*	1, 2	2, 3	Q2-2021	Yes	On track; nearing completion of initial draft, completing some final sections. *(High priority task for SPIDERWG)*

S2a	**SAR: Updates to TPL-001 Regarding DER Considerations** *Sub-team is developing a SAR that incorporates the recommendations put forth in the approved white paper, considering the items that need standards revisions to improve reliability. This activity will also be coordinated with IRPWG to address the issues identified in their recently approved white paper identifying issues with TPL-001.*	1, 2	2, 3, 4	Q2-2021	Yes	New task as follow-on to S2 white paper approval by RSTC. Sub-group beginning work. *(High priority task for SPIDERWG)*
S3	**Recommended Simulation Improvements and Techniques** *Guidance (white paper) to software vendors on tools enhancements for improved accounting and study of aggregate DER.*	1, 2	2, 3	Q1-2021	Infor-mation	On track; nearing completion of white paper providing vendor guidance.
S4a	**Reliability Guideline: Recommended Approaches for Developing Underfrequency Load Shedding Programs with Increasing DER Penetration** *Guidance on how to study UFLS programs and ensure their effectiveness with increasing penetration of DER represented.*	1, 2	2, 3	Q1-2021	Yes	On track. Nearly complete in sub-group team; needs Studies sub-group review, then to SPIDERWG.
S4b	**White Paper: DER Impacts to UVLS Programs** *Short white paper on potential impacts of DERs on UVLS program design; leverage work of PRC-010 standards review (C6 task).*	1, 2	2, 3	Q2-2021	Yes	On track.
S5	**White Paper: Beyond Positive Sequence RMS Simulations for High DER Penetration Conditions** *Considerations for high penetration DER systems and the need for more advanced tools (e.g., co-simulation tools) for studying DER impacts on the BPS.*	1, 2	2, 3	Q2-2021	Yes	On track.
Coordination Subgroup *(Co-Leads: Clayton Stice, ERCOT; Jimmy Zhang, AESO)*						
C2	**Reliability Guideline: Communication and Coordination Strategies for Transmission Entities and Distribution Entities regarding Distributed Energy Resources** *Develop recommended strategies to encourage coordination between Transmission and Distribution entities on issues related to DER such as information sharing, performance requirements, DER settings, etc.*	1, 2	2, 3	Q2-2021	Yes	Tabled to align with standards review (C6 activity) activity; will start later 2020.
C5	**SPIDERWG Terminology: Working Definitions Document** *Review of existing definitions and terminology and development and coordination of new terms, for consistent reference across sub-groups.*	1, 2	2, 3	Ongoing	Infor-mation	Initial draft complete; will update RSTC as necessary. Subsequent revisions will be explored by team, as needed.
C6	**NERC Reliability Standards Review** *White Paper reviewing NERC Reliability Standards and impacts of DER.*	1, 2	2, 3, 4	Q1-2021	Yes	On track; initial reviews complete, consolidating responses into draft white paper; white paper to be reviewed by SPIDERWG. *(High priority task for SPIDERWG)*

C7	**Tracking and Reporting DER Growth** *Coordinated review of information regarding DER growth, including types of DER, size of DER, etc. Consideration for useful tracking techniques for modeling and reliability studies.*	1, 2	2, 3	Ongoing	No	In monitoring and data collection stage.
Other / Sub-group Leadership *(Co-Leads: SPIDERWG Leadership; Dan Kopin, Utility Services)*						
C6	**White Paper: FERC Order 2222 and BPS Reliability Perspectives** *Short white paper identifying key BPS reliability perspectives with the recently released FERC Order 2222. Being developed by SPIDERG sub-group leadership and Dan Kopin, and will get full review and input from overall SPIDERWG once initial draft complete.*	1, 2	2, 3, 4	Q1-2021	Yes	New task, currently underway. *(High priority task for SPIDERWG)*

Completed and Cancelled Tasks (for Tracking Purposes Only)

#	Task Description	Risk Profile(s)	Strategic Focus Area(s)	Target Completion	Requested Action	Status
Completed Tasks						
M2	**Reliability Guideline: DER Data Collection for Modeling** *Guideline providing recommendations and industry practices for the mandatory and optional DER data to be collected by the Reliability Coordinator as well as on how, where, and when to gather such data.* • *Review the documentation of existing data collection techniques and processes that has been developed by the industry.* • *Recommendations for DER data collection technique suitable for various study types.* *Recommendations for the DER data complexity requirements based on DER penetration levels*	1, 2	2, 3	Q3 2020	Yes	Approved by RSTC at October 2020 meeting. *(High priority task for SPIDERWG)*
M3	**Reliability Guideline: DER_A Model Parameterization** *Guideline providing recommendation for DER modeling practices.*	1, 2	2, 3	Q3-2019 (Complete)	Yes	Complete. *(High priority task for SPIDERWG)*
M4	**Review of MOD-032-1 for DER Data Collection** *(In coordination with activity C4) Proposing MOD-032-1 SAR to address modifications to the standard to facilitate data collection for DERs for interconnection-wide modeling.*	1, 2	2, 3, 4	Q4-2019	Yes	Complete. PC endorsed at December 2019 PC meeting. Provided to NERC Standards staff December 2019.
M5	**Modeling Notification: Dispatching DER off Pmax in Case Creation** *Modeling notification on recommended practices and considerations for DER modeling when dispatching DER at output levels other than Pmax in the powerflow and dynamics data. Practices to ensure expected response from DER in these modeled conditions.*	1, 2	2, 3	Q3-2019 (Complete)	Infor-mation	Complete; approved by SAMS and posted to SAMS webpage.
C1	**Reliability Guideline: BPS Reliability Perspectives on the Adoption of IEEE Std. 1547-2018** *Reliability Guideline of BPS perspectives for adopting and implementing IEEE 1547-2018.*	1, 2	2, 3	Q1-2020	Yes	Complete. Approved March 2020, and posted. (High priority task for SPIDERWG)
C4	**Review of MOD-032-1 for DER Data Collection see M4 activity.**	1, 2	2, 3, 4	Q4-2019 (Complete)	Yes	Complete.

S2	**White Paper: Review of TPL-001 Standards for Incorporation of DER** *White paper discussing technical review of NERC TPL-001-5, and development of any recommendations pertaining to consideration and study of DER impacts to the BPS.*	1, 2	2, 3, 4	Q2-2020	Yes	Complete. Approved by RSTC at October 2020 meeting. *(High priority task for SPIDERWG)*
Cancelled Tasks						
C3	**Educational Material to Support Information Sharing between Industry Stakeholders** *Develop material to educate industry stakeholders on practices, recommendations and technical work developed by other industry organizations.*	1, 2	2, 3	Ongoing	No	Task cancelled; references to industry materials and SPIDERWG materials will be provided in other work products. Ongoing industry outreach and engagement by SPIDERWG members.

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Security and Reliability Training Working Group

Erik Johnson, Chair

RSTC Meeting

December 15, 2020

RELIABILITY | RESILIENCE | SECURITY




SRTWG Background

- The SRTWG was formed under the Operating Committee in February 2020 to:
  - Serve as the technical training advisor to the NERC Reliability and Security Technical Committee (RSTC) and subsequent working groups.
  - Provide resources to promote best practices, consistency, and continuous improvement within industry training programs.
  - Promote organizational resilience through training recommendations to mitigate potential risks.
- The SRTWG has created task forces to implement training recommendations identified in the 2019 ERO Reliability Risk Priorities Report, the ERO 2020 Work Plan Priorities and the ERO Enterprise Long-term Strategy.

RSTC Status Report
Security and Reliability Training Working Group (SRTWG)

Chair: Erik Johnson
December 15, 2020

On Track
Schedule at risk
Milestone delayed

Purpose: provide support, expertise, and resources for the Bulk Electric System (BES) training personnel related to the reliable operation of the BES including, but not limited to, any NERC Reliability Standard containing a training requirement*).*

Recent Activity

- Completed task forces' scope documents
- Completed the Standards Requirement Training Spreadsheet
- Completed:
  - Converting In-Class Training to Remote Training Guideline
  - Training Scenario Template
  - Sample Training Scenario – Loss of EMS During Upgrade

Items for RSTC Approval/Discussion:

- **Approve**: Task Forces' scope documents.
- and Standards Requirement Training Spreadsheet
- Converting In-class Training to Remote Training Guideline
- Training Scenario Template
- Sample Training Scenario – Loss of EMS During Upgrade

Upcoming Activity

- Revise SRTWG Scope Document
- Finalize SRTWG Work Plan
- Develop proposal for Reliability Training Guidelines
- Create a One-Stop-Shop for training resources
- Develop proposal for reporting metrics for the RSTC

Workplan Status *(6 month look-ahead)*

Milestone	Status	Comments
SRTWG Scope Revision	On Track	Target Q1: March RSTC Meeting
SRTWG Work Plan	On Track	Target Q1: March RSTC Meeting

Event Analysis Subcommittee 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 Meeting: December 14, 2020 **Location:** Conference Call
Duration: 1/2 Day

Next Meeting: January 2021 **Location:** Conference Call

Duration: 2 hours

Conference Calls: 2nd and 4th Monday of every month from 1100 to 1200 (EDT)

Chair: Vinit Gupta – ITC Holdings
Vice-Chair: Ralph Rufrano - NPCC

Pending RSTC Approval Items:

- Request approval to post the revised Generating Unit Winter Weather Readiness Reliability Guideline to the NERC website. **Key issues for RSTC Resolution:**
- None at this time

Key Issues for RSTC Information:

- EAS Lesson Learned presentation from a Substation Battery Fire event by Anthony Natale with Consolidated Edison.
- The EAS has published three new lesson learned since the September 2020 RSTC meeting and total of eleven lesson learned in 2020.
- The EAS team has reviewed the UK Blackout Report and developed a lesson learned which is expected to be published in the next few weeks.
- EAS is coordinating with the ORS to develop COVID-19 real-time operations lessons learned.

- The EMSWG hosted its eighth annual Monitoring and Situational Awareness Technical Conference via WebEx. The theme of this year's conference was "Energy Management System Reliability and Resiliency in the Pandemic." This year's conference united expertise from various utilities to share cutting-edge ideas and good industry practices, and to identify trends and lessons learned from events across different vendors, energy management system (EMS) platforms, and interconnections. There were three (3) sessions that made up the conference:

    Session 1: September 24, 2020 | 01:00 p.m. – 03:00 p.m. ET

    Session 2: October 15, 2020 | 01:00 p.m. – 03:00 p.m. ET

    Session 3: November 10, 2020 | 01:00 p.m. – 03:00 p.m. ET

The presentations from each session have been posted to the NERC Website.

- The Winter Preparation for Severe Cold Weather webinar was conducted on September 3rd from 2:00 to 3:00pm (ET). The purpose of the webinar is to provide the industry reports and material in preparation for the upcoming winter weather forecasts and entity cold weather preparedness. The webinar will provide an overview of updates to the Reliability Guideline for Generating Unit Winter Weather Readiness. The streaming webinar and presentation has been posted to the NERC Website

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:

- Review Event Analysis Process document as required
- Recommend need for training in coordination with Personnel Subcommittee (PS)
- Publish lessons learned as required
- Develop Reliability Guidelines
- Identify significant risk and the need for NERC Alerts
- Updates to the OC
- Input to the NERC Performance Analysis Subcommittee's (PAS) annual State of Reliability Report
- Information and recommendations related to the Event Analysis process

External requests to group:

- Outreach and coordination with NATF/NAGF regarding lesson learned usability
    - North American Generator Forum is actively participating in the EAS
- Outreach and Coordination with other NERC groups (PS, PAS, RS, ORS, and PC). Liaisons established with PS and PAS
    - Leadership calls are set up prior to OC meetings
    - Coordinating with PAS on 2018 State of Reliability Report

Internal requests to group:

- None at this time

Group's recurring deliverables:

- EAS continues to manage the ERO Event Analysis Process Document update process as required
- Action oriented Lessons Learned posted on NERC website
- EAS will continue to review and address reliability issues that pose a risk to the BPS and share information with the OC and industry

Any NERC Programs Oversight Responsibility for the Group:

- No

Any NERC Document (non-Reliability Standard) Responsibility for the Group:

- ERO Event Analysis Process Document

RSTC Status Report – Probabilistic Assessment Working Group (PAWG)

Chair: Andreas Klaube
Vice-Chair: Alex Crawford
December XX, 2020

On Track
Schedule at risk
Milestone delayed

Purpose: *The primary function of the NERC Probabilistic Assessment Working Group (PAWG) is to advance and continually improve the probabilistic components of the resource adequacy work of the ERO Enterprise in assessing the reliability of the North American Bulk Power System.*

Items for RSTC Approval/Discussion:

- **Approve**: *PAWG scope document* and *work plan*

Recent Activity

- Resolution of comments and inputs to the 2020 Probabilistic Assessment base case as part of the 2020 LTRA
- Responded to RAS comment period for the Data Collection document.
- Presented initial findings of 2020 Probabilistic Assessment scenario case.
- Proposed two new work items for 2021 PAWG work plan.

Upcoming Activity

- *2020 Probabilistic Assessment Scenario Case* – Plan to request review at March, 2021 RSTC meeting
- *Data Collection Approaches for Probabilistic Assessments Technical Reference Document* – Plan to request review at March, 2021 RSTC meeting

Workplan Status *(6 month look-ahead)*

Milestone	Status	Comments
Scope Review	On Track	In progress
Data Collection Approaches for Probabilistic Assessments Technical Reference Document	On Track	In progress
2020 Probabilistic Assessment Base Case	On Track	See 2020 LTRA
2020 Probabilistic Assessment Scenario Case	On Track	In progress. Draft expected Jan 2021.

RSTC Status Report – Reliability Assessments Subcommittee (RAS)

On Track
Schedule at risk
Milestone delayed

Chair: Lewis De La Rosa
Vice-Chair: Anna Lafoyiannis
December 15, 2020

Purpose: The RAS reviews, assesses, and reports on the overall reliability (adequacy and security) of the BPS, both existing and as planned. Reliability assessment program is governed by NERC RoP Section 800

Items for RSTC Approval/Discussion:

- **Approve**: RAS and *PAWG scope document*

Recent Activity

- 2020-2021 Winter Reliability Assessment: RSTC endorsement, ERO approval, and publication
- 2020 Long-Term Reliability Assessment: RSTC endorsement requested (voting through December 20)

Upcoming Activity

- Requesting Board acceptance of *2020 LTRA* on December 10
- *2020 Probabilistic Assessment Scenario Case* – RAS will review results with PAWG at the February 2021 web meeting.
- RAS is reviewing PAWG *Data Collection Approaches for Probabilistic Assessments Technical Reference Document* at December web meeting and anticipates forwarding to RSTC for approval

Workplan Status *(6 month look-ahead)*

Milestone	Status	Comments
2020 Probabilistic Assessment Scenario Case	On Track	PAWG is preparing results. RAS will review in February 2021.
2021 Summer Reliability Assessment	On Track	RAS is reviewing assessment area Information Request Material
2021 Long-term Reliability Assessment	On Track	RAS is reviewing assessment area Information Request Material

Internal Use Only

Load Modeling Task Force (LMWG)

Website: LMWG **Chair**: Kannan Sreenivasachar **NERC Lead**: Olushola Lutalo
Hierarchy: Reports to RSTC **Vice-Chair**: **Scope Update**: November 2020

#	Task / Deliverables	Target Completion	Status	Priority (at this time)
		Phase 1 - Initial CMLD Deployment		
1	Dynamic load model is implemented, tested and benchmarked in all production grid simulators - Siemens PTI PSS®E, General Electric PSLF, PowerWorld, and PowerTech TSAT	Q1-2019	COMPLETED - Phase 1 of the model benchmarking is completed successfully in PTI PSS®E, GE PSLF, PowerWorld, and PowerTech TSAT	10
1B	DER Models are implemented, tested and benchmarked as a part of the dynamic load model	Q2-2019	COMPLETED - Benchmarked DER Implementation, coordinated with SPIDER on DER modeling for dynamic load model, ensure that SPRIDER-develop models and data sets are updated in Load Model Data Tool	10
2	Load Model Data	Q2-2019	COMPLETED	10
2A	Mapping between powerflow Loads and "Load Type" Identfiers	Q2-2019	COMPLETED - NERC Regions identified load climate zones (airport codes) and corresponding "Load Type" identifiers, NERC Regions worked with Transmission Plannesrs to develop mapping between power flow load buses and "Load Type" identifiers	10
2B	Load Composition Data Sets Developed	Q2-2019	COMPLETED - NERC LMTF worked with DOE to develop 24-hour Load Composition Data Sets for 96 airport codes in NERC foorpring for three seasons.	10

2C	Model Data for Large Industrial Loads	Q2-2019	COMPLETED - NERC LMTF engaged industry experts to develop representative data sets for 20 types of industrial loads	10
2D	Robust Data Sets - End Use Data	Q2-2019	COMPLETED - Model data sets are developed based on extensive end-use testing and manufacturer's literature. The data is stress-tested in PTI PSS®E and GE PSLF	10
3	Tools for Load Model Data management	Q2-2019	COMPLETED - NERC Developed Load Model Data Tool for managing load model data and writing CMLD records in PTI PSS®E DYR and GE PSLF DYD formats. The tools are used to generate CMLD records for the field test and provided to NERC Regions	10
4B	Industry Outreach - working with NERC MMWG on data management processes	On-Going	IN PROGRESS - NERC LMTF presented and discussed CMLD model and data management processes at NERC MMWG meeting in Macrh of 2019 and 2020. Ultimate goal is to make CMLD available in 2021 MMWG series of cases	10

5	Field Test	On-Going	IN PROGRESS - NERC Regional Entities, Planning Coordinators and Transmission Planners are performing CMLD field test to make a decision on their CMLD deployment plans. Recent Benchmarking results have shown critical parameter changes and would require another round of field tests.	10
5A	Field Test Report	Q2-Q3_2021	NERC LMWG to develop the field test report for RSTC approval, Update the Reference Document(task 5 is a pre-requisite)	10
6	Regional Support	On-Going	NERC LMWG to work with Regions to develop support and feedback structure with CMLD deployment	10
Phase 2 - Modular Implementation				
7	Dynamic Load model for Real-Time Transient Stability Assessment	Q4-2021	NERC LMWG reached out to PowerTech Labs and RC West on testing load model in TSAT for real-time studies	7
8	Modular implementation of the dynamic load model	Q4-2021	GE PSLF and PowerWorld aready implemented dynamic load models in their software packages. PTI PSS®E will require the next release of the software - Version 35.	10
9	Improvements to single-phase motor models	Q4-2021	GE PSLF implemented dynamic phasor models of single-phase motor models. The next step is	10

			to compare the model against the existing performance model to make the determination whether to proceed with dynamic phasor model in all other programs (task 8 is a pre-requisite)	
10	Improvements to three-phase motor models	Q3-2021	GE PSLF implemented better three-phase motor models. The next step is to compare the model against the existing model to make the determination whether to proceed with it in all other programs (task 7 is pre-requisite). NERC LMWG found issues with frequency response of the existing three-phase models.	10
11	Improved protection and control models - progressive tripping	Q4-2021	GE PSLF implemented a motor model version with progressive tripping. The next step is to test the model to make the determination whether to proceed with it in all other programs (task 8is pre-requisite)	8
12	Power Electronic Loads	Q4-2021	EPRI and BPA tested a number of VFD, ECM drives, as well as charging loads. EPRI is working on more detailed models. The next step is to develop and implement the model in GE PSLF, and compare the model against the existing model to make the	7

			determination whether to proceed with it in all software programs (task 8 is pre-requisite)	
13	Load Composition Analysis	On-going	On-going effort to improve our understanding of load composition	7
14	Dynamic Load Monitoring	On-going	Deployment of dynamic data records in distribution substations and commercial buildings for purpose of load monitoring. DOE will provide resources to support data analysis	8
15	Coordination with SPIDERWG	On-going	Coordinate with SPIDERWG on DER modeling for dynamic load model, ensure that SPRIDERWG-develop models and data sets are updated in Load Model Data Tool	9
16	Transient Voltage Response Criteria	Q4-2021	Coordinate with LMWG members and ascertain their inputs and provide guidance on transient voltage response criteria that is required under TPL-001-4 R5	10
17	System Event Benchmarking	On-Going	Encourage entities to benchmark actual events with the composite load model and report to the group	7??

RSTC Status Report – Security Working Group (SWG)

Chair: Brent Sessions
Subgroup Lead: Keith St. Amand November 20, 2020

- On Track (green)
- Schedule at risk (yellow)
- Milestone delayed (red)

Purpose: Security and compliance risk self-assessment tool and instructions work aid

Items for RSTC Approval/Discussion:

- **Accept for 45-day posting**:
    - Self-Assessment tool
    - Instructions work aid

Recent Activity

- Completed:
    - 2 separate pilots on usage of self-assessment tool and instructions work aid
    - Incorporation of pilot feedback
    - Draft deliverables for industry comment

Upcoming Activity

- Complete 45-day comment period (revise document as needed)
- Incorporate industry feedback
- Finalize tool and instructions work aid
- Posting Approval
- Post completed tool and instructions work aid

Workplan Status *(6-month look-ahead)*

Milestone	Status	Comments
Industry Comment: December RSTC Meeting	Green	On Track
Comment Period: Dec-20 – Jan-21	Green	On Track
Deliverable Finalization: Feb-21	Green	On Track.
Publication Approval: March RSTC Meeting	Green	On Track.

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Lessons Learned Summary

December 1, 2020

Richard Hackman – NERC Event Analysis

RELIABILITY | RESILIENCE | SECURITY




Three Lessons Learned (LL) were published in 2020 since the last (Sept 2020) meeting:

- LL20201001 – "Single Phase Fault Precipitates Loss of Generation and Load" (UK Blackout)
- LL20201101 – "Cold Weather Operation of SF6 Circuit Breakers"
- LL20201102 – "Loss of State Estimator due to Contradicting Information from Dual ICCP Clusters"

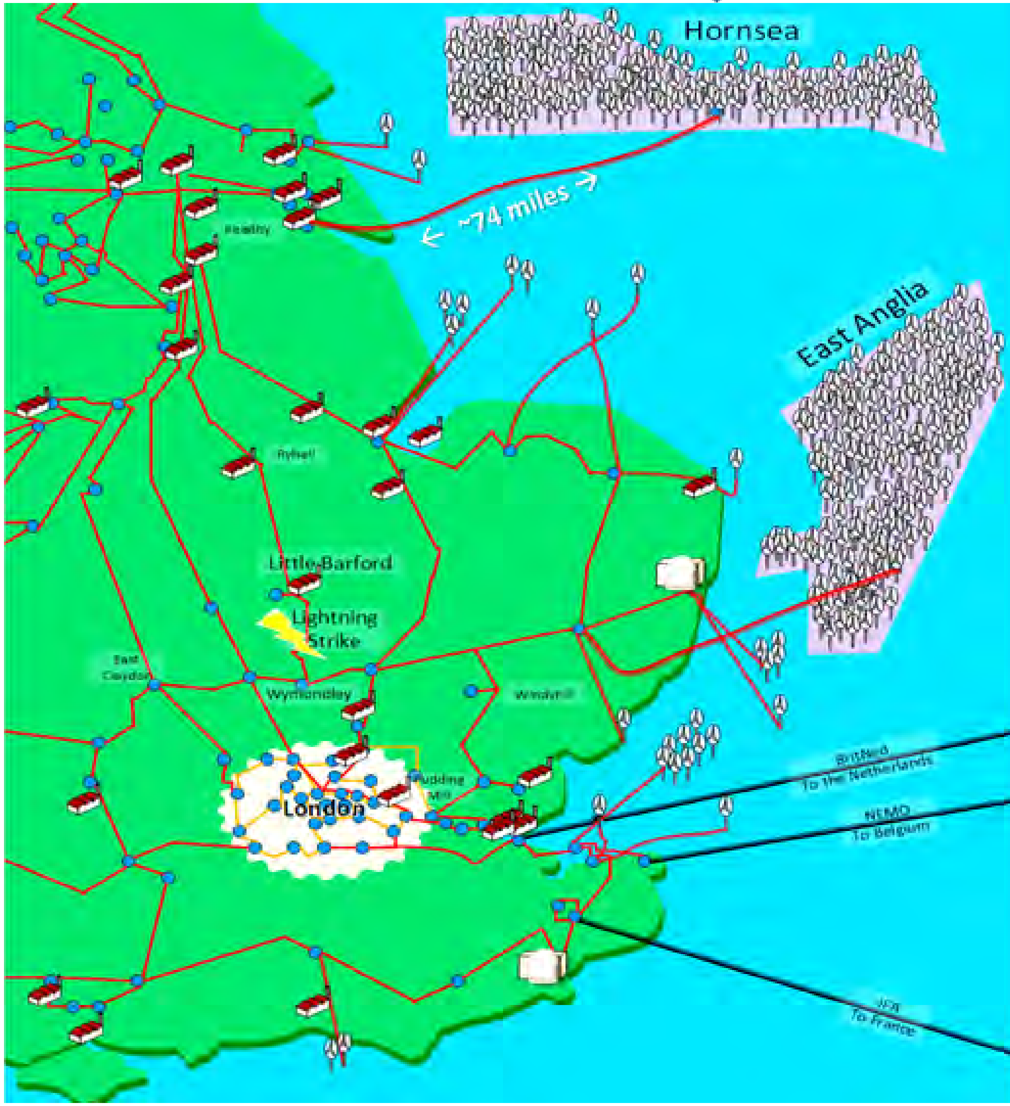
LL20201001 – "Single Phase Fault Precipitates Loss of Generation and Load" (UK Blackout)

- **Problem Statement**

  A single phase to ground fault on a 400 kV transmission line in Southern England precipitated the loss of 1,878 MW of generation. This led to a frequency decline that resulted in a loss of 931 MW of load. This European event has lessons applicable in North America.

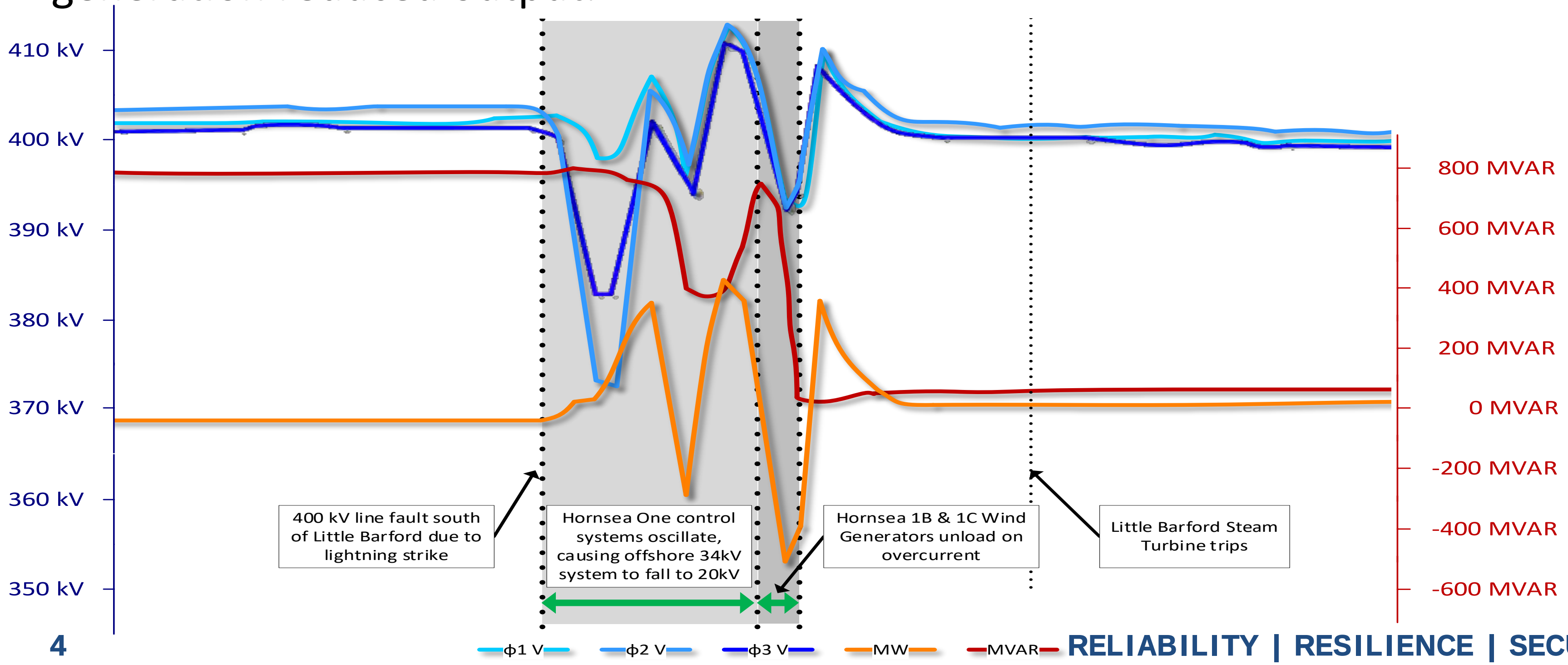
- **Description**

  A lightning-initiated single phase-to-ground fault on a 400 kV transmission line north of London was detected and isolated within its design parameters. The line was successfully reclosed 20 seconds later.



LL20201001 – "Single Phase Fault Precipitates Loss of Generation and Load" (UK Blackout)

- **Description Continued:**
  Along with the fault, a steam turbine (part of a 2-on-1 combined-cycle) at Little Barford tripped (244 MW). Also, Hornsea, a large offshore wind farm, unexpectedly reduced output from 799 MW to 62 MW (725 MW). Although a loss of 150 MW of distributed energy resources (DER) was expected for this type of fault, additional DER losses occurred ≈1 second into the event. ≈350 MW of DER tripped due to rate of change of frequency (ROCOF) protection when additional generation reduced output.



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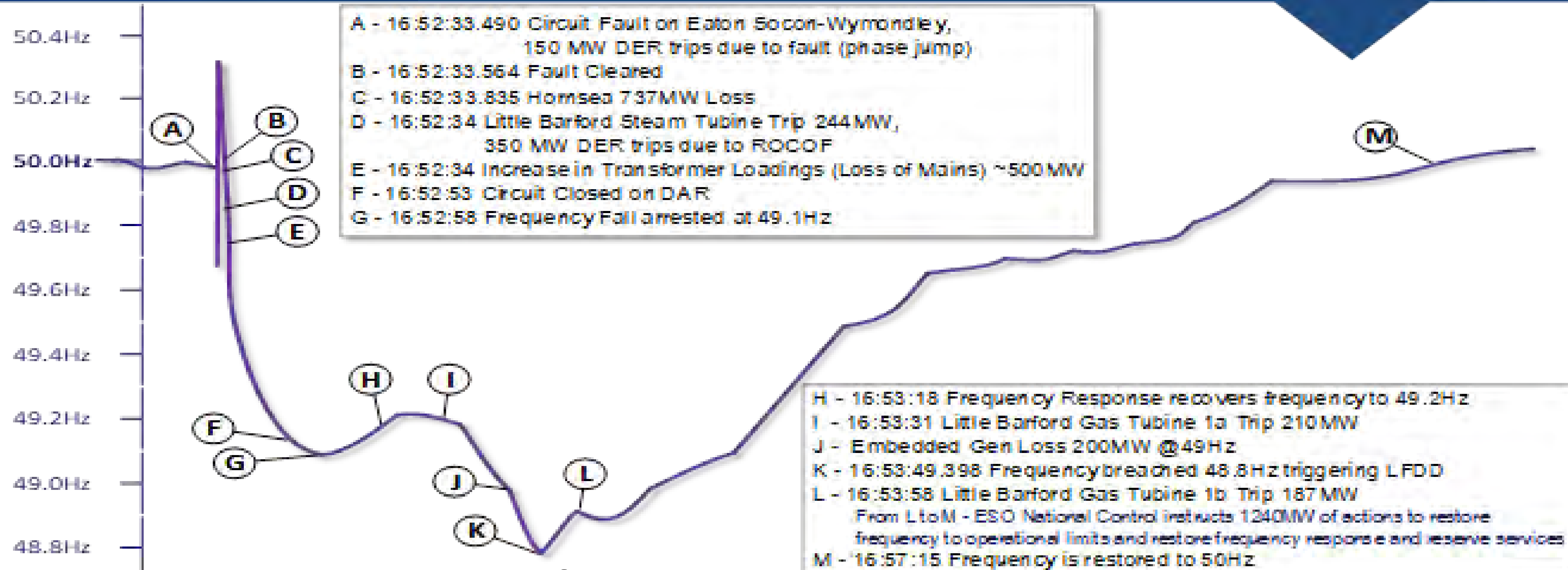
LL20201001 – "Single Phase Fault Precipitates Loss of Generation and Load" (UK Blackout)



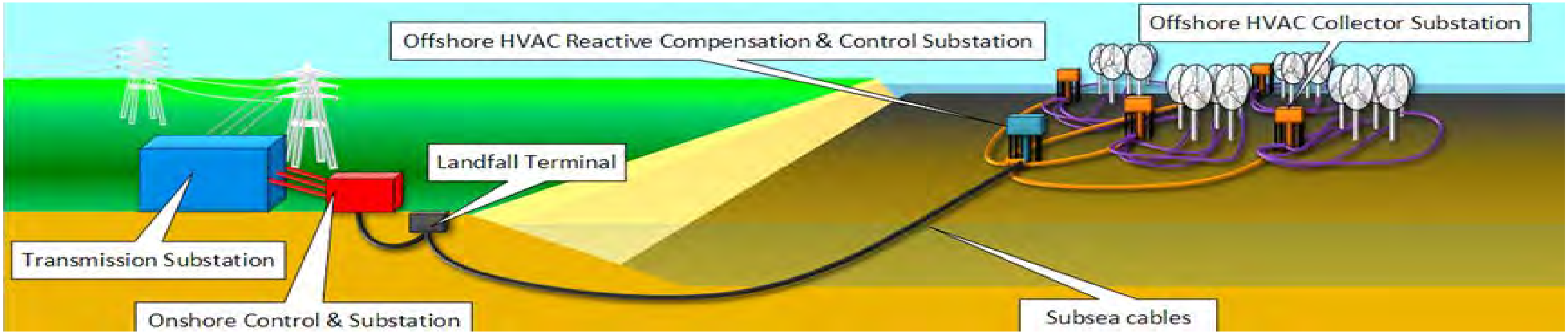
- **Description Continued:**

  ≈1,500 MW of generation was lost w/in 1s of the fault & frequency declined (from European std 50.0 Hz) to 49.1 Hz. As frequency began to recover 58s into the event, 1 combustion turbine (CT) at Little Barford tripped (210 MW), causing further frequency decline. When frequency got below 49 Hz, more DERs tripped. ≈85s into the event, a 2nd CT was shut down at Little Barford (187 MW). Total generation loss was ≈1,878 MW. UFLS schemes operated at 48.8 Hz, disconnecting 931 MW of load. Frequency stabilized & began to recover as system operators dispatched resources.

LL20201001 – "Single Phase Fault Precipitates Loss of Generation and Load" (UK Blackout)

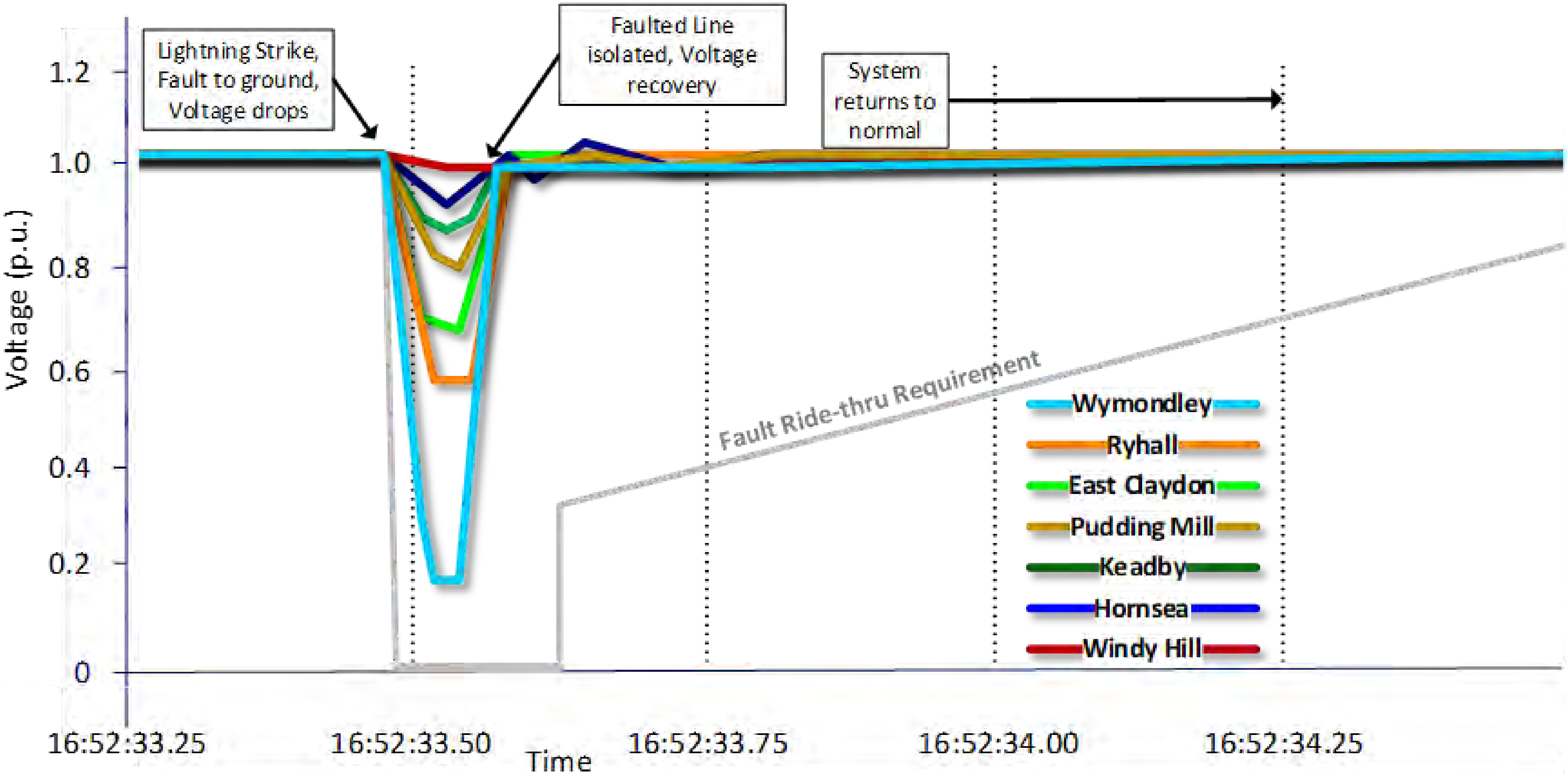
- **Description Continued:**

Limitations in entity knowledge of Hornsea 1's control system & interaction between its onshore & offshore arrangements impaired understanding the wind farm's performance during this event. Onshore control system operated as expected when the system voltage dipped with the lightning strike. Offshore controllers reacted incorrectly to voltage fluctuations following the fault, causing instability between the onshore control system & individual wind turbines. Instability triggered 2 modules to automatically shut down. There were several transmission facility outages at the time. Such outages & less synchronous generator dispatch reduce short circuit strength and contribute to creating a "weak grid" condition. The power electronics that inverter based resources use require a minimum short circuit strength relative to their capability, often referred to as the "short circuit ratio," for stable operation.



- **Description Continued:**

System voltages did not exceed the ride-through requirement. The figure below shows single phase voltage profiles at various locations.



LL20201001 – "Single Phase Fault Precipitates Loss of Generation and Load" (UK Blackout)

- **Corrective Actions**

A thorough analysis of the event was performed by the entity. Their report recommended the following actions:

- Review the operational criteria to determine whether it would be appropriate to provide for higher levels of resilience in the electric system
- Review the timescales for anti-islanding protection to reduce the risk of inadvertent tripping and disconnection of embedded generation
- In addition to the changes in its first-hour communications processes that the entity initiated, conduct a wider industry review, including regulators and other stakeholders to establish new and enduring communication arrangements for similar events

LL20201001 – "Single Phase Fault Precipitates Loss of Generation and Load" (UK Blackout)

- **Lessons Learned**

Simple single contingency planning is inadequate to protect against UFLS events. The UK and the US have different approaches to under frequency load shedding requirements, described here:

- The UK entity's operational planning determined frequency responsive reserve requirements based on frequency deviation. Generation loss was calculated for a given frequency deviation, which was 49.5 Hz in this case. No single contingency (N-1) loss of generation can cause frequency to decline below 49.5 Hz. Frequency responsive reserve is procured to meet this requirement. An infrequent loss of generation event (exceeding N-1) must not allow frequency decline below 49.2 Hz. However, there is no requirement to carry frequency responsive reserve for losses exceeding 49.5 Hz. UFLS begins at 48.8 Hz.
- Under NERC Standard BAL-003-2, frequency responsive reserve requirements are determined by ensuring that the loss of the two largest resources in an Interconnection will not result in UFLS. Stated differently, NERC Reliability Standard BAL-003-2 set frequency responsive reserve requirements to prevent UFLS.

LL20201001 – "Single Phase Fault Precipitates Loss of Generation and Load" (UK Blackout)

- **Lessons Learned Continued:**
- The UK entity in this event determined its frequency responsive reserve requirements by a frequency deviation above UFLS points. This allows the entity to carry less frequency responsive reserve but creates a situation where UFLS becomes more likely if a generation loss exceeds the requirement for 49.5 Hz (N-1 event).

This event also underlined the importance of understanding the reliability impacts associated with the rapidly changing portfolio of resources and their increasingly complex controls. The ability to predict resource responses to network faults are fundamental to the security and resilience of the power system.

- There was significant reliance on self-certification of models for the resources, including the interconnection of new resources, following modification to existing resources, and distributed energy resources. Enhanced compliance testing or verifications may have improved these models. Evaluate if more frequent review of the adequacy of modeling procedures is appropriate and identify any deficiencies.

LL20201001 – "Single Phase Fault Precipitates Loss of Generation and Load" (UK Blackout)

- **Lessons Learned Continued:**
  - Interactions between onshore and offshore wind generation control systems need to be understood and coordinated to prevent adverse results.
  - Transmission facility outages & less synchronous generator dispatch reduces short circuit strength and contributes to creating a "weak grid" condition. Power electronics that inverter based resources use require a minimum short-circuit strength relative to their capability for stable operation. These stability issues and their correlation to transmission system outages should be assessed.
  - Evaluate if coordination & communication between the TP, GO, TO, RC, & equipment manufacturers are sufficient to accurately model & understand connected resources & expected response under stressed (weak grid) conditions.
  - Evaluate if tools, techniques & simulation approaches in planning and operations horizons are adequate, especially in weak grid systems with high penetration of inverter-based resources. Consider weak grid conditions that can dynamically occur due to changes in transmission topology, synchronous generator dispatch, & outages of inverter based resources key components. This may include short circuit ratio screening technique development & use of advanced electromagnetic transient applications.

LL20201001 – “Single Phase Fault Precipitates Loss of Generation and Load” (UK Blackout)

- **Lessons Learned Continued:**

This event also highlights the impact distributed generation (DG) outages can have on the bulk power (BPS) system. Even though the loss of individual DG may have no impact on the BPS, the trip of multiple DGs may aggregate to a significant loss of generation which can impact the frequency of BPS.

- The UK system was operated under the assumption of certain amount of DG tripping for transmission faults; however, the amount of DG that was lost or could have been lost was more than anticipated, resulting in frequency decline.
- The majority of DG tripped due to rate of change of frequency and vector shift protection settings. The ROCOF at which the DG tripped was well within the ride-through requirements for distributed energy resources (DER) specified in IEEE-1547-2018. The vector shift setting of 6 degrees was conservative compared to the recommended 20 degrees in IEEE-1547-2018. The DG trip was also initiated at a frequency (49 HZ for this 50 Hz system), well within the lower bounds of operability. It seems that setting of some DGs were not modified per distribution code requirements in the UK. It is recommended that distribution operators ensure that DG settings are compliant with IEEE-1547-2018 to avoid unnecessary DG loss during a transmission fault.

LL20201001 – "Single Phase Fault Precipitates Loss of Generation and Load" (UK Blackout)

- **Lessons Learned Continued:**
  - It appears that there were no robust processes to analyze the impact of DG loss in a transmission system as credible contingencies. Gathering data on distribution-connected generation and incorporating it in a real-time transmission system analysis is not a common practice in North America either, but some entities have mechanisms in place to forecast distributed resources with publicly available data and weather forecasts in real-time. The forecast values are then incorporated in real-time systems for operator awareness; however, analyzing for the loss of a significant amount of DG as a contingency is not prevalent. The amount of DG is growing rapidly and its loss can put significant strain on transmission.
  - TOs and RCs should explore methods to incorporate the loss of distributed generation in real-time analysis.

LL20201001 – "Single Phase Fault Precipitates Loss of Generation and Load" (UK Blackout)

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LL20201101 – "Cold Weather Operation of SF6 Circuit Breakers"

- **Problem Statement**

When a SF6 circuit breaker (CB) hits its critical low pressure, its fault interrupting capability can be compromised. Most Transmission Owners protect against this by either auto-opening the CB prior reaching the critical low-pressure level or by blocking the CB from tripping (when it reaches the critical low-pressure level) and relying on adjacent CBs to open in the event of a fault (breaker failure mode). If this occurs across multiple locations, it can place the Bulk Electric System (BES) at additional risk since it weakens the overall topology of the system and can result in more facilities being removed from service to clear a fault.

Also, contingencies modeled and studied in real-time contingency analysis (RTCA) studies may become inaccurate, potentially putting the BES in a less secure or unknown state. That condition occurred January 29–30, 2019 during severe cold weather in the upper Midwest region of North America.

LL20201101 – "Cold Weather Operation of SF6 Circuit Breakers"

- **Description**

  At the 2019 Minnesota Power Conference, a presentation was given on the operation of SF6 CBs under low SF6 pressure conditions caused by severe ambient cold weather conditions. The presentation focused on SF6 breaker operations that occurred on two upper Midwest utilities' systems during the severe cold weather event that hit the upper Midwest region of North America January 29–30, 2019. A Regional Protective Relay Subgroup took up this topic at their meeting, where it became clear that additional Transmission Owners within that Area were also impacted by the cold weather event due to reaching critical low-pressure levels on their BES CBs.

  Discussion of SF6 and Mixed Gas Circuit Breaker Technology

  Gas insulated CBs must maintain a design pressure in order for the breaker to achieve its full fault interrupting capability. When pressure starts to drop in the tank, such as when the gas starts to condense (liquefy) due to cold ambient temperatures, it may eventually reach two alarm levels.

- **Description (continued)**

The first alarm is a low-pressure alarm that serves as a warning that SF6 gas density has decreased approximately half way to the lockout pressure. This alarm level allows the entity time to perform corrective actions prior to the lockout pressure.

The second alarm is the lockout (or critical) pressure alarm. This occurs at the lowest SF6 gas pressure at which the original equipment manufacturer has designed the CB to achieve its rated interrupting capability corresponding to the SF6 gas density based on ambient temperature. Tripping operations below this level may not successfully interrupt rated fault current and may also damage the CB. At this level, a protection scheme is typically installed to either auto-open the CB or block the trip and rely on a breaker failure relay to open all adjacent (or remote) breakers in the event of a fault.

- **Description (continued)**

When installed, tank heaters warm the SF6 inside the CB, raising it above the ambient temperature and the temperature where it may start to condense. During severe cold weather, ambient temperatures outside of the CB's specified operating range may overwhelm the tank heater's ability to keep the SF6 in a gaseous state.

It is likely this may have occurred during the January 29–30, 2019, event in the upper Midwest; 13 of the 81 CBs that hit their critical lockout pressure during that two-day event had heaters that were confirmed to be working. Additionally, there were high winds throughout the Midwest on January 29, 2019, and the effectiveness of the heaters was likely compromised due to these high winds.

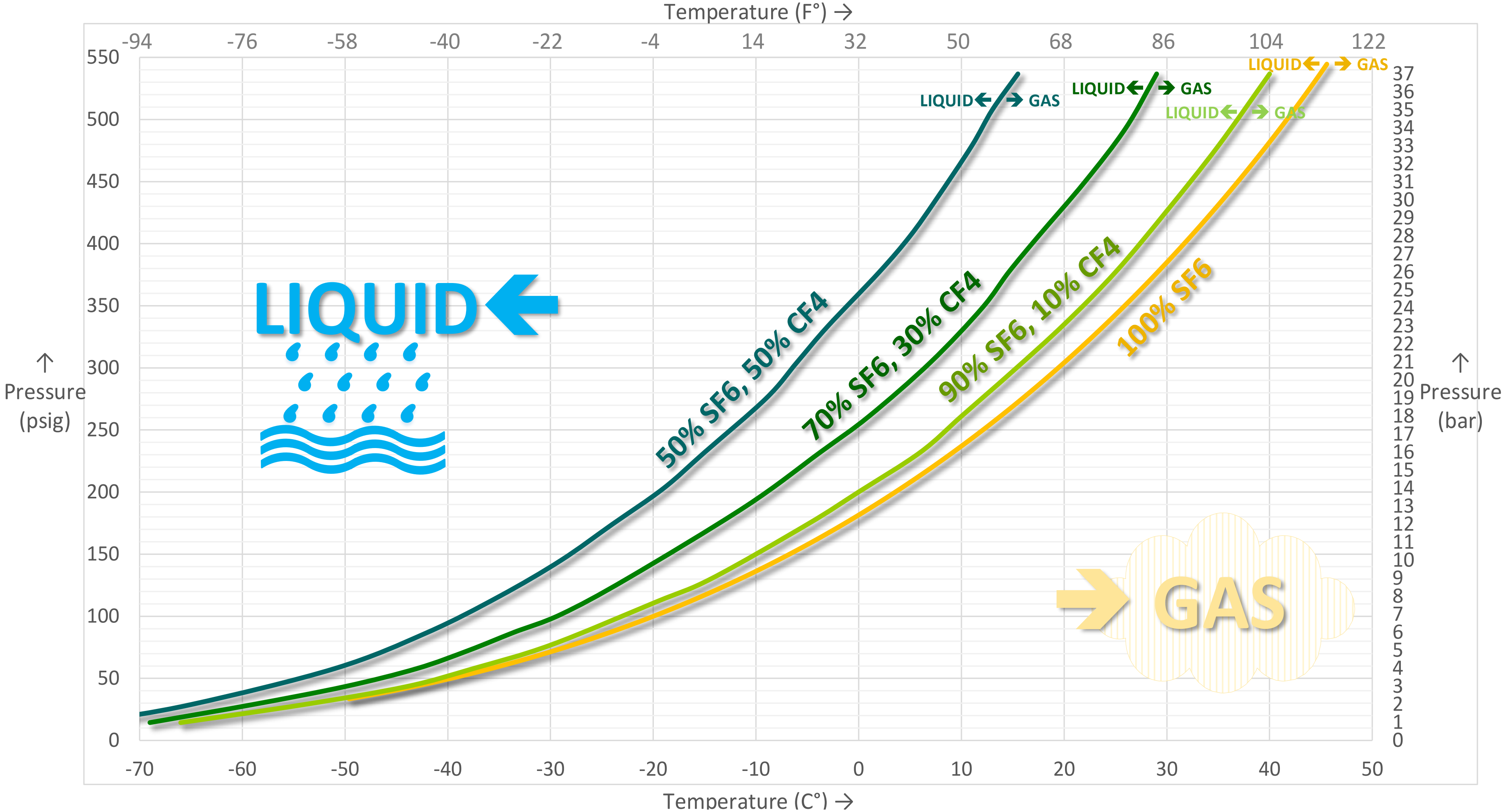
- **Description (continued)**

Mixed Gas CBs

For areas that can be regularly subjected to temperatures in the -30° to -40°F range or colder, a mixed gas approach is often used. Mixed-gas CBs were developed for use at temperatures as low as -50° C (-58° F). These breakers utilize a gas mixture of SF6 and CF4 or SF6 and N2 to prevent condensation of the SF6 gas. Today's mixed-gas CBs offer excellent cold weather performance and provide the reliability needed for even the most severe cold weather conditions. This is achieved without the use of heaters. Mixed gas CBs used for severe cold weather are predominantly live tank design vs. dead tank design (which can accommodate tank heaters, so a mixed gas is not needed). Canadian utilities within that area predominantly use mixed gas live tank CBs on their bulk power system and they performed without issue during the severe cold of January 29-30, 2020. Figure 1 illustrates how a mixture of SF6 and CF4 remains gaseous at much lower temperatures than pure SF6 gas.

- **Description (continued)**

Figure 1: SF6 and SF6-CF4 Mixed Gas Phase Change Diagram



- **Description (continued)**

Regional Data Query for CB Operations Due to Critical Low Pressure

Since there was no formal event analysis report for this cold weather event, Regional staff sent a data query to the Transmission Owners/Operators within the event area. Information was collected on each company's philosophy of SF6 breaker protection during critical low pressure conditions. The query also requested information on actual occurrences January 29–30, 2019, regarding SF6 breakers hitting their critical low pressure alarm level and what opening or blocking actions occurred. The query targeted the northern Transmission Owners/Operators since they experienced temperatures in the -30° to -40° F range.

Summary of Results from the Regional Data Query

Protection scheme philosophy when SF6 CBs hit critical low pressure (12 Entity responses)

- 7 Entities rely on breaker failure scheme protection upon hitting critical low pressure
- 3 Entities auto-trip the breaker and block the close upon hitting critical low pressure
- 2 Entities will auto-trip or rely on breaker failure, depending on location/situation.

- **Description (continued)**

Summary of actual operations January 29–30, 2019

- 6 of the 12 Entities had no occurrences of BES CBs hitting critical low pressure
- 6 Entities had a total of 81 CBs hit critical pressure and block or auto-open
- One CB was mixed gas design (-50°C, no heater); operation was unrelated to cold weather
- 56 of the remaining 80 CBs did not have heaters operating (70%)

  13 CBs had heaters working

  11 CBs had unknown heater operation
- Prewinter Heater Inspections/Maintenance

  3 of the 12 entities indicated they perform heater prewinter inspections
- Ambient temperatures were recorded for 27 of the 81 CBs that hit their critical pressure level. With the exception of two CBs, the temperatures ranged from -8°F to -35°F. Some of these temperatures were estimated after the fact based on historic weather data for that day/hour and for the vicinity of the substation.

- **Observations and Conclusions**

The following are observations of protection scheme philosophy when SF6 CBs hit critical low pressure:

• Auto-open vs. blocking at critical low pressure both appear to be routinely used schemes.

• RTCA results may be compromised (for CBs that have blocked trips), thereby potentially putting the BES in a less secure or unknown state.

Observations of live tank mixed gas CBs

• Mixed gas CBs perform exceptionally well down to -50°C (-58°F).

• Live tank CBs do not rely on heaters.

• Live tank mixed gas CBs are predominantly used in far northern locations where ambient temperatures can readily reach -50°C.

• Live tank mixed gas CBs may be more costly, requiring free standing Current Transformers (CTs).

• Back-fitting a dead tank CB with a live tank CB at an existing substation may be difficult.

• Mixed gas CBs require more equipment to handle mixed gases.

Observations and Conclusions Continued

Observations of dead tank SF6 CBs:

• SF6 dead tank CBs are very dependent on their tanks heaters to avoid hitting critical low pressure.

• Only 3 members out of 12 (25%) performed inspections on tank heaters prior to winter.

• Only two entities indicated they receive supervisory control and data acquisition (SCADA) alarms for tank heater failures.

• Wind speed can impact the effectiveness of the tank heaters and wind speed was significant during this cold weather event.

Live tank mixed gas CBs have proven to be very reliable performers down to the extreme cold temperatures that they are designed for (-50°C/-58°F). These types of CBs are predominantly used in far northern locations where ambient temperatures can readily reach -50°C. Mixed gas technology is key to preventing condensation within the breaker tank during severe low temperature conditions. This makes these breakers more reliable since there is no reliance on tank heaters, which may fail (an additional failure mechanism beside gas issues).

- **Observations and Conclusions Continued**

Dead tank SF6 CBs are predominantly used by the members of the region within the US with the exception of remaining oil tank CBs that are still in service. In the southern half of the region, SF6 CBs perform very well for the cold weather conditions that the southern portion of the region can experience. However, the northern portion relies on tank heaters to maintain SF6 pressure in their CBs during severe cold ambient temperatures. As can be seen from the query results, 56 CBs (70%) of the SF6 CBs that auto-opened or blocked their trip January 29–30, 2019, had inoperable tank heaters. Another 11 heaters had unknown status. This is a key disadvantage of using dead tank SF6 CBs in cold weather climes: reliance of external tank heaters to maintain SF6 tank pressure to assure sufficient interrupting capability during a fault condition.

LL20201101 – "Cold Weather Operation of SF6 Circuit Breakers"

- **Lessons Learned**
  - Some breakers have internal heaters and integral thermal insulation as part of their design. Others may use external heaters and temporary insulation. The maintenance and inspection of SF6 CB tank heaters and installation of any associated temporary thermal insulation (blankets) prior to the winter season is important to ensure the heaters will be effective going into the winter season.
  - Alarming for a tank heater failure can alert operations staff in advance that a CB may hit critical low pressure such that a maintenance crew can be scheduled. These are two best practices that several entities have adopted to minimize the risk of having SF6 CBs block their trip or auto-open during severe cold weather conditions.
  - In the event an SF6 CB reaches critical low pressure and blocks its trip, the Transmission Owner/Operator should assure that the contingency model involving that CB is updated and shared with all impacted TOPs and RCs such that all EMS models will accurately reflect the outage that will occur for fault clearing (breaker failure mode).

Also see LL20180702 "Preparing Circuit Breakers For Operation in Cod Weather"

https://www.nerc.com/pa/rrm/ea/Lessons%20Learned%20Document%20Library/LL20180702_Preparing_Circuit_Breakers_for_Operation_in_Cold_Weather.pdf

LL20201102 – "Loss of State Estimator due to Contradicting Information from Dual ICCP Clusters"

- **Problem Statement**

  The entity encountered an operational problem, causing the state estimator (SE) to become nonconvergent. An evaluation indicated that SE was failing upon opposing device status sent from independent dual ICCP clusters.

- **Description**

The entity encountered an operational problem, causing the SE solution to become invalid. It was discovered that hundreds of external devices periodically switched status and two isolated topology areas were formed due to external devices switching status.

The issue with isolated topology areas was resolved by disabling supervisory control and data acquisition (SCADA) updates for particular external companies and manually forcing external entity devices closed.

The cause of state estimator issues was determined to be a corrupted database on the backup ICCP cluster.

LL20201102 – "Loss of State Estimator due to Contradicting Information from Dual ICCP Clusters"

- **Description Continued:**

Order of Events

1) The SE received information that points on the primary ICCP cluster (defined as Site1 in SE) were suspect, and the backup ICCP cluster (defined as Site2 in SE) was chosen. The database on the backup ICCP cluster had incorrect indexes for point statuses and analog values. This caused the state change of hundreds of points and value changes for analogs.

2) The SE received information that the backup ICCP cluster was suspect and again chose the primary ICCP cluster. It was confirmed with the vendor that the primary source will be selected if all sources are suspect. Using the primary source corrected the indexing, resulting in the state change of those same hundreds of points and value changes for those same analogs. The corrupted database (the backup) was corrected by rebooting the backup ICCP cluster and the SE solution became valid.

LL20201102 – "Loss of State Estimator due to Contradicting Information from Dual ICCP Clusters"

- **Description Continued:**

The entity notified the area RC that the SE and RTCA were down and requested that the RC monitor contingencies until the SE and RTCA could be restored. During this event, there was no problem with the outbound ICCP data.

The entity utilized the backup capability, real-time line outage distribution factor (RTLODF), to perform their real-time assessment during this period of time.

The EMS SCADA functionality (control and indication) was not affected by this event and no transmission facilities were impacted.

- **Corrective Actions**

The two ICCP clusters each have three servers in them. This provides the ability to update the database of one cluster while maintaining complete failover capability in the other cluster.

After an investigation, it was determined that the database in the backup cluster had become corrupted and the point indexes were shifted. It has not been determined how this occurred. A reboot of the backup cluster corrected the problem.

LL20201102 – "Loss of State Estimator due to Contradicting Information from Dual ICCP Clusters"

- **Lessons Learned**
  - In the event of corruption of incoming SCADA data, entities should develop and practice plans for disabling one or more external company data feeds.
  - To minimize the possibility of database corruption or other problems during model updates, servers should be rebooted before any changes are implemented under the vendor's recommendations. Explore the possibilities for comparing and verifying model and database attributes between servers.
  - A dashboard should be developed to quickly show the values from all SCADA sources and the SE for each piece of incoming data. Searching for data points in need of attention can be made easier if data quality issues or differences between sources are highlighted by color.
  - The paging and call out procedures should be reviewed to determine if support staff are notified within an appropriate time frame.
  - Collaboration tools (chat sessions, conference bridges, email, etc.) should be reviewed and tested to determine if modifications are needed while staff may be working in disparate locations.

2020 to Date Lessons Learned Metrics

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Total
ERO Team*	0	0	0	0	0	0	0	0	0	2	1	3
MRO	0	2	2	0	3	1	2	0	3	0	4	17
NERC	23	1	0	0	1	0	0	1	0	0	1	27
NPCC	0	5	2	5	4	10	6	2	4	3	2	43
RF	0	3	1	3	4	1	1	1	5	2	1	22
SERC	0	1	0	2	4	2	2	0	0	1	0	12
TRE	0	5	8	1	2	1	1	2	0	0	0	20
WECC	0	5	5	3	1	1	1	3	3	3	2	27
Total	23	22	18	14	19	16	13	9	15	11	11	171

*"ERO Team" means multiple Regions contributed

NERC Lessons Learned Webpage

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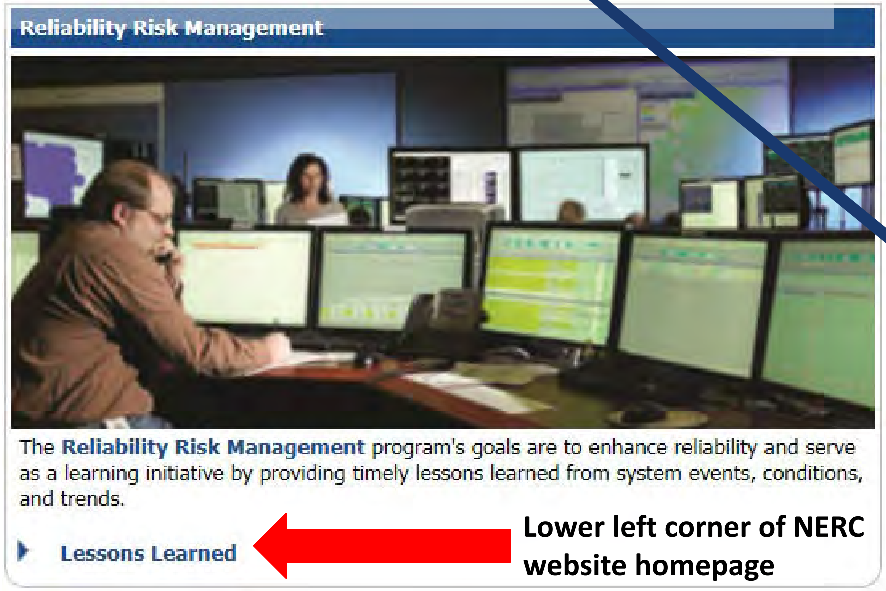
Ways to Access Lessons Learned

- On the NERC website,

  Go to www.NERC.com > Click on the "**Program Areas & Departments**" tab and click "**Reliability Risk Management**"

  Then on the left side menu under "**Event Analysis**" click "**Lessons Learned**"



Lower left corner of NERC website homepage

Questions and Answers

Reliability Guideline: Gas and Electrical Operational Coordination Considerations

Action
Accept to post the document for a 45-day public comment period.

Summary
The Reliability Guideline: Gas and Electrical Operational Coordination Considerations was revised by the Real Time Operating Subcommittee and the Electric Gas Working Group. These two groups are seeking acceptance to post the document for a 45-day public comment period.

Reliability Guideline

Gas and Electrical Operational Coordination Considerations

Applicability:

Reliability Coordinators (RCs), Balancing Authorities (BAs), Transmission Operators (TOPs)
Generator Owners (GOs), and Generator Operators (GOPs)

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) – are, per their charters authorized by the NERC Board of Trustees (Board) to develop Reliability (OC and PC) and Security (CIPC) Guidelines. Guidelines establish voluntary codes of practice for consideration and use by BES users, owners, and operators. These guidelines are developed by the technical committees and include the collective experience, expertise and judgment of the industry. Reliability guidelines do not 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 strongly encouraged to promote and achieve the highest levels of reliability for the BES. Nothing in this guideline negates obligations or requirements under an entity's regulatory framework (local, state or federal) and all parties must take those requirements into consideration when implementing any of the guidance detailed herein.

Background and Purpose

Coordination of operations between the gas and electric industries has become increasingly important over the course of the last decade. The electric power sector's use of gas, specifically natural gas-fired generation, has grown exponentially in many areas of North America due to increased availability of gas, potentially more competitive costs in relation to other fuels and a move throughout the industry to lower emissions to meet environmental goals. With increased growth in gas usage comes greater reliance and associated risk due to the dependency that each industry now has on the other. The operational impact of these dependencies requires gas and electric system operators to actively coordinate planning and operations. The goal of the coordination is to ensure that both the gas and electric systems remain secure and reliable during normal, and emergency conditions. This guideline attempts to provide a set of principles and strategies that may be adopted should the region in which you operate require close coordination due to increased dependency. This guideline does not apply universally, and an evaluation of your area's unique needs is essential to determine which principles and strategies you apply. The guideline principles and strategies may be applied by RCs, BAs, TOPs, GOs and GOPs in order to ensure reliable coordination with the gas industry. Finally, the document focuses on the areas of preparation, coordination, communication and gathering & sharing information that may be applied in order to coordinate gas-electric utility operations and minimize reliability-related risk.

Guideline Content:

A. Establish Gas and Electric Industry Coordination Mechanisms

B. Preparation, Supply Rights, Training and Testing

C. Establish and Maintain Open Communication Channels

D. Gathering, Sharing Information and Situational Awareness

E. Summary

A. Establish Gas and Electric Industry Coordination Mechanisms

- Establish Contacts
    - An essential part of any coordination activity is the identification of participants. For gas and electric coordination, this could involve the identification of the natural gas interstate/intrastate pipelines, gas suppliers and Local Distribution Companies (LDC) as well as gas industry operations staff within the electric footprint boundaries and in some instances beyond those boundaries. Once contacts among these participants are established, additional coordination activities can begin. Gas industry trade organizations, such as the Interstate Natural Gas Association of America, Natural Gas Supply Association, American Gas Association or a regional entity such as the Northeast Gas Association may be able to aid in development of operational contacts and the establishment of coordination protocols. These contacts should be developed for long and short term planning/outage coordination as well as near term and real-time operations. The contacts should include both control room operating staff contacts as well as management. Establishing and maintaining these contacts is the most important aspect of gas and electric coordination. Past lessons learned have taught the industry that the first call you make to a gas transmission pipeline or LDC should not be during emergency conditions.
- Communication Protocols
    - Once counterparts are identified in the gas industry, communications protocols will need to be established within the regulatory framework of both energy sectors looking to coordinate and share information. The Federal Energy Regulatory Commission issued a Final Rule under Order No. 787 allowing interstate natural gas pipelines and electric transmission operators to share non-public operational information to promote the reliability and integrity of their systems. Since the inception of this rule and the subsequent incorporation of those rules into the associated tariffs, followed by the appropriate confidentiality agreements, gas and electric entities have been able to freely share operational data. Data that could be shared to improve operational coordination may include but is not necessarily limited to the following:
        - Providing detailed operational reports to the gas pipeline operators by specific generating assets, operating on specific pipelines, which specify expected fuel burn by asset, by hour

over the dispatch period under review. It is important to convert dispatch plans from electric power (MWh) to gas demand (in terms of gas units/time such as dekatherms/day or MMcf/hour) when conveying that information to gas system operators.

- Combining the expected fuel to be used by asset on each pipeline in aggregate to provide an expected draw on the pipeline by generation connected to that pipeline on an hourly basis and on a gas and electric day basis.

- Exchanging real-time operating information in both verbal and electronic forms (e.g., pipeline company informational postings) of actual operating conditions on specific assets on specific pipelines.
- Outage planning for elements of significance to include sharing detailed electric and gas asset scheduling information on all time horizons and coordinating outages of those assets to ensure reliability on both the gas and electric systems.
- Scheduling face-to-face coordination meetings to discuss a range of topics including but not limited to outage coordination, proposed electric/gas market rule changes, upcoming gas generator additions, pending electric retirements/repowers, enhancements/modifications to gas/electric coordination tools, gas pipeline infrastructure changes, near/long-term seasonal forecasts and load shape changes.
- Sharing normal, and emergency conditions in real-time and ensuring each entity understands the implications to their respective systems. This should include gas and electric entities proactively reaching out to the operators of stressed gas systems to discuss the impacts, adverse or otherwise, of their expected or available actions. Under extreme gas system operating conditions, understand the direct impacts to electric generation assets when gas pipelines are directed under force majeure conditions.
- The sharing of non-public operating information between the electric operating entity and LDC, intrastate pipelines, and gathering pipelines is not covered under FERC Order 787. For this reason, individual communication and coordination protocols should be considered with each LDC and intrastate pipelines within the footprint of the operating entity. Understanding the conditions under which an LDC or intrastate pipeline would interrupt gas-fired generation is of particular importance and incorporating this information into operational procedures and planning will assist in identification of potential at-risk generation. Setting up electronic/email alerts from each LDC or intrastate pipeline as to the potential declaration of interruptions is one key means of real time identification of potential loss of generation behind the LDC city gate or meter station on an intrastate pipeline.

- Coordinating Procurement Time Lines
  - Operating entities may want to consider changing next day operating plan scheduling practices to align more efficiently with gas day procurement cycles. The gas and electric industries operate on differing timelines for the Day Ahead planning processes and in real-time, with the electric day on a local midnight to midnight cycle. The gas industry process operates on a differing timeline with the operating day beginning at 9 a.m. Central Clock Time and uniform throughout

North America. This difference in operating days can lead to inefficient scheduling of natural gas to meet the electric day demands. In many instances throughout North America, the electric industry has moved the development and publishing of unit commitments and next day operating plans in order to ensure that generation resources have the ability to procure and nominate natural gas more efficiently to better meet the scheduling timelines of the gas industry. In addition, the gas industry has adjusted some of its nomination and scheduling practices to allow for more efficient scheduling that meets the needs of the electric system.

- Coordinating and modifying scheduling practices using more effective time periods may allow for a higher level of pipeline utilization, but more importantly, may provide the early identification of constraints that could require starting gas generation with alternate fuels if available, or using non-gas-fired facilities for fuel diversity to meet the energy and reserve needs of the electric system. As the mix of resources trends toward more renewable energy, primarily with variable and intermittent supplies of fuel (e.g. sunshine, wind, and water), maintaining a balanced power system will require a more flexible approach to energy and capacity adequacy in order to maintain operational awareness.
- Identification of Critical Gas System Components and Dual-fuel Supplier Components
  - It is essential gas and electric operating entities coordinate to ensure that critical natural gas pipelines, compressor stations, LNG, storage, natural gas processing plants, and other critical gas system components should not be subject to electric utility load shedding in general but more specifically Under Frequency and or Manual Load shedding programs.
    - Electric transmission and distribution owners are capable of interrupting electrical load either automatically through under frequency load shedding relays installed in substations throughout North America or via manual load shedding ordered by RCs, BAs and or TOPs via SCADA. These manual and automatic load shedding protocols are part of every entity's emergency procedures. Entities should try to ensure critical gas sector infrastructure is not located on electrical circuits that are subject to the load shedding described above. Electric operators should establish contact with the gas companies operating within its jurisdiction to compile a list of critical gas and other fuel facilities which are dependent upon electric service for operations. This list should also consider the availability of backup generation at critical gas facilities. Once the list is compiled, a comprehensive review of load shedding procedures/schemas/circuits should be done to verify that critical infrastructure is not connected to or located on any of those predefined circuits. This review should be considered for evaluation at least annually. The best practice in this area is to try and and ensure that these facilities are not included in the initial under frequency or manual load shedding protocols at the outset.
  - In a similar manner, it may be appropriate to coordinate with secondary fuel (e.g., diesel or fuel oil, onsite LNG) suppliers to ensure that any necessary critical terminals, pump stations, and other critical components are not subject to electric utility load shedding programs in general and more specifically Under Frequency and or Manual Load shedding programs. This is especially appropriate if adequate on-site fuel reserves are not guaranteed and just-in-time fuel delivery practices are required.

- Operating Reserves
    - The electric industry may want to consider adjustments to operating reserve or capacity requirements to better reflect the increased reliance on natural gas for the generation fleet. For instance, if the loss of a fuel forwarding facility has the ability to result in an instantaneous or near instantaneous electric energy loss, that contingency should be reflected in the reserve or capacity procurement for the operating day. In addition, some electric operators are considering the implementation of a risk-based operating reserve protocol that increases or decreases the amount of operating reserve procured based upon the risks identified to both the gas and electric system.

B. Preparation, Supply Rights, Training and Testing

- Assessments
    - Preparing the gas and electric system for coordinated operations benefits from up front assessments and activities to ensure that when real-time events occur, the system operators are prepared for and can effectively react. Preparation activities that may be considered include the following:
        - Developing a detailed understanding of where and how the gas infrastructure interfaces with the electric industry including:
            - Identifying each pipeline (interstate and intrastate) that operates within the electric footprint and mapping the associated electric resources that are dependent upon those pipelines.
            - Identifying the level and quantity of pipeline capacity service (firm or interruptible; primary/secondary) and any additional pipeline services (storage, no-notice, etc.) being utilized by each gas-fired generator.
            - Developing a model of and understanding the non-electric generation load that those pipelines and LDCs serve and will protect when gas curtailments are needed.
            - Identifying gas single element contingencies and how those contingencies will impact the electric infrastructure. For instance, although most gas side contingencies will not impact the electric grid instantaneously, they can be far more severe than electric side contingencies over time because gas side contingencies may impact several generation facilities. When identifying gas system contingencies, the electric entity should consider what the gas operator will do to secure its firm customers. This could include the potential that the gas system will invoke mutual aid agreements with other interconnected pipelines and this may involve curtailment of non-firm electrical generation from the non-impacted pipeline to aid the other.
            - Understanding how gas contingencies may interact with electric contingencies during a system restoration effort.

  - An additional example of appropriate actions to consider as part of the assessment phase of preparation is provided as a Natural Gas Risk Matrix[1].

- Emergency Procedure Testing and Training
  - Consider the development of testing and training activities to recognize abnormal gas system operating conditions and to support extreme gas contingencies such as loss of compressor stations, pipelines, pipeline interconnections, large LNG facilities,which can result in multiple generator losses over time. Particular attention should be focused on any gas related contingency that may result in an instantaneous generation loss.
  - Consider the addition of electric and natural gas coordination and interdependencies training to educate and exercise RCs, BAs, TOPs, and GOPs during potentially adverse natural gas supply disruptions.
  - If voltage reduction capability exists within your area, practical testing and training should be considered as part of seasonal or annual work plans.
  - The use of manual firm load shedding may be required for beyond criteria extreme gas and or electric contingencies. Consideration should be given to practicing the use of manual load-shedding in a simulated environment. These simulations should also be used as part of recurring system operator training at a minimum. The use of tabletop exercises can be a valuable training aid, but wherever possible, consideration should be given to using an advanced training simulator that employs the same tools the operators would use to accomplish the load shedding tasks.
  - Consider conducting periodic operational drills and tabletop exercises between ISO/RTO's, local emergency management entities, and the applicable natural gas industry providers (interstate and intrastate pipelines as well as local distribution companies that serve gas generators) where possible.
  - Consider the development of and drill on internal communication protocols specific to potential natural gas interruptions.
- Generator Testing
  - Consideration should be given to adopting generator testing requirements for dual fuel auditing. Some items to consider when establishing a dual fuel audit program are:
    - How often should the audits be conducted and under what weather and temperature conditions.
    - Verify sufficient alternate fuel (e.g., fuel oil) inventory to ensure required generation response and output. As part of this assessment, ensure that the stored fuel is fully burnable as well since the full volume of the tank may not be pumpable at very low inventories.
    - Capacity, ramping capability or other reductions related to alternate fuels.
    - Understanding the exact time it takes to startup, switch to alternate fuel, ramp to and operate at full capacity, ramp down and resource shut down. Additional consideration

[1] https://www.misoenergy.org/StakeholderCenter/CommitteesWorkGroupsTaskForces/ENGCTF/Pages/home.aspx

should be given for those assets which require a shutdown in order to swap to an alternate fuel source.

- The operating entity should consider any environmental constraints the generator under test must meet in order to swap to and operate on the alternate fuel.

- Capacity and Energy Assessments
  - Consideration should be given to the development of forward looking capacity analyses with which the electric industry is familiar but applying the impacts of fuel restrictions that may occur due to pipeline constraints or other fuel delivery constraints such as LNG shipments or liquid fuel delivery considerations. In order to conduct these types of assessments, the analysis needs to consider the LDC loads within the region. The weather component of the assessment should consider normal, and extreme conditions (i.e., Gas Design Day, which is the equivalent to the highest peak that the pipeline was designed for). This capacity assessment can be on several time horizons including; Real-time, Day Ahead, Month Ahead and Years into the future. These assessments should consider pipeline maintenance, known future outages, construction and expansion activities as well as all electric and gas industry considerations, such as potential or anticipated regulatory changes.
  - In addition to a capacity assessment that represents only a single point in time, consideration should be given to the development of a seasonal, annual or multiannual energy analysis that uses fuel delivery capability/limitations as a component. Such assessments can be scenario based, simulate varied weather conditions over the course of months, seasons and/or years, and consider the same elements as discussed in the capacity analysis. The output of the assessments should determine whether there is the potential for unserved energy and/or determine the ability to provide reserves over the period in question.
- Seasonal Readiness Reviews
  - Winter events, such as the 2014 Polar Vortex, have magnified the need to ensure that seasonal awareness and readiness training is completed within the electric industry including System Operators, Generator Operators and Transmission Operators. Seasonal readiness training for winter weather could include reviews and training associated with dual fuel testing, emergency capacity and energy plans, weather forecasts over the seasonal period, fuel survey protocols and fuel storage readiness. Other areas that require attention in winter readiness reviews include reviewing and setting specific operational expectations on communications protocols. Finally, any winter readiness seminars should include individual generator readiness such as ensuring adequate fuel arrangements are in place for unit availability, adequate freeze protection guidelines are in place, understanding access to primary and secondary fuels and testing to switch to alternate fuels, ensuring all environmental permitting is in place for the fuel options available to the asset, and making sure that the Balancing and Transmission Operators are kept apprised of the unit availability. Many of the same benefits as winter readiness exercises can be realized with the added benefit of exercises under summer operating conditions when electric loads are higher than winter loads.

- Extreme Event Readiness Reviews
  - Seasonal readiness reviews for extreme events (e.g., hurricane, earthquakes, wildfires) could include response to potential natural gas supply limitations and corresponding decreases in natural gas deliveries that may impact electric generation.

C. Establish and Maintain Open Communication Channels

- Industry Coordination
  - In the long and short term planning horizons, regularly scheduled meetings between the gas and electric industries should be held to discuss upcoming operations including outage coordination, industry updates, project updates and exchange of contact information.
  - Operating entities should consider the development of a coordinated and annually updated set of operational and planning contact information for both the gas and electric industries. This information should include access to emergency phone numbers for management contacts as well as all control center real-time and forecaster desks for use in normal, and emergency conditions.
  - Gas and Electric emergency communication conference call capability should be considered between the industries such that operating personnel can be made available from both industries immediately, including off hours and within the confines of the individual confidentiality provisions of each entity. Electric sector personnel should periodically monitor pipeline posted information and notices.
- Emergency Notifications to Stakeholders
  - Operating Entities may want to consider proactive notifications to stakeholders of abnormal and or emergency conditions on gas infrastructure to ensure widespread situational awareness and obligations associated with dispatch relationships in the electric sector. An example of a notification used for generators in New England appears below:

1. Notices Indicating Abnormal and/or Emergency Conditions on the Pipeline Infrastructure Serving Generators

> **NOTE**
>
> Notices indicating abnormal and/or emergency conditions on the pipeline infrastructure serving a Generator in the ISO RCA/BAA could come in the form of, but **not** limited to, Operational Flow Orders, Imbalance Warnings or even a verbal notification.

A) When electronic and or verbal notices indicating abnormal and or emergency conditions on the pipeline infrastructure serving a Generator in the ISO RCA/BAA are received, the Forecaster notifies the Operations Forecast and Scheduling Supervisor (or designee)

(1) The Forecaster reviews this information and depending upon the severity of the condition may pass the publicly available information along by drafting an email and submitting it to Customer Service for dissemination to each applicable Generator Designated Entity (DE) management contact(s) and/or Lead Market Participant (MP) contact(s).

> **NOTE**
>
> The following guideline or one tailored to the current situation can be used as a template for drafting this notification;

"ISO-NE has received the following information via the publicly available notices published by the gas pipelines:

(Insert Notice, such as Operational Flow Order or Force Majeure, etc.)

"Because of this situation, it is critical that each applicable Generator DE or Lead MP provide ISO-NE with up to date and reliable estimates of each Generator current and future capabilities including the ability to have fuel for a Generator under their control. This includes immediately reporting any information that may prevent a Generator from operating in accordance with submitted offer data, including, but **not** limited the following:

- Planned, Maintenance and or Forced outages of the Generator facilities as soon as that information is available
- Immediate reporting of any updates to outages including overruns and or early returns to service of the Generator facilities
- Any high risk activities at a Generator location that may reduce its capability or place the capability at risk
- Any fuel reductions or outages that may limit a Generator's ability to perform in any way
- Any changes to any operating limits of a Generator which must reflect the most accurate and up to date information available
- Any changes at all in a Generator ability to follow dispatch instructions including manual response rates, ability to provide reserve, ability to provide energy, and/or ability to provide capacity
- Any changes in projected Generator self schedules

Depending upon the level of severity and risk exposure, these written notifications and a means to communicate them may need to be followed up with direct verbal communications.

- Emergency Communication Protocols in the Public and Regulatory Community
  - Most every electric operating entity has long standing capacity and energy emergency plans in place that focus on public awareness, and emergency communications as well as appeals for conservation and load management. However, as the gas and electric industry become further dependent, considerations should be made for both industries to coordinate for extreme circumstances. Gas and electric operators in coordination with public officials, including relevant regulatory communities, may find situations where the energy of both the gas and electric sector is required to be reduced in order to preserve the reliability of both. While these types of efforts are still in their infancy they should be explored depending upon the particular circumstances of each entity's region.

D. Gathering, Sharing Information, and Situational Awareness

- Fuel Surveys and Energy Emergency Protocols
  - Energy emergency procedures and fuel surveys are important tools in understanding the energy situation in a region. The surveys can be used to determine energy adequacy for the region's electric power needs and for the communications and associated actions in anticipation or

declaration of an energy emergency[2]. The fuel surveys[3][4] should focus on the availability of other types of fuels if the gas infrastructure is the constrained resource.

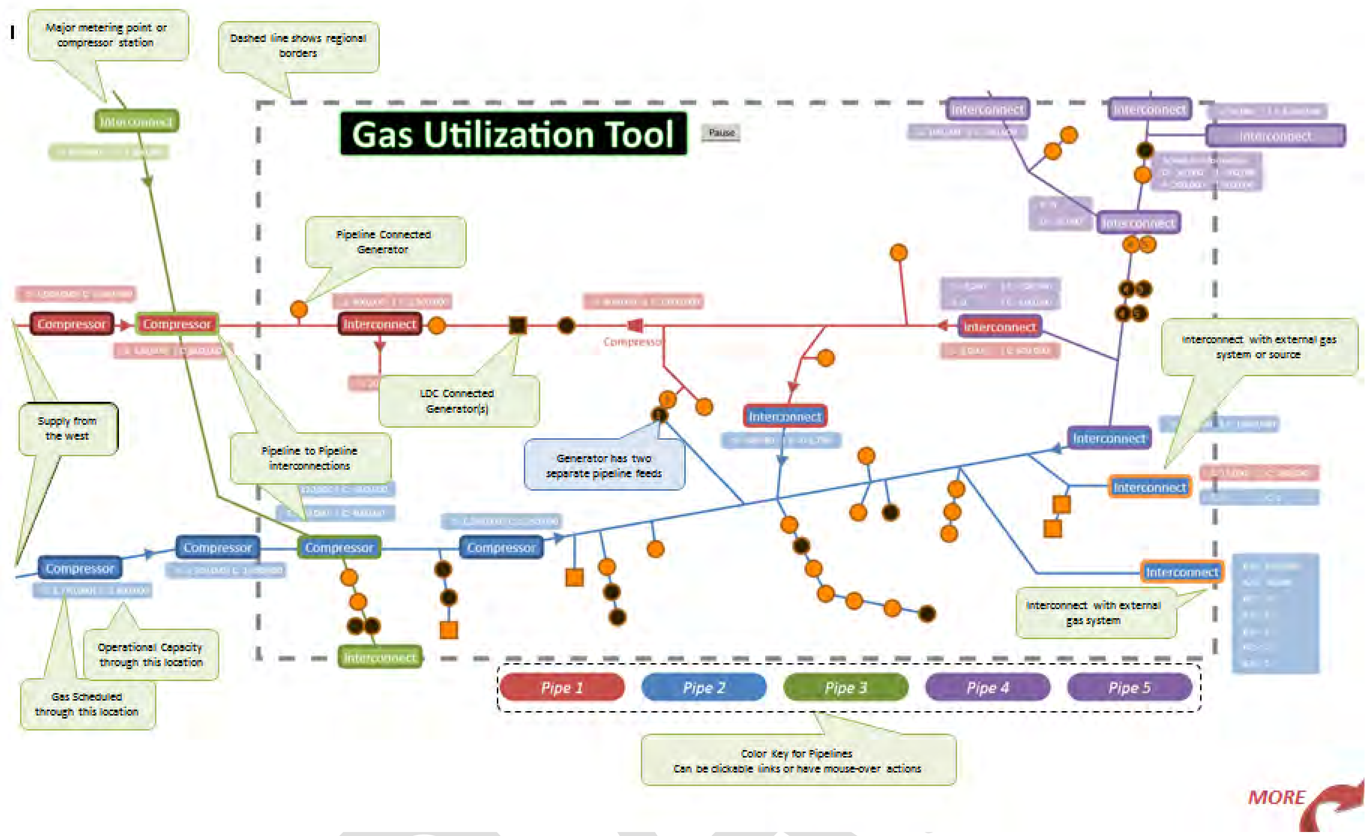
- Fuel Procurement
  - Operating entities should consider evaluating each electric generator's natural gas procurement and commitment to determine fuel security for the operating day.
    - The electric operating entity can collect publicly available interstate pipeline bulletin board data and compare the gas schedules for individual generators against the expected electric operations of the same facility in the current or next day's operating plan. An example of this type of data collection appears below with the data helping to determine if enough fuel is available to meet an individual plant or in aggregate an entire gas fleet's expected operation for the current or future day. The report can indicate whether a fuel surplus or deficit exists by asset or for an entire pipeline. If sufficient gas has not been nominated and scheduled to the generator meter, assessments can be done to determine the impact on system operations and the operating staff may call the generator to inquire as to whether the intention is to secure the requisite gas supply to match its expected dispatch plus operating reserve designations.

[2] Energy emergency example: https://www.iso-ne.com/static-assets/documents/rules_proceds/operating/isone/op21/op21_rto_final.pdf
[3] Seasonal survey example – See section 7.3.5 in Manual 14 http://www.pjm.com/~/media/documents/manuals/m14d.ashx
[4] Real-time survey example – See section 6.4 of Manual 13http://www.pjm.com/~/media/documents/manuals/m13.ashx

Plant	MWh Burned So Far	MWh Before Midnight	MWh After Midnight	MWh Scheduled	MWh Surplus	Gas Scheduled
1	2201	169	1932	4493	191	34600
2	777	0	663	0	(1440)	0
3	1910	0	901	2849	38	20700
4	2131	0	0	2736	605	20028
5	5903	403	0	7706	1400	53800
6	2369	0	798	3097	(70)	22500
7	1253	0	350	93	(1510)	1000
8	2402	185	1850	5129	692	45500
9	0	0	0	28	28	300
10	3	0	525	0	(528)	0
11	0	0	0	0	0	0
12	1	0	0	0	(1)	0
13	4	0	0	0	(4)	0
14	5077	389	2864	9591	1261	65621
15	3394	215	0	3347	(262)	25048
16	3554	550	6017	221	(9900)	1500
17	10639	797	4157	17418	1825	126540
18	7249	545	3892	11096	(590)	80813
19	972	45	1066	9	(2074)	100
20	0	0	0	0	0	0
21	0	0	0	0	0	0
22	6294	0	2476	1643	(7127)	17471
23	2758	0	1209	3944	(23)	30000
24	2400	250	1250	579	(3321)	5000
25	4998	0	2317	6917	(398)	52595
26	3208	250	1189	0	(4647)	0
27	2434	0	0	2747	313	23512
28	4222	0	0	5634	1412	42963
29	2121	0	0	2343	222	20000
30	0	0	0	0	0	0
31	1141	86	860	2344	257	27000
32	0	0	0	0	0	0
33	1071	0	3490	5037	476	38325

Varying configurations of generator gas supplies can quickly complicate reports. Efforts should be made prior to the development of such reporting tools to ensure that all facets of gas scheduling can be displayed. Not all scheduled gas data will be publically available, especially when dealing with LDC and intrastate-connected generators. Generators are occasionally supplied by multiple interstate pipelines simultaneously and may change supply sources based on daily natural gas prices. If possible, the electric operating entity should list its range of contractual arrangements with the natural gas sector such as firm capacity and supply, no-notice storage, etc.

- Gas System Visualization
  - Several Reliability Coordinators have developed visualization tools to provide scheduling and real-time operations staff with situational awareness that ties the gas and electric infrastructure together at their common point of operation. What follows is an example of one such tool that has been made generic for the purposes of the illustration. The bubbles in the tool indicate the functionality available to the user with notes that follow.



Notes:

- The display is updated automatically or on demand. Historical data is available for 30 days in the past. Can be expanded to more days or specific days.
- Generators are clickable and additional information is provided via popup message.
- Pipeline Color Key is clickable and navigates to the specific pipeline EBB.
- All of the values are in MMBtu for the gas day. When operational capacity changes, the display automatically updates based on EBB posted capacity and schedule values.
- Schedules are for the GAS DAY, rolling over at 10:00. (e.g. Gas Day 4/15/2016 starts at 10 am on 4/15 and ends at 4/16 at 10am.)
- These are SCHEDULES and may not reflect the physical flow of gas. Schedules may not match due to differences in scheduling cycles or accounting methods used by different companies.
- Just because there's room for gas to flow at a throughput meter or cross connect, doesn't mean there's gas there to move through.
- *Delivery* is gas leaving the pipeline. *Receipt* is gas entering the pipeline.
- Schedule Badges show Delivery and Receipt where there can be bi-directional scheduling and Schedule where there is not bi-directional scheduling. Most of the schedule badges show a Capacity value as well.
    - o You have to net multiple schedules to derive an estimated final schedule at a location
- Some generators have a single meter to their facility with shared ownership. Through that meter, gas can be scheduled via Pipe 4 or Pipe 5.
- Many generators have multiple connections to separate pipelines and that can be displayed as well
- Meters with zero gas scheduled have darkened icons on this display

Possibilities:

- Real-time power information for the generators as well as how much gas has been consumed and how much remains
- OFO display information based on EBB postings
- Graphical trending of any value you can select

E. Summary

The transformation in the mix of fuel sources used to power electric generation throughout North America and in particular, the increased penetration of renewable resources, as well as the continued increase in the use of natural gas highlights the continued need for the coordination processes discussed in thisguideline. This guideline should serve as a reference document that NERC functional entities may use as needed to improve and ensure BES reliability and is based upon actual lessons learned over the last several years as natural gas has developed into the fuel of choice due to its availability and economic competitiveness. The document focuses on the areas of preparation, coordination, communication, and intelligence that may be applied to improve gas and electric coordinated operations and minimize interdependent risks. Each entity should assess the risks associated with this transformation and apply a set of appropriate processes and practices across its system to mitigate those risks. The guidance is not a "one size fits all" set of measures but rather a list of principles and strategies that can be applied according to the circumstances encountered in a particular system, Balancing Authority, generator fleet or even an individual Generator Operator.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Reliability Guideline

Gas and Electrical Operational Coordination Considerations

Commented [A1]: With edits by IRC EGCTF

Applicability:

Reliability Coordinators (RCs), Balancing Authorities (BAs), Transmission Operators (TOPs) Generator Owners (GOs), and Generator Operators (GOPs)~~RCs, BAs, TOPs, GOs and GOPs~~

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) – are, per their charters authorized by the NERC Board of Trustees (Board) to develop Reliability (OC and PC) and Security (CIPC) Guidelines. Guidelines establish voluntary codes of practice for consideration and use by BES users, owners, and operators. These guidelines are developed by the technical committees and include the collective experience, expertise and judgment of the industry. Reliability guidelines do not 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 strongly encouraged to promote and achieve the highest levels of reliability for the BES. Nothing in this guideline negates obligations or requirements under an entity's regulatory framework (local, state or federal) and all parties must take those requirements into consideration when implementing ~~developing~~ any of the guidance detailed herein.

Commented [A2]: NERC should align this language with their current practices for reliability guidelines.

Background and Purpose

Coordination of operations between the gas and electric industries has become increasingly important over the course of the last decade. The electric power sector's use of gas, specifically natural gas-fired generation, has grown exponentially in many areas of North America due to increased availability of gas, potentially more competitive costs in relation to other fuels and a move throughout the industry to lower emissions to meet environmental goals. With increased growth in gas usage comes greater reliance and associated risk due to the dependency that each industry now has on the other. The operational impact of these dependencies requires gas and electric system operators to actively coordinate planning and operations. The goal of the coordination is to ensure that both the gas and electric systems remain secure and reliable during normal, ~~abnormal~~ and emergency conditions. This guideline attempts to provide a set of principles and strategies that may be adopted should the region in which you operate require close coordination due to increased dependency. This guideline does not apply universally, and an evaluation of your area's unique needs is essential to determine which principles and strategies you apply. The guideline principles and strategies may be applied by RCs, BAs, TOPs, GOs and GOPs in order to ensure reliable coordination with the gas industry. Finally, the document focuses on the areas of preparation, coordination, communication and ~~intelligence~~ gathering & sharing information that may be applied in order to coordinate gas-electric utility operations and minimize reliability-related risk.

Guideline Content:

A. Establish Gas and Electric Industry Coordination Mechanisms

B. Preparation, Supply Rights, Training and Testing

C. Establish and Maintain Open Communication Channels

D. ~~Intelligence~~ Gathering, Sharing Information and Situational Awareness

E. Summary

A. Establish Gas and Electric Industry Coordination Mechanisms

- Establish Contacts
  - An essential part of any coordination activity is the identification of participants. For gas and electric coordination, this could involve the identification of the natural gas interstate/intrastate pipelines, gas suppliers and Local Distribution Companies (LDC) ~~gas entities~~ as well as gas industry operations staff within the electric footprint boundaries and in some instances beyond those boundaries. Once contacts among these participants are established, additional coordination activities can begin. Gas industry trade organizations, such as the Interstate Natural Gas Association of America, Natural Gas Supply Association, American Gas Association or a regional entity such as the Northeast Gas Association may be able to aid in development of operational contacts and the establishment of coordination protocols. These contacts should be developed for long and short term planning/outage coordination as well as near term and real-time operations. The contacts should include both control room operating staff contacts as well as management. Establishing and maintaining these contacts is the most important aspect of gas and electric coordination. Past lessons learned have taught the industry that the first call you make to a gas transmission pipeline or LDC should not be during ~~abnormal or~~ emergency conditions.
- Communication Protocols
  - Once counterparts are identified in the gas industry, communications protocols will need to be established within the regulatory framework of both energy sectors looking to coordinate and share information. The Federal Energy Regulatory Commission issued a Final Rule under Order No. 787 allowing interstate natural gas pipelines and electric transmission operators to share non-public operational information to promote the reliability and integrity of their systems. Since the inception of this rule and the subsequent incorporation of those rules into the associated tariffs, followed by the appropriate confidentiality agreements, gas and electric entities have been able to freely share operational data. Data that could be shared to improve operational coordination may include but is not necessarily limited to the following:

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  - Providing detailed operational reports to the gas pipeline operators by specific generating assets, operating on specific pipelines, which specify expected fuel burn by asset, by hour over the dispatch period under review. It is important to convert dispatch plans from electric power (MWh) to gas demand (in terms of gas units/time such as dekatherms/day or MMcf/hour) when conveying that information to gas system operators.
  - Combining the expected fuel to be used by asset on each pipeline in aggregate to provide an expected draw on the pipeline by generation connected to that pipeline on an hourly basis and on a gas and electric day basis.

- Exchanging real-time operating information in both verbal and electronic forms (e.g., pipeline company informational postings) of actual operating conditions on specific assets on specific pipelines.
- Outage planning for elements of significance to include sharing detailed electric and gas asset scheduling information on all time horizons and coordinating outages of those assets to ensure reliability on both the gas and electric systems.
- ~~This coordination should include if~~Scheduling ~~possible~~ face-to-face coordination meetings~~.~~ to discuss a range of topics including but not limited to outage coordination, proposed electric/gas market rule changes, upcoming gas generator additions, pending electric retirements/repowers, enhancements/modifications to gas/electric coordination tools, gas pipeline infrastructure changes, near/long-term seasonal forecasts and load shape changes.
- Sharing normal, ~~abnormal~~ and emergency conditions in real-time and ensuring each entity understands the implications to their respective systems. This should include gas and electric entities proactively reaching out to the operators of stressed gas systems to discuss the impacts, adverse or otherwise, of their expected or available actions. Under extreme gas system operating conditions, understand the direct impacts to electric generation assets when gas pipelines are directed under force majeure conditions.
- The sharing of non-public operating information between the electric operating entity and LDC, intrastate pipelines, and gathering pipelines is not covered under FERC Order 787. For this reason, individual communication and coordination protocols should be considered with each LDC and intrastate pipelines within the footprint of the operating entity. Understanding the conditions under which an LDC or intrastate pipeline would interrupt gas-fired generation is of particular importance and incorporating this information into operational procedures and planning will assist in identification of potential at-risk generation. Setting up electronic/email alerts from each LDC or intrastate pipeline as to the potential declaration of interruptions is one key means of real time identification of potential loss of generation behind the LDC city gate or meter station on an intrastate pipeline.

- Coordinating Procurement Time Lines
  - Operating entities may want to consider changing next day operating plan scheduling practices to align more efficiently with gas day procurement cycles. The gas and electric industries operate on differing timelines for the Day Ahead planning processes and in real-time, with the electric

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day on a local midnight to midnight cycle. The gas industry process operates on a differing timeline with the operating day beginning at 9 a.m. Central Clock Time and uniform throughout North America. This difference in operating days can lead to inefficient scheduling of natural gas to meet the electric day demands. In many instances throughout North America, the electric industry has moved the development and publishing of unit commitments and next day operating plans in order to ensure that generation resources have the ability to procure and nominate natural gas more efficiently to better meet the scheduling timelines of the gas industry. In addition, the gas industry has adjusted some of its nomination and scheduling practices to allow for more efficient scheduling that meets the needs of the electric system.

- Coordinating and modifying scheduling practices using more effective time periods may allow for a higher level of pipeline utilization, but more importantly, may provide the early identification of constraints that could require starting gas generation with alternate fuels if available, or using non-gas-fired facilities for fuel diversity to meet the energy and reserve needs of the electric system. As the mix of resources trends toward more renewable energy, primarily with variable and intermittent supplies of fuel (e.g. sunshine, wind, and water), maintaining a balanced power system will require a more flexible approach to energy and capacity adequacy in order to maintain operational awareness.

- Identification of Critical Gas System Components and Dual-fuel Supplier Components
  - It is essential gas and electric operating entities coordinate to ensure that critical natural gas pipelines, compressor stations, LNG, storage, natural gas processing plants, and other critical gas system components should not be subject to electric utility load shedding in general but more specifically Under Frequency and or Manual Load shedding programs.
    - Electric transmission and distribution owners are capable of interrupting electrical load either automatically through under frequency load shedding relays installed in substations throughout North America or via manual load shedding ordered by RCs, BAs and or TOPs via SCADA. These manual and automatic load shedding protocols are part of every entity's emergency procedures. Entities should try to ensure critical gas sector infrastructure is not located on electrical circuits that are subject to the load shedding described above. Electric operators should establish contact with the gas companies operating within its jurisdiction to compile a list of critical gas and other fuel facilities which are dependent upon electric service for operations. This list should also consider the availability of backup generation at critical gas facilities. Once the list is compiled, a comprehensive review of load shedding procedures/schemas/circuits should be done to verify that critical infrastructure is not connected to or located on any of those predefined circuits. This review should be considered for evaluation at least annually. The best practice in this area is to try and and ensure that these facilities are not included in the initial under frequency or manual load shedding protocols at the outset.
  - In a similar manner, it may be appropriate to coordinate with secondary fuel (e.g., diesel or fuel oil, onsite LNG) suppliers to ensure that any necessary critical terminals, pump stations,

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and other critical components are not subject to electric utility load shedding programs in general and more specifically Under Frequency and or Manual Load shedding programs. This is especially appropriate if adequate on-site fuel reserves are not guaranteed and just-in-time fuel delivery practices are required.

- Operating Reserves
  - The electric industry may want to consider adjustments to operating reserve or capacity requirements to better reflect the increased reliance on natural gas for the generation fleet. For instance, if the loss of a fuel forwarding facility has the ability to result in an instantaneous or near instantaneous electric energy loss, that contingency should be reflected in the reserve or capacity procurement for the operating day. In addition, some electric operators are considering the implementation of a risk-based operating reserve protocol that increases or decreases the amount of operating reserve procured based upon the risks identified to both the gas and electric system.

B. Preparation, Supply Rights, Training and Testing

- Assessments
  - Preparing the gas and electric system for coordinated operations benefits from up front assessments and activities to ensure that when real-time events occur, the system operators are prepared for and can effectively react. Preparation activities that may be considered include the following:
    - Developing a detailed understanding of where and how the gas infrastructure interfaces with the electric industry including:
      - Identifying each pipeline (interstate and intrastate) that operates within the electric footprint and mapping the associated electric resources that are dependent upon those pipelines.
      - Identifying the level and quantity of pipeline capacity service (firm or interruptible; primary/secondary) and any additional pipeline services (storage, no-notice, etc.) being utilized by each gas-fired generator.
      - Developing a model of and understanding the non-electric generation load that those pipelines and LDCs serve and will protect when gas curtailments are needed.
      - Identifying gas single element contingencies and how those contingencies will impact the electric infrastructure. For instance, although most gas side contingencies will not impact the electric grid instantaneously, they can be far more severe than electric side contingencies over time because gas side contingencies may impact several generation facilities. When identifying gas system contingencies, the electric entity should consider what the gas operator will do to secure its firm customers. This could include the potential that the gas system will invoke mutual aid agreements with other interconnected pipelines and this may involve curtailment of non-firm electrical generation from the non-impacted pipeline to aid the other.

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- Understanding how gas contingencies may interact with electric contingencies during a system restoration effort.
- An additional example of appropriate actions to consider as part of the assessment phase of preparation is provided as a Natural Gas Risk Matrix[1].

- Emergency Procedure Testing and Training
  - Consider the development of testing and training activities to recognize abnormal gas system operating conditions and to support extreme gas contingencies such as loss of compressor stations, pipelines, pipeline interconnections, large LNG facilities,which can result in multiple generator losses over time. Particular attention should be focused on any gas related contingency that may result in an instantaneous generation loss.
  - Consider the addition of electric and natural gas coordination and interdependencies training to educate and exercise RCs, BAs, TOPs, and GOPs during potentially adverse natural gas supply disruptions.
  - If voltage reduction capability exists within your area, practical testing and training should be considered as part of seasonal or annual work plans.
  - The use of manual firm load shedding may be required for beyond criteria extreme gas and or electric contingencies. Consideration should be given to practicing the use of manual load-shedding in a simulated environment. These simulations should also be used as part of recurring system operator training at a minimum. The use of tabletop exercises can be a valuable training aid, but wherever possible, consideration should be given to using an advanced training simulator that employs the same tools the operators would use to accomplish the load shedding tasks.
  - Consider conducting periodic operational drills and tabletop exercises between ISO/RTO's, local emergency management entities, and the applicable natural gas industry providers (interstate and intrastate pipelines as well as local distribution companies that serve gas generators) where possible.
  - Consider the development of and drill on internal communication protocols specific to potential natural gas interruptions.

- Generator Testing
  - Consideration should be given to adopting generator testing requirements for dual fuel auditing. Some items to consider when establishing a dual fuel audit program are:
    - How often should the audits be conducted and under what weather and temperature conditions.
    - Verify sufficient alternate fuel (e.g., fuel oil) inventory to ensure required generation response and output. As part of this assessment, ensure that the stored fuel is fully burnable as well since the full volume of the tank may not be pumpable at very low inventories.
    - Capacity, -ramping capability or other reductions ~~on~~ related to alternate fuels.

[1] https://www.misoenergy.org/StakeholderCenter/CommitteesWorkGroupsTaskForces/ENGCTF/Pages/home.aspx

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- Understanding the exact time it takes to startup, switch to alternate fuel, ramp to and operate at full capacity, ramp down and resource shut down. Additional consideration should be given for those assets which require a shutdown in order to swap to an alternate fuel source.
- The operating entity should consider any environmental constraints the generator under test must meet in order to swap to and operate on the alternate fuel.

- Capacity and Energy Assessments
  - Consideration should be given to the development of forward looking capacity analyses with which the electric industry is familiar but applying the impacts of fuel restrictions that may occur due to pipeline constraints or other fuel delivery constraints such as LNG shipments or liquid fuel delivery considerations. In order to conduct these types of assessments, the analysis needs to consider the LDC loads within the region. The weather component of the assessment should consider normal, ~~abnormal~~ and extreme conditions (i.e., Gas Design Day, which is the equivalent to the highest peak that the pipeline was designed for). This capacity assessment can be on several time horizons including; Real-time, Day Ahead, Month Ahead and Years into the future. These assessments should consider pipeline maintenance, known future outages, construction and expansion activities as well as all electric and gas industry considerations, ~~including~~ such as ~~known or~~ potential or anticipated regulatory changes~~, which are normally analyzed~~.
  - In addition to a capacity assessment that represents only a single point in time, consideration should be given to the development of a seasonal, annual or multiannual energy analysis that uses fuel delivery capability/limitations as a component. Such assessments can be scenario based, simulate varied weather conditions over the course of months, seasons and/or years, and consider the same elements as discussed in the capacity analysis. The output of the assessments should determine whether there is the potential for unserved energy and/or determine the ability to provide reserves over the period in question.

- Seasonal~~Winter~~ Readiness Reviews
  - ~~Recent system~~Winter events, such as the 2014 Polar Vortex, have magnified the need to ensure that seasonal awareness and readiness training is completed within the electric industry including System Operators, Generator Operators and Transmission Operators. Seasonal readiness training for winter weather could include reviews and training associated with dual fuel testing, emergency capacity and energy plans, weather forecasts over the seasonal period, fuel survey protocols and fuel storage readiness. Other areas that require attention in winter readiness reviews include reviewing and setting specific operational expectations on communications protocols. Finally, any winter readiness seminars should include individual generator readiness such as ensuring adequate fuel arrangements are in place for unit availability, adequate freeze protection guidelines are in place, understanding access to primary and secondary fuels and testing to switch to alternate fuels, ensuring all environmental permitting is in place for the fuel options available to the asset, and making sure that the Balancing and Transmission Operators are kept apprised of the unit availability. Many of the

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same benefits as winter readiness exercises can be realized with the added benefit of exercises under summer operating conditions when electric loads are higher than winter loads.

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- Extreme ~~Weather~~ Event Readiness Reviews
  - Seasonal readiness reviews for extreme ~~summer weather~~ events (e.g., ~~Gulf of Mexico~~ hurricane, earthquakes, wildfires) could include response to potential natural gas supply limitations and corresponding decreases in natural gas deliveries that may impact electric generation. ~~Many of the same benefits as winter readiness exercises can be realized with the added benefit of exercises under summer operating conditions when electric loads are higher than winter loads.~~

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C. Establish and Maintain Open Communication Channels

- Industry Coordination
  - In the long and short term planning horizons, regularly scheduled meetings between the gas and electric industries should be held to discuss upcoming operations including outage coordination, industry updates, project updates and exchange of contact information.
  - Operating entities should consider the development of a coordinated and annually updated set of operational and planning contact information for both the gas and electric industries. This information should include access to emergency phone numbers for management contacts as well as all control center real-time and forecaster desks for use in normal, ~~abnormal~~ and emergency conditions.
  - Gas and Electric emergency communication conference call capability should be considered between the industries such that operating personnel can be made available from both industries immediately, including off hours and within the confines of the individual confidentiality provisions of each entity. Electric sector personnel should periodically monitor pipeline posted information and notices.
- Emergency Notifications to Stakeholders
  - Operating Entities may want to consider proactive notifications to stakeholders of abnormal and or emergency conditions on gas infrastructure to ensure widespread situational awareness and obligations associated with dispatch relationships in the electric sector. An example of a notification used for generators in New England appears below:

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1. Notices Indicating Abnormal and/or Emergency Conditions on the Pipeline Infrastructure Serving Generators

NOTE

Notices indicating abnormal and/or emergency conditions on the pipeline infrastructure serving a Generator in the ISO RCA/BAA could come in the form of, but **not** limited to, Operational Flow Orders, Imbalance Warnings or even a verbal notification.

A) When electronic and or verbal notices indicating abnormal and or emergency conditions on the pipeline infrastructure serving a Generator in the ISO RCA/BAA are received, the Forecaster notifies the Operations Forecast and Scheduling Supervisor (or designee)

(1) The Forecaster reviews this information and depending upon the severity of the condition may pass the publicly available information along by drafting an email and submitting it to Customer Service for dissemination to each applicable Generator Designated Entity (DE) management contact(s) and/or Lead Market Participant (MP) contact(s).

NOTE

The following guideline or one tailored to the current situation can be used as a template for drafting this notification;

"ISO-NE has received the following information via the publicly available notices published by the gas pipelines:

(Insert Notice, such as Operational Flow Order or Force Majeure, etc.)

"Because of this situation, it is critical that each applicable Generator DE or Lead MP provide ISO-NE with up to date and reliable estimates of each Generator current and future capabilities including the ability to have fuel for a Generator under their control. This includes immediately reporting any information that may prevent a Generator from operating in accordance with submitted offer data, including, but **not** limited the following:

- Planned, Maintenance and or Forced outages of the Generator facilities as soon as that information is available
- Immediate reporting of any updates to outages including overruns and or early returns to service of the Generator facilities
- Any high risk activities at a Generator location that may reduce its capability or place the capability at risk
- Any fuel reductions or outages that may limit a Generator's ability to perform in any way
- Any changes to any operating limits of a Generator which must reflect the most accurate and up to date information available
- Any changes at all in a Generator ability to follow dispatch instructions including manual response rates, ability to provide reserve, ability to provide energy, and/or ability to provide capacity
- Any changes in projected Generator self schedules

Depending upon the level of severity and risk exposure, these written notifications and a means to communicate them may need to be followed up with direct verbal communications.

- Emergency Communication Protocols in the Public and Regulatory Community
  - Most every electric operating entity has long standing capacity and energy emergency plans in place that focus on public awareness, ~~abnormal~~ and emergency communications as well as appeals for conservation and load management. However, as the gas and electric industry become further dependent, considerations should be made for both industries to coordinate for extreme circumstances. Gas and electric operators in coordination with public officials, including relevant regulatory communities, may find situations where the energy of both the gas and electric sector is required to be reduced in order to preserve the reliability of both. While these types of efforts are still in their infancy they should be explored depending upon the particular circumstances of each entity's region.

D. ~~Intelligence~~ Gathering, Sharing Information, and Situational Awareness

- Fuel Surveys and Energy Emergency Protocols
  - Energy emergency procedures and fuel surveys ~~can be~~are important tools in understanding the energy situation in a region. The surveys can be used to determine energy adequacy for the region's electric power needs and for the communications and associated actions in anticipation

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or declaration of an energy emergency[2]. ~~Interestingly, T~~The fuel surveys[3][4] ~~will most likely~~should focus on the ~~fuel~~ availability of other types of fuels if the gas infrastructure is the constrained resource.

- Fuel Procurement
  - Operating entities should consider evaluating each electric generator's natural gas procurement and commitment to determine fuel security for the operating day.
    - The electric operating entity can collect publicly available interstate pipeline bulletin board data and compare the gas ~~procurement nomination~~schedules for individual generators against the expected electric operations of the same facility in the current or next day's operating plan. An example of this type of data collection appears below with the data helping to determine if enough fuel is available to meet an individual plant or in aggregate an entire gas fleet's expected operation for the current or future day. The report can indicate whether a fuel surplus or deficit exists by asset or for an entire pipeline. If sufficient gas has not been nominated and scheduled to the generator meter, assessments can be done to determine the impact on system operations and the operating staff may call the generator to inquire as to whether the intention is to secure the requisite gas supply to match its expected dispatch plus operating reserve designations.

[2] Energy emergency example: https://www.iso-ne.com/static-assets/documents/rules_proceds/operating/isone/op21/op21_rto_final.pdf
[3] Seasonal survey example – See section 7.3.5 in Manual 14 http://www.pjm.com/~/media/documents/manuals/m14d.ashx
[4] Real-time survey example – See section 6.4 of Manual 13http://www.pjm.com/~/media/documents/manuals/m13.ashx

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Plant	MWh Burned So Far	MWh Before Midnight	MWh After Midnight	MWh Scheduled	MWh Surplus	Gas Scheduled
1	2201	169	1932	4493	191	34600
2	777	0	663	0	(1440)	0
3	1910	0	901	2849	38	20700
4	2131	0	0	2736	605	20028
5	5903	403	0	7706	1400	53800
6	2369	0	798	3097	(70)	27500
7	1253	0	350	93	(1510)	1000
8	2402	185	1850	5129	692	45500
9	0	0	0	28	28	300
10	3	0	525	0	(528)	0
11	0	0	0	0	0	0
12	1	0	0	0	(1)	0
13	4	0	0	0	(4)	0
14	5077	389	2864	9591	1261	65621
15	3394	215	0	3347	(262)	25048
16	3554	550	6017	221	(9900)	1500
17	10639	797	4157	17418	1825	126540
18	7749	545	3892	11096	(590)	80813
19	972	45	1066	9	(2074)	100
20	0	0	0	0	0	0
21	0	0	0	0	0	0
22	6294	0	2476	1643	(7127)	17471
23	2758	0	1209	3944	(23)	30000
24	2400	250	1250	579	(3321)	5000
25	4998	0	2317	6917	(398)	52595
26	3208	250	1189	0	(4647)	0
27	2434	0	0	2747	313	23512
28	4222	0	0	5634	1412	42963
29	2121	0	0	2343	222	20000
30	0	0	0	0	0	0
31	1141	86	860	2344	257	27000
32	0	0	0	0	0	0
33	1071	0	3490	5037	476	38325

Varying configurations of generator gas supplies can quickly complicate reports. Efforts should be made prior to the development of such reporting tools to ensure that all facets of gas scheduling can be displayed. Not all scheduled gas data will be publically available, especially when dealing with LDC~~-~~ and intrastate-connected generators. Generators are ~~often~~ occasionally supplied by multiple interstate pipelines simultaneously and may change supply sources based on daily natural gas prices. If possible, the electric operating entity should list its range of contractual arrangements with the natural gas sector such as firm capacity and supply, no-notice storage, etc.

- Gas System Visualization
  - Several Reliability Coordinators have developed visualization tools to provide scheduling and real-time operations staff with situational awareness that ties the gas and electric infrastructure together at their common point of operation. What follows is an example of one such tool that has been made generic for the purposes of the illustration. The bubbles in the tool indicate the functionality available to the user with notes that follow.

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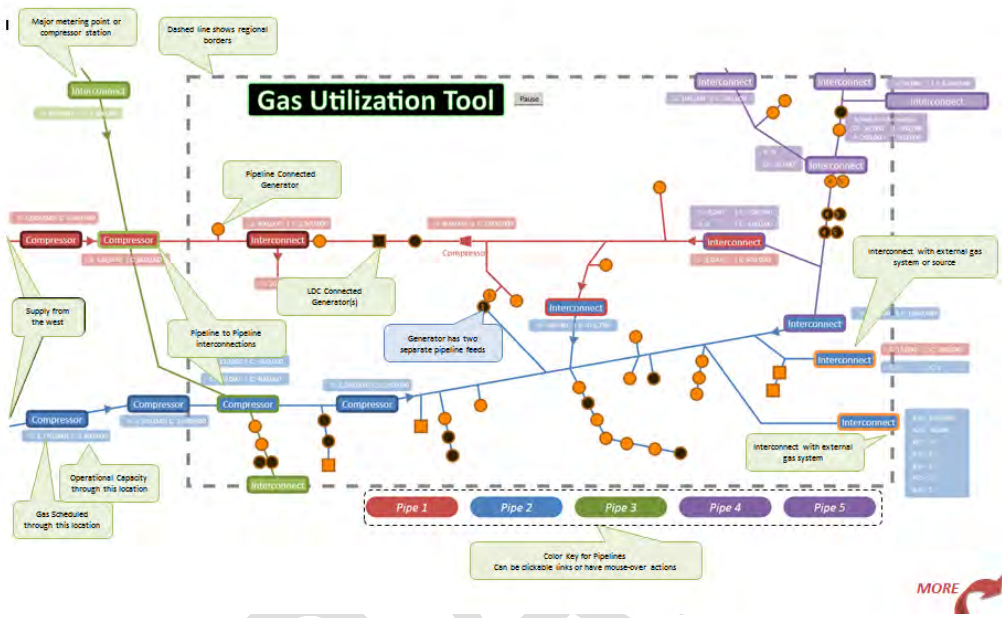

Notes:

- The display is updated automatically or on demand. Historical data is available for 30 days in the past. Can be expanded to more days or specific days.
- Generators are clickable and additional information is provided via popup message.
- Pipeline Color Key is clickable and navigates to the specific pipeline EBB.
- All of the values are in MMBtu for the gas day. When operational capacity changes, the display automatically updates based on EBB posted capacity and schedule values.
- Schedules are for the GAS DAY, rolling over at 10:00. (e.g. Gas Day 4/15/2016 starts at 10 am on 4/15 and ends at 4/16 at 10am.)
- These are SCHEDULES and may not reflect the physical flow of gas. Schedules may not match due to differences in scheduling cycles or accounting methods used by different companies.
- Just because there's room for gas to flow at a throughput meter or cross connect, doesn't mean there's gas there to move through.
- *Delivery* is gas leaving the pipeline. *Receipt* is gas entering the pipeline.
- Schedule Badges show Delivery and Receipt where there can be bi-directional scheduling and Schedule where there is not bi-directional scheduling. Most of the schedule badges show a Capacity value as well.
  - You have to net multiple schedules to derive an estimated final schedule at a location
- Some generators have a single meter to their facility with shared ownership. Through that meter, gas can be scheduled via Pipe 4 or Pipe 5.
- Many generators have multiple connections to separate pipelines and that can be displayed as well
- Meters with zero gas scheduled have darkened icons on this display

Possibilities:

- Real-time power information for the generators as well as how much gas has been consumed and how much remains
- OFO display information based on EBB postings
- Graphical trending of any value you can select

E. Summary

The transformation in the mix of fuel sources used to power electric generation throughout North America and in particular, the increased penetration of renewable resources, as well as the continued increase in the use of natural gas ~~has naturally led~~highlights the continued need for ~~to~~ the coordination processes

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discussed in th~~is~~ ~~preceding~~ guideline. Th~~is~~e guideline should serve as a reference document that NERC functional entities may use as needed to improve and ensure BES reliability and is based upon actual lessons learned over the last several years as natural gas has developed into the fuel of choice due to its availability and economic competitiveness. The document focuses on the areas of preparation, coordination, communication, and intelligence that may be applied to improve gas and electric coordinated operations and minimize interdependent risks. Each entity should assess the risks associated with this transformation and apply a set of appropriate processes and practices across its system to mitigate those risks. The guidance is not a "one size fits all" set of measures but rather a list of principles and strategies that can be applied according to the circumstances encountered in a particular system, Balancing Authority, generator fleet or even an individual Generator Operator.

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Inverter-Based Resources Performance Working Group Performance, Modeling, and Simulations of BPS-Connected Battery Energy Storage Systems and Hybrid Power Plants Reliability Guideline

Action

Accept to post the document for a 45-day public comment period.

Summary

Interconnection queues across North America are seeing a rapid influx of requests for battery energy storage systems (BESSs) and hybrid power plants. While there are different types of energy storage technologies, BESSs are experiencing a rapid increase in penetration levels due to favorable economics, policies, and technology advancements. Similarly, BESSs are most commonly being coupled with inverter-based generating resources such as wind and solar photovoltaic (PV). Therefore, BESSs and inverter-based hybrid power plants are the primary focus of this Reliability Guideline.

NERC previously published a Reliability Guideline outlining the recommended performance for BPS-connected inverter-based resources.[1] The guidance provided in that document included BESSs as an inverter-based technology; however, there are certain considerations and nuances to the operation of this technology that warrant additional guidance. Hybrid plants also pose new benefits to the BPS by combining operational capabilities across different technologies; however, there are different types of hybrid configurations (ac-coupled versus dc-coupled) and complexities and unique operational considerations of hybrid plants that need additional guidance as well. This Reliability Guideline provides the clarifications and considerations that were not covered in the initial NERC guidance specifically focused on BESSs and hybrid power plants.

This Reliability Guideline includes the recommended performance of BPS-connected BESSs and hybrid power plants and modeling and study practices that should be considered by planning entities.

Proposed motion language, if applicable:
"I move to approve the Inverter-Based Resources Performance Working Group Performance, Modeling, and Simulations of BPS-Connected Battery Energy Storage Systems and Hybrid Power Plants Reliability Guideline for a 45-day industry comment period."

[1] https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Inverter-Based_Resource_Performance_Guideline.pdf

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

IRPWG Reliability Guideline: Performance, Modeling, and Simulations of BPS-Connected Battery Energy Storage Systems and Hybrid Power Plants

Approve Posting for Industry Comment

Jeff Billo, IRPWG Vice Chair
NERC Reliability and Security Technical Committee Meeting
December 2020

RELIABILITY | RESILIENCE | SECURITY




Background

- Interconnection queues across North America are seeing a rapid influx of battery energy storage systems (BESSs) and hybrid power plants
- In 2018 IRPWG (IRPTF) published the BPS-Connected Inverter-Based Resource Performance Reliability Guideline[1]
- BESSs and hybrid power plants have similarities but also unique characteristics when compared to other inverter-based resources

1 https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Inverter-Based_Resource_Performance_Guideline.pdf

Reliability Guideline

- IRPWG reviewed BESS and hybrid power plant technology and applications
- The draft reliability guideline covers:
  - Performance
  - Modeling
    - Steady State
    - Dynamics
    - Short Circuit
  - Studies
    - Interconnection Studies
    - Transmission Planning Assessment Studies
    - Other Considerations

Request

- The IRPWG requests that the Reliability and Security Technical Committee approve the Reliability Guideline for a 45-day industry comment period

Questions and Answers

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Reliability Guideline

Performance, Modeling, and Simulations of BPS-Connected Battery Energy Storage Systems and Hybrid Power Plants

November 2020

DRAFT

RELIABILITY | RESILIENCE | SECURITY

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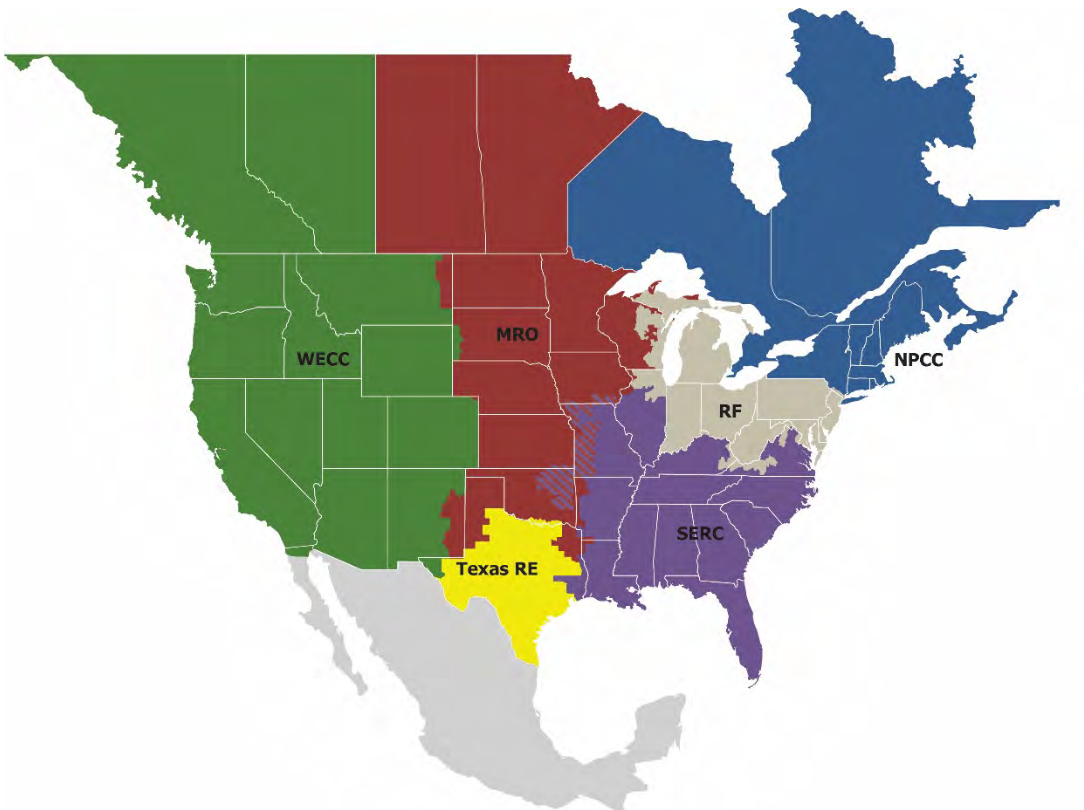
Preface

Electricity is a key component of the fabric of modern society and the Electric Reliability Organization (ERO) Enterprise serves to strengthen that fabric. The vision for the ERO Enterprise, which is comprised of the North American Electric Reliability Corporation (NERC) and the six Regional Entities (REs), is a highly reliable and secure North American bulk power system (BPS). Our mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid.

Reliability | Resilience | Security

Because nearly 400 million citizens in North America are counting on us

The North American BPS is divided into six RE boundaries as shown in the map and corresponding table below. The multicolored area denotes overlap as some load-serving entities participate in one Region while associated Transmission Owners/Operators participate in another.



MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
Texas RE	Texas Reliability Entity
WECC	WECC

Preamble

The NERC Reliability and Security Technical Committee (RSTC), through its subcommittees and working groups, develops and triennially reviews reliability guidelines in accordance with the procedures set forth in the RSTC Charter. Reliability guidelines include the collective experience, expertise, and judgment of the industry on matters that impact bulk power system (BPS) operations, planning, and security. Reliability guidelines provide key practices, guidance, and information on specific issues critical to promote and maintain a highly reliable and secure BPS.

Each entity registered in the NERC compliance registry is responsible and accountable for maintaining reliability and compliance with applicable mandatory Reliability Standards. Reliability guidelines are not binding norms or parameters; however, NERC encourages entities to review, validate, adjust, and/or develop a program with the practices set forth in this guideline. Entities should review this guideline in detail and in conjunction with evaluations of their internal processes and procedures; these reviews could highlight that appropriate changes are needed, and these changes should be done with consideration of system design, configuration, and business practices.

Executive Summary

Interconnection queues across North America are seeing a rapid influx of requests for battery energy storage systems (BESSs) and hybrid power plants.[1] While there are different types of energy storage technologies, BESSs are experiencing a rapid increase in penetration levels due to favorable economics, policies, and technology advancements.[2] Similarly, BESSs are most commonly being coupled with inverter-based generating resources such as wind and solar photovoltaic (PV). Therefore, BESSs and inverter-based hybrid power plants are the primary focus of this reliability guideline.

NERC previously published a reliability guideline outlining the recommended performance for BPS-connected inverter-based resources.[3] The guidance provided in that document included BESSs as an inverter-based technology; however, there are certain considerations and nuances to the operation of this technology that warrant additional guidance. Hybrid plants also pose new benefits to the BPS by combining operational capabilities across different technologies; however, there are different types of hybrid configurations (ac-coupled versus dc-coupled) and complexities and unique operational considerations of hybrid plants that need additional guidance as well. This reliability guideline provides the clarifications and considerations that were not covered in the initial NERC guidance specifically focused on BESSs and hybrid power plants. NERC also published a reliability guideline in September 2019 recommending all Transmission Owners (TOs), Transmission Planners (TPs), and Planning Coordinators (PCs) to improve their interconnection requirements and planning processes for newly interconnecting inverter-based resources. That guidance also pertained to BESS and hybrid power plants yet was not specifically addressed in detail. Therefore, the guidance contained in the materials presented in this document should also be used by TOs, TPs, and PCs to further enhance their interconnection requirements and study processes for BESSs and hybrid power plants.

The recommendations in this guideline should apply to all BPS-connected BESSs and hybrid plants, and should not be limited only to Bulk Electric System (BES) facilities. Many newly interconnecting BESS projects and hybrid plants may not meet the BES definition; however, having unified performance and behavior from all BPS-connected inverter-based resources (including BESSs and hybrid plants) is important for reliable operation of the North American BPS. The IEEE P2800 project is currently developing "interconnection capability and performance criteria for inverter-based resources interconnected with transmission and networked sub-transmission systems" that will also apply to BESSs and hybrid power plants.[4] Where any potential overlap exists, the guidance in this reliability guideline should be considered by applicable entities until IEEE P2800 is approved and fully implemented by industry.

This Reliability Guideline includes the recommended performance of BPS-connected BESSs and hybrid power plants, which should be considered by all Generator Owners (GOs) and developers seeking interconnection to the BPS. These performance recommendations can also be used by TOs, TPs, and PCs to improve their interconnection requirements and study processes for these facilities. This reliability guideline also covers recommended modeling and study practices that should be considered by TPs and PCs as they perform planning assessments with increasing numbers of BESSs and hybrid power plants both in the interconnection study process, annual planning process, and for any specialized studies needed to ensure BPS reliability.

High-Level Recommendations

This Reliability Guideline contains detailed recommendations regarding BESS and hybrid power plant performance, modeling, and studies. Industry is strongly encouraged to review the guidance provided, use the technical details and reference materials provided, and adapt the recommendations provided for their specific processes and practices.

[1] A hybrid power plant is defined herein as "a generating resource that is comprised of multiple generation or energy storage technologies controlled as a single entity and operated as a single resource behind a single point of interconnection."

[2] https://www.eia.gov/analysis/studies/electricity/batterystorage/

[3] https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Inverter-Based_Resource_Performance_Guideline.pdf

[4] https://standards.ieee.org/project/2800.html

Table ES.1 provides a set of high-level recommendations (categorized by performance, modeling, and studies), and applicability of the recommendations provided, that encompass all aspects of the guidance contained throughout this Reliability Guideline.

Table ES.1: High-Level Recommendations for BESS and Hybrid Plant Performance, Modeling, and Studies

#	Recommendation	Applicable Entities
A1	**Applicability:** The recommendations in this guideline should be applied to all BPS-connected BESSs and hybrid plants, and should not be limited to only BES facilities. Many newly interconnecting BESSs and hybrid power plants may not meet the BES definition; however, having unified performance and behavior from all BPS-connected inverter-based resources is important for reliable operation of the North American BPS.	TOs, TPs, PCs, BAs, RCs, GOs, GOPs, developers, equipment manufacturers
P1	**BESS and Hybrid Plant Performance:** Equipment manufacturers, developers, and GOs of existing or newly interconnecting BESSs and hybrid power plants should closely review the recommended performance characteristics outlined in this Reliability Guideline and adopt these recommendations into existing and new facilities to the extent possible. Newly interconnecting GOs of BESSs and hybrid power plants should work closely with their respective TOs, Balancing Authorities (BAs), Reliability Coordinators (RCs), TPs, and PCs to ensure all entities have an understanding of the operational capabilities and limitations of the facilities being interconnected.	GOs, GOPs, developers, equipment manufacturers
P2	**Interconnection Requirements and Processes:** TOs should update or improve their interconnection requirements to ensure they are clear and consistent for BESSs and hybrid power plants. TPs and PCs should ensure that their modeling requirements include clear specifications for BESSs and hybrid power plants. TPs and PCs should also ensure that their study processes and practices are updated and improved to consider the unique operational capabilities of those facilities.	TOs, TPs, PCs
P3	**Unique Operational Capabilities of BESSs and Hybrid Power Plants:** All applicable entities should consider the detailed guidance contained in this guideline and fully utilize the operational capabilities of these new technologies to support reliable operation of the BPS. New capabilities such as grid forming technology, operation in low short-circuit networks, ability to provide primary and fast frequency response, and other functions more readily available in these new technologies should be fully utilized and are essential reliability services for the BPS.	TOs, TPs, PCs, BAs, RCs, GOs, GOPs, developers, equipment manufacturers
M1	**Models Matching As-Built Controls, Settings, and Performance:** All applicable entities should ensure that the models used to represent BESSs and hybrid power plants match the controls, settings, and performance of the equipment installed in the field. This requires concerted focus by the GO, developer, and equipment manufacturer during the study and commissioning process as well as more rigorous verification and testing by the TP and PC throughout.	TPs, PCs, GOs, developers, equipment manufacturers
M2	**Use of Appropriate Models:** All BESS and hybrid power plant GOs, developers, and equipment manufacturers need to ensure that the dynamic models used to represent the facility are suitable to represent the dynamic response and behavior of the resource installed in the field. This may include representation using standardized library models, detailed user-defined models, as well as electromagnetic transient (EMT) models. All TPs and PCs should ensure their modeling requirements and processes clearly define the types of models that are acceptable, the level of detail expected for each model, and benchmarking between models required during the planning study process. GOs, GOPs, and developers of each BESS and hybrid power plant should verify, in coordination with their TP, PC, and equipment manufacturer, that the dynamic models fully represent the expected behavior of the as-built facility.	TPs, PCs, GOs, GOPs, developers, equipment manufacturers

Table ES.1: High-Level Recommendations for BESS and Hybrid Plant Performance, Modeling, and Studies		
#	**Recommendation**	**Applicable Entities**
M3	**Software Enhancements:** The technological advancement of BESS and hybrid plant controls is outpacing the capabilities available in the standardized library models. Simulation software vendors should work with BESS and hybrid plant inverter and plant-level controller manufacturers to develop more flexible dynamic models to represent these facilities. Software developers should be proactive in addressing modeling challenges faced by TPs and PCs in this area, particularly as the number of these types of resources rapidly increases in interconnection-wide base cases. Software vendors should support the advancement of using “real-code” models or other user-defined models in a manner that does not degrade or limit the quality and fidelity of the overall interconnection-wide base case. Software vendors should consider adding model validation, verification, quality review, and other screening tools to their programs to support TP and PC review of model quality. Lastly, software vendors should improve the steady-state model representation of hybrid plants such that engineers are not required to use workarounds such as modeling two separate units to represent a single hybrid plant.	Simulation software vendors, equipment manufacturers
S1	**Study Process Enhancements:** TPs and PCs should improve their study processes for both interconnection studies and annual planning studies to ensure they are appropriate for a BPS with significantly more BESSs and hybrid power plants. Determination of stressed operating conditions, selection of study assumptions, inclusion of various modeling practices, and determination of appropriate dispatch conditions are just a few areas where close attention will be needed by TPs and PCs to ensure their study approaches align with the new technologies.	TPs, PCs
S2	**Expansion of Study Conditions:** The variability and uncertainty of renewable energy resources has led TPs and PCs to study different expected operating conditions than were previously used for planning assessments. BESSs and hybrid plants may help address some of the operational variability; however, developing suitable and reasonable study assumptions will become a significant challenge for future planning studies. TPs and PCs may need to expand the set of study conditions used for future planning assessments as the most severe operating conditions may change over time.	TPs, PCs

Introduction

The North American generation mix like many areas around the world is trending towards increasing amounts of inverter-based resources, most predominantly wind and solar PV resources. According to the U.S. Energy Information Administration (EIA) Annual Energy Outlook 2020,[5] wind power capacity in the United States more than doubled in the past decade (39.6 GW in 2010 to 107.4 GW in 2019) and solar generation multiplied by 25x from 2.7 GW in 2010 to 67.7 GW in 2019. Wind and solar generation supplied nearly 7.2% and 2.7% of U.S. energy in 2019, respectively. The EIA and many other organizations have projected continued rapid growth of both technologies over the next several decades. This rapid evolution at both the BPS and distribution system challenges conventional planning and operating practices yet also poses benefits to BPS planning, operations, and design. One of the primary challenges is the variability and uncertainty of renewable energy resources, which leads to additional variability and uncertainty in the planning and operations horizons. The need for flexibility coupled with favorable economics has therefore led to an influx of BPS-connected energy storage projects and hybrid power plants using energy storage.[6]

Areas across North America are also seeking low-carbon power systems. For example, California requires[7] by the end of 2045 that eligible renewable energy resources and zero-carbon resources supply 100% of retail sales of electric energy to California end-use customers and 100% of electric energy procured to serve all state agencies. As such, the California Public Utilities Commission has seen a surge of new energy storage contracts, achieved its 2020 energy storage goal of 1,325 MW ahead of time,[8] and is projected to have 55,000 MW of new storage by 2045.[9] At the same time, the risk and impact of wildfires in the region is leading California utilities, policymakers, and end-use customers toward more close consideration for grid resilience and flexibility. Energy storage systems, particularly battery energy storage systems (BESSs), and BESSs coupled with inverter-based resources to create hybrid power plants are providing short-term energy and reliability services including ramping and variability control, voltage and frequency regulation, operation in low short-circuit strength conditions, and other features.

Historically, BESSs have not been a significant factor in planning and operating the BPS; however, interconnection requests and projects being constructed today have scaled up to match the size of solar PV and wind plants. For example, the Gateway Project in the San Diego Gas and Electric area consists of a 250 MW BESS providing energy and ancillary services in the California Independent System Operator (CAISO) market.[10] California recently approved a proposed 1,500 MW battery at Moss Landing.[11] Southern California Edison currently has several hundred megawatts of BESSs deployed in their region with much more in their interconnection queue.[12] Figure I.1 shows a cursory review of the CAISO interconnection queue (captured in early 2020), where

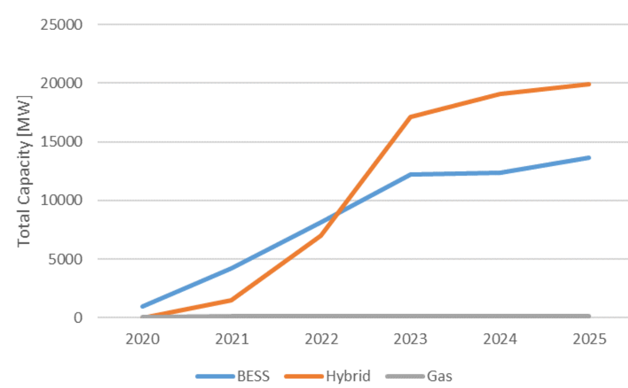


Figure I.1: Review of CAISO Interconnection Queue for Hybrid Resources and BESSs

[5] U.S. Energy Information Administration (EIA), "Annual Energy Outlook 2020 with projections to 2050," Jan. 2020. [Online]. Available: https://www.eia.gov/outlooks/aeo/pdf/aeo2020.pdf.

[6] Hybrid plants combine multiple technologies of generation and energy storage at the same facility, enabling benefits to both the plant and to the BPS. The majority of newly interconnecting hybrid resources are a combination of renewable energy and battery energy storage.

[7] California Senate Bill No. 100: https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201720180SB100.

[8] https://www.cpuc.ca.gov/General.aspx?id=3462.

[9] Phil Pettingill, "Ensuring RA in Future High VG Scenarios – A View from CA", ESIG Spring Workshop. April 10, 2020.

[10] https://www.ferc.gov/CalendarFiles/20180914102642-TX18-2-000.pdf

[11] https://pv-magazine-usa.com/2020/08/13/vistra-approved-to-build-a-grid-battery-bigger-than-all-utility-scale-storage-in-the-us-combined/

[12] https://www.edison.com/home/innovation/energy-storage.html

most new interconnection requests are either stand-alone BESSs or hybrid plants consisting mainly of solar PV or wind combined with a BESS component. Elsewhere, in ERCOT over 1600 MW of BESSs are expected to be in-service by end of 2021.[13] These types of interconnection requests are observed across North America, and these newly connecting resources will need to operate reliably to provide essential reliability services, be modeled appropriately, and also be studied as part of the interconnection study process.

Generation interconnection queues are currently inundated with requests for new interconnections of BESSs and hybrid power plants. TPs and PCs need the capabilities to accurately model and study these resources in the interconnection studies and annual planning processes. While early BESSs were primarily proposed for energy arbitrage and mitigating renewable resource variability, there has been more recent interest in installing BESSs for broader services as a generating resource or even as a source of transmission services such as voltage support under "storage as transmission facility"[14] programs. Therefore, it is imperative to have clear guidance on how BESSs and hybrid power plants should perform when connected to the BPS, and also to have recommended practices for modeling and studying BESSs and hybrid power plants for power flow, stability, short-circuit, and electromagnetic transient (EMT) studies. These types of modeling practices and studies are the primary focus of this guideline.[15]

For the purposes of this guideline, the terms BESS and hybrid plant refer to the resource in its entirety, up to the point of interconnection (POI) including the main power transformers; the terms do not refer only to the individual storage device or converters themselves. As such, both BESSs and hybrid plants are considered inverter-based resources.

Fundamentals of Energy Storage Systems

Energy storage can take many different forms, and some are synchronously connected to the grid while others are connected through a power electronics interface (i.e., inverter-based). Examples of different energy storage technologies include, but are not limited to, the following:[16]

- **Battery Energy Storage:** There are many types of battery energy storage systems (BESSs) – lithium-ion, nickel-cadmium, sodium sulfur, redox flow, and other types of batteries.[17] Batteries convert stored chemical energy to direct current (dc) electrical energy, and vice versa. Power electronic converters (i.e., inverters) are used to connect the battery to the alternating current (ac) power grid.

- **Pumped Hydroelectric Storage:** Pumped hydroelectric power is one of the most mature and commonly used large-scale electric storage technologies today. Water flowing through a hydroelectric turbine-generator produces electric energy to be used on the BPS. Energy is then stored by sending the water back to the upper reservoir through a pump.

- **Mechanical Energy Storage:** Mechanical systems store kinetic or gravitational energy for later use as electric energy. An example of mechanical energy storage includes flywheels that accelerate a rotor to very high speed and maintain rotational energy using the inertia of the flywheel, which can then be delivered to the grid when needed.

- **Hydrogen Energy Storage:** Hydrogen energy storage involves the separation of hydrogen from some precursor material such as water or natural gas and storage of the hydrogen in vessels ranging from

[13] http://www.ercot.com/content/wcm/lists/197386/Capacity_Changes_by_Fuel_Type_Charts_October_2020.xlsx

[14] https://cdn.misoenergy.org/20190109%20PAC%20Item%2003c%20Storage%20as%20a%20Transmission%20Asset%20Phase%20I%20Proposal%20(PAC%20004)307822.pdf

[15] Other types of studies such as harmonics and geomagnetic disturbance studies are outside the scope of this guideline.

[16] https://energystorage.org/why-energy-storage/technologies/

[17] https://energystorage.org/why-energy-storage/technologies/solid-electrode-batteries/

pressurized containers to underground salt caverns for later use. The hydrogen can later be used to produce electricity with fuel cells or combined-cycle power plants.[18]

- **Thermal Energy Storage:** Thermal energy storage involves heating or cooling a material with a high heat capacity and recovering the energy later using the thermal gradient between the thermal storage medium and the ambient conditions. For example, electric energy could be used to heat volcanic stones, which can then be converted back to electric energy using a steam turbine.[19] Concentrated solar plants use molten salt as thermal storage medium and steam turbines to convert heat to electric energy.
- **Compressed Air Energy Storage:** Compressed air storage stores energy in the form of pressurized air in a geological feature or other facility. Energy can be delivered back to the grid at a later time, usually by heating the pressurized air and sending it through a turbine to generate power.
- **Supercapacitors:** Supercapacitors are high-power electrostatic devices with fast charging and discharging capability (order of 1-10 seconds) and low energy density. There are no chemical reactions occurring during charging and discharging, which can result in low maintenance costs, long lifetimes, and high efficiency. These devices are scalable, but their fast response can generally not be sustained due to the low energy density.

There are multiple benefits of BPS-connected energy storage systems including, but not limited to, the following:

- Providing balancing and fast-ramping services
- Mitigating transmission congestion
- Enabling energy arbitrage to charge during low price periods and discharge during high price periods
- Providing essential reliability service such as frequency response and dynamic voltage support

Each of the energy storage technologies described can provide benefits to BPS reliability and resilience. As we focus on BESS, the interaction between the battery energy storage device and the electrical grid is dominated by the power electronics interface at the inverter-level and plant controller level, specifically on small time scales (from microseconds to tens of seconds to minutes). This is the primary focus of this guideline, and it also covers ways that industry can model and study BESSs connecting to the BPS.

Fundamentals of Hybrid Plants with BESS

Hybrid power plants are also becoming increasingly popular due to federal incentives, cost savings, flexibility, and higher energy production by sharing land, infrastructure, and maintenance services. Hybrid power plants ("hybrid resources") are defined here as:

> **Hybrid Power Plant (Hybrid Resource):** A generating resource that is comprised of multiple generation or energy storage technologies controlled as a single entity and operated as a single resource behind a single point of interconnection (POI).

There are many types of hybrid power plants that combine synchronous generation, inverter-based generation, and energy storage systems;[20] however, the most predominant type of hybrid power plant observed in interconnection queues across North America is the combination of renewable energy (solar PV or wind) and battery energy storage technologies.[21] Due to this fact, this guideline focuses primarily on hybrid plants combining renewable (specifically inverter-based) generation with BESS technology.

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[18] https://energystorage.org/why-energy-storage/technologies/hydrogen-energy-storage/

[19] https://www.siemensgamesa.com/products-and-services/hybrid-and-storage/thermal-energy-storage-with-etes

[20] Such as natural gas and BESS hybrid plants, combined heat and power with BESS, or multiple types of inverter-based generation technologies.

[21] Note that hybrid natural gas-BESS plants may be desirable in some areas where capacity shortages have been identified.

The conversion of dc to ac current occurs at the power electronics interface. However, the way this conversion occurs within a hybrid plant impacts how the resource interacts with the BPS, its ability to provide essential reliability services, how it is modeled, and how it is studied. Hybrid plants can be classified as either of the following:

- **AC-Coupled Hybrid Plants:** An ac-coupled hybrid power plant couples each form of generation or storage at a common collection bus after it has been converted from dc to ac at each individual inverter. Figure I.3 shows a simple illustration of one possible configuration of an ac-coupled hybrid power plant where a BESS is coupled with a solar PV or wind power plant on the ac side. The BESS may be charged either from the renewable generating component or from the BPS, if appropriate contracts and rates are available.
- **DC-Coupled Hybrid Plants:** A dc-coupled hybrid power plant couples both sources at a dc bus tied to the grid via a dc-ac inverter. There are often dc-dc converters between the individual units and the common dc collection bus. Figure I.4 shows a simple illustration of one possible configuration of a dc-coupled hybrid power plant, where the energy storage component is coupled through a dc-dc converter on the dc side. The dc-ac inverter can be unidirectional where the BESS can only be charged from the renewable resource or bi-directional where the BESS can also be charged from the BPS (depending on interconnection requirements and agreements).[22] There are multiple different possible configurations for dc-coupled facilities, particularly on the dc-side between the generating resource, the BESS, and ways they connect through the ac-dc inverter.[23]

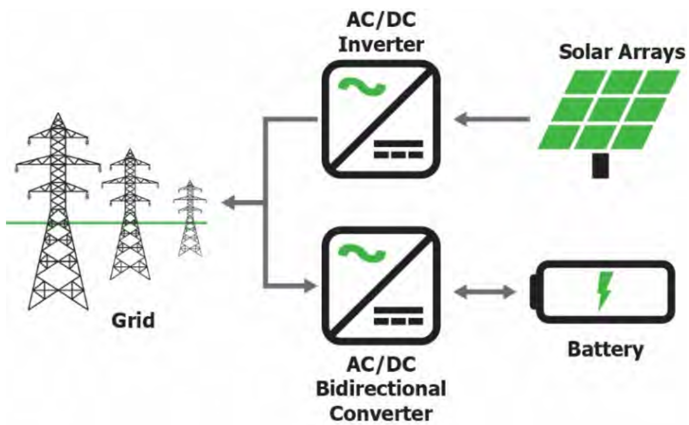
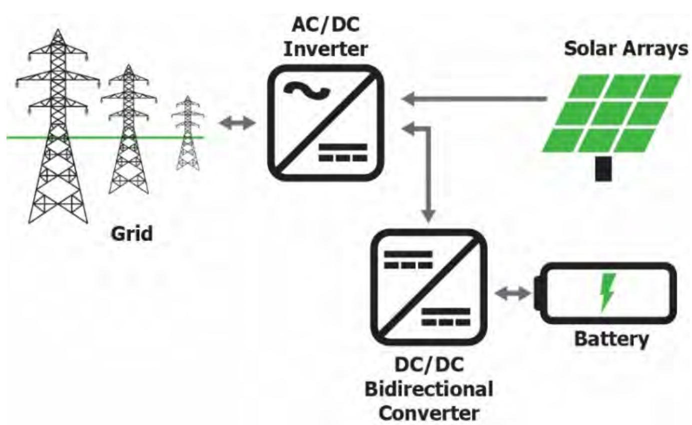


Figure I.3: Illustration of AC-Coupled Hybrid Plant



[22] ERCOT has drafted a concept paper specifically on DC-coupled resources, which may be a useful reference: http://www.ercot.com/content/wcm/key_documents_lists/191191/KTC_11_DC_Coupled_2-24-20.docx

[23] https://www.dynapower.com/products/energy-storage-solutions/dc-coupled-utility-scale-solar-plus-storage/

Figure I.4: Illustration of DC-Coupled Hybrid Plant

Different technologies may deploy ac- and dc-coupled systems for different reasons. For example, it may be economical for a solar PV and BESS system to be coupled on the dc-side whereas it may be more cost effective for wind turbine generators to be coupled with a BESS on the ac-side. Each newly interconnecting hybrid will have its reasons for using ac- or dc-coupled technology, which ultimately comes down to which configuration provides the most value for the given installation.

Hybrid plants combine many of the benefits of stand-alone BESSs with renewable energy generating resources, including but not limited to the following:[24]

- **Cost Efficiencies:** Integrating different technologies at the same location enables a developer to save on shared electrical, controls, and communications equipment; simplifies siting; allows for shared personnel; improves maintenance schedules; reduces electrical losses associated with ac/dc conversion efficiency (i.e., dc-coupled); and saves on other relevant operational costs.
- **Reduced Interconnection Costs:** In some cases, adding a battery that can charge and discharge on command can reduce interconnection costs for a renewable generator by avoiding overloads on existing transmission equipment or addressing reliability needs that may have required new transmission equipment.
- **Energy Arbitrage:** The storage element in a hybrid plant can be used to charge during low-priced hours and discharge during high-priced hours, shifting energy production to those hours where energy is needed. Current arbitrage for hybrids (and BESSs) is on the order of hours and days; future technologies may be able to further shift energy storage and production based on system needs.
- **Excess Energy Harvesting:** Hybrid plants have the added benefit of being able to capture any excess solar or wind production that would otherwise be lost or "clipped" (e.g., due to curtailment or oversizing of PV panels compared to inverter size). Capturing excess energy increases plant capacity factor, enabling it to continue operating when the generating resource output decreases.
- **Frequency Response Capability:** Most renewable energy resources (i.e., wind and solar PV) operate at maximum available power since they have a very low marginal cost of energy compared with other resources (due to fuel cost). There are presently few market-based mechanisms to permit or incentivize these resources to offer services that require them to operate at a reduced power output. Therefore, because these resources are usually already fully dispatched for their energy, they typically do not have the operational ability (i.e., headroom) to increase power output during underfrequency conditions. Adding energy storage to a renewable facility can enable the ability to respond to underfrequency events while still operating the renewable component at maximum available power (given appropriate interconnection practices and agreements). Addition of storage to a synchronous generator may also allow the hybrid plant to deliver fast frequency response.[25] The energy storage component can initially charge or discharge rapidly while the synchronous generator turbine-governor provides a slower, longer-term sustained response.
- **Reduce Generating Fleet Variability:** As higher penetrations of renewable energy resources enter the BPS, higher levels of uncertainty and variability are occurring. This requires additional flexibility in resources. Hybrid plants, with the BESS component, can be a significant source of fast and flexible energy.

[24] The benefits noted are also generally applicable to stand-alone energy storage devices such as BESSs; the benefits noted here focus on how addition of a BESS to a traditional renewable energy generating project can improve the operational capabilities and flexibility of the resource.
[25] In ERCOT, a BESS was added to a quick-start combustion turbine for participation in ERCOT's Responsive Reserve Service. The combustion turbine is normally offline, and if frequency falls outside of a pre-defined deadband, the BESS will provide fast frequency response until the combustion turbine is turned on to sustain the provided response.

Co-Located Resources versus Hybrid Resources

As described above, a hybrid power plant is "a single generating resource comprised of multiple generation or storage technologies controlled as a single entity and operated as a single resource behind a single POI." Similarly, some transmission entities[26] are differentiating co-located power plants from hybrid plants due to their key differences. Co-located power plants can be defined as:

> **Co-Located Power Plants (Co-Located Resources):** Two or more generation or storage resources that are operated and controlled as separate entities yet are connected behind a single point of interconnection.

The key difference here is that the units are operated independently from one another even though they may be electrically connected identically to a hybrid resource. This distinction is important when considering how and when these resources will operate, as well as how to model and study these resources in operations and planning assessments.

[26] http://www.caiso.com/InitiativeDocuments/RevisedStrawProposal-HybridResources.pdf
http://www.caiso.com/Documents/IssuePaper-HybridResources.pdf

Chapter 1: BPS-Connected BESS and Hybrid Plant Performance

BESSs and hybrid plants have similar recommended performance to other BPS-connected inverter-based resources (e.g., wind and solar PV plants). However, there are unique operational and technological differences that need to be considered when describing the recommended performance for these facilities. The NERC *Reliability Guideline: BPS-Connected Inverter-Based Resource Performance*[27] provided a foundation of recommended performance for BPS-connected inverter-based resources, including BESSs and hybrid plants; however, it did not go into the technical details for these resources. This chapter describes in more depth the specific technological considerations that should be made when describing the recommended performance for these resources.

Key Takeaway:
Until the publication and widespread adoption of future IEEE Standard 2800 (being developed by the IEEE P2800 project), TOs, TPs, and PCs are strongly encouraged to improve their interconnection requirements and study processes by adopting and integrating the recommended performance characteristics outlined in this guideline.

The IEEE P2800 effort currently underway to standardize the performance of newly-interconnecting inverter-based resources, including BESSs and hybrid plants, will likely address many of these issues. However, in the meantime, TOs, TPs, and PCs are strongly encouraged to improve their interconnection requirements and study processes by adopting and integrating the recommended performance characteristics outlined in this guideline.

Recommended Performance and Considerations for BESS Facilities

Table 1.1 provides an overview of the considerations that should be made when describing the recommended performance of BESS facilities compared with other BPS-connected inverter-based generating resources. The following sub-section elaborates on these high-level considerations in more detail.

Table 1.1: High Level Considerations for BESS Performance

Category	Specifications and Comparison with BPS-Connected Inverter-Based Generators
Momentary Cessation	No significant differences from other BPS-connected inverter-based generating resources; momentary cessation should not be used to greatest possible extent[28] during charging and discharging operation.
Phase Jump Immunity	No significant difference from other BPS-connected inverter-based generating resources.
Capability Curve	The capability curve of a BESS extends into both the charging and discharging regions to create a four-quadrant capability curve. The shape of many individual BESS inverter capability curves is almost[29] symmetrical for charging and discharging. From an overall plant-level perspective, the capability curves may be asymmetrical. System-specific requirements may not necessitate the use of the full equipment capability; however, the resources should not be artificially limited from providing its full capability (particularly reactive capability) to support reliable operation of the BPS.

[27] https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Inverter-Based_Resource_Performance_Guideline.pdf
[28] Unless there is an equipment limitation or a need for momentary cessation to maintain system stability. The former has to be communicated by the GO to the TP while the latter has to be validated by extensive studies.
[29] The capability curve is almost symmetrical because when the BESS is operated in the second and third quadrant (consuming active power), a rise in dc voltage could limit the amount of power generation where reactive power also has to be consumed.

Table 1.1: High Level Considerations for BESS Performance

Category	Specifications and Comparison with BPS-Connected Inverter-Based Generators
Active Power-Frequency Controls	Active power-frequency controls can be extended to the charging region of operation for BESSs. The conventional droop characteristic can be used in both discharging and charging modes. Further, a droop gain[30] and deadband should be used in both operating modes, and there should be a seamless transition between modes (i.e., there should not be a deadband in the power control loop for this transition), unless interconnection requirements or market rules preclude such operation. As with all resources, speed of response[31] of active power-frequency control to support the BPS should be coordinated with system needs. The fast response of BESSs to frequency deviations can provide reliability benefits. Consistent with FERC Order 842, there should be no requirement for BESS resources to provide frequency response if the SOC is very low or very high (which may be specified by the BA), though that service can be procured by the BA.
Fast Frequency Response (FFR)	BESSs are well-positioned for providing FFR to systems with high rate-of-change-of-frequency (ROCOF) due to not having any rotational components (similar to a solar PV facility). The need for FFR is based on each specific Interconnection's need.[32] Sustained forms of FFR help arrest fast frequency excursions but also help overall frequency control. BESSs are likely to be able to provide sustained FFR within their state of charge constraints. With the ability for BESSs to rapidly change MW output across their full charge and discharge ranges (within SOC limits), BPS voltage fluctuations should be closely monitored especially on systems with lower short-circuit ratios.
Reactive Power-Voltage Control	BESSs should be configured to provide dynamic voltage control during both discharging and charging operations to support BPS voltages during normal and abnormal conditions. TOPs should provide a voltage schedule (i.e., a voltage set point and tolerance) to all BESSs, applicable to both operating modes.
Reactive Current-Voltage Control	No significant difference from other BPS-connected inverter-based generating resources. BESSs should be configured to provide dynamic voltage support during large disturbances both while charging and discharging.
Reactive Power at No Active Power Output	No significant difference from other BPS-connected inverter-based generating resources.
Inverter Current Injection during Fault Conditions	BESSs should be configured to provide fault current contribution during large disturbance events that can support legacy BPS protection and stability.[33] Inverter limits will need to be met, as with all inverter-based resources; however, SOC may not be an issue for providing fault current for BESSs since faults are typically cleared in fractions of a second. Additionally, limits on dc voltage magnitude can apply.

[30] Droop should be set using the same base for both charging and discharging mode of operation (e.g., rated active power, P_{max}), so that the same rate of response is provided regardless of charging or discharging.

[31] Speed of response is dictated by the controls programmed into the inverter-based resource (most commonly in the plant-level controller), which is a function of the time constants and gains used in the proportional-integral controls as well as the droop characteristic.

[32] NERC, "Fast Frequency Response Concepts and Bulk Power System Reliability Needs," March 2020: https://www.nerc.com/comm/PC/InverterBased%20Resource%20Performance%20Task%20Force%20IRPT/Fast_Frequency_Response_Concepts_and_BPS_Reliability_Needs_White_Paper.pdf

[33] Large disturbance fault current contribution from inverter-based resources can help ensure BPS protection schemes operate appropriately by ensuring they have appropriate voltage-current relationships of magnitude and phase angles (i.e., appropriate positive and negative sequence current injection).

Table 1.1: High Level Considerations for BESS Performance	
Category	**Specifications and Comparison with BPS-Connected Inverter-Based Generators**
Return to Service Following Tripping	BESSs should return to service following any tripping or other off-line operation by operating at the origin (no significant exchange of active or reactive power with the BPS), and then ramp back to the expected power output. This is a function of plant settings and interconnection requirements set by the BA or TO.
Balancing	No significant difference from other BPS-connected inverter-based generating resources. The capability to provide balancing services for the BPS should be available from all BESSs. BAs, TPs, PCs, and RCs should ensure requirements are in place for appropriate balancing of the BPS.
Monitoring	No significant difference from other BPS-connected inverter-based generating resources.
Operation in Low Short-Circuit Strength Systems	No significant difference from other BPS-connected inverter-based generating resources. BESSs should utilize grid forming operation, as appropriate (see below), to support BPS stability and reliability in low short-circuit strength operating conditions.
Grid Forming	BESSs have the unique capabilities to effectively deploy grid forming technology to help improve BPS reliability in the future of high penetration of inverter-based resources. Key aspects that enable this functionality include availability of an energy buffer to be deployed for imbalances in generation and load, low communication latency between different layers of controllers, and robust dc voltage that enables synthesis of an ac voltage for a wide variety of system conditions. In grids where system strength and other stability issues are of concern, BESSs may be required to have this capability to support reliable operation of the BPS. TPs and PCs should develop interconnection requirements and new practices, as needed, to integrate the concepts of grid forming technology into the planning processes.
Fault Ride-Through Capability	No significant difference from other BPS-connected inverter-based generating resources. BESSs should have the same capability to ride through fault events on the BPS, when point of measurement (POM) voltage and frequency is within the curves specified in the latest effective version of PRC-024.[34] This applies to both charging and discharging modes; unexpected tripping of generation or load resources on the BPS will degrade system stability and adversely impact BPS reliability. Ride-through capability is a fundamental need for all BPS-connected resources such that planning studies can identify any expected risks. However, the behavior during ride-through while discharging and charging may be different.
System Restoration and Blackstart Capability	BESSs may have the ability to form and sustain their own electrical island if they are to be designated as part of a blackstart cranking path. This may require new control topologies or modifications to settings that enable this functionality. Blackstart conditions may cause large power and voltage swings that must be reliably controlled and withstood by all blackstart resources (i.e., operation under low short circuit grid conditions). For BESSs to operate as a blackstart resource, assurance of energy availability as well as designed energy rating that ensures energy availability for the entire period of restoration activities is required. At this time, it is unlikely that most legacy BESSs can support system restoration activities as a stand-alone resource; however, they may be used to enable start-up of subsequent solar PV, wind, or synchronous machine plants.

[34] Unless there is an equipment limitation, which has to be communicated by the GO to the TP.

Table 1.1: High Level Considerations for BESS Performance	
Category	**Specifications and Comparison with BPS-Connected Inverter-Based Generators**
Protection Settings	No significant difference from other BPS-connected inverter-based generating resources.
State of Charge *(new)*	The state of charge (SOC) of a BESS affects the ability of the BESS to provide energy or other essential reliability services to the BPS at any given time.[35] In many cases, the BESS may have SOC limits that are tighter than 0–100%[36] for battery lifespan and other equipment and performance considerations. SOC limits affect the ability of the BESS to operate as expected, and any SOC limits will override any other ability of the BESS to provide essential reliability services (ERSs) or energy to the BPS. These limits and how they affect BESS operation should be defined by the BESS owner and provided to the BA, TOP, RC, TP and PC.
Oscillation Damping Support	BESSs can have the capability of providing damping support similarly to synchronous generators and HVDC/FACTS facilities. BPS-connected inverter-based resources could also provide damping support. A major difference from other BPS-connected inverter-based resources is that BESSs can operate in the charging mode in addition to the discharging mode, which provide greater capabilities of damping support.

Topics with Minimal Differences between BESSs and Other Inverter-Based Resources

The following topics have minimal difference between the recommended performance of BESSs and other BPS-connected inverter-based resources:

- **Momentary Cessation:** To the greatest possible extent,[37] BESSs should not use momentary cessation as a form of large disturbance behavior when connected to the BPS. Any existing BESSs using momentary cessation should eliminate its use to the extent possible, and its use for newly interconnecting BESSs should be disallowed by TOs in their interconnection requirements. Sufficiently fast dynamic active and reactive current controls are more suitable.[38] If voltage at the POM is outside the curves specified in the latest effective version of PRC-024, then momentary cessation may be used to avoid tripping of the BESS. However, inside the curves, momentary cessation should not be used, subject to limitations for legacy equipment. This recommendation applies for both charging and discharging operation.
- **Phase Jump Immunity:** Similar to other inverter-based resources, BESSs should be able to withstand all expected phase jumps on the BPS; this applies during both charging and discharging operation. Efforts such as P2800 may help standardize expected thresholds for newly interconnecting inverters to be able withstand in terms of phase jump immunity. In the meantime, the TO should clearly specify what this expectation is so that newly interconnecting projects can test their performance against worst-case expected phase jumps during grid events.
- **Reactive Current-Voltage Control (Large Disturbances):** Fundamentally, there are no significant differences between BESSs and other BPS-connected inverter-based resources with respect to reactive current-voltage control during large disturbances. BESS inverters should maintain stability, adhere to inverter current limits, and provide fast dynamic response to BPS fault events in both charging and discharging modes. Transitions from charging to discharging (e.g., caused by active power-frequency controls) during large disturbances should not impede the BESS from dynamically supporting BPS voltage and reactive current injection. Studies should ensure stable performance for charging and discharging.

[35] https://www.nrel.gov/docs/fy19osti/74426.pdf
[36] Or the values 0% and 100% can simply be defined as the normally allowable range of operation.
[37] Unless there is an equipment limitation or a need for momentary cessation to maintain system stability. The former has to be communicated by the GO to the TP while the latter has to be validated by extensive studies.
[38] In rare cases, momentary cessation may be admissible based on reliability studies performed by the TP and PC on a case-by-case basis.

- **Reactive Power at No Active Power Output:** BESSs should have capability to provide dynamic reactive power to support BPS voltage while not discharging or charging active power. This is one of the benefits of inverter-based technology and can be utilized by grid operators to help regulate BPS voltages. Every BESS should have the capability to perform such operation, and the actual use of such capability should be coordinated with the TOP and RC regarding any voltage regulation requirements and scheduled voltage ranges.
- **Return to Service Following Tripping:** BESSs should adhere to any requirements set forth by its respective BA. In general, following any tripping or other off-line operation, BESSs should return to service starting at their origin point on the capability curve (i.e., operation at no active or reactive power loading) and then ramp to their expected operating point based on recommendations or requirements provided by the BA (or TO in their interconnection requirements).
- **Balancing:** The capability to provide balancing services to the BA for the purposes of ensuring BPS reliability should be available from all BESSs. BAs, TPs, PCs, and other applicable entities should understand what services are being provided from BESSs; however, the capability to providing balancing services to the BA should be available from all BESSs.
- **Monitoring:** BESSs should be equipped with digital fault recorder (DFR), dynamic disturbance recorder (DDR), sequence of events recorder (SER), and harmonics recorder capability.
- **BESS Stability:** Appropriate studies should be conducted to ensure that the BESS will operate stably in its electrical environment and in any of its operating modes. For example, if the short-circuit strength is low, operation of the hybrid resource should be studied in detail by the TP and PC using EMT simulations, as appropriate. Studies should also be conducted to ensure that no instability modes exist at higher frequencies. In addition, the ability of newly interconnecting BESSs to operate with grid forming technology[39] (described below) enable BESSs to operate in very low short-circuit strength networks and further provide BPS support beyond other grid-following inverter-based resources. Refer to recommendations from NERC *Reliability Guideline: BPS-Connected Inverter-Based Resource Performance* as well as NERC *Reliability Guideline: Integrating Inverter-Based Resources into Low Short Circuit Strength Systems*.[40]
- **Fault Ride-Through Capability:** BESSs, like other BPS-connected inverter-based resources, should have the capability to ride through voltage and frequency disturbances when RMS voltage at the POM is within the curves of the latest effective version of PRC-024, subject to limitations for legacy equipment. Ride-through performance requirements should apply to both charging and discharging modes, since unexpected tripping of any generation or load resources on the BPS will degrade system stability and adversely impact BPS reliability. Ride-through capability is a fundamental need for all BPS-connected resources such that planning studies can identify any expected risks.
- **Protection Settings:** Appropriate protections should be in place for BESSs safely and reliably operate when connected to the BPS. Any applicable protection settings should be clearly documented and provided by the BESS owner to the TP, PC, TOP, RC, and BA to ensure all entities are aware of expected performance of the BESS during planning and operations horizons.

Refer to the recommendations outlined in NERC *Reliability Guideline: BPS-Connected Inverter-Based Resource Performance*[41] for more details on each of the aforementioned subjects. The following sub-sections outline the additional topics from Table 1.1 that warrant additional details and where BESSs have specific considerations that need to be taken.

[39] There are different types of control topologies or definitions that could be considered "grid forming". Inverter manufacturers are beginning to offer commercial products that can support the BPS more broadly using these capabilities.
[40] https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Item_4a._Integrating%20_Inverter-Based_Resources_into_Low_Short_Circuit_Strength_Systems_-_2017-11-08-FINAL.pdf
[41] https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Inverter-Based_Resource_Performance_Guideline.pdf

Capability Curve

BESSs are generally four-quadrant devices that extend into the charging region. BESS inverters may be nearly symmetrical[42] (see Figure 1.1). From an overall plant-level perspective, the capability curves may be asymmetrical (see Figure 1.2) and further impacted by collector system losses and any dependencies on external factors such as ambient temperature (if applicable). Capability curves should ensure the capture the gross ratings as well as net rating of the facility that accounts for station service, losses, and other factors. Capability curves for the overall BESS should be provided by the GO to the TO, TP, PC, TOP, and RC to ensure sufficient understanding of the capabilities of the BESS to provide reactive power under varying active power outputs.

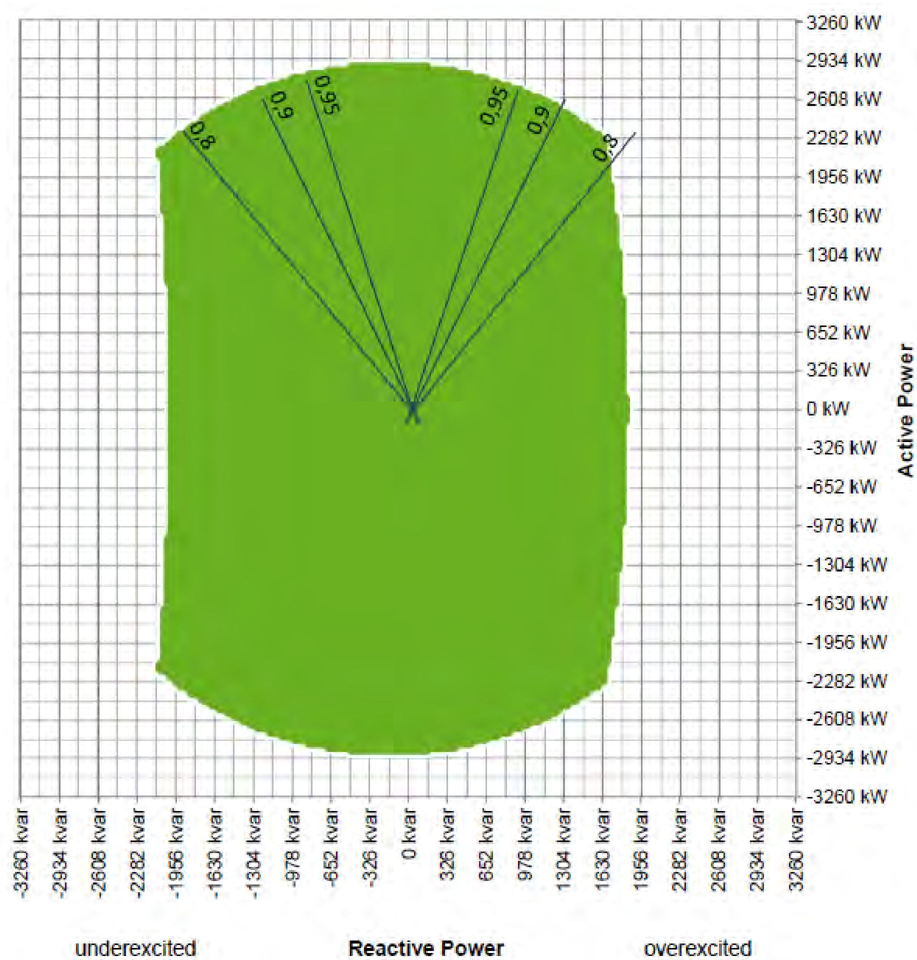


Figure 1.1: Example of 5.3 MVA BESS Capability Curve [Source: SMA America]

[42] Due to effects of BESS dc voltage and inverter derating due to temperature and altitude impacting reactive and active power output.

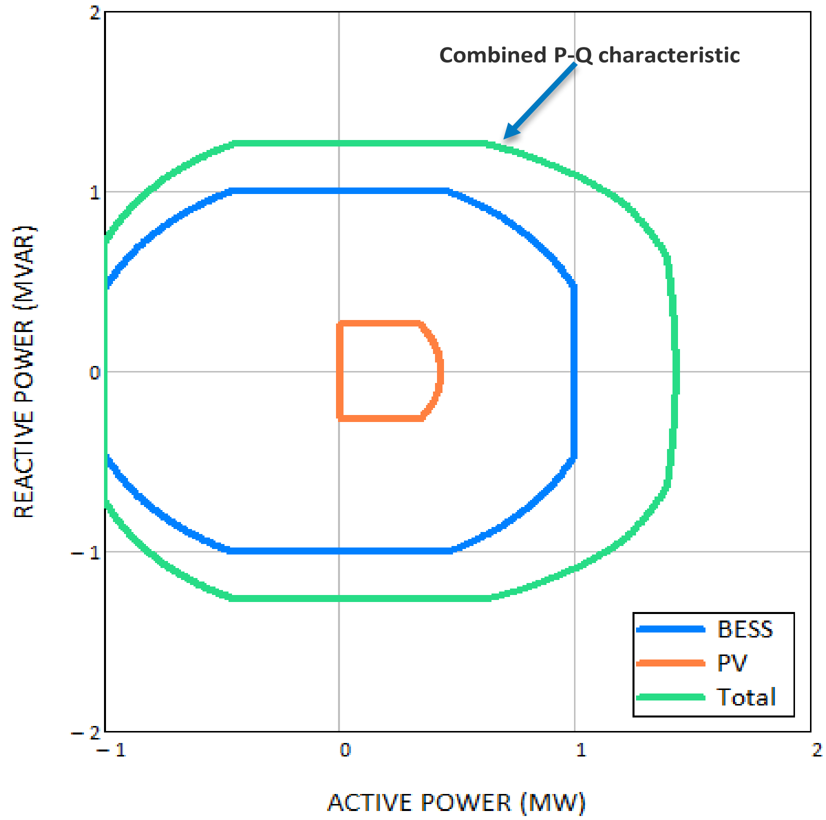


Figure 1.2: Example of AC-Coupled Solar PV + BESS Hybrid Plant Capability Curve [Source: NREL]

Active Power-Frequency Control

BESSs should have the capability to provide active power-frequency control that extends to the charging region. The conventional droop characteristic can be extended into this region, and operation along the droop characteristic can occur naturally. Deadbands, droop settings, and other response characteristics should be specified by the BA based on studies performed by TPs and PCs. The droop characteristic and deadbands should be symmetrical, meaning same settings for charging and discharging modes. Droop should be set using the same base for both charging and discharging mode of operation (e.g. rated active power, P_{max}), so that same rate of response is provided regardless of operation mode (charging/discharging). Any transition between charging and discharging modes of operation should occur seamlessly (i.e., a continuous smooth transition between charging and discharging). The speed of response should also be coordinated with the BA based on primary frequency response needs. Consistent with FERC Order 842, there should be no requirement for BESS resources to maintain a specific SOC for provision of frequency response. Any active power-frequency control should be sustained unless the BESS state of charge limits power consumption or injection from the resource. However, the capacity and energy needed to support interconnection frequency control is relatively small and for short period of time. Sustaining times may be specified by the BA. The number of times active power-frequency controls change power output outside of the defined deadbands will have a small but finite impact on battery lifespan depending of the technology used.

Fast Frequency Response

As the instantaneous penetration of inverter-based resources continues to increase, on-line synchronous inertia may decrease and rate-of-change of frequency (ROCOF) may continue to increase. High ROCOF systems may be faced with the need for faster-responding resources to ensure that unexpected underfrequency load shedding (UFLS) operations do not occur.[43]

BESSs have the capability of providing FFR to counter rapid changes in frequency due to disturbances on the BPS. Similar to solar PV, there are no rotational elements and therefore the active power output is predominantly driven by the controls that are programmed into the inverter. BESSs should have at least the following functional capabilities that may be utilized if the BESS is within SOC and set points limits consistent with FERC Order 842:

- Configurable and field-adjustable droop gains, time constants, and deadbands within equipment limitations; tuned to the requirements or criteria specified by the BA
- Real-time monitoring of BESS SOC to monitor performance limitations imposed on FFR capabilities
- Ability to provide a specified power response for a pre-determined time profile, in coordination with primary frequency response, as defined by the BA

Many different simulations can be performed to show the benefits of utilizing BESSs for improving frequency response, particularly improving the nadir of system frequency following a large loss of generation. Figure 1.3 illustrates one study demonstrating these affects. The blue trace shows the response following a large generation loss for a synchronous-based system. The red plot shows the same system (with same amount of reserves) with the synchronous generation replaced with BESSs (with one option of frequency control enabled). The green plots show the system with BESSs with a different frequency control logic and tuned appropriately. The system dominated by synchronous machines exhibits an initial inertial response followed by a slower turbine-governor response. On the other hand, while the BESS system does not have physical inertia like a synchronous machine, its controls can be tuned to provide a suitably fast injection of energy such that the initial ROCOF remains nearly the same (or even improved) and the frequency nadir is significantly improved. Note that voltages should be monitored closely as high-speed active power responses can cause high-speed voltage fluctuations, especially in low short-circuit-ratio conditions.

[43] https://www.nerc.com/comm/PC/InverterBased%20Resource%20Performance%20Task%20Force%20IRPT/Fast_Frequency_Response_Concepts_and_BPS_Reliability_Needs_White_Paper.pdf

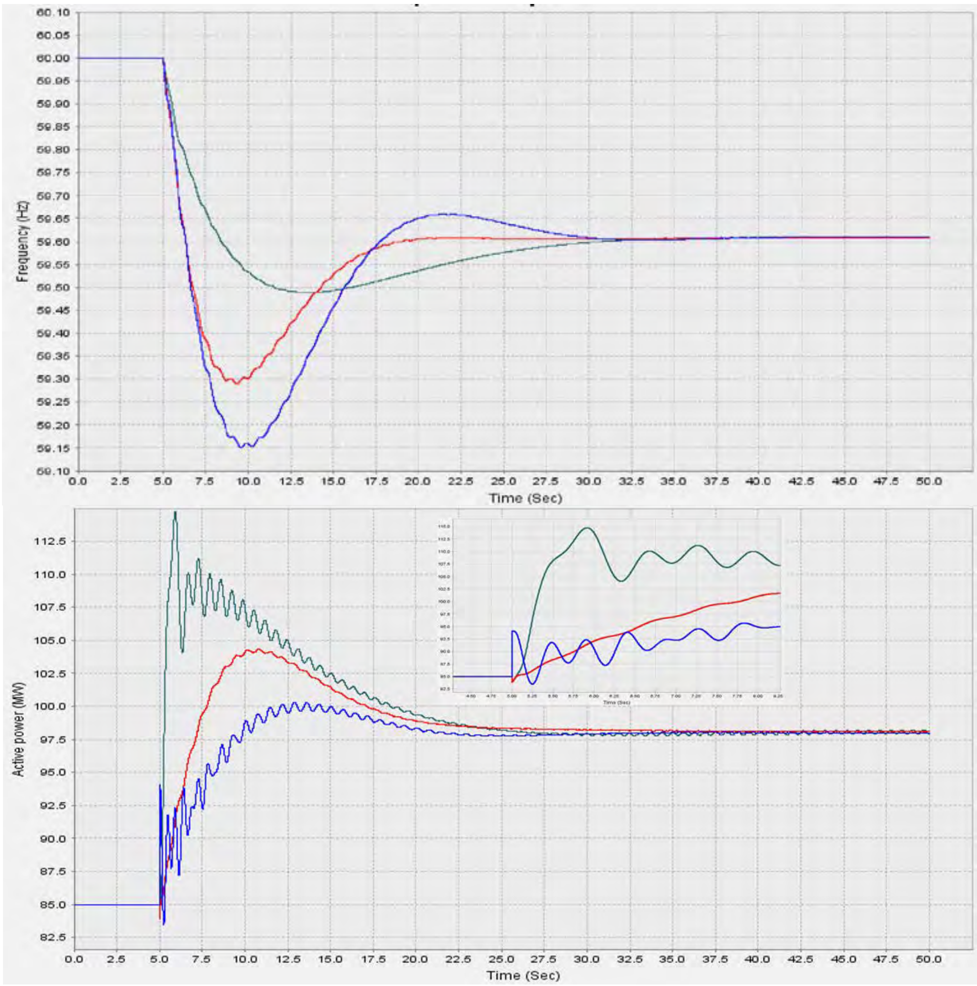


Figure 1.3: Demonstration of Impacts of a BESS on Frequency Response [Source: EPRI]

Reactive Power-Voltage Control (Normal Conditions and Small Disturbances)

BESSs should have the capability to provide reactive power-voltage control in both charging and discharging modes; however, it is useful to separate out the recommendations into each mode of operation:

- **Discharging Operation:** There are no significant differences between BESSs during discharge operation and other BPS-connected inverter-based generators with respect to reactive power-voltage control. BESSs should have the ability to support BPS voltage control by controlling their POM voltage within a reasonable range during normal and abnormal grid conditions. Refer to the recommendations from the NERC *Reliability Guideline: BPS-Connected Inverter-Based Resource Performance*.
- **Charging Operation:** BESSs should have the capability to control POM voltage during normal operation and abnormal small disturbances on the BPS while operating in charging mode. The ability for resources consuming power to support BPS voltage control adds significant reliability benefits to the BPS and may be required by TOs as part of their interconnection requirements or by BAs, TOPs, or RCs for BPS operations.

As the resource transitions from charging to discharging modes of operation (or vice versa) or operates at zero active power output while connected to the BPS, the BESS should have the capability and operational functionality enabled to continuously control BPS voltage. This should be coordinated with any requirements established by the TO or TOP.

Inverter Current Injection during Fault Conditions

BESSs should behave similar to other inverter-based resources during fault conditions in terms of active and reactive current injection. Active and reactive current injection during severe fault events should be configured to support the BPS during and immediately following the fault event such that legacy BPS protection can operate as expected and the BPS can remain stable during and after the event. Inverter-based resources, including BESSs, should ensure that the appropriate voltage-current relationships of magnitude and phase angles (i.e., appropriate positive and negative sequence current injection) are applied. Inverter current limits should be adhered to in order to avoid unnecessary tripping of inverters during fault events. Injection of current during and immediately after faults should be configured to enable the inverter-based resource to remain connected to the BPS and support BPS reliability.

BESSs will need to ensure adherence to SOC limits. BPS fault typically persist for fractions of a second, and SOC should typically not be a concern; however, the SOC limits are always in effect and closely monitored by BESSs. If necessary, it may be possible to reserve a minor amount of energy for transient response to fault conditions.

The reactive current injection during fault conditions while the BESS is charging or discharging will depend on the specific inverter controls and settings as well as the BESS PQ curve and its symmetry. In either case, dynamic reactive current injection should support BPS voltages in both operating states. Further, controls should be configured for each specific installation such that voltage control (i.e., reactive current injection) has priority and the BESS can stably recover active current output very quickly. Typically, this should occur in less than 1 second; however, this will need to be studied by the TP and PC, and configured accordingly.

Grid Forming

Most commercially available inverters currently require an external source to provide a reference voltage to which the inverter phase-locks. These inverters are termed “grid-following”.[44] An alternative option is to control the BESS in a way that it does not rely on external system strength for stable operation (i.e., termed “grid-forming”).[45] While there is currently no standard industry definition for grid forming technology, a broad definition can be:

> **Grid Forming:** An inverter operating mode that enables reliable, stable, and secure operation when the inverter is operating on a part of the grid with few (or zero) synchronous machines along with the possibility of weak or non-existent ties to the rest of the bulk power system.

Four key aspects that enable achieving this operation mode are:

1. Availability of an ‘energy buffer’ to be deployed for imbalances in generation and load
2. Ability of the inverter to contribute towards regulation of voltage and frequency
3. Minimal communication latency between different layers of controllers
4. A robust dc voltage that enables synthesis of an ac voltage for a wide variety of system conditions.

BESSs have these attributes and can effectively employ grid forming technology to improve BPS performance in the future as penetrations of inverter-based resources continues to grow. Operation in grid forming mode may help support BPS reliability and inverter stability during low short-circuit strength conditions. The capability to enable this feature should be provided by all future BESSs and utilized by the TP and PC as a possible solution option if necessary to mitigate reliability issues that would otherwise result in costly reinforcement projects. However, the application

[44] If short-circuit strength falls too low (i.e. the apparent fundamental-frequency impedance of the grid source becomes too high due to high impedance or lack of available fault current), then the sensitivity of the POM voltage to the active and reactive current injection of the inverter-based resource increases and grid-following inverters can be susceptible to instability or control malfunction. There are multiple mitigation options for these low short-circuit strength issues to help stabilize the ac voltage.

[45] https://www.epri.com/research/products/000000003002018676

of grid forming technology is unlikely to be the sole solution that addresses all issues and should be used in coordination with other possible solutions.

Tesla's Grid Forming + Grid Following Philosophy

Tesla BESSs are currently utilizing a concept of "grid forming + grid following" where the BESS is able to provide both functionalities based on BPS reliability needs. When the BESS is operating in virtual machine mode, the dynamics of a virtual synchronous condenser are added to the output of the current-source inverter (see Figure 1.4). In a high short-circuit strength grid, the virtual machine remains naturally inert and preserves the rapid, precisely controllable behaviors of traditional inverter controls. On a lower short-circuit strength grid, the machine model reinforces grid strength by providing sub-cycle phase response, voltage stability, and fast fault current injection that helps in smooth transitions between different operating states. With such a hybrid approach, the BESS remains responsive to active and reactive power dispatch commands while providing essential reliability services to the BPS during dynamic grid events. While there are many possible ways to accomplish grid forming capabilities, Tesla has implemented this feature into its products in an effort to support BPS operation with decreased inertia and overall system strength.

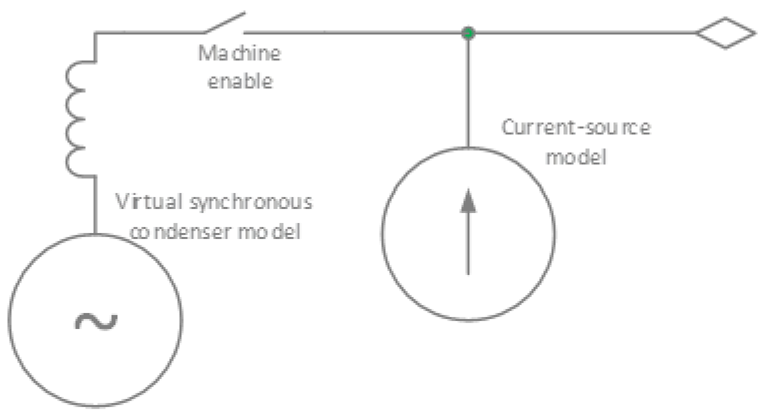


Figure 1.4: Concept of Tesla "Grid Forming + Grid Following" Mode [Source: Tesla]

System Restoration and Blackstart Capability

In the event of a large-scale outage caused by system instability, uncontrolled separation, or cascading, system operators are tasked with executing blackstart plans to re-energize the BPS and return electric service to all customers. This process is relatively slow as the blackstart plan identifies the boundaries of outage conditions, system elements, critical loads, etc.; reconnects pre-defined generators and load points to the overall BPS; and carefully resynchronizes regions or portions of the BPS. Throughout this entire process, grid operators are closely balancing generation and demand as well as managing BPS voltages within operating limits. In order to actively participate in blackstart and system restoration, a BESS will need to:

- Generate its own voltage and seamlessly synchronize to other portions of the BPS.
- Stably operate during large frequency, voltage, and power swings, and reliably operate in low short-circuit strength networks. Detailed EMT studies demonstrating the ability to operate under these conditions should be conducted.
- Provide sufficient inrush current to energize transformers and transmission lines and start electric motors. Note that BESSs, like other inverter-based resources, have limited ability to provide high levels of inrush current. This necessitates the need to coordinate the BESS resource with the blackstart load.

- Have assurance that the BESS will be available immediately after a large-scale outage requiring system restoration activities. BESSs will need to demonstrate to their RC and TOP they can be available at any point in time to be considered as a blackstart resource.
- Have sufficient energy to remain on-line and operational for the time required to ensure blackstart plans can be fully executed.[46] Therefore, BESS energy ratings should be designed to achieve the required time frames. And their states of charge should be maintained above a limit to ensure enough energy is available for blackstart purposes.
- Be able to quickly respond to and control fluctuations in system voltage and frequency.
- Be able to start rapidly to minimize system restoration times.
- Have redundancy to self-start in the event of any failures within the facility.
- In order to ensure proper integration into the overall system blackstart scheme and coordination between resources via appropriate engineering studies, all control design, settings, configurable parameters, and accurate models should be made available to the BA, TP, PC, TOP, and RC.
- Have remote startup and operational control capabilities to avoid requiring dispatch of personnel to the field.

State of Charge

State of charge (SOC) represents the present level of charge of an electric battery relative to its capacity, within the range of fully discharged (0%) to fully charged (100%). Refer to the description of FERC Order No. 841 in Appendix A. The SOC of a BESS affects the ability of the BESS to provide energy or other essential reliability services to the BPS at any given time.[47] In many cases, the BESS may have SOC limits that are tighter than 0–100% for battery lifespan and other equipment and performance considerations. Alternatively, 0% and 100% may be defined as the normal range of operation, ignoring the extreme-but-not-recommended charge and discharge levels.

In terms of performance, the following should be considered for capability and operation of a BESS:

- **Provision of ERSs to the BPS:** All BESSs should have the capability to provide ERSs such as voltage support, frequency response, and ramping capabilities to support BPS operation. However, each BESS will be configured to provide any one or multiple ERS during on-line operation, based on real-time dispatch, SOC, and system needs.
- **Nearing SOC limits:** As a BESS approaches its SOC limits, the BESS will ramp down its charging or discharging. This ramp should be clearly defined by the owner of the BESS and communicated to the BA, TOP, and RC.
- **SOC Limits and Frequency Response:** Consistent with FERC Order 842, there should be no requirement for BESS resources to maintain a specific SOC for provision of frequency response.
- **SOC Limits and Reactive Power Support:** Through the full range of SOC limits (SOC_{min} to SOC_{max}), the BESS should be designed to provide full reactive power capability as required by the interconnection agreement. SOC limits should not impact reactive power capability.
- **SOC Limits and Blackstart Capabilities:** SOC should be maintained above a limit to ensure there is energy to fully execute a blackstart process as designed.

SOC limits affect the ability of the BESS to operate as expected, and any SOC limits will override any other ability of the BESS to operate. These limits and how they affect BESS operation should be defined by the BESS owner and

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[46] This is defined by the TOP and RC. For example, PJM has requirements for blackstart resources to be operational for 16 hours: http://www.pjm.com/-/media/markets-ops/ancillary/black-start-service/pjm-2018-rto-wide-black-start-rfp.ashx?la=en
[47] https://www.nrel.gov/docs/fy19osti/74426.pdf

provided to the BA, TOP, and RC. For planning assessments, this information is also important to the TP and PC as they establish planning cases.

The SOC of any BESS depends on the past operating conditions of the BESS and the services it is providing to the BPS. To study BESS SOC, a time series (or quasi-dynamic) study can be used. Figure 1.5 shows an example of a BESS providing two services: peak shaving (charging in morning and discharging at night) and transmission line congestion management around a set of wind power plants. The magnitude and duration of any other service provided by the BESS (such as voltage control or frequency support capability) revolves around the two primary services. Figure 1.5 shows the evolution of the BESS SOC over two days, evaluated at half-hour time steps but with tracking of the dynamic evolution of the SOC.

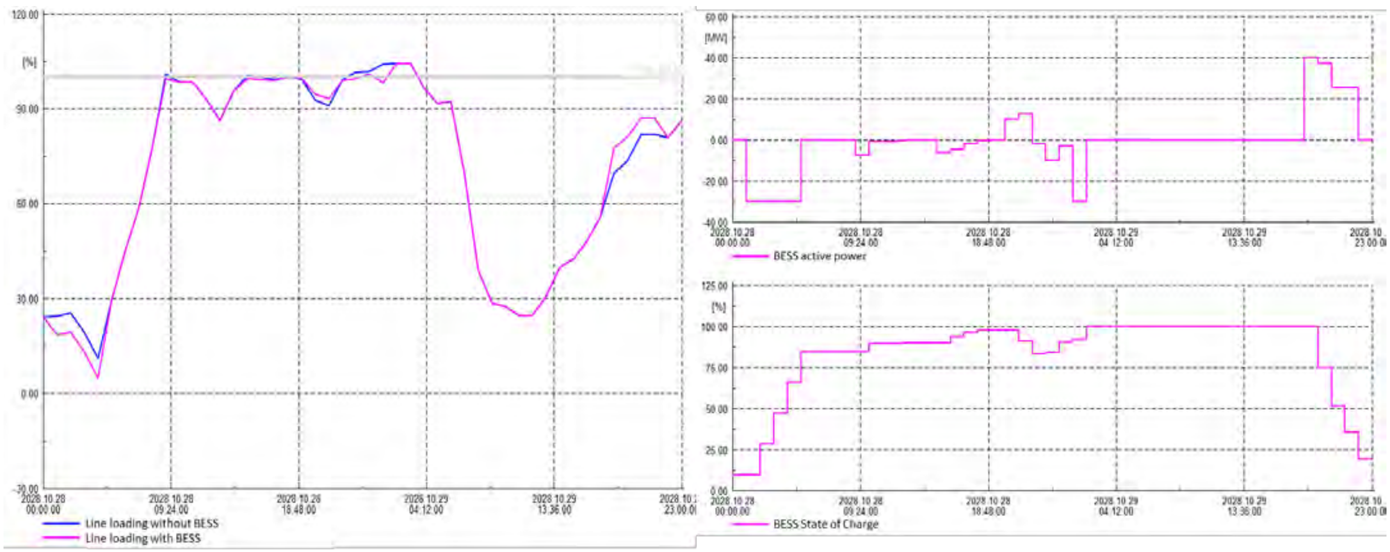

Figure 1.5: Example Time Series of BESS State of Charge [Source: EPRI]

The assumption used in dynamic stability simulations is that SOC will not affect or limit the response of the BESS for short-duration events (i.e., faults or short-term frequency excursions). However, longer-term issues such as thermal overload mitigation may require more extensive information regarding BESS SOC. BESS manufacturers establish a full operating range of the batteries (i.e., 0-100% SOC); however, the equipment manufacturer may establish a tigher range (e.g., 5-95% SOC) as the full operating range and this information may be provided to the GO or developer. The full operating range of the BESS should be provided to the RC, TOP, BA, TP, and PC for inclusion in tools and studies. It is important that the SOC base value (i.e., what establishes the operational 0-100% SOC) be well-defined by the appropriate entities.

Oscillation Damping Support

Many synchronous generators are equipped with power system stabilizers (PSSs) that provide damping to system oscillation typically in the range of 0.2 Hz to 2 Hz. As these resources become increasingly limited (either retire or are off-line during certain hours of the day), there is a growing need for oscillation damping support in certain parts of the BPS. For example, in the West Texas area of the ERCOT footprint where significant amounts of renewable generation resources connect, synchronous generators in West Texas may be off-line under high renewable output condition and could lead to insufficient damping support required to maintain stability for high power long distance power transfer during and after large disturbances. Currently, renewable generation resources are not required to provide damping support in ERCOT, and synchronous condensers typically are not equipped with PSS. A study conducted by ERCOT in 2019 identified oscillatory responses around 1.8 Hz between synchronous condensers in the

Panhandle area and other synchronous generators far away from the Panhandle region under a high renewable generation penetration condition with large power transfers to electrically distant load centers.[48]

Newly interconnecting BPS-connected IBRs should have the capability to provide power oscillation damping controls. A major difference from BPS-connnected inverter-based resources is that BESSs can operate in the charging mode in addition to the discharging mode, which provide greater capabilities of damping support. TPs and PCs may identify a reliability need for this type of control as the penetration of inverter-based resources continues to increase. At that time, requirements should be developed by TOs to ensure that the capability is activated and properly damps power oscillations typically in the range of 0.2 Hz to 2 Hz when the resources are on-line and operational. Newly interconnecting facilities require detailed studies that would ensure the controls provide oscillation damping as intended. Controls may need to be tuned (and possibly re-turned after interconnection) for optimal performance as the grid evolves over time. These types of studies are critical to ensure reliable operation of the BPS over time. TOs should ensure interconnection requirements suitably address this functionality such that the capabilities can be utilized when and if needed.

Recommended Performance and Considerations for Hybrid Plants

Hybrid power plants, as described in the Introduction, include both dc-coupled and ac-coupled facilities. In terms of describing the nuances and differences across technologies and configurations, it is useful to differentiate between ac- and dc-coupled plants. Therefore, the following sub-sections introduce dc-coupled plants first (since there are minimal differences between these facilities and standalone BESS facilities) and then provide more details around considerations for ac-coupled plants. As previously mentioned, the guideline focuses primarily on hybrid plants combining inverter-based renewable generation with BESS technology. The recommended performance characteristics for hybrid plants generally refer to the overall hybrid facility since this is coordinated at the plant-level; however, some description of the individual BESS or generation components within the facility may be used when necessary.

DC-Coupled Hybrid Plants

There is no significant difference in recommended performance between dc-coupled hybrid plants and stand-alone BESS. The following performance characteristics are practically the same and are covered in Table 1.1 and in the previous section:

- Momentary cessation
- Phase jump immunity
- Reactive current-voltage control during large disturbances
- Reactive power at no active power output
- Return to service following tripping
- Inverter current injection during fault conditions
- Balancing
- Monitoring
- Operation in low short-circuit strength systems
- Fault ride-through capability
- System Restoration and Black Start Capability

[48] http://www.ercot.com/content/wcm/lists/197392/2019_PanhandleStudy_public_V1_final.pdf

- Grid forming[49]
- Protection settings
- State of Charge
- Damping support

Additionally, the following topics from Table 1.1 warrant additional details where dc-coupled hybrids have specific considerations that need to be taken into account:

- **Reactive Capability Curve:** It is likely that total installed capacity of BESS and of other generating resources behind the common inverter will be higher than the common inverter rating. Therefore reactive capability of dc-coupled hybrid both during active power injection and withdrawal, as well as zero active power, will be limited by the inverter rating.
- **Active Power – Frequency Controls and FFR:** for these two topics dc-coupled performance considerations will be similar to that of ac-coupled hybrid as discussed in the next section. Overall dc-coupled plant's capability to provide frequency control both for under- and overfrequency events will be further limited by the common inverter rating.
- **Monitoring:** BAs, TPs, PCs, ISO/RTOs may require telemetry from each individual component within the facility (e.g., separate metering points for the BESS and the generating component) to support forecasting, situational awareness tools in the control room, and operations and planning study dispatch assumptions.
- **State of Charge:** Similar performance considerations as ac-coupled hybrids discussed in the next section.

AC-Coupled Hybrid Plants

Table 1.2 provides an overview of the considerations that should be made when describing the recommended performance of ac-coupled hybrid plants compared with other BPS-connected inverter-based generating resources. The following sub-section elaborate on these high-level considerations in more detail.

Table 1.2: High Level Considerations for AC-Coupled Hybrid Plant Performance

Category	Comparison with BPS-Connected Inverter-Based Generators
Momentary Cessation	No significant differences from other BPS-connected inverter-based generating resources; for BESS part of the hybrid, momentary cessation should not be used to the greatest possible extent[50] during charging and discharging operation.
Phase Jump Immunity	No significant difference from other BPS-connected inverter-based generating resources.

[49] The entire plant can have the capability to be grid forming, the capabilities will be limited by the inverter current limits and size of BEES portion of the dc-hybrid.

[50] Unless there is an equipment limitation or a need for momentary cessation to maintain BPS stability. The former has to be communicated by the GO to the TP while the latter has to be validated by extensive studies.

Table 1.2: High Level Considerations for AC-Coupled Hybrid Plant Performance	
Category	**Comparison with BPS-Connected Inverter-Based Generators**
Capability Curve	The overall composite capability curve of a hybrid plant is the aggregation of the individual capability curves of the generating resources and BESSs plus any other reactive devices and less any losses within the facility, as measured at the plant POI. The capability curve extends into the BESS charging region to create a four-quadrant capability curve. The curve is not symmetrical for injection and withdrawal. On the injection side, the capability curve will be equal to the sum of capability curves of a generator and capability curve of BEES during discharging. On the withdrawal side capability will be equal to BEES capability curve, when charging. Note that interconnection requirements may not allow the full use of hybrid resource capability depending on how the BESS can charge and discharge with the generating component and with the grid.
Active Power-Frequency Controls	No significant difference from other BPS-connected inverter-based generating resources and BESS. The conventional droop characteristic can be used in both generating and charging modes of the hybrid. Active power-frequency control capability may be limited by total active power injection and/or withdrawal limit of the hybrid plant at POI that may be set lower than the sum of active power ratings of the individual resources within the hybrid plant. Due to the presence of the BESS, a hybrid plant can also have the capability of providing frequency response for under frequency conditions, subject to the SOC and set point limits outlined in FERC Order 842.
Fast Frequency Response (FFR)	FFR capability will depend on the resources making up the hybrid plant. BESSs are well-positioned for providing FFR to systems with high rate-of-change-of-frequency (ROCOF) due to not having any rotational components (similar to a solar PV facility). However, if BESS is combined with wind generation facility coordination between resources within the hybrid may be needed to achieve sustained FFR. Additionally, hybrid plant FFR capability may be limited to total active power injection and/or withdrawal limit of the hybrid plant. The need for FFR is based on each specific Interconnection's need.[51] Sustained forms of FFR help arrest fast frequency excursions but also help overall frequency control. BESSs are likely to be able to provide sustained FFR within their state of charge constraints. Consistent with FERC Order 842, there should be no requirement for hybrid resources to reserve headroom or violate set point or SOC limits to provide frequency response, though that service can be procured by the BA.
Reactive Power-Voltage Control (Small Disturbance)	No significant difference from other BPS-connected inverter-based generating resources. The dynamic voltage support capability of a hybrid is a combination of capability of the generating resource(s) and BESS(s), which are part of the hybrid. BESSs portion of the hybrid have the capability to provide dynamic voltage control during both discharging and charging operations. Note that system specific requirements may not necessitate the use of the full equipment capability of the hybrid plant. TOPs should provide a voltage schedule (i.e., a voltage set point and tolerance) to the hybrid that can apply to both operating modes (injection and withdrawal).

[51] NERC, "Fast Frequency Response Concepts and Bulk Power System Reliability Needs," March 2020: https://www.nerc.com/comm/PC/InverterBased%20Resource%20Performance%20Task%20Force%20IRPT/Fast_Frequency_Response_Concepts_and_BPS_Reliability_Needs_White_Paper.pdf

Table 1.2: High Level Considerations for AC-Coupled Hybrid Plant Performance	
Category	**Comparison with BPS-Connected Inverter-Based Generators**
Reactive Current-Voltage Control (Large Disturbance)	No significant difference from other BPS-connected inverter-based generating resources. BESS portion of the hybrid can be configured to provide dynamic voltage support during large disturbances both while charging and discharging.
Reactive Power at No Active Power Output	No significant difference from other BPS-connected inverter-based generating resources.
Inverter Current Injection during Fault Conditions	No significant difference from stand-alone BPS-connected inverter-based generating resources and BESS.
Return to Service Following Tripping	No significant difference from other BPS-connected inverter-based generating resources. Hybrid plant should return to service following any tripping or other off-line operation by operating at the origin (no significant exchange of active or reactive power with the BPS), and then ramp back to the expected set point values, as applicable. This is a function of settings and any requirements set forth by the BA (or TO in their interconnection requirements).
Balancing	No significant difference from other BPS-connected inverter-based generating resources.
Monitoring	No significant difference from other BPS-connected inverter-based generating resources.
Operation in Low Short-Circuit Strength Systems	No significant difference from other BPS-connected inverter-based generating resources.
Grid Forming	BESSs portion of a hybrid plant have the unique capabilities to effectively deploy grid forming technology to help improve BPS reliability in the future of high penetration of inverter-based resources. Newly interconnecting hybrid plants should consider using grid forming technology to support the BPS under these future conditions.
Fault Ride-Through Capability	No significant difference from other BPS-connected inverter-based generating resources. A hybrid plant should have the same capability to ride through fault events on the BPS, when point of measurement (POM) voltage is within the curves specified in the latest effective version of PRC-024, subject to limitations of legacy equipment. For the BESS part of the hybrid this applies to both charging and discharging modes. Unexpected tripping of generation or load resources on the BPS will degrade system stability and adversely impact BPS reliability. Ride-through capability is a fundamental need for all BPS-connected resources such that planning studies can identify any expected risks.

Table 1.2: High Level Considerations for AC-Coupled Hybrid Plant Performance	
Category	**Comparison with BPS-Connected Inverter-Based Generators**
System Restoration and Blackstart Capability	Hybrid plants may have the ability to form and sustain their own electrical island if they are a part of a blackstart cranking path. This may require new controls topologies or modifications to settings that enable this functionality. Blackstart conditions may cause large power and voltage swings that must be reliably controlled and withstood by all blackstart resources (i.e., operation under low short circuit grid conditions). For the hybrid to operate as a blackstart resource, assurance of energy availability is needed as well as designed energy rating that ensures energy availability for the entire period of restoration activities. At this time, it is unlikely that most legacy hybrid plants can support system restoration activities as a stand-alone resource; however, they may be used to enable start-up of subsequent solar PV, wind, or synchronous machine plants and accommodate fluctuations in supply and demand.
Protection Settings	No significant difference from other BPS-connected inverter-based generating resources.
Power Quality	No significant difference from other BPS-connected inverter-based generating resources.
State of Charge *(new)*	Similarly to the standalone BESS, The state of charge (SOC) of a BESS portion of the hybrid may affect the ability of the hybrid to provide energy or other essential reliability services to the BPS at any given time.[52] These limits and how they affect BESS operation should be defined by the hybrid owner and provided to the BA, TOP, RC, TP and PC. BESS's SOC will be optimized by the hybrid plant controller in coordination with other parts of the hybrid (wind or solar), based on irradiance and/or wind conditions, market prices, energy and ESR obligations of the hybrid. In addition, the manner in which the BESS would charge is to be communicated by the GO. Here, system loading conditions and generation from other parts of the hybrid plant will play a role. For example, in a wind-BESS hybrid plant during low load high renewable scenarios, the BESS may be charged directly from the wind output. In this scenario, the hybrid plant will not appear as a load on the system. Alternatively, the plant may be directed to charge from the network in order to increase the loading on the system to satisfy stability considerations.
Operational Limits *(new)*	Based on economics or design considerations, BESS portion of the hybrid may be operated to only charge from other wind and/or solar part of the hybrid or to charge from the grid as well. This information should be provided by the hybrid owner to the BA, TOP, RC, TP and PC. Hybrid plant owners may choose to limit injection/withdrawal at the POI to a level that is lower than actual capability of the hybrid. This information should be provided by the hybrid owner to the BA, TOP, RC, TP and PC. Where such limit exists, the studies as well as voltage support and frequency support requirements may apply only up to the limits.
Damping Support	BESSs can have the capability of providing oscillation damping support, similar to synchronous gnerators, HVDC/FACTS facilities, and other BPS-connected inverter-based resources. BESSs can operate in the both charging and discharging mode, which provides greater capabilities for damping support.

[52] https://www.nrel.gov/docs/fy19osti/74426.pdf

Topics with Minimal Differences between AC-Coupled Hybrids and standalone BESS Resources

The following performance characteristics have practically no difference between ac-coupled hybrid plants and standalone BESSs:

- Momentary cessation
- Phase jump immunity
- Reactive current-voltage control during large disturbances
- Reactive power at no active power output
- Return to service following tripping
- Inverter current injection during fault conditions
- Balancing
- Monitoring
- Operation in low short-circuit strength systems
- Fault ride-through capability
- System restoration and blackstart capability
- Grid forming[53]
- Protection settings
- Damping support

Refer to the recommendations outlined in NERC *Reliability Guideline: BPS-Connected Inverter-Based Resource Performance*[54] for more details on each of the aforementioned subjects. The following sub-sections outline the additional topics from Table 1.2 that warrant additional details and where AC-Coupled hybrids have specific considerations that need to be taken.

Capability Curve

The overall active and reactive power capability of an ac-coupled hybrid plant is the summation of the capabilities for each of the BESS and generating components within the facility. In terms of establishing the capability curve for an ac-coupled hybrid plant, both the BESS and generating component should have their own capability curve, which would each be represented separately in the simulation models. Any contractual limits that may limit active power to a pre-determined level at the POI should be explicitly documented and provided by the GO to the RC, TOP, BA, TP, and PC for inclusion in their tools and studies. Further, the facility should not be unnecessarily limited from providing its full reactive power capability by any plant-level controls. In general, the overall plant-level capability of an ac-coupled hybrid plant will be asymmetrical with more active and reactive power capability when both the generating component and BESS are injecting active power to the BPS.

TOs should ensure their interconnection requirements are clear on how capability curves are provided for BESSs and hybrid power plants, and TPs and PCs should ensure that their modeling requirements are also clear on how to represent steady-state capability curves in the simulation tools used to studies these resources.

[53] The BESS component of an ac-coupled hybrid can have the capability to provide grid forming capability; if the hybrid facility is dc-coupled, the entire plant can have the capability to be grid forming.
[54] https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Inverter-Based_Resource_Performance_Guideline.pdf

Active Power-Frequency Control

Active power-frequency controls can be extended to the charging region of operation for BESSs part of the hybrid, as described in detail in standalone BESS section above. The overall active power-frequency control capability of the hybrid is equal to combined capability of all resources that are part of the hybrid plant. The overall capability may be limited by total active power injection and/or withdrawal limit of the hybrid plant that may be set lower than the sum of active power ratings of the individual resources within the hybrid plant.

Fast Frequency Response

BESSs and solar PV have the capability of providing FFR to rapid changes in frequency disturbances on the BPS. Since there are no rotational elements, the active power output is predominantly driven by the controls that are programmed into the inverter. Wind generating resources can provide FFR through tapping into kinetic energy of rotating mass of a wind turbine.[55] Such response, however, cannot be sustained. To obtain sustained fast frequency response from hybrid plants containing wind/solar PV generating resources along with BESS the FFR capability of the AC-coupled hybrid plant is equal to combined capability of all resources that are part of the hybrid plant. The resources within the hybrid can be coordinated to optimize total FFR and achieve required sustain time. The overall capability may be limited by total active power injection and/or withdrawal limit of the hybrid plant that may be set lower than actual capability of the plant.

AC-coupled hybrid plant should have at least the following capabilities (which may be utilized based on BA requirements and BPS reliability needs):

- Configurable and field-adjustable droop gains, time constants, and deadbands; tuned to the requirements or criteria specified by the BA
- Real-time monitoring of BESS SOC to understand performance limitations that could impose on FFR capabilities from the hybrid
- Ability to provide sustained response, coordinated with primary frequency response, as defined by the BA
- Consistent with FERC Order 842, there should be no requirement for hybrid plants to maintain a specific SOC for provision of frequency response

Reactive Power-Voltage Control (Normal Conditions and Small Disturbances)

There are no significant differences between AC-coupled hybrids and BPS-connected inverter-based resources with respect to reactive power-voltage control during normal grid conditions and small disturbances. In essence, the hybrid plant should have the capability to provide reactive power-voltage control both during power injection at the POM and power withdrawal (during BESS charging); however, it is useful to separate out the recommendations into each mode of operation:

- **Power Injection:** There are no significant differences between hybrid plants during power injection into the grid and other BPS-connected inverter-based generators with respect to reactive power-voltage control. Hybrids plant should have the ability to support BPS voltage. Voltage control needs to be coordinated between all resources within the hybrid plant to control hybrid plant's POM voltage within a reasonable range during normal and abnormal grid conditions. Refer to the recommendations from the NERC *Reliability Guideline: BPS-Connected Inverter-Based Resource Performance*.
- **Power Withdrawal:** Hybrid plants should have the capability to control POM voltage during normal operation and abnormal small disturbances on the BPS while BESS part of the hybrid is operating in charging mode. The ability for resources consuming power to support BPS voltage control adds significant reliability benefits to

55 https://www.nerc.com/comm/PC/InverterBased%20Resource%20Performance%20Task%20Force%20IRPT/Fast_Frequency_Response_Concepts_and_BPS_Reliability_Needs_White_Paper.pdf

the BPS and may be required by TOs as part of their interconnection requirements or by BAs, TOPs, or RCs for BPS operations.

As the resource transitions from charging to discharging modes of operation (or vice versa) or operates at zero active power output while connected to the BPS, the BESS should have the capability and operational functionality enabled to continuously control BPS voltage. This should be coordinated with any requirements established by the TO or TOP. Generally, the output voltages of inverter-based renewable energy resources vary severely due to large fluctuations and rapid changes in the availability of their energy resources. Therefore, if used individually, these resources have difficulty controlling their voltage. In a Hybrid power plant, however, this issue is resolved. Since the output voltage variation of the BESS from a fully charged to a discharged state is typically less, this variation can be easily controlled to maintain a stable output voltage. In addition, the battery is capable of balancing the power fluctuations either by absorbing the excess power from the renewable energy resources during charging or by supplying the power to satisfy the load-demand changes, during discharging. As the resource transitions from charging to discharging modes of operation, or vice versa, the Hybrid power plant should continuously have the ability to control BPS voltage throughout the transition

State of Charge

State of charge considerations for the BESS portion of the ac-coupled hybrid plant are similar to those of a stand-alone BESS discussed above. The state of charge (SOC) of a BESS portion of the hybrid may affect the ability of the BESS to provide energy or other essential reliability services to the BPS at any given time.[56] These limits and how they affect BESS operation should be defined by the hybrid owner and provided to the BA, TOP, RC, TP and PC. BESS's SOC will be optimized by the hybrid plant controller in coordination with other parts of the hybrid (wind or solar), based on irradiance and/or wind conditions, market prices, energy and ESR obligations of the hybrid.

Operational Limits

Based on economics or design considerations, the BESS portion of a hybrid plant may be operated to only charge from the generating component or to charge from the grid as well. Technical, economic, and policy considerations will dictate whether the hybrid plant charges from the grid or only from the generating component.[57] TOs and BAs should clearly define the acceptable charging behavior from the hybrid plant. Characteristic of charging and any operational limitations should be provided by the hybrid plant owner to the BA, TOP, RC, TP and PC.

Hybrid plant owner for various economic consideration may choose to set on injection/withdrawal at the POI that is lower than actual capability of the hybrid plant. This information should be provided by the hybrid owner to the BA, TOP, RC, TP and PC. Where such limit exists, the studies as well as voltage support and frequency support requirements may apply only up to the limits.

[56] https://www.nrel.gov/docs/fy19osti/74426.pdf

[57] In addition to any requirements imposed by the TO or BA regarding acceptable charging behavior, the structure of investment tax credits may also contribute to the charging characteristic. For example, currently a hybrid plant may need charge the BESS by renewable energy for more than 75% of the time for the first five years of commercial operation, and the tax credit value for the storage component is derated in proportion to the amount of grid charging between 0% and 25%.

Chapter 2: BESS and Hybrid Plant Power Flow Modeling

BPS-connected BESS and hybrid plants are modeled very similarly to other BPS-connected inverter-based resources such as solar PV and wind power plants. This chapter provides a brief overview of the presently recommended power flow modeling practices.

BESS Power Flow Modeling

As mentioned, the power flow representation for a BPS-connected BESS is similar to other types of BPS-connected inverter-based resources. Figure 2.1 shows a generic[58] power flow model for a BPS-connected BESS facility. The power flow representation of a BPS-connected BESS facility will include the following components:

- **Generator Tie Line:** Where the BESS is connected to the BPS (to the POI) through a transmission circuit (i.e., the generator tie line), this element should be explicitly modeled in the power flow to properly represent active and reactive power losses and voltage drops or rises.
- **Substation Transformer:** Any substation transformers[59] (also referred to as "main power transformers") should be explicitly modeled in the power flow base case. All relevant transformer data such as tap ratios, load tap changer controls, and impedance values should be modeled appropriately.
- **Collector System Equivalent:** Based on the cabling and layout of the BESS facility, some GOs may choose to model an equivalent collector system to capture any voltage drop across the collector system. However, BESS facilities are not geographically and electrically dispersed like wind and solar PV facilities, so BESS collector system equivalent impedances are likely much smaller. Therefore, this may or may not be included in the BESS power flow model.
- **Equivalent Pad-Mounted Transformer:** Each of the inverters interfacing the battery systems with the ac electrical network will include a pad-mounted transformer. An equivalent pad-mounted transformer is typically modeled, which is scaled to an appropriate size to match the overall MVA rating of the aggregate inverters at the BESS facility.
- **Equivalent BESS:** An equivalent BESS generating resource is modeled to represent the aggregate amount of inverter-interfaced BESSs installed at the facility. The capability is scaled to match the overall capability of aggregate inverters. The equivalent BESS is modeled as a generator in the power flow, and appropriate voltage control settings (and other applicable control settings) should be specified in the model. In situations where different inverter types (e.g., make and model of inverter) are used[60] within the BESS, each different inverter type is typically separately aggregated. GOs should consult with their TP and PC for recommended modeling practices.
- **Shunt Compensation and Reactive Devices:** The plant may include shunt reactive devices to meet reactive capability and voltage requirements defined by the TO and TOP. These may include shunt capacitors and reactors, FACTS devices, or synchronous condensers, as applicable. If these devices are installed, they should be modeled appropriately. Figure 2.1 also denotes that these installations could even be located at the POI, within the boundary of the GO and GOP, and those devices should also be modeled appropriately.
- **Plant Loads:** The plant may include a small load to represent station service load, as deemed necessary based on the TP and PC modeling requirements. Auxiliary loads supplied by the dc bus are generally not modeled.

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[58] Different configurations may exist for BESS facilities based on considerations at each individual installation. The power flow model provided by the GO to the TP and PC should be an accurate representation of the actual installed (or expected) facility and should not use any default or generic parameters or configurations.
[59] Some BESSs may have more than one substation transformer, and each should be explicitly modeled.
[60] This occurs more frequently in inverter-based generating resources, either installed in different phases or often in large facilities.

Elements in Figure 2.1 shown in red are denoted as those elements that may or may not be represented in BESS models based on each specific installation's modeling needs, with the goal of capturing all the needed electrical effects. Those elements described in black should be modeled in all BPS-connected BESS facilities. Common voltage levels are shown in Figure 2.1 only for illustrative purposes.

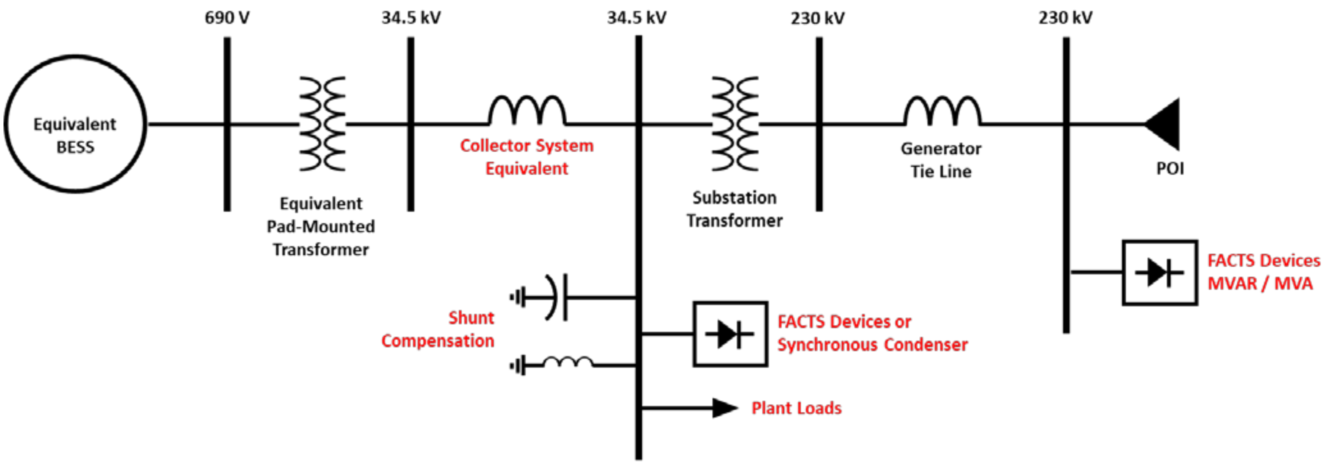

Figure 2.1: Generic Power Flow Model Example for BESS

The GO, TP, and PC will need to consider the following aspects of steady-state power flow modeling for BESSs:

- **Charging Operation:** Charging capability can be modeled by setting the equivalent BESS generator with an appropriate negative value for the active power limit, P_{min}. Note that the maximum charging limit (P_{min}) may be different than the maximum discharging limit (P_{max}). These P_{min} and P_{max} limits in the equivalent BESS generator record should be set to any limits imposed by the plant and inverter controllers in coordination with the capability of the inverters. Also, the BA, TOP, RC, TP, and PC should ensure they understand how the other BESS facility components (e.g., shunt compensation) operate during charging operation such that the overall BESS model can be set up correctly in both charging and discharging modes.
- **Point of Voltage Control and Power Factor Mode:** As with other generating resources, the generating resource (i.e., the equivalent BESS) can be configured to operate either in a power factor control mode or a voltage control mode with a specific control point in the grid (i.e., the POM or POI). This should be configured appropriately in the generator record voltage controls. Newer models may enable advanced controls such as voltage droop characteristic to be represented. Generator voltage reference can be changed to meet the voltage schedule.

Hybrid Power Flow Modeling

The configuration of hybrid plants will likely vary more than BESS facilities, based on the size of the plant, the type of technologies used, and the overall layout of the facility. Regardless, each hybrid plant should be modeled according to the expected[61] or actual facilities installed in the field. Further, hybrid plants may be modeled differently depending on whether they are ac-coupled or dc-coupled facilities. GOs should consult with their TP and PC to determine the appropriate modeling approach based on whether the facility is ac-coupled or dc-coupled.

AC-Coupled Hybrid Plant Power Flow Modeling

Figure 2.2 illustrates a generic model representation for an example[62] ac-coupled hybrid plant. Since the BESS and the generating resource are connected through the ac network, then each component should be represented

[61] During the interconnection study process.

[62] There are many different types of ac-coupled hybrid plant configurations; this is used as an example only.

accordingly, as shown in Figure 2.2. An equivalent BESS generation and equivalent pad-mounted transformer should be represented, as well as an equivalent collector system (if needed to properly represent the electrical effects). For the example shown in Figure 2.2, where the ac-coupling is at the low-side of the substation main power transformer, the inverter-based generating resource is coupled to the BESS at this point. The inverter-based generating resource also has its own equivalent generator model, equivalent pad-mounted transformer, and equivalent collector system modeled appropriately. The substation main power transformers and plant generator tie line are also modeled explicitly. Any shunt compensation such as shunt reactors, capacitors, FACTS devices, or synchronous condensers should be modeled as well. Again, elements shown in red may or may not be represented in the model based on each specific location, and elements shown in black should be modeled for all facilities. Common voltage levels are shown only for illustrative purposes.

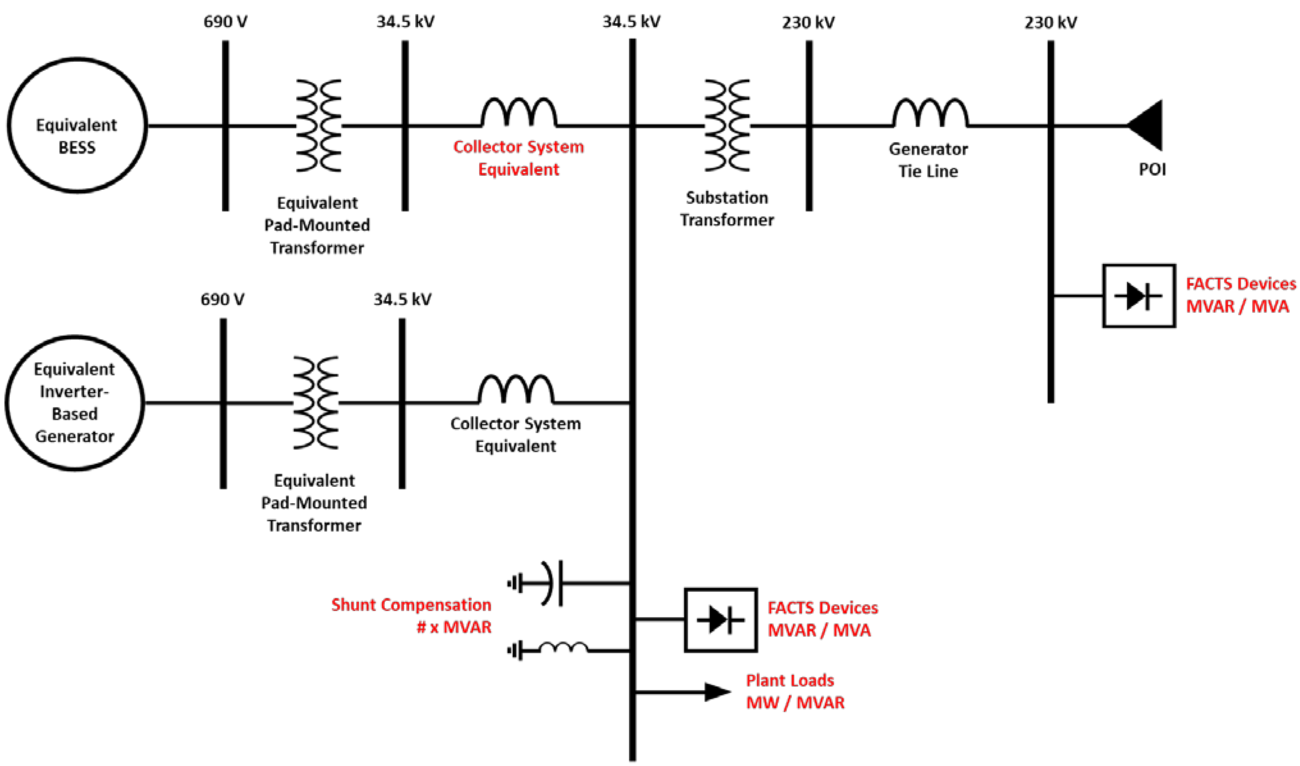

Figure 2.2: Generic Power Flow Model Example for AC-Coupled Hybrid Power Plants

The GO, TP, and PC will need to consider the following aspects of steady-state power flow modeling for ac-coupled hybrid power plants:

- **Plant Configuration:** AC-coupled hybrid plants can have significantly different configurations on the ac-side of the inverter interface. Therefore, special attention should be given to ensuring that the power flow model accurately represents the overall configuration of the plant (which may be different from Figure 2.2).
- **Coordinated Operation of BESS and Generating Component:** Since the BESS is explicitly modeled, charging and discharging capability can be represented by setting the equivalent BESS generator P_{min} and P_{max} values appropriately. The P_{min} and P_{max} limits in the equivalent BESS generator record should be set to any limits imposed by the plant and inverter controllers in coordination with the capability of the inverters. BESS operation should be modeled by setting active power output, P_{gen}, accordingly. The BA, TOP, RC, TP, and PC should ensure they understand how the BESS is expected to operate in relation to the inverter-based generating component within the plant, such that the output of both resources is coordinated.

  - **Maximum Overall Plant Power Output (Plant P_{max}):** The maximum power output of the overall hybrid facility may be limited by interconnection agreement, plant controller, or other means. While the nameplate rating of the individual BESSs and generating resources may exceed the limit, the power output of the overall facility may not. Therefore, it is important to understand what the maximum operational output of the plant will be. Most power flow software today does not have a way to represent this limit, but the software industry should pursue the ability to explicitly model both the BESS and the generator within an overall plant model with its own limitations. In the meantime, BAs, TOPs, RCs, TPs, PCs, and GOs should develop a standardized way of documenting and communicating such limits.
  - **BESS Charging from BPS or from Generating Resource:** Depending on the interconnection agreement, the hybrid plant may or may not be able to charge from the BPS. If allowed, the BESS may be able to charge power from the BPS with the generating unit dispatched off. If not allowed, the BESS will only charge using energy produced by the generating component of the plant. Most power flow software today does not have a way to represent this limit, but the software industry should pursue this capability. In the meantime, BAs, TOPs, RCs, TPs, PCs, and GOs should develop a standardized way of documenting and communicating such limits.
- **Coordinating Voltage Controls for BESS and Generating Component:** The hybrid power plant will have obligations per VAR-002-4.1 to control voltage at its POI or POM, and the power flow base case should be configured to ensure similar voltage control strategies as used in the field. In an ac-coupled hybrid plant with the BESS and generating component modeled explicitly, the voltage controls will need to be coordinated among both devices. Both equivalent generator records for the BESS and generating component can be coordinated using the reactive power sharing parameter in each unit.[63]

The WECC Renewable Energy Modeling Task Force (REMTF) has developed recommendations for software vendors to improve the capability for modeling BESSs and hybrid plants,[64] particularly for representing overall plant-level active power limitations as well plant-level coordinated voltage controls in the power flow base case. This will enable more effective modeling of hybrid plant dispatch scenarios as well as overall plant voltage control.

DC-Coupled Hybrid Plant Power Flow Modeling

Figure 2.3 illustrates a generic model representation for a dc-coupled hybrid plant. For dc-coupled plants, the BESS and inverter-based generating resources are coupled on the dc-side of the inverter. Therefore, the coupling is not modeled in power flow simulation tools, and the coupled BESS and inverter-based generating resources are aggregated to a single aggregate generator model. Since the coupling occurs at each individual generating resource, there is no BESS inverter, pad-mounted transformer, or equivalent collector system represented. Only the equivalent inverter-based generating resource (including the battery), the ac-side equivalent pad-mounted transformer, and the equivalent collector system are represented. Similar to ac-coupled hybrid plants and other BPS-connected inverter-based resources, the substation main power transformer and generator tie line are modeled explicitly. Any shunt compensation such as shunt reactors, capacitors, FACTS devices, or synchronous condensers should be modeled as well. Again, elements shown in red may or may not be represented in the model based on each specific location, and elements shown in black should be modeled for all facilities. Common voltage levels are shown only for illustrative purposes.

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[63] This is similar to configuring multiple synchronous generators to control the same bus voltage.

[64] WECC White Paper on Modeling Hybrid Power Plant of Renewable Energy and Battery Energy Storage System https://www.wecc.org/_layouts/15/WopiFrame.aspx?sourcedoc=/Administrative/WECC%20White%20Paper%20on%20modeling%20hybrid%20solar-battery.pdf

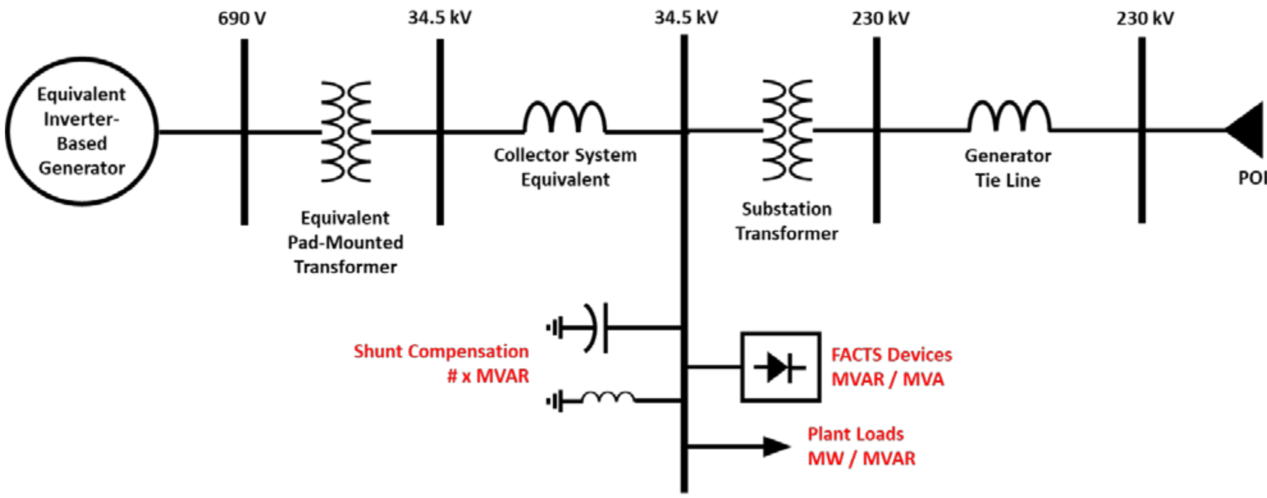

Figure 2.3: Generic Power Flow Model for DC-Coupled Hybrid Power Plants

The GO, TP, and PC will need to consider the following aspects of steady-state power flow modeling for dc-coupled hybrid power plants:

- **Charging and Discharging Operation:** If the BESS only charges from the generating component (due to interconnection requirements or if the ac/dc inverter is not bidirectional), then P_{min} will remain zero for the facility. If the BESS can charge from the grid, then P_{min} for the equivalent generator component can be set to the corresponding aggregate negative active power limit. Similarly, the maximum equivalent generator power output, P_{max}, should also be set according to equipment capabilities and plant limitations. Note that the maximum charging limit (P_{min}) may be different than the maximum discharging limit (P_{max}). The TP and PC should ensure they understand how the BESS and generating components are expected or required to operate during charging and discharging operation so that the overall model can be set up correctly.
- **Voltage Control:** The appropriate type of voltage control should be accurately modeled (as with other inverter-based resources), and all plant voltage control settings should be coordinated in the models.
- **Frequency Response:** While frequency response is modeled in the dynamic models, and active power limits for the facility should be coordinated between models so the resource is configured appropriately in the steady-state and dynamic simulations appropriately.

Chapter 3: BESS and Hybrid Plant Dynamics Modeling

With an appropriate power flow representation for the BESS or hybrid plant, dynamic models can be used to represent the behavior of these resources during BPS disturbances. Dynamic modeling practices for BESSs and hybrid plants are similar to those of other BPS-connected inverter-based resources; however, there are some unique characteristics to capture regarding four-quadrant operation of energy storage and consideration of SOC. This chapter describes recommended practices for modeling BESS and hybrid plants including use of appropriate models, model quality considerations, and electromagnetic transient (EMT) models.

Use of Standardized, User-Defined, and EMT Models

As with other inverter-based resources, the dynamic models used to represent BESSs and hybrid power plants will depend on TP and PC modeling requirements as well as the types of studies being conducted. GOs should refer to the specific modeling requirements for each TP and PC when providing models during the interconnection study process, and should ensure that those models reflect the expected behavior of the facility seeking interconnection (or facility installed in the field). TPs and PCs should consider updating their modeling requirements to ensure clarity and consistency for modeling BESSs and hybrids during interconnection studies, during annual planning assessments, and any other studies being conducted. Some considerations for different model types include:

- **Standardized Library Models:** These types of models may be appropriate (and required) for interconnection-wide base case development. Standardized models, however, may not fully capture all characteristics of the behavior and response of BESSs and hybrids during large disturbances. Nonlinearities in control, communications delays across technologies, dynamic rise times, etc., may be not able to be fully represented by the standardized library models. GOs should coordinate with their equipment manufacturers and any consultants developing plant-level models to ensure these models are appropriate. TPs and PCs should ensure that sufficient documentation is provided by the GO to verify that the performance will sufficiently match the dynamic model provided.
- **User-Defined Models:** These types of models are more appropriate for interconnection studies that may be testing or screening for various issues such as ride-through performance, operation in low short circuit conditions, local stability analysis, and other localized reliability assessments. The user-defined models may be required in conjunction with the standardized library models, and TPs and PCs may require the GO to provide benchmarking reports between the two models. A user-written dynamic model can be used to tune the response of a standardized library model to represent the actual response of the resource as closely as possible. Any discrepancies can and should be documented and explained by the equipment manufacturers.
- **EMT Models:** EMT models are the most accurate representation of the dynamic response of an inverter-based resource (including BESSs and hybrid plants). TPs and PCs are encouraged to require EMT models for newly interconnecting BESSs and hybrid plants since these models are the most appropriate to test for any controls instability, unbalanced fault analysis, operation in low short circuit strength conditions, and to analyze any anomalous controls or instability performance that may be identified during screening using the aforementioned model types. EMT models that capture the “real code” of the inverters and plant-level controller installed in the field are preferred. As the grid continues to evolve, modeling practices improve, and inverter control schemes get more complex, it is likely that EMT models will be utilized more extensively.

As BESSs and hybrid plants continue to interconnect to the BPS, it imperative that these resources are studied appropriately using accurate models. TPs and PCs will weigh these considerations against their modeling practices and capabilities, and determine appropriate modeling requirements for existing and newly interconnecting generating resources.

Dynamic Model Quality Review Process

All TPs and PCs should have modeling requirements that include quality testing to ensure that the dynamic model is a reasonable representation of the equipment installed in the field, that the model meets certain specifications, and that the model performs reasonably when subjected to a set of simulation tests. Many TPs and PCs currently have these types of quality tests in place,[65] and all TPs and PCs are encouraged to strengthen their requirements particularly in the area of BESS and hybrid plant modeling. These quality tests can be applied to standardized library models, to user-defined models, as well as to EMT models. The goal of these tests is to give the TP and PC assurance that the model being used reasonably represents the equipment in the field and meets the expected performance specifications established by the TO in their interconnection requirements. Examples of model quality tests used for inverter-based resources that should also be applied to BESSs and hybrid plants include, but are not limited to, the following:

- **Low and High Voltage Ride-Through Analysis:** under various charging and discharging conditions (included at power output limits), SOC conditions, and both consuming and producing reactive power
- **Small Voltage and Frequency Disturbances:** under various charging and discharging conditions (including at power output limits), SOC conditions, and both consuming and producing reactive power
- **Short-Circuit Strength Analysis:** under varying levels of short-circuit strength, with different (or stressed) local dispatch scenarios, for different charging and discharging conditions (including at power output limits) and SOC conditions

BESS Dynamic Modeling

Although the implementation may be different among equipment manufacturers, the modeling structure of BPS-connected BESSs is (in principle) the same as BPS-connected solar PV and Type 4 wind plants. The overall structure consists of a converter control module, an electrical control module, and a plant control module. Frequency ride-through and voltage ride-through settings are modeled with the generator protection modules. This section describes using the latest standardized library models to represent BESSs (see Figure 3.1). The standardized library models with variation of each module provides flexibility to simulate the overall plant dynamic behavior. The modules may not directly match control blocks in the field, but can be set up to achieve the desired performance by selecting proper modules and control flags. User-defined models may also be required as described above. If user-defined models are required by the TP and PC, specific modeling requirements should be in place that describe the level of detail, transparency, functionality, and documentation.

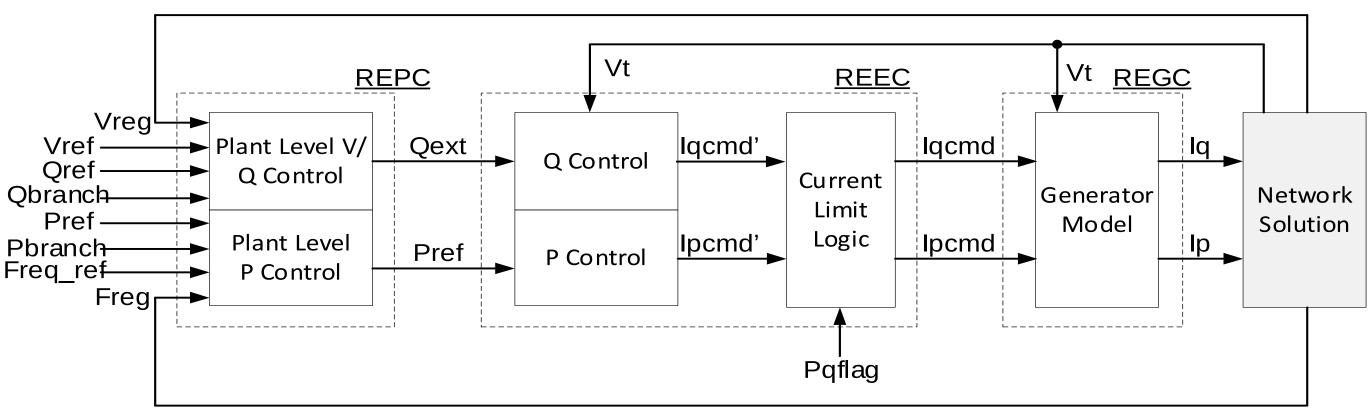

Figure 3.1: Block Diagrams of Different Modules of the WECC Generic Models[66]

[65] ERCOT Model Quality Guide: http://www.ercot.com/content/wcm/lists/168284/ERCOT_Model_Quality_Guideline.zip
[66] WECC Solar PV Plant Modeling and Validation Guideline: https://www.wecc.org/Reliability/Solar%20PV%20Plant%20Modeling%20and%20Validation%20Guidline.pdf

- **REGC (REGC_*)[67] Module:** Used to represent the converter (inverter) interface with the grid. It processes the real and reactive current command and outputs of real and reactive current injection into the grid model.
- **REEC (REEC_C/REEC_D)[68] Module:** Used to represent the electrical controls of the inverters. It acts on the active and reactive power reference from the REPC module, with feedback of terminal voltage and generator power output, and gives real and reactive current commands to the REGC module.
- **REPC (REPC_*) Module:** Used to represent the plant controller. It processes voltage and reactive power output to emulate volt/var control at the plant level. It also processes frequency and active power output to emulate active power control. This module gives active reactive power commands to the REEC module.

Table 3.1 shows the list of BESS simulation modules used in two commonly used simulation platforms. Although implementation across simulation platforms may differ, the modules have the same functionality and parameter sets.

Table 3.1: Dynamic Models used to Represent BESSs in PSLF and PSSE

Module	GE PSLF Modules	Siemens PTI Modules
Grid interface	regc_*	REGC*
Electrical controls	reec_c or reec_d	REECC1 or REECD1
Plant controller	repc_*	REPC*/PLNTBU1
Voltage/frequency protection	lhvrt/lhfrt	VRGTPA/FRQTPA

Model invocation varies across software platforms, and users should refer to the software manuals for software-specific implementations. The regulated bus and monitored branch in the repc invocation should match the control modes used in the repc model. For example, if voltage droop control is used (droop control gain kc), then the monitored branch should be specified in the model invocation.

Scaling for BESS Plant Size and Reactive Capability

Model parameters are expressed in per unit of the generator MVA base except in repc_b. The specification of MVA base is implementation-dependent.[69] To scale the dynamic model to the size of the plant, the generator MVA base parameter must be adjusted. It should be set to sum of the individual inverter MVA rating. The active and reactive range are expressed in per unit on the scaled MVA base. The MVA base for REPC_B model is always the system MVA base in GE PSLF; Siemens PTI PSS/e implementation allows a different MVA base to be specified. The per unit parameters of REPC_B model should be expressed on the MVA base used.

Reactive Power / Voltage Controls Options

The plant-level control module allows for the following reactive power control modes:

- Closed loop voltage regulation ("V control") at a user-designated bus with optional line drop compensation, droop response and deadband.
- Closed loop reactive power regulation ("Q control") on a user-designated branch, with optional deadband.
- Constant power factor control (PF) ("PF control") on a user-designated branch active power and power factor. This control function is available in repc_b, not in repc_a.

[67] The symbol * is used throughout this document to refer to all available variation of the module (e.g., REGC_A, REGC_B, and REGC_C).
[68] REEC_D and REPC_B model descriptions: https://www.wecc.org/Administrative/Memo_RES_Modeling_Updates_083120_Rev17_Clean.pdf
[69] For example, in the PSLF implementation, if MVA base is zero in reec_* or repc_*, then the MVA base entered for the regc applies to those models as well. The user may specify a different MVA, if desired. In the PSSE implementation, the MVA base is set in the power flow model.

In the electrical control module, other reactive control options are available:

- Constant power factor ("PF"), based on the generator PF in the solved power flow case.
- Constant reactive power based on either the equivalent generator reactive power in the solved power flow case or from the plant controller.
- Closed loop voltage regulation at the generator terminal.
- Proportional reactive current injection during a user-defined voltage-dip event.

Various combinations of plant-level and inverter-level reactive control are possible by setting the appropriate parameters and switches. Table 3.2 shows a list of control options and respective models and switch that would be involved. Additional variations[70] of flag settings are not shown in Table 3.2 since they are not likely to be used for BESS operation.

Table 3.2: Reactive Power Control Options for BESS Generic Models

Functionality	Required Models	pfflag	vflag	qflag	refflag
Plant-level V control	REEC + REPC	0	N/A*	0	1
Plant-level Q control & local coordinated Q/V control	REEC + REPC	0	1	1	0
Plant-level V control & local coordinated Q/V control	REEC + REPC	0	1	1	1
Plant-level PF control & local coordinated Q/V control	REEC + REPC (repc_b and above)	0	1	1	2

* "N/A" indicates that the state of the switch does not affect the indicated control mode.

Active power control options

The plant controller models include settable flags for the user to specify active power control. Table 3.3 shows the active power control modes, the models, and parameters involved, respectively. These types of controls include:

- Constant active power output based on the generator output in the solved power flow case
- Active power-frequency control with a proportional droop of different gains for over- and under-frequency conditions, based on frequency deviation at a user-designated bus

The BESS is expected to provide frequency response in both upward and downward directions. The no response and down only options are greyed out because they are unlikely to be approved by the transmission planning entity (assuming interconnection requirements are fully utilizing the bi-direction capabilities of BESS technology). In the WECC recommended modeling enhancement for hybrid power plants,[71] the base load flag in the power flow model could override the frqflag setting in the dynamic model. The frqflag/ddn/dup are meant to reflect the inverter capability while base load flag represents the availability of the operational headroom. It is important to set base load flag to 0 for BESS generators regulating frequency.

[70] These unlikely variations include no representation of the plant-level controller (which is not likely with new facilities) and voltage regulation options that would not meet automatic voltage regulation requirements found in NERC VAR Standards and most interconnection requirements.

[71] WECC White Paper on Modeling Hybrid Power Plant of Renewable Energy and Battery Energy Storage System https://www.wecc.org/_layouts/15/WopiFrame.aspx?sourcedoc=/Administrative/WECC%20White%20Paper%20on%20modeling%20hybrid%20solar-battery.pdf

Table 3.3: Active Power Control Options				
Functionality	**BaseLoad flag***	**frqflag**	**ddn**	**dup**
No frequency response	2	0	0	0
Frequency response, down only regulation	1	1	> 0	> 0
Frequency response, up and down	0	1	> 0	> 0

*BaseLoad flag is set in the power flow model.

Current Limit Logic

The electrical control module first determines the active and reactive current commands independently according to the active power control option and reactive power control option. Each command is subject to the respective current limit, 0 to *Ipmax* for active current and *Iqmin* to *Iqmax* for reactive current. Then the total current of $\sqrt{Ipcmd^2 + Iqcmd^2}$ is limited by *Imax*. In situations where current limit *Imax* of the equivalent inverter is reached, the user should specify whether active or reactive current takes precedence, by setting the *pqflag* parameter in the REEC module.

State of Charge

The REEC_C module includes simulation of BESS's SOC (see Figure 3.2). An initial condition SOCini is specified. Then Pgen is integrated during the simulation and added to SOCini. When SOC reaches SOCmax, i.e. fully charged, charging is disabled by adjusting ipmin from a negative value to 0. Similarly, when SOC reaches SOCmin, i.e. depleted of energy, discharging is disabled by adjusting ipmax from a positive value to 0. This requires the user sets SOCini based on the dispatching condition being analyzed. It has been a common source of error that the BESS is in the charging mode with SOCini = 1 and the Pgen is forced to 0 in the simulation. Given the timeframe of transient stability simulation, change of SOC throughout the simulation is negligible. For this reason, the SOC is removed from the REEC_D module.

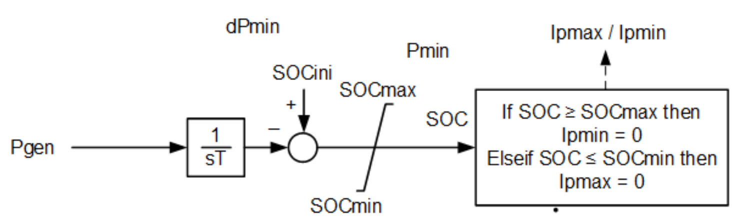

Figure 3.2: Block Diagram of the Charging/Discharging Mechanism of the BESS

Representation of Voltage and Frequency Protection

Frequency and voltage ride-through are needed for transmission-connected solar PV plants. Because they are simplified, the generic models may not be suitable to fully assess compliance with the voltage and frequency ride-through requirement. Voltage ride-through is engineered as part of the plant design and needs far more sophisticated modeling detail than is possible to capture in a positive-sequence simulation environment. It is best to use a standardized (existing) protection model with voltage and frequency thresholds and time delays to show the minimum disturbance tolerance requirement that applies to the plant. Also, the frequency calculations in a positive-sequence simulation tool is not accurate during or immediately following a fault nearby. It is best to use the frequency protection relay model in a monitor-only mode and always have some time delay (e.g., at least 50 ms) associated with any under- and over-frequency trip settings.[72]

[72] https://www.wecc.org/Reliability/WECC_White_Paper_Frequency_062618_Clean_Final.pdf

Hybrid Plant Dynamics Modeling

The dynamic modeling approach to hybrid power plants also depends on whether they are ac-coupled or dc-coupled. The modeling practices for the BESS component for ac-coupled hybrid resources generally follow the same principles discussed in the previous section. This section provides additional considerations unique to the hybrid power plants, both ac-coupled and dc-coupled.

As with stand-alone BESS modeling, model invocation is based on the specific simulation tool being used. In general, the plant-level controller model for ac-coupled hybrid resources will require careful consideration. In general, this model needs to be invoked from one of the on-line generators in the plant, and the regulated bus and monitored branch must be specified for REPC_* model.

AC-Coupled Hybrid Modeling

For an ac-coupled hybrid plant, each type of the resources is modeled explicitly by a set of equivalent generator(s), equivalent pad-mounted transformer(s) and equivalent collector system(s) in the power flow. Each generator has its set of REGC and REEC models. It is recommended that REPC_B is used as the master plant controller to coordinate electrical controls among all generators and apply plant level active and reactive power limits. It is also recommended that REEC_D is used for the non-BESS inverter-based generators for the reason discussed later in active power control. Refer to Table 3.4 for implementations in two different software platforms.

Table 3.4: Models for AC-Coupled Hybrid Plants (in PSLF and PSSE)

Functionality	GE PSLF Module	Siemens PTI Module
BESS Grid Interface	regc_*	REGC*
BESS Electrical Controller	reec_c or reec_d	REECC1 or REECD1
Plant-Level Controller	repc_b[73]	PLNTBU1
Auxiliary Controller		REAX4BU1 or REAX3BU1
Voltage/Frequency Protection	lhvrt/lhfrt	VRGTPA/FRQTPA
Non-BESS Generation Component of Hybrid Facility	Use appropriate modules for the generation type (i.e., applicable models for wind, solar, synchronous generation, etc.)	

Reactive Power Control

Each individual generation type in the hybrid power plant has its qmax and qmin specified in the REEC module. The qmax and qmin values in REPC_B represents the reactive capability limits at the plant level. Depending on specific interconnection requirements, the plant level limit could be contractual instead of physical. The qmax and qmin values should reflect how the plant operates. The qmax and qmin values in REPC_B are provided on the system MVA base instead of the generator MVA base. Similar practices need to be carefully applied when using other software platforms

The reactive power capability requirement is generally specified at the high side of the substation transformer(s). For a hybrid power plant, an individual generation type may not have the capability to meet the requirement. Instead different generation types supplement each other to provide required var capability. Depending on the dispatch condition, one type may have little reactive capability available and the other has full capability. The weighting factors of voltage/var control, kwi, need to be tuned for different operating conditions.

[73] The repc_b module in PSLF is equivalent to the combined PLNTBU1 and REAX4BU1/REAX3BU1 in PSS®E.

Active Power Control

Most of the hybrid power plant has a contractual plant level Pmax less than the sum of the individual generator Pmax. Pmax and Pmin in the REPC_B module represents the contractual plant level active power limits. Pmax and Pmin in REPC_B are provided on the system MVA base instead of the generator MVA base. Similar practices need to be carefully applied when using other software platforms

The frequency response is only modeled in REPC_B for the entire plant and pref is distributed among generators by the weighting factors kzi. Kzi may need to be tuned for different operation conditions. But more often, the hybrid plant relies on BESS for upward frequency response. REEC_D module should be used in conjunction with REPC_B to block or enable frequency response at the generator level. See an example in Table 3.5. The gen type that does not have headroom for upward frequency response has base load flag set to 1. REEC_D module will set Pmax to initial Pgen during the initialization, thus the blocking upward frequency response. The BESS has base load flag set to 0 and will respond to the active power command from REPC_B.

Table 3.5: Active Power-Frequency Control Settings for Hybrid Configurations

Component	BaseLoad Flag	Module
Solar PV - Frequency response, down only regulation	1	reec_d
BESS - Frequency response, up and down	0	reec_c or reec_d
Plant controller	N/A*	Repc_b with Frqflag=1, dup > 0, ddn > 0

* The baseload flag in the power flow is associated with each individual component. There is no baseload flag for the plant.

DC-Coupled Hybrid Modeling

For a dc-coupled hybrid plant, one equivalent generator represents the inverters for multiple DC side sources, typically solar PV and battery storage. One set of REGC, REEC and REPC models is needed for the equivalent generator. The electrical control module suitable for the battery storage (REEC_C or REEC_D) could always be used for this type of inverters. In case the battery does not charge from the grid, one may choose to use the electrical control module suitable for the other DC side energy source, e.g. REEC_A module. Refer to Table 3.6 for implementations in two different software platforms.

Table 3.6: Models for DC-Coupled Hybrid in PSLF and PSS®E

Component		PSLF Module	PSS®E Modules
Grid Interface		regc_*	REGC*
Electrical Controls	May Charge from Grid	reec_c or reec_d	REECC1 or REECD1
	DC-Side Charging Only	reec_a or reec_d	REECA1 or REECD1
Plant Controller		repc_*	REPC*/PLNTBU1
Voltage/Frequency Protection		lhvrt/lhfrt	VRGTPA/FRQTPA

The modeling considerations for dc-coupled hybrid plant are the same as the discussed in BESS modeling above.

Electromagnetic Transient Modeling for BESSs and Hybrid Plants

Recommendations pertaining to EMT modeling of BESSs and hybrid power plants are very similar to those that have previously been put forth in NERC Reliability Guidelines.[74] All TPs and PCs should establish EMT modeling requirements for all newly interconnecting BESSs and hybrid plants. GOs should coordinate with equipment manufacturers and any other entities (e.g., consultants developing the models) to ensure the model represents the expected topologies, controls, and settings of the plant seeking interconnections and to ensure that the models are updated after commissioning to represent the as-built settings of the facility. TPs and PCs should collect sufficient data and supplementary information from the GO to ensure that the as-built settings match the model.

It is important that the fundamental-frequency positive sequence dynamic models are a reasonable representation of the facility as well, and the EMT models can help serve as a useful verification of those models. Benchmarking becomes increasingly important as plant-level controls get more complex across multiple manufacturers and different technologies. TPs and PCs should ensure that documentation is provided by the equipment manufacturers and GOs to explain how the plant controller works, and how the model(s) map to those controls.

[74] https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability_Guideline_IBR_Interconnection_Requirements_Improvements.pdf

Chapter 4: BESS and Hybrid Plant Short Circuit Modeling

BESSs and hybrid plants should be modeled in short-circuit programs during the interconnection process and during ongoing planning, design, and protection setting activities. TPs, PCs, TOs, and other entities should develop or enhance modeling practices for BESSs and hybrid plants as new capabilities and features within existing tools become available. At a high-level, the recommendations for modeling BESSs and hybrid plants are the same as for modeling other full-converter inverter-based generating resources (e.g., Type 4 wind, solar PV, voltage source converter HVDC, and other FACTS devices).[75] The modeling practices described in this chapter should help industry develop standardized approaches for modeling BESSs and hybrid plants, similar to other inverter-based resources, that capture the key performance characteristics, appropriately represent equipment ratings, and capture other nuances[76] involved with modeling each specific facility.

BESS Short Circuit Modeling

The IEEE Power System Relaying and Control (PSRC) Committee Working Group C24 led the development of state-of-the-art inverter-based resource short-circuit modeling practices, and recently published *Technical Report #78: Modification of Commercial Fault Calculation Programs for Wind Turbine Generators*.[77] This report advises industry on necessary modifications to commercial short-circuit programs to allow accurate modeling of wind turbine generators and wind power plants. While the report does not specifically discuss modeling solar PV, BESS, or other inverter-based resources, the recommendations for modeling Type 4, full-converter wind resources also apply to solar PV and BESS facilities. Presently, the software vendors for commercial short-circuit programs have incorporated the new modeling approach of representing voltage-dependent current sources into their respective programs.[78] TOs, TPs, and PCs should coordinate to ensure that modeling requirements are reflective of these new capabilities, and that well-defined specifications are in place to collect all necessary short-circuit modeling information from the GO. GOs can work with their inverter manufacturer to gather the necessary information to meet the modeling requirements.

In general, inverters are voltage-dependent current sources, meaning the amount of active and reactive current injected by the inverter during a fault is dependent on its terminal voltage. Inverter control logic dictates the voltage dependency (e.g., K-factor or closed-loop response) and is typically non-linear. As with wind and solar PV resources, the fault current from a BESS also depends on the pre-fault current. Particularly for BESSs, it also depends on whether the BESS is charging or discharging prior to the fault. BESS fault current is relatively independent of BESS SOC since the SOC does not modify any control loops or affect inverter overload current capability.[79]

The IEEE PSRC WG C24 report recommends that fault current injection information be provided for inverter-based resources in a tabular form (see Table 4.1 as an example). These tables should be provided for different fault types as specified by the TO, TP, and PC. Further, inverter controls may take time to reach a steady-state fault current levels so the report recommends that fault current data be provided for various time instants after fault initiation (e.g., 1, 3 and 5 cycles). If the resource provides unbalanced fault currents for unbalanced faults, then additional tables will be needed for the negative sequence current contribution. Particularly for BESSs, different set of tables should be provided for BESS in charging and discharging operation. Most TPs and PCs prefer data provided in sequence domain (positive, negative, and zero) rather than in phase domain. Again, TOs, TPs, and PCs should ensure their modeling

[75] See Chapter 3 of NERC *Reliability Guideline: Improvements to Interconnection Requirements for BPS-Connected Inverter-Based Resources*: https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability_Guideline_IBR_Interconnection_Requirements_Improvements.pdf
[76] Such as capturing different control algorithms and any additional short-circuit current from BESSs due to additional energy on the dc bus.
[77] IEEE PES Technical Report TR78: Modification of Commercial Fault Calculation Programs for Wind Turbine Generators: https://resourcecenter.ieee-pes.org/technical-publications/technical-reports/PES_TP_TR78_PSRC_FAULT_062320.html
[78] See "Siemens Technical Bulletin - Inverter-Based Generator Models with Controlled Power and Current – 2019 PSS CAPE User Group Meeting" and "ASPEN Technical Bulletin – Modeling Type-4 Wind Plants and Solar Plants" for more details.
[79] BESS SOC is closely managed and not expected to be operated near the edge of its charge or discharge limit during normal operation.

requirements are clear regarding the type of information (and format) needed, and GOs should coordinate with their inverter manufacturer to provide the necessary modeling information.

Table 4.1 shows an example (and should only be taken as an example) of the steady-state fault current contribution of a BESS to a symmetrical three-phase fault, and assumes that the BESS only provides positive sequence current. In this example, if a three-phase fault were to cause the inverter terminal positive sequence voltage to drop to 50%, the inverter will inject 120% of rated current at a power factor angle of -45 degrees. Negative power factor angle (i.e., current lags voltage) means the reactive current is injected into the network. Assuming that the inverter is not designed to inject unbalanced current during unbalanced faults, the inverter would inject the same current if a L-L fault on the network results in an inverter terminal positive sequence voltage of 50%. However, if the inverter can inject an unbalanced current, then a similar table representing negative sequence quantities should be provided by the GO. TOs, TPs, and PCs should ensure that their interconnection requirements clearly state how this short-circuit behavior (and short-circuit models) is required to be provided during the interconnection process.

Table 4.1: Example Positive Sequence Fault Current from BESS

V1* (pu)	I1* (pu)			Angle between V1 and I1 (deg)
	Active	Reactive	Total	
0.9	1.00	0.17	1.01	-9.7
0.8	1.00	0.34	1.06	-18.8
0.7	1.00	0.51	1.12	-27.0
0.6	0.80	0.68	1.20	-34.5
0.5	0.85	0.85	1.20	-45.0
0.4	0.63	1.02	1.20	-58.3
0.3	0.15	1.19	1.20	-82.9
0.2	0.0	1.20	1.20	-90.0
0.1	0.0	1.20	1.20	-90.0

* V1 = positive sequence voltage; I1 = positive sequence current

Hybrid Plant Short Circuit Modeling

As with the steady-state and dynamics modeling recommendations described in Chapter 2 and Chapter 3, respectively, short-circuit modeling recommendations depend on whether the plant is ac-coupled or dc-coupled:

- **DC-Coupled Hybrid Plant:** As noted earlier, the fault current contribution is dictated by the inverter that couples the ac side with multiple resources on the dc side. The fault behavior of an inverter does not change if there are multiple energy sources behind it. For the purpose of short-circuit modeling, inverter modeling practices are the same as noted above (i.e., dc-coupled plants are modeled like other inverter-based resources).
- **AC-Coupled Hybrid Plant:** An ac-coupled hybrid power plant couples each form of generation or storage at a common collection bus on the ac side. AC-coupled plants should have the generating component and the BESS component modeled separately. The inverters used may be from different manufacturers, different models, and have different control philosophies that need to each be represented appropriately.

Chapter 5: Studies for BESS and Hybrid Plants

As BESS and hybrid plants become more prevalent, it will become increasingly important to accurately reflect these resources in simulations of BPS reliability, including studies during the interconnection process as well as operational planning and annual planning assessments. When considering study assumptions, the primary difference between BESS (including hybrid plants with BESS), when compared to other resources, revolves around the assumptions regarding charging and discharging operating points under various system conditions. This chapter describes considerations to be accounted for in these studies modeling the various dispatches and studying the reliability impacts of these resources.

Interconnection Studies

Interconnection studies for new or modified BESS and hybrid plants include the same types of studies performed for any other IBR, including steady-state, short circuit, and stability analyses. These studies should be designed to consider all reasonable charging and discharging scenarios the plant may be expected to experience and that may be expected to stress the system and the plant under study. Given that a BESS or the battery component of a hybrid resource are controllable and generally responsive to system conditions, study assumptions should be appropriate for all possible operating scenarios, (e.g., when the BESS or battery component of a hybrid plant are charging and discharging). In addition, the most-stressed assumptions should be modeled to assess reliability, keeping in mind there can be different most-stressed scenarios for different hours of a year and for different local networks. Consideration should be given to the characteristics of the system where the plant is interconnecting, including other resource types in the area.

Interconnection studies should incorporate appropriate steady-state and dynamic ratings of all equipment, and identify the most-limiting elements that establish any system operating limits. Interconnecting entities should apply dynamic limits of equipment, as appropriate, to support all services available from the BESS or hybrid plant. No administrative limits should be applied. Entities should avoid establishing static limits that will limit dynamic services from BESSs and hybrid plants from being provided to the BPS. Short-circuit studies will also be needed in order to ensure appropriate breaker duty ratings, protective relay settings, and sufficient and appropriate fault currents. EMT studies may also be needed based on specific-system conditions at the point of interconnection (e.g., control interactions or control instability in low short circuit strength areas). All reliability studies should use models that have been validated and rigorously verified by the TP and PC to be appropriate for the type of study being conducted.

Table 5.1 provides a list of example scenarios possibly studied during the interconnection process and considerations for each. This list is not exhaustive nor is it necessary for every interconnection study. TPs and PCs should consider the full extent of possible BESS and hybrid plant modes of operation based on the local interconnection requirements or market rules and perform reliability studies to ensure reliable operation of the BPS under all expected operating conditions. For example, hybrid plants may or may not be allowed to charge from the BPS depending on local requirements. These considerations will need to be made by TPs and PCs as they develop their study approaches. In general, BESSs and hybrid plants will follow directives from the BA and RC based on system reliability needs and market incentives, where applicable, and TPs and PCs can use this assumption when determining appropriate charge and discharge assumptions. For example, in a market environment, the battery will typically discharge during periods of high power prices and charge during times of low power prices. Generally, the price of power will be higher during peak demand and lower during low demand or high renewable output conditions.[80] Table 5.1 was constructed with these assumptions in mind, with exceptions noted.

[80] However, these assumptions may change over time as more BESSs and hybrid plants connect to the BPS, changing the overall system's operational characteristics.

Table 5.1: Potential BESS and Hybrid Plant Study Dispatch Scenarios			
System Conditions	**Plant Type**	**Plant Dispatch**	**Considerations**
Peak net demand	BESS	Fully discharging	This is a feasible scenario.
		Fully charging	Depending on market mechanisms and system rules, this scenario may not be feasible. However, there may be situations where this is a feasible scenario. For example, in a system that has a lot of wind generation, if there is high wind output at peak load a BESS may be charging to prepare for a time later in the day when the wind is expected to die down. Another feasible scenario would be when a BESS is charging right before peak load, when the system is "near" peak.
	Hybrid	Maximum plant output	This is a feasible scenario. This scenario could be achieved by a combination of maximum renewable generation output and/or maximum battery output to achieve the maximum facility rating as limited by the power plant controller.
		Maximum renewable generation output with battery fully charging	This may be a feasible scenario. Though it is unlikely to stress the system, this scenario could stress the plant and may need to be studied in transient simulations.
		No or low renewable generation output with battery fully discharging	This is a feasible scenario. The BESS component injects power at its maximum capability with some or no contributions from the generating component.
		No or low renewable generation output with battery fully charging from the grid	Similar to BESS fully charging scenario, as described above. Depending on interconnection requirements and market rules, this scenario may not be feasible. However, there may be situations where this is a feasible scenario depending on localized transmission constraints.
Off-peak (low) net demand	BESS	Fully discharging	This is an unlikely scenario, but it is possible an area could have a high price, due to nearby constraints, so it could need to be studied.
		Fully charging	This is a feasible scenario.
	Hybrid	Maximum plant output	This is a feasible scenario. This scenario could be achieved by maximum renewable generation output that is sustained for a period long enough that the battery is no longer able to charge.
		Maximum renewable generation output with maximum battery charging	This may be a feasible scenario. Though it is unlikely to stress the system, this scenario could stress the plant and may need to be studied in transient simulations.
		No or low renewable generation output with battery fully discharging	This is unlikely to be feasible, but may be a feasible scenario for ac-coupled hybrids in some situations depending on localized transmission constraints.

Table 5.1: Potential BESS and Hybrid Plant Study Dispatch Scenarios			
System Conditions	**Plant Type**	**Plant Dispatch**	**Considerations**
		No or low renewable generation output with battery fully charging from the grid	This may be a feasible scenario depending on interconnection requirements, market rules, and plant design. Solar investment tax credit rules may incent hybrids to not charge from the grid during the first five years of operation, but it may be feasible starting in year six.
High system-wide renewable generation output	BESS	Fully discharging	This is an unlikely yet possible scenario.
		Fully charging	This is a feasible scenario.
	Hybrid	Maximum plant output	This is a feasible scenario.
		Maximum renewable generation output with maximum battery charging	This may be a feasible scenario. Though it is unlikely to stress the system, this scenario could stress the plant and may need to be studied in transient simulations.
Changes in dispatch	BESS	Variable	BESS transitions between charging and discharging should be tested in both steady-state and dynamic simulations. TPs and PCs should test that the model matches required ramping requirements (as applicable) and ensure that change in power dispatch do not adversely affect BPS reliability (e.g., power quality, flicker, voltage deviations, successive operation[81] of voltage control devices).

BESSs can operate in different operating modes that may change over time. Examples include: active power-frequency control, peak shaving, energy arbitrage, etc. TPs should consider the impact of each operating mode on BPS performance.

Hybrid Additions – Needed Studies

When a BESS component is added to an existing generating facility, additional interconnection studies are required per the latest version of the NERC FAC-002 Reliability Standards as this would constitute a material modification of the existing facility. Studies of material modifications are crucial for ensuring that changes to facility ratings, performance, or behavior do not adversely affect BPS reliability. The types of studies and the level of detail of those studies should be determined by the TP and PC as part of the study process. This is particularly dependent on how the addition of the BESS affects the existing facility, including:

- If the BESS connects through the same existing ac/dc inverter as the generating component (i.e., dc-coupled), and no modifications to the ac/dc inverter occur
- If the BESS connects through the same existing ac/dc inverter as the generating component (i.e., dc-coupled), and modifications to the ac/dc inverter occur or a new ac/dc inverter is used
- If the BESS connects through its own ac/dc inverter (i.e., ac-coupled)

[81] Some voltage control devices such as transformer load tap changers or fixed capacitors are limited in the number of operations that are allowed in a given timeframe.

A key aspect to consider, particularly with the second and third scenarios above, is whether the modifications to the facility and its new operational characteristics allow the BESS to charge from the BPS or only from the generating component (a key factor for existing unidirectional inverter technology). The operational capabilities and requirements in place should drive the specific types of studies to be performed by the TP and PC. Again, any modifications to the facility that result in its electrical behavior, operational characteristics, or performance to change should be studied through the material modification process of the latest version of the FAC-002 standard. Table 5.2 provides some guidance on the studies that should be performed for these situations.

Table 5.2: Interconnection Study Needs for Battery Storage Addition at Existing Plant

Process/ Study	AC-Coupled or DC-Coupled with New/Modified Inverter	DC-Coupled with Existing Inverter and Grid Charging	DC-Coupled without Grid Charging (no inverter changes)
Registration with and Notification to the TP/PC	Needed	Needed	Needed
Steady-State Power Flow Study	Needed if the maximum plant active power injection or withdrawal capability changes or if the operational characteristics change; not needed otherwise	Needed to study charging mode	May be needed to study different operating conditions
Short-Circuit Study	Needed	Not needed	Not needed
Stability Study[82]	Needed	Needed to study charging mode	May be needed to study different operating conditions

In all cases above regarding the modification of an existing facility to convert it to a hybrid facility, the GO should coordinate with their TP and PC to ensure that any necessary modeling, study, and performance requirements are met with the changes being made. TPs and PCs should ensure that their interconnection process and requirements clearly describe how studies are performed using accurate models of the expected facility modifications.

Transmission Planning Assessment Studies

Traditionally, system-assessment steady-state and stability studies tend to focus on peak-load and off-peak study conditions. However, with the growth of variable energy resources, combined with an increase in BESSs and hybrid resources, operational planning and long-term planning studies need to evolve to analyze more scenarios as there may be critical and stressed conditions outside of those traditionally studied. TPs and PCs should develop a set of study conditions that reasonably stress the system for their region. TPs and PCs may begin relying on the operational flexibilities of BESSs and hybrid plants in the future, and will need to consider the operational limitations and energy ratings of the BESSs and hybrid plants. Planners will need to consider the impact of BESS SOC and duration of charge available to ensure that the operational solution can remain in place until other automatic or operator actions take place. This is particularly important when performing steady-state contingency analysis, where TPs and PCs will need

[82] This includes review of system and plant stability as well as other types of performance tests such as voltage, frequency, and phase jump ride-through performance.

to closely consider the duration of the outage and the energy available from BESSs and hybrid plants to support the BPS post-contingency.[83] Refer back to Table 5.1 as a reference for study scenarios to begin these conversations.

A good approach to determine when the BESS or hybrid plant is expected to charge versus discharge is to employ production cost simulation techniques. The results from production cost simulations can provide useful information regarding the operational characteristics of the BESS or hybrid plant. The most stressed system conditions can then be determined using engineering judgement for future-year cases. Similar tools could also be used for the power flow and dynamics analyses to avoid guessing at the most stressed conditions. One challenge with using production cost approaches is determining the exact location and operational characteristics of future BESSs and hybrid plants in future year cases where system operational characteristics may be different than past experience. This poses a challenge for grid planners in developing corrective action plans and planning a future system that has sufficient operational flexibility.

Even when charging from the grid, a BESS or a hybrid plant is not considered to be load. Curtailment of charging should not be considered non-consequential load loss if such curtailment is needed to meet performance requirements of Table 1 of TPL-001-4/TPL-001-5.

Blackstart Study Considerations

In the near-term, it is not likely that BESSs will be sized with sufficient energy to meet blackstart requirements (in terms of sustained power output); however, it is likely that BESSs and hybrid plants may be able to help support system restoration. This will require that the BESS or hybrid plant can operate in “island mode” or stand-alone operation and be able to transition to BPS-connected automatically. It also requires that the resource operate in “grid forming” mode where it can develop its own local voltage (without any, or minimal, support form synchronous machines), energize BPS elements, and connect to other local loads and generators. TPs and PCs performing blackstart studies should ensure proper transitions to and from operation in islanding mode. Considerations for these studies include:

- **Transitioning to and from Islanding Mode:** The objective is to ensure stable transition of BESS operation between grid-connected mode and islanding mode. An example of such study is to consider loss of the last synchronous machine in the network that results in the BESS or hybrid plant (possibly along with other IBRs) being the only sources of energy to serve load. Following the transition, and for any subsequent events within the island (example a fault or load change), the BESS or hybrid plant (and other IBR) controls should be able to bring voltage and frequency back close to their nominal values while meeting existing reliability and system security metrics. The same stable transition should be delivered when returning to a grid connected mode.
- **Operating in Islanding Mode:** The objective is to ensure that the BESS or hybrid plant can properly control local voltage and frequency when connected to local load with no, or minimal, other synchronous machines or other generators. Simulation tests to be performed may include load step up/down, ringdown, voltage ride-through, and frequency ride-through tests.
- **Blackstart:** If the BESS or hybrid plant meets the TO, TP, and PC requirements for blackstart, then the objective is to ensure the blackstart capability can be met whether the BESS or hybrid plant is the sole resource or is deployed as part of the blackstart cranking path. A typical example of a blackstart study can be conducted as follows: energize main power transformer from project side, connect the project to the local BPS network and serve localized load, and then apply a bus fault at the POI to demonstrate that the resource can stably and reliably serve that local load during the system restoration process.

[83] This may become more complex as increasing numbers of BESSs and hybrid plants connect to the BPS and are modeled in power flow studies.

CAISO BESS and Hybrid Study Approach Example

This section provides a brief description of the CAISO approach for studying BESSs and hybrid plants.

CAISO Generation Interconnection Study

Most of the active CAISO interconnection requests are hybrid plants. All hybrid plant requests are studied at the hybrid plant full output level with the BESS at discharging mode. If the interconnection customer elects to charge from the grid, the hybrid request is studied in the charging assessment as well. The maximum charging power is specified in the interconnection request. The two studies that are performed include:

- **Discharging Assessment:** This assessment includes gross peak and off-peak daytime scenarios with dispatch shown in Table 5.3. For hybrid power plant requests, total hybrid plant active power is enforced.
- **Charging Assessment:** This assessment includes gross peak or shoulder peak, and off-peak nighttime scenarios. In shoulder peak and off-peak nighttime scenarios, solar power output is zero. For most of the hybrid requests, this means on-site generation is not available to charge the energy storage and create the most stressed condition for the transmission grid.

Table 5.3 shows the different assumptions that are used for the studies conducted. The purpose of the reliability assessment is to define the boundaries of operation. Mitigation of a potential problem is usually through generation re-dispatch (congestion management) or RAS actions.

Table 5.3: CAISO Reliability Assessment Dispatch Assumptions

Condition	Peak	Peak Charging	Shoulder Peak Charging	Off-Peak Daytime	Off-Peak Nighttime Charging
Load Level[84]	1-in-10 years	1-in-10 years	75% of peak	50% ~ 65% of peak	40% of peak
Solar Generation	Pmax	Pmax	0	85% of Pmax	0
Wind Generation	Pmax	50–65% of Pmax	50% of Pmax	Pmax	Pmax
Energy Storage Dispatch	Max discharging[85]	Max charging[86]	Max charging	Max discharging	Max charging
Other Renewable	Pmax	Pmax	Pmax	Pmax	Pmax
Thermal Generation	Pmax	As needed to balance load	As needed to balance load	As needed to balance load	As needed to balance load
Hydro Generation	Based on historical data	Based on historical data	Based on historical data	Based on historical data	Based on historical data
Import Levels	Historical max flows adjusted to accommodate output from renewable generation as needed				

BESSs follow market dispatch instructions and will be discharged or charged according to system needs. A possible solution to mitigate reliability issues is to dispatch the BESS in a different mode (charging or discharging). However,

[84] Forecasted demand levels for peak conditions are in likelihoods (1-in-10 is a 1 in 10 year likelihood) and are based on historical data for off-peak conditions that are then scaled to selected study years.
[85] Maximum steady-state positive output associated with the maximum net output in the Interconnection Request
[86] Maximum steady-state negative output for re-charging of the energy storage facility

there are challenges associated with reliance on this capability without knowing detailed information about the SOC of the BESS. Further, experience has shown that the frequency of deep cycling the BESS shortens its life time and therefore BESS should be sized based on expected frequency profile at the POI.

The CAISO also performs deliverability assessments[87] as part of the interconnection study process. This includes a deliverability assessment at peak demand for resource adequacy purposes as well as a delivery assessment at off-peak demand to evaluate potential curtailment of intermittent resources (i.e., wind and solar). Table 5.4 shows the assumptions used in these deliverability assessments.

Table 5.4: Study Assumptions for BESS and Hybrid Resources in Deliverability Assessment

Delivery Assessment	Standalone BESS	AC-Coupled Hybrid	DC-Coupled Hybrid
Peak	4-hr discharging capacity	4-hr discharging capacity with total plant output <= plant pmax	
Off-Peak	Pgen=0 from BESS. Existing BESS or hybrid may be put into charging mode in order to mitigate overload.		

CAISO Transmission Planning Study

Many different power flow and stability studies are conducted when considering the overall annual transmission planning study program. The dispatch of BESSs and hybrid plants are set based on the time stamp and assumptions used for each scenario being studied. Production cost simulations are used to determine the appropriate dispatch scenarios for future year cases.

[87] http://www.caiso.com/Documents/IssuePaper-GenerationDeliverabilityAssessment.pdf

Appendix A: Relevant FERC Orders to BESSs and Hybrids

The Federal Energy Regulatory Commission (FERC) recently issued Orders pertaining to electric storage resources, relevant to the guidance contained in this Reliability Guideline. FERC defined an electric storage resource as:

> **Electric Storage Resource (FERC Definition):**[88] a resource capable of receiving electric energy from the grid and storing it for later injection of electric energy back to the grid."

FERC's determinations in Order No. 841, Order No. 842, and Order No. 845 are leading to new wholesale market participation models, updates to interconnection studies processes, and new operating practices.

FERC Order No. 841

In Order No. 841[89] (February 15, 2018), FERC required Regional Transmission Organizations (RTOs) and Independent System Operators (ISOs) under its jurisdiction to establish participation models that recognize the physical and operational characteristics of electric storage resources. Each participation model, per the Order, must "ensure that a resource using the participation model for electric storage resources is eligible to provide all capacity, energy, and ancillary services that it is technically capable of providing in the RTO/ISO markets" and "account for the physical and operational characteristics of electric storage resources through bidding parameters or other means." These ancillary services may include blackstart service, primary frequency response service, reactive power service, frequency regulation, or any other services defined by the RTO/ISO.

The Commission gave flexibility to both transmission providers, in determining telemetry requirements, as well as to electric storage resources, in managing state of charge. To the extent that electric storage resources are providing ancillary services, such as frequency regulation, an electric storage resource managing its state of charge is required to follow dispatch signals. For ease of reference, the Commission provided a chart of "physical and operational characteristics of electric storage resources for which each RTO's and ISO's participation model for electric storage resources must account", as shown in Table A.1. How these characteristics are accounted for in participation models may vary between RTOs and ISOs. Note that these definitions are not endorsed by the NERC IRPWG; rather, they are provided here only as a reference.

Table A.1: FERC Participation Model Parameters

Physical or Operational Characteristic	Definition
State of Charge (SOC)	The amount of energy stored in proportion to the limit on the amount of energy that can be stored, typically expressed as a percentage. It represents the forecasted starting State of Charge for the market interval being offered into.
Maximum State of Charge (SOC_{max})	A State of Charge value that should not be exceeded (i.e., gone above) when a resource using the participation model for electric storage resources is receiving electric energy from the grid (e.g., 95% State of Charge).[90]
Minimum State of Charge	A State of Charge value that should not be exceeded (i.e., gone below) when a resource using the participation model for electric storage resources is injecting electric energy to the grid (e.g., 5% State of Charge).

[88] FERC Order No. 841, paragraph 29.

[89] https://ferc.gov/sites/default/files/2020-06/Order-841.pdf

[90] The IRPWG notes that the base for defining the percentage SOC is not defined and therefore up to interpretation by the ISO/RTO.

Table A.1: FERC Participation Model Parameters	
Physical or Operational Characteristic	**Definition**
Maximum Charge Limit	The maximum MW quantity of electric energy [power][91] that a resource using the participation model for electric storage resources can receive from the grid.
Maximum Discharge Limit	The maximum MW quantity that a resource using the participation model for electric storage resources can inject to the grid.
Minimum Charge Time	The shortest duration that a resource using the participation model for electric storage resources is able to be dispatched by the RTO/ISO to receive electric energy from the grid (e.g., one hour).
Maximum Charge Time	The maximum duration that a resource using the participation model for electric storage resources is able to be dispatched by the RTO/ISO to receive electric energy from the grid (e.g., four hours).
Minimum Run* Time	The minimum amount of time that a resource using the participation model for electric storage resources is able to inject electric energy to the grid (e.g., one hour).
Maximum Run Time	The maximum amount of time that a resource using the participation model for electric storage resources is able to inject electric energy to the grid (e.g., four hours).
Minimum Discharge Limit	The minimum MW output level that a resource using the participation model for electric storage resources can inject onto the grid.
Minimum Charge Limit	The minimum MW level that a resource using the participation model for electric storage resources can receive from the grid.
Discharge Ramp Rate	The speed at which a resource using the participation model for electric storage resources can move from zero output to its Maximum Discharge Limit.
Charge Ramp Rate	The speed at which a resource using the participation model for electric storage resources can move from zero output to its Maximum Charge Limit.

* Note that the definitions here interchange “run” and “discharge”. The preferred term is “discharge”.

FERC Order No. 842

In Order No. 842[92] (February 15, 2018), the Commission determined that electric storage resources under its jurisdiction are only required to provide primary frequency response (PFR) when they are “online and are dispatched to inject electricity to the grid and/or dispatched to receive electricity from the grid.” This excludes situations when an electric storage resource is not dispatched to inject or receive electricity.[93] The Commission required electric storage resources and transmission providers to specify an “operating range for the basis of the provision of primary frequency response.” The operating range, the Commission explained, represents the minimum and maximum states of charge between which an electric storage resource must provide PFR. The operating range for each electric storage resource must:

[91] There is a disagreement between units in the FERC definitions. The term “power” is added to note that IRPWG believes this refers to a power term (i.e, MW) and it not intended to be a rate (i.e., MW/sec).

[92] https://cms.ferc.gov/sites/default/files/whats-new/comm-meet/2018/021518/E-2.pdf

[93] As in, electric storage resources are not obligated to provide any frequency response to the BPS if dispatched at 0 MW output. However, the requirements in Order No. 842 are minimum requirements and an electric storage resource may provide this service if the market rules or interconnection requirements are set up to enable this capability. Providing primary frequency response when dispatched at 0 MW could help BPS frequency stability moving forward.

- be agreed to by the interconnection customer and the transmission provider, in consultation with the balancing authority
- consider the system needs for primary frequency response
- consider the physical limitations of the electric storage resource as identified by the developer and any relevant manufacturer specifications
- be established in Appendix C of the LGIA or Attachment 5 of the SGIA

The Commission noted that this suite of requirements "effectively allows electric storage resources to identify a minimum and maximum set point below and above which they will not be obligated to provide primary frequency response comparable to synchronous generation." In sum, the Commission provided electric storage resource interconnection customers with the ability to propose an operating range and the transmission provider or BA the ability to consider system needs for primary frequency response before determining final operating ranges.

Given that "system conditions and contingency planning can change" and that "capabilities of electric storage resources to provide primary frequency response may change due to degradation, repowering, or changes in service obligations," the Commission determined that the ultimate operating ranges may be dynamic values. If a dynamic range is implemented, then transmission providers must also determine the periodicity of reevaluation and the factors that will be considered during reevaluation of the operating ranges. The Commission provided electric storage resources specific exemptions from PFR provision for a "physical energy limitation":

> *"the circumstance when a resource would not have the physical ability, due to insufficient remaining charge for an electric storage resource or insufficient remaining fuel for a generating facility to satisfy its timely and sustained primary frequency response service obligation, as dictated by the magnitude of the frequency deviation and the droop parameter of the governor or equivalent controls."*

The Commission also clarified that MW droop response is derived from nameplate capacity. If dispatched to charge during an abnormal frequency deviation, the Commission required electric storage resources to meet PFR requirements by increasing (for overfrequency) or decreasing (for underfrequency) the "rate at which they are charging according to the droop parameter." To illustrate, the Commission gave an example of an electric storage resource charging at two MW with a calculated response per the droop parameter to increase real-power output by one MW. According to the Commission, during an underfrequency deviation the electric storage resource could "satisfy its obligation by reducing its consumption by one MW (instead of completely reducing its consumption by the full two MW and then discharging at one MW, which would result in a net of three MW provided as primary frequency response)." Electric storage resources are not required to change from charging to discharging, or vice versa, if technically incapable of doing so during the event when PFR is needed.

The Commission also noted that requirements adopted in Order No. 842 are minimum requirements. An electric storage resource may elect, in coordination with its transmission provider and BA, "to operate in a more responsive mode by using lower droop or tighter deadband settings."

As with all frequency-responsive resources connected to the BPS, speed of response has a significant impact on frequency performance during large disturbances, particularly in low inertia systems with high ROCOF. FERC Order No. 842 does not prescribe any speed of response characteristics for electric storage resources. See Chapter 1 for more details on how the performance of BESSs and hybrid plants can be configured to support BPS frequency response needs.

FERC Order No. 845

In Order No. 845[94] (April 19, 2018), the Commission clarified that "in certain situations, electric storage resources can function as a generating facility, a transmission asset, or both." The Commission made clear that electric storage resources under its jurisdiction greater than 20 MW had the option to interconnect pursuant to the Large Generator Interconnection Procedures (LGIP) and Large Generator Interconnection Agreement (LGIA), "so long as they meet the threshold requirements as stated in those documents." In the event the LGIA does not accommodate for the load characteristics of electric storage resources, transmission providers may enter into non-conforming LGIAs.

Further, in Order No. 845, the Commission declined to move forward with "any requirements for modeling electric storage resources":

> *"…given the limited experience interconnecting electric storage resources and the abundant desire for regional flexibility, we are not imposing any standard requirements at this time and instead continue to allow transmission providers to model electric storage resources in ways that are most appropriate in their respective regions."*

Instead, the Commission encouraged transmission providers to continue to consider modeling approaches that will "save costs and improve the efficiency of the interconnection process."

FERC Order No. 845-A

In Order No. 845-A[95] (February 21, 2019), the Commission reiterated that Order No. 845 allows electric storage resources to interconnect pursuant to the LGIP and LGIA, but declined to impose requirements on how transmission providers study the load characteristics of electric storage resources. Instead, the Commission clarified that transmission providers "have the flexibility to address the load characteristics of electric storage resources" within studies, including studies of electric storage resource load characteristics and studies of the upgrades required to accommodate electric storage resource load characteristics. Further, the Commission stated that transmission providers may enter into non-conforming LGIAs "when necessary" in order to accommodate a particular electric storage resource.

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[94] https://www.ferc.gov/sites/default/files/2020-04/E-2_47.pdf
[95] https://ferc.gov/sites/default/files/2020-06/Order-845-A.pdf

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NERC gratefully acknowledges the invaluable contributions and assistance of the following industry experts in the preparation of this guideline. NERC also would like to acknowledge all the contributions of the NERC IRPWG.

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Security Guideline for the Electricity Sector: Assessing and Reducing Risk

Action

Accept to post the document for a 45-day industry comment period.

Summary

The purpose of this Guideline is to help organizations determine their current security and compliance posture and develop an improvement plan for addressing any gaps that are identified. The tool for that analysis maps requirements of the CIP Reliability Standards to the National Institute of Standards and Technology (NIST) Cybersecurity Framework (hereafter referred to as "the framework"), and it can help a responsible entity identify areas that may require further action. The SWG is requesting that the RSTC accept this guideline for a 45-day industry comment period.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Security Guideline for the Electricity Sector: Assessing and Reducing Risk

The North American Electric Reliability Corporation (NERC) Reliability and Security Technical Committee (RSTC), through its subcommittees and working groups, develops and triennially reviews reliability guidelines in accordance with the procedures set forth in the RSTC Charter[1]. Reliability guidelines include the collective experience, expertise, and judgment of the industry on matters that impact bulk power system (BPS) operations, planning, and security. Reliability guidelines provide key practices, guidance, and information on specific issues critical to promote and maintain a highly reliable and secure BPS.

Each entity registered in the NERC compliance registry is responsible and accountable for maintaining reliability and compliance with applicable mandatory Reliability Standards. Reliability guidelines are not binding norms or parameters; however, NERC encourages entities to review, validate, adjust, and/or develop a program with the practices set forth in this guideline. Entities should review this guideline in detail and in conjunction with evaluations of their internal processes and procedures; these reviews could highlight that appropriate changes are needed, and these changes should be done with consideration of system design, configuration, and business practices.

Executive Summary

The purpose of this Guideline is to help organizations determine their current security and compliance posture and develop an improvement plan for addressing any gaps that are identified. The tool for that analysis maps requirements of the CIP Reliability Standards to the National Institute of Standards and Technology (NIST) Cybersecurity Framework[2] (hereafter referred to as "the framework"), and it can help a responsible entity identify areas that may require further action.

The tool and associated instructions were the result of a collaborative effort by industry volunteers from the RSTC, Security Working Group (SWG), and representatives from NERC and NIST. The deliverables associated with the guideline underwent a pilot study with SWG members; their recommendations were incorporated into the final version.

Background

NIST's mission is to promote United States innovation and industrial competitiveness by advancing measurement science, standards, and technology in ways that enhance economic security and improve quality of life. As a part of its mission, NIST has developed standards, special publications, and guidelines on various topics, including cybersecurity. In February 2014, NIST published the original Cybersecurity Framework based on existing standards, guidelines, and practices for reducing cybersecurity risks. The framework provides a prioritized, flexible, repeatable, and cost-effective approach, including information

[1] https://www.nerc.com/comm/RSTC/RelatedFiles/RSTC_Charter_approved20191105.pdf
[2] https://www.nist.gov/cyberframework

security measures and controls to help owners and operators of critical infrastructure and other interested entities to identify, assess, and manage cybersecurity-related risk while protecting business confidentiality, individual privacy, and civil liberties.

In January 2020, NERC and NIST representatives approached the SWG to review the framework 1.1 mapping[3] and update it to align with the current version of the CIP Reliability Standards.

The SWG team that produced this Guideline had the following objectives:

- **Vision**

  Provide responsible entity subject matter experts or practitioners with the capability to assess current compliance and security posture and develop a roadmap and/or business justification to reach risk levels per their organization's acceptable risk appetite.

- **Deliverables**

  Documentation

  Guideline that provides a methodology for performing a self-assessment, directions for using the self-assessment tool, potential use cases for identifying gaps in compliance or programs, and assistance in developing risk basked business justifications for improvement

  Tool

  Spreadsheet to self-assess compliance with CIP requirements and security practices and prioritize risk management strategies based on the self-assessment results

Methodology

The methodology used to develop this Guideline leverages the external sources that are indicated below to highlight the relationships between the CIP Reliability Standard requirements and cybersecurity outcomes. "Outcomes" provide a common language for assessing, understanding, and communicating the results for managing cybersecurity-related risk to internal and external stakeholders without limiting the focus to compliance.

- **Authoritative documents[4]**

  NERC CIP Reliability Standards
  The cybersecurity requirements for reliable operation of the North American BPS

  NIST Framework V1.1:
  A set of activities to achieve specific cybersecurity outcomes and informative reference examples of guidance how to achieve them

- **Informative references**

[3] Mapping of CIP Standards to NIST Cybersecurity Framework (CSF) v1.1
[4] Note: mechanisms and processes being implemented to update the self-assessment tool to reflect authoritative document changes

Standards, guidelines, and practices that illustrate a method to achieve the cybersecurity outcomes, as cited in the framework

- **Relationships**
  The association of framework outcomes to CIP requirements to inform overall cybersecurity posture, program, and risk management practice maturity:

  Compliance
  Outcomes that directly relate to and support compliance and cybersecurity requirements

  Cybersecurity
  Although not directly applicable to compliance with the CIP Reliability Standards, associated framework outcomes provide cybersecurity program assurance

Self-Assessment Tool Usage Instructions

These are the instructions for using the companion self-assessment tool of this Guideline. See the **Appendix - Self-Assessment tool design and logic** of this document for an explanation of the design, logic, and screen shots of the self-assessment tool.

1. **Required:** read the "Instructions" tab of the self-assessment tool that mirror these instructions.

2. **Optional:** familiarize yourself with the "Implementation Tier" short descriptions on the Data Validation Values tab of the self-assessment also. You may wish to print those and have them on hand when performing the self-assessment.

   a. Implementation tiers are a direct copy of the tiers as described in the NIST framework.

   b. Implementation tiers provide context on how an organization views cybersecurity risk and the processes in place to manage risk.

   c. The tool provides the capabilities for changing the implementation tier short descriptors to suit your organizations terms if so desired in cells B2:B5.

3. **Optional:** if not intimately familiar with the CIP requirements, review the "CIP Standards" tab and/or the link included in the instructions to NERC's CIP Reliability Standards for the detailed requirements associated with each CIP Reliability Standard.

4. **Optional:** for a list of security standards, guidelines, and practices that map to each framework sub-category, see the "Cyber Security Framework" tab. The associated standards can be used to compare your company's internal controls or cybersecurity program against to identify potential gaps.

5. **Required:** on the "Self-Assessment" tab, perform a risk self-assessment of your company's CIP compliance and cybersecurity practices by selecting from Column I the tier that best represents your implementation level/status of associated outcome.

   Note: the self-assessment tool is intended for CIP requirement owners or practitioners responsible for the creation and implementation of the security controls

6. **Optional:** included with the tool is the capability to modify the provided relationships for each framework sub-category to the associated CIP requirements if so desired.

   a. Select an alternate relationship from the available drop-down list of Column H.

   b. If different and/or a set of alternative relationships are desired, provisions have been built into the tool to do so on the "data validation values" tab in cells B16:B20.

7. **Required:** review the self-assessment results on the "Implementation Dashboard" tab. This tab is automatically updated based on the information entered on the "Self-Assessment" tab. Results displayed are as follows:

a. Column E (Average Implementation Score) shows the average implementation of the associated framework sub-categories. Conditional color formatting is used to show levels of risk based on the level of implemented cybersecurity-related risk management practices (larger numbers = higher implementation levels, with lower risk):

   i. Green for > 3.5 – low risk

   ii. Yellow for between 2.5–3.5 – minimal risk

   iii. Orange for between 3.5–4.5 – moderate risk

   iv. Red for between 1.0–1.5 – high risk

b. Column H (CSF-ID to CIP relationship) is provided to identify compliance or cybersecurity-related categories related to an associated CIP requirement that could be used to prioritize risk treatment activities based on the risk focus of your organization.

c. Column I (Cybersecurity Risk Management Tier) represents the implementation tier of the framework sub-category outcomes associated with a given CIP requirement.

   i. Level 1 represents low or immature capabilities and Level 5 represents high or very mature capabilities.

Note: Column J contains the descriptor with the associated Implementation Tier from the "data validation values" tab in cells B2:B5.

Self-Assessment Results Use Cases

The following are potential suggested use cases of the self-assessment results on the "Implementation Dashboard" of the self-assessment tool:

1. **CIP Violation Risk Factor focus:** filter on Column D (VRF) to identify VRF with a low average implementation scores in Column E, to identify potential CIP Violation Risk Factor compliance improvement opportunities

2. **CIP Compliance focus:** filter on Column H (CSF-IT to CIP Relationship) for "compliance related" relationships (or your equivalent alternative you may have added), to identify potential CIP compliance improvement opportunities based on associated risk implementation tier noted in columns I and J

3. Cybersecurity focus: filter on Column H (CSF-IT to CIP Relationship) for "cybersecurity related" relationships (or your equivalent alternative you may have added), to identify potential cybersecurity compliance improvement opportunities based on associated risk implementation tier noted in columns I and J

Regardless of focus, results can be used to develop business justification for annul budget and resource planning purposes focused on security and compliance risk reduction. Results could also be used to develop a long-term improvement roadmap.

In all cases, responsible entities are encouraged to leverage the framework informative references that may be used in the following manners:

- **Center for Internet Security (CIS) Top 20 Critical Security Controls[5]:** technology teams leverage the CIS top 20 security controls to review IT internal controls against
- **Security Programs:** cybersecurity teams utilize NIST 800-53 or ISO27001 comprehensive security controls to compare implemented security programs against
- **Governance:** governance and oversight teams utilize COBIT security controls to review IT governance and management practices against
- **Industrial Control/OT:** control system operations leverage the ISA 62443 security controls to review implemented security protection measures against

SWG Task Force Members

The following is the list of SWG task force members who volunteered to develop this Guideline document, associated self-assessment tool and overview PowerPoint.

Keith St. Amand (project lead)
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National Institute of Standards and Technology

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Southern California Edison

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Department of Water Resources California

Matthew Light
Western Area Power Administration

[5] https://www.cisecurity.org/controls/cis-controls-list/

Appendix: Self-Assessment Tool Design and Logic

A companion self-assessment tool to this Guideline document has also been developed. The self-assessment tool is based on Microsoft Excel (see **Figure 1**) and provides a mechanism for CIP standard and requirement owners to perform a simple rating of their current risk implementation levels and obtain a "dashboard" that provides actionable criteria to focus on and communicate to stakeholders.

Note: this self-assessment tool was tested within a volunteer set of SWG member companies—their feedback and update suggestions were incorporated into this Guideline and the self-assessment tool.

Figure 1: Excel workbook tabs

Tabs: The Excel workbook contains the following tabs and associated descriptions:

- **Instructions:** contains intended use, background, benefits, tab descriptions, and self-assessment usage instructions
- **Implementation Dashboard:** presents the results of the Self-Assessment tab; results depicting summary score of each the framework sub-category associated with a CIP requirement
- **Self-Assessment:** mapping of CIP requirements aligned to the framework categories (Objectives) and sub-categories (outcomes) with a cybersecurity risk management tier selection item for CIP requirement owner to choose.
- **CIP Standards:** containing unique ID, purpose + requirements, and violation risk factor (VRF) Rating associated with each requirement (Columns B and C are direct copies from the standards. Column A is provided to facilitate Excel pivot table and formula functionality).

  Note: this tab is for reference purposes only and is used in the first two tabs to minimize future maintenance and update efforts of the tool.
- **Cyber Security Framework**: contain information downloadable and available directly from the NIST Cybersecurity Framework.

  Note: this tab is for reference purposes only and is used in the first two tabs to minimize maintenance and update efforts.
- **Pivot Tables:** contains Excel pivot tables that depict the cross-references of CIP requirement ID to the Framework Sub-Category ID and the Framework Sub-Category to CIP to CIP requirement IT.

  Note: The purpose of these cross-references is to facilitate independent analysis if needed/desired.
- **Data Validation Values:**
  - Contains Excel "named references" used throughout the workbook.

- Provides the capability of changing the implementation tier descriptions if the native framework risk implementation tiers are not preferred.
- Contains a description for the framework risk tiers
- Contains a description of the CIP to the framework relationships used in the tool

Logic: The following provides the highlights of the logic applied in the Excel self-assessment tool:

- All tabs are password protected and cells are locked in order to preserve the dynamic and automated features built into the tool.

  Note: The SWG task force team has designed the tool to minimize future update and maintenance efforts. Plans are to provide updates periodically, as either the CIP requirements or the framework updates are released.

- **Implementation Dashboard Tab (see Figure 2)**
  - Contains cell formula in all but Column A and F to automatically update cell contents
    - Column C and D contents updated based on matching row in the CIP Standards tab
    - Column E is the average calculated from the corresponding Risk Management Tier values in Column I
    - Column G contents updated based on matching row in the Cyber Security Framework tab
    - Column H was filled in based on the analysis for the SWG task force team and feedback from testing volunteers
    - Column J contents based on the corresponding value from the data validation values tab
    - Color Conditional formatting:
      - Column D: red for high, brown for medium, green for Lower
      - Column E: green for > 3.5, yellow for 2.5–3.5, orange for 1.5–2.5, red for 1.0–1.5 (in order to avoid applying color formatting to blank rows)
      - Colum J: dynamic formula based on the matching tier on the data validation values tab

CIP Requirement	CIP Standard Purpose and Requirement	VRF Rank	Average Impl Score	CSF-ID	NIST CSF Sub-Category Description *Outcomes*	Sub-Catergory CIP Relationship	Cyber Security Risk Mgmt Tier	Risk Tier Descriptor
CIP-002-5.1a-R1	Purpose: To identify and categorize BES Cyber Systems and their associated BES Cyber Assets for the application of cyber security requirements commensurate with the adverse impact that loss, compromise, or misuse of those BES Cyber Systems could have on the reliable operation of the BES. Identification and categorization of BES Cyber Systems support appropriate protection against compromises that could lead to misoperation or instability in the BES. Requirement 1: Each Responsible Entity shall implement a process that considers each of the following assets for purposes of parts 1.1 through 1.3:	HIGH	2.3	ID.AM-01	Physical devices and systems within the organization are inventoried	directly relates	1	Partial
				ID.AM-02	Software platforms and applications within the organization are inventoried	directly relates	4	Adaptive
				ID.AM-03	Organizational communication and data flows are mapped	indirectly relates	4	Adaptive
				ID.AM-04	External information systems are catalogued	indirectly relates	3	Repeatable
				ID.AM-05	Resources (e.g., hardware, devices, data, and software) are prioritized based on their classification, criticality, and business value	directly relates	2	Risk Informed
				ID.BE-04	Dependencies and critical functions for delivery of critical services are established	directly Relates	1	Partial
				ID.RA-04	Potential business impacts and likelihoods are identified	indirectly relates	1	Partial
CIP-002-5.1a-R2	Purpose: To identify and categorize BES Cyber Systems and their associated BES Cyber Assets for the application of cyber security requirements commensurate with the adverse impact that loss, compromise, or misuse of those BES Cyber Systems could have on the reliable operation of the BES. Identification and categorization of BES Cyber Systems support appropriate protection against compromises that could lead to misoperation or instability in the BES. Requirement 2: The Responsible Entity shall: (See Sub-Requirements 2.1 and 2.2)	LOWER	1.0	ID.AM-01	Physical devices and systems within the organization are inventoried	directly relates	1	Partial
				ID.AM-02	Software platforms and applications within the organization are inventoried	directly relates	1	Partial
				ID.AM-04	External information systems are catalogued	indirectly relates	1	Partial
				ID.BE-04	Dependencies and critical functions for delivery of critical services are established	directly Relates	1	Partial
				ID.RA-04	Potential business impacts and likelihoods are identified	indirectly relates	1	Partial

Figure 2: Implementation Dashboard Tab

- **Self-Assessment Tab (see Figure 3)**
  - All cell contents are populated based on formula reading from either the CIP standards, cyber security framework, or data validation values tabs—intent is to simplify future maintenance update efforts

	CIP	NIST CSF	CSF ID	NIST-CSF Category	NIST CSF ID	NIST-CSF Sub-Category	Cybersecurity	Risk Tier
CIPv5 ID	Requirement and Parts	*Function*	*Cat*	*Objectives*	*Sub-cat*	*Outcomes*	*Risk Mgmt Tier*	*Descriptor*
CIP-002-5.1a-R1	Purpose: To identify and categorize BES Cyber Systems and their associated BES Cyber Assets for the application of cyber security requirements commensurate with the adverse impact that loss, compromise, or misuse of those BES Cyber Systems could have on the reliable operation of the BES. Identification and categorization of BES Cyber Systems support appropriate protection against compromises that could lead to misoperation or instability in the BES. Requirement 1: Each Responsible Entity shall implement a process that considers each of the following assets for purposes of parts 1.1 through 1.3.	IDENTIFY (ID)	ID.AM	Asset Management (ID.AM): The data, personnel, devices, systems, and facilities that enable the organization to achieve business purposes are identified and managed consistent with their relative importance to business objectives and the organization's risk strategy.	ID.AM-01	Physical devices and systems within the organization are inventoried	1	Partial
CIP-002-5.1a-R1	Purpose: To identify and categorize BES Cyber Systems and their associated BES Cyber Assets for the application of cyber security requirements commensurate with the adverse impact that loss, compromise, or misuse of those BES Cyber Systems could have on the reliable operation of the BES. Identification and categorization of BES Cyber Systems support appropriate protection against compromises that could lead to misoperation or instability in the BES. Requirement 1: Each Responsible Entity shall implement a process that considers each of the following assets for purposes of parts 1.1 through 1.3.	IDENTIFY (ID)	ID.AM	Asset Management (ID.AM): The data, personnel, devices, systems, and facilities that enable the organization to achieve business purposes are identified and managed consistent with their relative importance to business objectives and the organization's risk strategy.	ID.AM-02	Software platforms and applications within the organization are inventoried	4	Adaptive

Figure 3: Self-Assessment Tab

- **CIP Standards Tab** (see **Figure 4**)**:** is a compilation of the current effective CIP standards subject to enforcement, as posted on the [NERC CIP Standards site.](#)

  Note: normalized/standardize ID in Column A were created in order to facilitate linkage between the various tabs, filtering, and pivot table capabilities

A	B	C
CIP ID	Purpose and Requirements	VRF Rating
CIP-002-5.1a-R1	**Purpose:** To identify and categorize BES Cyber Systems and their associated BES Cyber Assets for the application of cyber security requirements commensurate with the adverse impact that loss, compromise, or misuse of those BES Cyber Systems could have on the reliable operation of the BES. Identification and categorization of BES Cyber Systems support appropriate protection against compromises that could lead to misoperation or instability in the BES. **Requirement 1:** Each Responsible Entity shall implement a process that considers each of the following assets for purposes of parts 1.1 through 1.3:	HIGH
CIP-002-5.1a-R2	**Purpose:** To identify and categorize BES Cyber Systems and their associated BES Cyber Assets for the application of cyber security requirements commensurate with the adverse impact that loss, compromise, or misuse of those BES Cyber Systems could have on the reliable operation of the BES. Identification and categorization of BES Cyber Systems support appropriate protection against compromises that could lead to misoperation or instability in the BES. **Requirement 2:** The Responsible Entity shall: ***(See Sub-Requirements 2.1 and 2.2)***	LOWER

Figure 4: CIP Standards Tab

- **Cyber Security Framework Tab (see Figure 5):** contains a modified download of the Excel file available from the framework site[6]. The only modification was to place the informative references into individual columns as opposed to including them all in a single cell for each sub-category.

  Note: normalized/standardized IDs were created in order to facilitate linkage between the various tabs, filtering, and Pivot Table capabilities

A	B	C	D	E	F	G	H	I	J
		Outcomes		*Outcomes*	*Informative References*				
Function		Category	ID	Sub-Categories	*NIST 800-53 Rev.*	*CIS CSC*	*COBIT*	*ISA*	*ISO*
	ID.AM	**Asset Management (ID.AM):** The data, personnel, devices, systems, and facilities that enable the organization to achieve business purposes are identified and managed consistent with their relative importance to business objectives and the organization's risk strategy.	ID.AM-01	Physical devices and systems within the organization are inventoried	CM-8, PM-5	CIS CSC 1	BAI09.01, BAI09.02	ISA 62443-2-1:2009 4.2.3.4 ISA 62443-3-3:2013 SR 7.8	ISO/IEC 27001:2013 A.8.1.1, A.8.1.2
			ID.AM-02	Software platforms and applications within the organization are inventoried	CM-8, PM-5	CIS CSC 2	BAI09.01, BAI09.02, BAI09.05	ISA 62443-2-1:2009 4.2.3.4 ISA 62443-3-3:2013 SR 7.8	ISO/IEC 27001:2013 A.8.1.1, A.8.1.2, A.12.5.1
			ID.AM-03	Organizational communication and data flows are mapped	AC-4, CA-3, CA-9, PL-8	CIS CSC 12	DSS05.02	ISA 62443-2-1:2009 4.2.3.4	ISO/IEC 27001:2013 A.13.2.1
			ID.AM-04	External information systems are catalogued	AC-20, SA-9	CIS CSC 12	APO02.02, APO10.04, DSS01.02	N/A	ISO/IEC 27001:2013 A.11.2.6
			ID.AM-05	Resources (e.g., hardware, devices, data, and software) are prioritized based on their classification, criticality, and business value	CP-2, RA-2, SA-14, SC-6	CIS CSC 13, 14	APO03.03, APO03.04, APO12.01, BAI04.02, BAI09.02	ISA 62443-2-1:2009 4.2.3.6	ISO/IEC 27001:2013 A.8.2.1
			ID.AM-06	Cybersecurity roles and responsibilities for the entire workforce and third-party stakeholders (e.g., suppliers, customers, partners) are established	CP-2, PS-7, PM-11	CIS CSC 17, 19	APO01.02, APO07.06, APO13.01, DSS06.03	ISA 62443-2-1:2009 4.3.2.3.3	ISO/IEC 27001:2013 A.6.1.1

Figure 5: Cyber Security Framework Tab

- **Data validation Values (see Figure 6):** primarily for lookup and Excel "named references" purposes used throughout the workbook:
  - **Customization:** cells B2–B5 are unlocked, if a responsible entity does not like the Risk Implementation Tiers as provided by the framework. Changing those to whatever an entity prefers, will automatically update the correspond values on the other sheets.

[6] https://www.nist.gov/cyberframework/framework

Note: Cells C2–C5 are for reference purposes only, describing the conditional formatting colors used on the Implementation Dashboard corresponding to the associated Implementation Tier #.

	A	B	C
1	Implementation Tier	Description	Condiitonal formatting applied
2	1	Partial	Red
3	2	Risk Informed	Orange
4	3	Repeatable	Yellow
5	4	Adaptive	Green
6			

Figure 6: Data Validation Values tab: Customization #1

- **Customization (see Figure 7)**: cells A16 and A17 are unlocked if a responsible entity wishes to use different text to describe.

	A	B
15	Relationships	Descriptions
16	directly Relates	*There are clear and/or direct relationships between the CSF Sub-Category and CIP Requirement*
17	indirectly Relates	*NIST-CSF Focal Document element is a subset of the CIP Reference Document element*

Figure 7: Data Validation Values tab: Customization #2

Design Assumptions

- Each responsible entity will have implemented their own security controls that are often based on the same security guidance identified in the framework informative references.
- Generally, there are separate CIP requirements owners assigned within responsible entity companies and usually develop associated policies, controls, and/or practices.
- By providing a cross-mapping of the CIP standards to the framework sub-categories, requirement owners can view the associated informative reference practices to compare their implemented security controls against.
- The Implementation Dashboard tab summary results will help identify gaps and/or improvement opportunities

Self-Assessment Tab Instructions (see Figure 8)

1. Either distribute the self-assessment tool spreadsheet to individual CIP requirement owners or gather all CIP requirement owners together to collectively review and assess their associated requirement implementation level
2. CIP requirement owners review each of their associated CIP requirements and select the risk implementation level from the available drop-down number in Column H (Cybersecurity Risk Management Tier) that best represents their current practice implementation level.
3. Once completed, move on to review summary results in the Implementation Dashboard tab.

CIPv5 ID	CIP Requirement and Parts	NIST CSF Function	CSF ID Cat	NIST-CSF Category Objectives	NIST CSF ID Sub-cat	NIST-CSF Sub-Category Outcomes	Cybersecurity Risk Mgmt Tier	Risk Tier Descriptor
CIP-002-5.1a-R1	Purpose: To identify and categorize BES Cyber Systems and their associated BES Cyber Assets for the application of cyber security requirements commensurate with the adverse impact that loss, compromise, or misuse of those BES Cyber Systems could have on the reliable operation of the BES. Identification and categorization of BES Cyber Systems support appropriate protection against compromises that could lead to misoperation or instability in the BES. Requirement 1: Each Responsible Entity shall implement a process that considers each of the following assets for purposes of parts 1.1 through 1.3:	IDENTIFY (ID)	ID.AM	Asset Management (ID.AM): The data, personnel, devices, systems, and facilities that enable the organization to achieve business purposes are identified and managed consistent with their relative importance to business objectives and the organization's risk strategy.	ID.AM-01	Physical devices and systems within the organization are inventoried	1	Partial
CIP-002-5.1a-R1	Purpose: To identify and categorize BES Cyber Systems and their associated BES Cyber Assets for the application of cyber security requirements commensurate with the adverse impact that loss, compromise, or misuse of those BES Cyber Systems could have on the reliable operation of the BES. Identification and categorization of BES Cyber Systems support appropriate protection against compromises that could lead to misoperation or instability in the BES. Requirement 1: Each Responsible Entity shall implement a process that considers each of the following assets for purposes of parts 1.1 through 1.3:	IDENTIFY (ID)	ID.AM	Asset Management (ID.AM): The data, personnel, devices, systems, and facilities that enable the organization to achieve business purposes are identified and managed consistent with their relative importance to business objectives and the organization's risk strategy.	ID.AM-02	Software platforms and applications within the organization are inventoried	4	Adaptive

Figure 8: Completing Self-Assessment tab

Implementation Dashboard potential Use Cases:

After all rows in the Self-Assessment tab (see Figure 9) have been completed, the implementation dashboard will represent the summary risk results by CIP requirement to highlight the following:

- Identify where there may be **CIP Violation** risks based on the VRF rank value in Column D and the corresponding average imply score in Column E
- Identify where there may be **Compliance** risks, based on the "Directly Relates" relationship in Column H and a corresponding low implementation level in Column J
- Identify where there may be **Security** risks, based on the "Indirectly Relates" relationship in Column H and a corresponding low implementation level in Column J

CIP Requirement	CIP Standard Purpose and Requirement	VRF Rank	Average Impl Score	CSF-ID	NIST CSF Sub-Category Description Outcomes	Sub-Catergory CIP Relationship	Cyber Security Risk Mgmt Tier	Risk Tier Descriptor
CIP-002-5.1a-R1	Purpose: To identify and categorize BES Cyber Systems and their associated BES Cyber Assets for the application of cyber security requirements commensurate with the adverse impact that loss, compromise, or misuse of those BES Cyber Systems could have on the reliable operation of the BES. Identification and categorization of BES Cyber Systems support appropriate protection against compromises that could lead to misoperation or instability in the BES. Requirement 1: Each Responsible Entity shall implement a process that considers each of the following assets for purposes of parts 1.1 through 1.3:	HIGH	2.3	ID.AM-01	Physical devices and systems within the organization are inventoried	directly relates	1	Partial
				ID.AM-02	Software platforms and applications within the organization are inventoried	directly relates	4	Adaptive
				ID.AM-03	Organizational communication and data flows are mapped	indirectly relates	4	Adaptive
				ID.AM-04	External information systems are catalogued	indirectly relates	3	Repeatable
				ID.AM-05	Resources (e.g., hardware, devices, data, and software) are prioritized based on their classification, criticality, and business value	directly relates	2	Risk Informed
				ID.BE-04	Dependencies and critical functions for delivery of critical services are established	directly Relates	1	Partial
				ID.RA-04	Potential business impacts and likelihoods are identified	indirectly relates	1	Partial
CIP-002-5.1a-R2	Purpose: To identify and categorize BES Cyber Systems and their associated BES Cyber Assets for the application of cyber security requirements commensurate with the adverse impact that loss, compromise, or misuse of those BES Cyber Systems could have on the reliable operation of the BES. Identification and categorization of BES Cyber Systems support appropriate protection against compromises that could lead to misoperation or instability in the BES. Requirement 2: The Responsible Entity shall: (See Sub-Requirements 2.1 and 2.2)	LOWER	1.0	ID.AM-01	Physical devices and systems within the organization are inventoried	directly relates	1	Partial
				ID.AM-02	Software platforms and applications within the organization are inventoried	directly relates	1	Partial
				ID.AM-04	External information systems are catalogued	indirectly relates	1	Partial
				ID.BE-04	Dependencies and critical functions for delivery of critical services are established	directly Relates	1	Partial
				ID.RA-04	Potential business impacts and likelihoods are identified	indirectly relates	1	Partial

Figure 9: Review Self-Assessment Results

References

- NIST Cybersecurity Framework 1.1: https://nvlpubs.nist.gov/nistpubs/CSWP/NIST.CSWP.04162018.pdf
- NERC CIP Enforceable Standards: https://www.nerc.com/pa/Stand/Pages/CIPStandards.aspx
- Mapping of NIST Cybersecurity Framework to NERC CIP v3/v5 November 2014 - https://www.nerc.com/comm/CIPC_Security_Guidelines_DL/CSSWG-Mapping_of_NIST_Cybersecurity_Framework_to_NERC_CIP.pdf
- Mapping of CIP Standards to NIST Cybersecurity Framework v1.1 Updated: https://www.nerc.com/pa/comp/Pages/CAOneStopShop.aspx (under Compliance | NIST)
- SWG Security and Compliance Guideline November 2020: TBD

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Version History

Security Guideline: Assessing and Reducing Risk Version History					
Version No.	**Date**	**Chapter**	**Page**	**Description**	**Version**
1	October 2020	All	All	Original Document	.1
2	November 12, 2020	All	All	Publications and Admin review complete	.2
3	December 2020	All	All	Approved for posting by the RSTC	1.0

Reliability Guideline: ACE Diversity Interchange

Action
Accept to post the document for a 45-day industry comment period.

Summary
This Reliability Guideline, "ACE Diversity Interchange (ADI) Process Guideline" is up for the periodic 3-year review by the NERC Resources Subcommittee (RS). This document is intended as a tutorial for those new to ACE Diversity Interchange Process or as a reference for those consider implementing ADI.

Background
The RS drafted this Reliability Guideline at the request of the former NERC Operating Committee as part of a series on operating and planning reliability concepts. The document covers ACE Diversity Interchange Process concepts, issues, and recommendations with the goal to provide an understanding of the fundamentals.

Changes to the Updated Document
A sub-team of the RS has revised the ACE Diversity Interchange Process Guideline and vetted those changes through the full subcommittee. The major changes include:

- Numerous errata edits, re-wording and organizational changes
- Preamble section: Updated Committee Structure to reflect the recently formed Reliability and Security Technical Committee (RSTC)
- End of Hour Settlements section: Moved the section to after the Within Hour Assessments (Real Time) section and removed description of different methods of ADI settlement as they are not considered reliability issues.
- Within Hour Assessments (Real Time) section: Modified verbiage to provide better clarity
- Operating Principles section:
  - OP3: Clarified that both initial implementation and any subsequent modifications need to be reviewed and approved
  - OP4 and OP5 are combined into OP4
  - OP8: modified verbiage to reflect changes in BAL-002 (BAL-002-2 version)
  - OP9: added clarifying verbiage

On October 22, 2020 the RS approved the recommendation to move this technical reference document to the RSTC for approval and posting for 45-day industry comment.

Reliability Guideline

Area Control Error Diversity Interchange Process – Version 3

Applicability

Balancing Authorities (BAs)

For Information

Transmission Operators (TOPs)
Reliability Coordinators (RCs)

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 NERC Reliability and Security Technical Committee per its charter is authorized by the NERC Board of Trustees (Board) to develop Reliability and Security Guidelines. These guidelines establish a voluntary code of practice on a particular topic for consideration and use by BES users, owners, and operators. These guidelines are coordinated by the technical committees and include the collective experience, expertise and judgment of the industry. The objective of this reliability guideline is to distribute key best practices and information on specific issues critical to maintaining the highest levels of BES reliability. Reliability guidelines are not to be used to provide binding norms or create parameters by which compliance to standards is monitored or enforced. While the incorporation 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.

Background

Area Control Error Diversity Interchange (ADI) is a process in which participating Balancing Authorities exchange information related to their unadjusted Area Control Error (ACE) values (ACE before, or without, adjustment by the ADI process) in order to develop ADI adjustment values to their ACE. When there is a diversity of algebraic sign among ADI participants' unadjusted ACE, ADI adjustments are applied to yield ADI-adjusted ACE values that are closer to zero. Fundamentally, ADI is simply exchanging a real-time portion of one Balancing Authority's ACE for an equal but opposite portion of another Balancing Authority's ACE, thereby, reducing the ACE values of both Balancing Authorities. ADI is considered by some to be a form of supplemental regulation, and there have been several implementations since its inception in the 1990s, of which a few have been retired due to Balancing Authority consolidations. Eastern Interconnection ADI participants consider it to be supplemental regulation, while Western Interconnection ADI participants consider it to be solely an ACE exchange. Balancing Authorities participating in ADI cite the following benefits as reasons for their participation:

- Low cost and ease of implementation.

- Fewer output adjustments that reduce heat rate degradation and "wear and tear" on generating facilities.
- Reduced regulation requirements while having fewer generators operate out of economic merit order.

Purpose

The purpose of this reliability guideline is to address industry practices related to the usage of ADI.

Relevant Definitions from the NERC Glossary

Capitalized terms in this document are defined in the *NERC Glossary of Terms Used in NERC Reliability Standards*. Note that a definition for ADI does not exist within the NERC glossary at this time but a working definition is provided in the section below, entitled Basic ADI Operating Concepts.

Basic ADI Operating Concepts

The following working definition was developed and reflects the present implementations of ADI:

- **ACE Diversity Interchange** – A frequency neutral form of ACE exchange that uses real-time, sub-minute adjustments to the unadjusted ACE values of participating Balancing Authorities that always net to zero and are non-zero individually only when at least one participating Balancing Authority's unadjusted ACE value differs in algebraic sign from at least one other participating Balancing Authority's unadjusted ACE. Participating Balancing Authorities achieve reductions in their generation control and reporting ACE values by incorporating the ADI adjustments computed by an ACE Diversity Interchange algorithm. A participating BA's ADI adjustment term for each calculating cycle allows a flow that has already occurred on the participating BA's tie-lines to be maintained.

While ADI adjustment allocation methods may differ among the ADI implementations, two key features are that the computed ADI adjustments for all participating Balancing Authorities must always have a zero sum (see OP1 below) and the computed ADI adjustment for each participating Balancing Authority will equal zero in the absence of diversity in algebraic sign of the participating Balancing Authorities' unadjusted ACE. These are distinguishing features of the ADI process.

ADI Implementation Mechanics

ADI processes depend on the timely exchange of relevant data, and consistent implementation of ADI adjustments in the same timeframe of EMS scan rates (e.g., six seconds, or less). While the information exchange processes used for ADI have very high availability, Balancing Authorities participating in ADI have backup plans to address failures in data exchange communications.

The ADI processes that exist presently allow for individual Balancing Authorities to enable or disable their participation in real-time for local or interconnected reliability concerns and allow for a global enabling or disabling of ADI when appropriate for global reliability concerns.

Balancing Authorities participating in ADI communicate with their Transmission Operators and Reliability Coordinators, often with a consistent set of data being exchanged, to address congestion management problems that might be affected adversely by the continued use of ADI.

Present ADI implementations require that the participating Balancing Authorities are electrically contiguous (see OP5 below).

Balancing Authorities presently utilizing ADI do not use or acquire transmission service for the ADI process. The common premise is that ADI is a net zero flow that would have occurred absent ADI. However, Balancing Authorities must have transmission connectivity and have arrangements for transmission to participate in ADI. The ADI process will be disabled in the event that normal or contingent operations require the use of transmission being used for ADI-related power flows. Most often, the inadvertent power flows do not persist for extended periods and would net reasonably close to zero over longer intervals.

In theory, the ADI adjustment for each participating Balancing Authority should net to zero in the longer term if ACE values are more or less random, normally distributed, and having a mean of zero. Deviations from this basic premise could impact inadvertent energy accumulations.

Present ADI implementations all track the impact that the ADI process is having on hourly inadvertent and its cumulative impact in the longer term (e.g., monthly). Differing methods are in use among the present ADI implementations to address various aspects of managing the ADI adjustments.

Within Hour Assessments (Real Time)

The ADI process as defined above is a process that directly modifies ACE with an ADI adjustment term in order to achieve a final value of lesser magnitude for each participating Balancing Authority. The resulting ACE value is used in the calculation of CPS1 and BAAL. However, if ADI adjustments are made to the instantaneous Actual Net Interchange (NI_A) in calculating ACE, then for after-the-fact calculation of primary frequency response under BAL-003 it is necessary to exclude (or back out) the ADI adjustment from the NI_A value, as primary frequency response is measured using solely the change in actual tie line measurements. Similarly, it is also necessary to ignore (or back out) the ADI adjustment when calculating the Balancing Authority Area's (BAA's) Load, as the ADI adjustment is the shared Area Control Error that does not represent a transfer of load between to or from the BAA.

End of Hour Settlements

Since the summation of ADI adjustments within an ADI group sum to zero hourly, it is up to the ADI participants, as a group, to decide on how to settle for their ADI adjustment accounts, as long as the settlement method does not affect interconnection reliability and non-participants. Regardless of which method is used, all participants within an ADI group must use the same method.

ADI Implementation Mechanics and Controls Summary

- Balancing Authorities participating in ADI have backup plans to address failures in data exchange communications.
- Individual Balancing Authorities can enable or disable their participation in real-time for local or interconnected reliability concerns.
- Global enabling or disabling of ADI is activated when appropriate for global reliability concerns.
- The ADI process will be disabled in the event that normal or contingent operations require the use of transmission being used for ADI-related power flows.
- The present ADI implementations all have limits on the magnitude of ADI exchanges and are subject to oversight by the ADI program's stakeholders.

Operating Principles Associated with ADI Applications

The following Operating Principles (OP) must be observed by those participating in ADI applications.

OP1 – The algebraic sum of the ADI adjustments used in participating Balancing Authorities' ACE equations need to be zero so that frequency is not affected (hence frequency neutral), with due consideration of different scan rates and data latency.

OP2 – Since ADI is dependent on successful exchange of ACE-related data, Balancing Authorities that participate in ADI need to have an agreed upon backup plan that utilizes a consistent method of validating the integrity of its data exchange process, in the event of the loss of communications or data quality. (For example, the detection of an invalid data exchange due to the loss of communications or data quality will initiate the backup plan within 1 minute, with automatic disabling of participation upon detection.)

OP3 – The initial implementations and any subsequent modifications of ADI need to be reviewed and approved, prior to implementation, by the NERC Resources Subcommittee and the NERC Real-Time Operating Subcommittee in order to verify that the implementation of applicable Balancing and Transmission related Standards are not compromised by the implementation.

OP4 –Balancing Authorities participating in ADI need to develop and implement an appropriate methodology to continuously assure that their regulation control is not affecting the reliability of the transmission system.

OP5 – Balancing Authorities need to have transmission connectivity and arrangements for transmission to participate in ADI. ADI needs to be designed to avoid adverse impacts on intermediary Balancing Authorities and Transmission Operators. Additionally, there needs to be an established method by which affected Balancing Authorities, Transmission Operators and Reliability Coordinators can be updated with the real-time ADI adjustments being exchanged so that they can monitor any potential reliability impacts.

OP6 – The implementation of ADI needs to allow participating Balancing Authorities to change their participation status in real-time, and the ADI algorithm needs to respond immediately to apply the ADI adjustments in recognition of the status changes.

OP7 – Real-time observability of participation and communication status, unadjusted ACE, ADI adjustments, and ADI-adjusted ACE values need to be available to Balancing Authorities, Transmission Operators, and Reliability Coordinators. The ADI participants need to share the ADI results with the appropriate Reliability Coordinators who can also assess the impacts.

OP8 – When a Balancing Authority participates in supplemental regulation and it experiences a contingency that qualifies as a NERC Reportable Balancing Contingency Event and the other Balancing Authorities participating in supplemental regulation do not jointly activate contingency reserve sharing for the resource loss or restoration of demand, then supplemental regulation needs to be disabled by the contingent Balancing Authority when their contingency occurs, or after-the-fact corrections need to be made to remove the supplemental regulation adjustment from ACE to compute the percentage of recovery (BAL-002).

OP9 – For purposes of calculating Frequency Response Measure (BAL-003) or the calculation of BAA's load, the ADI adjustment term should be excluded as it will distort the true values.

OP10 – Balancing Authorities participating in ADI need to determine a maximum value for capping real-time ADI adjustments and ADI accumulations.

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Reliability Guideline

Area Control Error Diversity Interchange Process – Version 3~~2~~

Applicability

Balancing Authorities (BAs)

For Information

Transmission Operators (TOPs)
Reliability Coordinators (RCs)

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 NERC Reliability and Security Technical Committee ~~Committees of NERC; the Operating Committee (OC), the Planning Committee (PC) and the Critical Infrastructure Protection Committee (CIPC)~~ per ~~their~~ its charter~~s~~ ~~are~~ is authorized by the NERC Board of Trustees (Board) to develop Reliability ~~(OC and PC)~~ and Security Guidelines ~~(CIPC)~~. These guidelines establish a voluntary code of practice on a particular topic for consideration and use by BES users, owners, and operators. These guidelines are coordinated by the technical committees and include the collective experience, expertise and judgment of the industry. The objective of this reliability guideline is to distribute key best practices and information on specific issues critical to maintaining the highest levels of BES reliability. Reliability guidelines are not to be used to provide binding norms or create parameters by which compliance to standards is monitored or enforced. While the incorporation 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.

Background

Area Control Error Diversity Interchange (ADI) is a process in which participating Balancing Authorities exchange information related to their unadjusted Area Control Error (ACE) values (ACE before, or without, adjustment by the ADI process) in order to develop ADI adjustment values to their ACE. When there is a diversity of algebraic sign among ADI participants' unadjusted ACE, ADI adjustments are applied to yield ADI-adjusted ACE values that are closer to zero. Fundamentally, ADI is simply exchanging a real-time portion of one Balancing Authority's ACE for an equal but opposite portion of another Balancing Authority's ACE, thereby, reducing the ACE values of both Balancing Authorities. ADI is considered by some to be a form of supplemental regulation, and there have been several implementations since its inception in the 1990s, of which a few have been retired due to Balancing Authority consolidations. Eastern Interconnection ADI participants consider it to be supplemental regulation, while Western Interconnection ADI participants consider it to be solely an ACE exchange. Balancing Authorities participating in ADI cite the following benefits as reasons for their participation:

- Low cost and ease of implementation.

- Fewer output adjustments that reduce heat rate degradation and "wear and tear" on generating facilities.
- Reduced regulation requirements while having fewer generators operate out of economic merit order.

Purpose

The purpose of this reliability guideline is to address industry practices related to the usage of ADI.

Relevant Definitions from the NERC Glossary

Capitalized terms in this document are defined in the *NERC Glossary of Terms Used in NERC Reliability Standards*. Note that a definition for ADI does not exist within the NERC glossary at this time but a working definition is provided in the section below, entitled Basic ADI Operating Concepts.

Basic ADI Operating Concepts

The following working definition was developed and reflects the present ~~three~~ implementations of ADI:

Commented [A1]: Removed. No needs to be specific.

- **ACE Diversity Interchange** – A frequency neutral form of ACE exchange that uses real-time, sub-minute adjustments to the unadjusted ACE values of participating Balancing Authorities that always net to zero and are non-zero individually only when at least one participating Balancing Authority's unadjusted ACE value differs in algebraic sign from at least one other participating Balancing Authority's unadjusted ACE. Participating Balancing Authorities achieve reductions in their generation control and reporting ACE values by incorporating the ADI adjustments computed by an ACE Diversity Interchange algorithm. A participating BA's ADI adjustment term for each calculating cycle allows a flow that has already occurred on the participating BA's tie-lines to be maintained.

While ADI adjustment allocation methods may differ among the ADI implementations, two key features are that the computed ADI adjustments for all participating Balancing Authorities must always have a zero sum (see OP1 below) and the computed ADI adjustment for each participating Balancing Authority will equal zero in the absence of diversity in algebraic sign of the participating Balancing Authorities' unadjusted ACE. These are distinguishing features of the ADI process.

ADI Implementation Mechanics

ADI processes depend on the timely exchange of relevant data, and consistent implementation of ADI adjustments in the same timeframe of EMS scan rates (e.g., six seconds, or less). While the information exchange processes used for ADI have very high availability, Balancing Authorities participating in ADI have backup plans to address failures in data exchange communications.

The ADI processes that exist presently allow for individual Balancing Authorities to enable or disable their participation in real-time for local or interconnected reliability concerns~~,~~ and allow for a global enabling or disabling of ADI when appropriate for global reliability concerns.

Balancing Authorities participating in ADI communicate with their Transmission Operators and Reliability Coordinators, often with a consistent set of data being exchanged, to address congestion management problems that might be affected adversely by the continued use of ADI.

Present ADI implementations require that the participating Balancing Authorities are electrically contiguous (see OP5~~6~~ below).

Balancing Authorities presently utilizing ADI do not use or acquire transmission service for the ADI process. The common premise is that ADI is a net zero flow that would have occurred absent ADI. However, Balancing Authorities must have transmission connectivity and have arrangements for transmission to participate in ADI. The ADI process will be disabled in the event that normal or contingent operations require the use of transmission being used for ADI-related power flows. Most often, the inadvertent power flows do not persist for extended periods and would net reasonably close to zero over longer intervals.

In theory, the ADI adjustment for each participating Balancing Authority should net to zero in the longer term if ACE values are more or less random, normally distributed, and having a mean of zero. Deviations from this basic premise could impact inadvertent energy accumulations.

Present ADI implementations all track the impact that the ADI process is having on hourly inadvertent and its cumulative impact in the longer term (e.g., monthly). Differing methods are in use among the present ADI implementations to address various aspects of managing the ADI adjustments.

~~End of Hour Settlements~~

~~Since the summation of ADI adjustments within an ADI group sum to zero, participant accounts could be settled off-line or added to the Inadvertent Interchange accounts of the participants. If settlements are handled as inadvertent, participants could modify their NI_A values by treating their integrated hourly ADI adjustments as Pseudo-Ties, thereby affecting their end of hour Inadvertent Interchange, a similar result can be obtained by using Dynamic Schedules instead of Pseudo-Ties. Regardless of which method is used, all participants' within an ADI group must use the same method.~~

Within Hour Assessments (Real Time)

The ADI process as defined above is a process that directly modifies ACE with an ADI adjustment term in order to achieve a final value of lesser magnitude~~s~~ for each participating Balancing Authority. ~~to use in~~ The resulting ACE value is used in the calculation of CPS1 ~~or~~ and BAAL. ~~And, since~~ However, if ADI adjustments are made to the instantaneous Actual Net Interchange (NI_A) in calculating ACE, then for after-the-fact calculation of primary frequency ~~-~~response under BAL-003 it is necessary to exclude (or back out) the ADI adjustment from the NI_A value, as primary frequency response is measured using solely the change in actual~~with~~ tie line measurements ~~Net Actual Interchange (NI_A) and frequency, it is necessary to ignore (or leave out) the ADI adjustment from the NI_A value when evaluating the participant's frequency response~~. Similarly, ~~I~~it is also necessary to ignore (or ~~leave~~ back out) the ADI adjustment when calculating the Balancing Authority Area's (BAA's) Load, as the ADI adjustment is the shared Area Control Error that does not represent a transfer of load between to or from the BAA~~s~~. ~~*To clarify, the ADI adjustment should not*~~

Commented [A2]: Renumbered as below.

Commented [A3]: Replaced with new End Of Hour Settlements section below the next section.

Commented [A4]:

Commented [A5R4]: the term Net Actual Interchange is deliberately removed here to make this argument stand out. Furthermore, the term Net Actual Interchange (defined as a MWH value in NERC Glossary) expressed in BAL-003 should be read as Actual Net Interchange (defined as a MW value in NERC Glossary).

~~*modify the real-time NI_A value for any other purpose other than end of hour Inadvertent Interchange accounting.*~~

End of Hour Settlements

Since the summation of ADI adjustments within an ADI group sum to zero hourly, it is up to the ADI participants, as a group, to decide on how to settle for their ADI adjustment accounts, as long as the settlement method does not affect interconnection reliability and non-participants. Regardless of which method is used, all participants within an ADI group must use the same method.

Commented [A6]: The small group recommend removing all details of different settlement methods since ATF settlement is not considered reliability related.

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ADI Implementation Mechanics and Controls Summary

- Balancing Authorities participating in ADI have backup plans to address failures in data exchange communications.
- Individual Balancing Authorities can enable or disable their participation in real-time for local or interconnected reliability concerns.
- Global enabling or disabling of ADI is activated when appropriate for global reliability concerns.
- The ADI process will be disabled in the event that normal or contingent operations require the use of transmission being used for ADI-related power flows.
- The present ADI implementations all have limits on the magnitude of ADI exchanges and are subject to oversight by the ADI program's stakeholders ~~and industry subject matter experts~~.

Commented [A7]: Removed. Covered by approval process described in OP3 below

Operating Principles Associated with ADI Applications

The following Operating Principles (OP) must be observed by those participating in ADI applications.

OP1 – The algebraic sum of the ADI adjustments used in participating Balancing Authorities' ACE equations need to be zero so that frequency is not affected (hence frequency neutral), with due consideration of different scan rates and data latency.

Commented [A8]: Added to clarify the meaning of "frequency neutral" used in the definition of ADI term above

OP2 – Since ADI is dependent on successful exchange of ACE-related data, Balancing Authorities that participate in ADI need to have an agreed upon backup plan that utilizes a consistent method of validating the integrity of its data exchange process, in the event of the loss of communications or data quality. (For example, the detection of an invalid data exchange due to the loss of communications or data quality will initiate the backup plan within 1 minute, with automatic disabling of participation upon detection.)

OP3 – The initial ~~I~~implementations and any subsequent modifications of ADI need to be reviewed and approved, prior to implementation, by the NERC Resources Subcommittee and the NERC Real-Time Operating ~~Reliability~~ Subcommittee in order to verify that the implementation of applicable Balancing and Transmission related Standards are not compromised by the implementation.

Commented [A9]: Does ORS have a new name? NERC Staff to replace if needed.

Commented [A10]: Is this name change official? The NERC RSTC Org chart still shows ORS. Edited by Darrel earlier.

OP4 – ~~Balancing Authorities participating in ADI need to continuously assure that their regulation control is not affecting the reliability of the transmission system.~~

~~OP5 –~~ Balancing Authorities participating in ADI need to develop and implement an appropriate methodology to continuously ~~verify~~ assure that their regulation control is not affecting the reliability of the transmission system.

Commented [A11]: Merged OP4 and OP5 into OP4. All subsequent OPs renumbered.

OP5~~6~~ – Balancing Authorities need to have transmission connectivity and arrangements for transmission to participate in ADI. ADI needs to be designed to avoid adverse impacts on intermediary Balancing Authorities and Transmission Operators. Additionally, there needs to be an established method by which affected Balancing Authorities, Transmission Operators and Reliability Coordinators can be updated with the real-time ADI adjustments being exchanged so that they can monitor any potential reliability impacts.

OP6~~7~~ – The implementation of ADI needs to allow participating Balancing Authorities to change their participation status in real-time, and the ADI algorithm needs to respond immediately to apply the ADI adjustments in recognition of the status changes.

OP7~~8~~ – Real-time observability of participation and communication status, unadjusted ACE, ADI adjustments, and ADI-adjusted ACE values need to be available to Balancing Authorities, Transmission Operators, and Reliability Coordinators. The ADI participants need to share the ADI results with the appropriate Reliability Coordinators who can also assess the impacts.

OP8~~9~~ – When a Balancing Authority participates in supplemental regulation and it experiences a contingency that qualifies as a NERC ~~DCS~~ Reportable Balancing Contingency Event~~,~~ and~~,~~ the other Balancing Authorities participating in supplemental regulation do not jointly activate contingency reserve sharing for the resource loss or restoration of demand, then supplemental regulation needs to be disabled by the contingent Balancing Authority when their contingency occurs, or after-the-fact corrections need to be made to remove the supplemental regulation adjustment from ACE to compute ~~DCS~~ the percentage of recovery (BAL-002).

OP9~~10~~ – For purposes of calculating Frequency Response Measure (BAL-003) or the calculation of BAA's load, the ADI adjustment term should be excluded as it will distort the true values.

OP10~~11~~ – Balancing Authorities participating in ADI need to determine a maximum value for capping real-time ADI adjustments and ADI accumulations.

Reliability Guideline: Operating Reserve Management

Action
Accept to post the document for a 45-day industry comment period.

Summary
This Reliability Guideline, "Operating Reserve Management" is up for the periodic 3-year review by the NERC Resources Subcommittee (RS). The RS approved the recommendation to move this technical reference document to the RSTC for approval and posting for 45-day industry comment.

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Reliability Guideline

Operating Reserve Management: Version 3

Preamble

It is in the public interest for NERC to develop guidelines that are useful for maintaining and enhancing the reliability of the Bulk Electric System (BES). The subgroups of the Reliability and Security Technical Committee (RSTC)—in accordance with the RSTC charter[1] are authorized by the NERC Board of Trustees to develop reliability and security guidelines. These guidelines establish a voluntary code of practice on a particular topic for consideration and use by BES users, owners, and operators. These guidelines are coordinated by the technical committees and include the collective experience, expertise, and judgment of the industry. The objective of this reliability guideline is to distribute key practices and information on specific issues critical to appropriately maintaining BES reliability. Reliability guidelines are not to be used to provide binding norms or create parameters by which compliance to standards are monitored or enforced. While the incorporation, of guideline practices, is strictly voluntary, reviewing, revising, or developing a program using these practices is highly encouraged to promote and achieve appropriate BES reliability.

Purpose

This reliability guideline is intended to provide recommended practices for the management of an appropriate mix of Operating Reserve as well as readiness to respond to loss of load events. It also provides guidance with respect to the management of Operating Reserve required to meet the NERC Reliability Standards.

The reliability guideline applies primarily to Balancing Authorities (BAs) or, as appropriate, contingency reserve sharing groups (RSGs), regulation RSGs, or frequency response sharing groups. For ease of reference, this guideline uses the common term “responsible entity” for these entities, and allows the readers to make the appropriate substitution applying to them when participating or not in various groups.

Reserve planning has been practiced for a long time by NERC operating entities, dating back to Policy 1 of NERC’s operating policies. This reliability guideline leads responsible entities toward the best practices for management of the operating reserve types by dividing them into individual components to provide visibility and accountability. While the incorporation of guideline practices is strictly voluntary, reviewing, revising, or developing a process using these practices is highly encouraged to promote and achieve reliability for the BES.

Assumptions

[1] https://www.nerc.com/comm/RSTC/RelatedFiles/RSTC_Charter_approved20191105.pdf

- There can be a variety of methods that responsible entities use to ensure that sufficient Operating Reserves are available to deploy in order to support reliability. This guideline does not specify or prescribe how the need for sufficient operating reserves are met.
- NERC, as the FERC certified ERO,[2] is responsible for the reliability of the BES and has a suite of tools to accomplish this responsibility, including but not limited to lessons learned, reliability and security guidelines, assessments and reports, the Event Analysis Program, the Compliance Monitoring and Enforcement Program, and mandatory NERC Reliability Standards.
- Each registered entity in the NERC compliance registry is responsible and accountable for maintaining reliability and compliance with the mandatory standards to maintain the reliability of the BES.
- Entities should review this reliability guideline in detail in conjunction with the periodic review of their internal processes and procedures and make any needed changes to their procedures based on their system design, configuration, and business practices.

Background

There is often confusion when operators and planners talk about reserves. One major reason for misunderstanding is a lack of common definitions; NERC's definitions have changed over time. In addition, most NERC Regional Entities (REs) developed their own definitions. Capacity obligations have historically been the purview of state and provincial regulatory bodies, meaning that there are many different expectations and obligations across North America.

The second area of confusion concerning reserves deals with the limitations of each BA's energy management system (EMS). Common problems include the following:

- Counting all "headroom" of on-line units as spinning reserve even though it may not be available in 10 minutes (i.e., lag from adding mills or fan speed changes)
- No intelligence in the EMS regarding load management resources
- No corrections for "temperature sensitive" resources, such as natural gas turbines
- Inadequate information on resource limitations and restrictions
- Reserves that may exist and are deployed outside the purview of the EMS system

[2] http://www.ferc.gov/whats-new/comm-meet/072006/E-5.pdf

Definitions

Capitalized terms used within this guideline are defined as part of the NERC Glossary. Terms which are not capitalized are used as references within this guideline.

Contingency Reserve: This is the provision of capacity deployed by the BA to respond to a balancing contingency event and other contingency requirements, such as energy emergency alerts (EEAs) as specified in the associated NERC Reliability Standards.

Contingency Event Recovery Period: A period that begins at the time that the resource output begins to decline within the first one-minute interval of a Reportable Balancing Contingency Event and extends for fifteen minutes thereafter.

Contingency Reserve Restoration Period: A period not exceeding 90 minutes following the end of the Contingency Event Recovery Period.

Frequency-Responsive Reserve (FRR): On-line generation with headroom that has been tested and verified to be capable of providing droop as described in the *Primary Frequency Control Reliability Guideline Reliability Guideline.*[3] Variable load that mirrors governor droop and dead-band may also be considered FRR.

Interruptible Load: Demand that the end-use customer makes available to its load-serving entity via contract or agreement for curtailment. Note: If the load can be interrupted within 10 minutes, it may be included in Contingency Reserve; otherwise, this load is generally included in Operating Reserves - Supplemental.

Most Severe Single Contingency (MSSC): The Balancing Contingency Event, due to a single contingency that was identified using system models maintained within the RSG or a BA's area that is not part of an RSG, that would result in the greatest loss (measured in megawatt (MW) of resource output used by the RSG or a BA that is not participating as a member of an RSG at the time of the event to meet firm demand and export obligation (excluding export obligation for which contingency reserve obligations are being met by the sink BA).

Operating Reserve: Operating reserve is the capability above firm system demand required to provide for regulation, load forecasting error, equipment forced and scheduled outages, and local area protection. It consists of spinning and non-spinning reserve.

Operating Reserve–Spinning: This includes generation synchronized to the system and fully available to serve load within the Disturbance Recovery Period following the contingency event or load fully removable from the system within the Disturbance Recovery Period disturbance recovery period following the contingency event deployable in 10 minutes.

[3] https://www.nerc.com/comm/OC_Reliability_Guidelines_DL/PFC_Reliability_Guideline_rev20190501_v2_final.pdf

Operating Reserve–Supplemental: This includes generation (synchronized or capable of being synchronized to the system) that is fully available to serve load within the disturbance recovery period following the contingency event or load fully removable from the system within the disturbance recovery period following the contingency event that can be removed from the system within 10 minutes.

Other Reserve Resources: This includes resources that can be used outside the continuum of Operation Reserves *Figure: 1* (i.e., on four hours' notice).

Planning Reserve: This is the difference between a BA's expected annual peak capability and its expected annual peak demand expressed as a percentage of the annual peak demand.

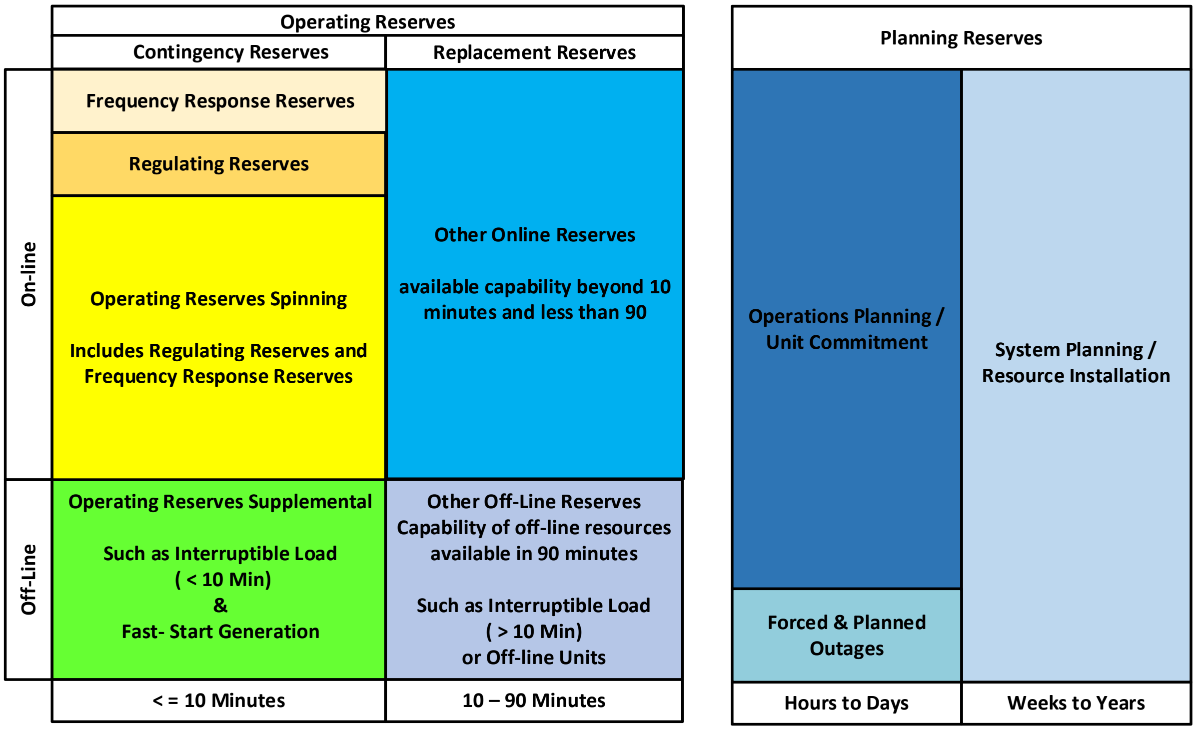
Projected Operating Reserve: This includes resources expected to be deployed for the point in time in question.

Regulating Reserve: This is an amount of Operating Reserve – Spinning that is responsive to automatic generation control (AGC) sufficient to provide normal regulating margin.

Replacement Reserve: Resources used to replace designated Contingency Reserve that have been deployed to respond to a contingency event. Each NERC RE sets times for Contingency Reserve restoration, typically in the 60–90-minute range. The NERC default Contingency Reserve restoration period is 90 minutes after the Disturbance Recovery Period.

Supplemental Reserve Service: Supplemental reserve service provides additional capacity from electricity generators that can be used to respond to a contingency within a short period, usually 10 minutes. This is an ancillary service identified in FERC Order 888 as necessary to affect a transfer of electricity between purchasing and selling entities and is effectively FERC's equivalent to NERC's Operating Reserve.

Figure 1: Operating Reserves



Guideline Details

An effective Operating Reserve program should address the following components:

- Management roles and expectation
- System operator roles
- Regulating reserve
- Contingency reserve
- Frequency responsive reserve
- Capability to respond to large loss-of-load events
- Reserve sharing groups
- Operating reserve interaction
- Load forecast error
- Fuel constraints
- Deliverability of reserves
- Unit commitment

Each individual component should address safety; processes and procedures; evaluation of any issues or problems along with solutions; testing; training; and communications. These provisions and activities together should be understood to be an Operating Reserve program.

Each responsible entity should evaluate the total reserve needed to meet its obligations under NERC Reliability Standards, namely frequency response reserves, regulating reserves up, regulating reserves down, contingency reserves, and operating reserves. Given that different reserves may be difficult to separate in actual operation, the system operator will need an understanding of the quantity of each type of reserve required. Each responsible entity should consider the types of resources and the associated portion of their capacity capable of reducing the BA's area control error (ACE) in either direction in response to each of the following:

- Frequency deviations
- Bottoming out conditions
- Ramping requirements
- A Balancing Contingency Event
- Events associated with EEA 2
- Events associated with EEA 3
- A large loss-of-load event

Management Roles and Expectations

Management plays an important role in maintaining an effective Operating Reserve program. The management role and expectations below provide a high-level overview of the core management responsibilities related to each Operating Reserve program. The management of each responsible entity should tailor these roles and expectations to fit within its own structure:

- Set expectations for safety, reliability, and operational performance
- Assure that an Operating Reserve program exists for each responsible entity and is current
- Provide annual training on the Operating Reserve program and its purpose and requirements
- Ensure the proper expectation of Operating Reserve program performance
- Share insights across industry associations
- Conduct an evaluation of the effectiveness of the Operating Reserve program and incorporate lessons learned

System Operator Roles

BA Operator

It is important for the system operator know the specifics of their BA reserve strategy and maintain situation awareness through the following:

- Participate in appropriate system operator training
- Ensure the Operating Reserve information is always current
- Maintain situation awareness and projection of reserves for a 2-hour to 6-hour horizon
- Review and validate reserve plan while considering load forecast, unit commitment, fuel supply, weather conditions, and reserve requirements
- Implement the BA Operating Reserve program in real-time that should
  - Ensure adequate reserves are available to address loss of MSSC or Frequency deviations in real-time
  - Coordinate communications with RC if inadequate reserves are forecasted or experienced
  - Adhere to EOP Operating Standards
  - Issue the proper EEA is called when a reserve short fall is forecasted or experienced

RC Operator

It is important for the system operator to look at other indicators to determine the ultimate course of action, such as the following:

- Is the BA or BAs' ACE predominantly negative for an extended period?
- Is frequency low (i.e., more than 0.03 Hz below scheduled frequency)?
- Are reserves low in multiple BAs?
- Is load trending upward or higher than anticipated?

Based on the duration and severity of the situation, action steps may include the following:

- Verify reserve levels
- Follow EEA–review and understand individual BA EEA plans
- Direct BA(s) to take action to restore reserves
- Direct the identification of load to shed to withstand the next contingency for a post contingent action.
- Redistribute reserves
- Shed load where appropriate if the BA or Transmission Operator cannot withstand the next contingency

Regulating Reserve

The responsible entity's balance between demand, supply (generation minus metered interchange) and frequency support is measured by its ACE. Because changes in supply and demand cannot be predicted precisely, there will be a mismatch between them, resulting in a nonzero ACE.

Each responsible entity should have a documented regulating reserve process that ensures that the responsible entity has sufficient capacity to meet the performance requirements of BAL-001-2. The responsible entity's process should include the following at a minimum:

- **A method for determining its regulating needs**: This method should consider the entity's generation mix, type of load, the variability in both generation and load, and the probability of extreme influences (e.g., weather).
- **Knowing what types of resources and the portion of their capacity that can be made available for regulation:** The responsible entity should have resources that will respond to the entity's need to balance supply and demand to meet the performance requirements of NERC Reliability Standards.
- **The incorporation of contractual arrangements into regulating needs, such as exports and imports:** Changes to contractual arrangements should be assessed and accounted for in the responsible entity's ability to respond and meet the performance requirements
- **Evaluation of its planned regulating reserve needs over the operating time horizon and gauge its ability to meet its regulating reserve needs on at least an hourly basis:** This should be based on changing system conditions, such as the current load, forecast errors, and generation mix.
- **Planning and implementation of the ability to restore its regulating reserve as needed:** This may include the ability to restore regulating reserve in either direction.
- **Ensuring that the regulating reserve is used by only one entity:** The regulating reserve process should include a method whereby its regulating reserve is not included in another responsible entity's Operating Reserve (i.e. regulating, contingency, or FRR) policy.

Contingency Reserve

When a responsible entity experiences an event (i.e., loss of supply or significant scheduling problems that can cause frequency disturbances), it should be able to adjust its resources in such a manner to assure its ACE recovers in accordance with the requirements of the applicable Reliability Standards.

For a responsible entity to meet the requirements of the NERC Reliability Standards BAL-002-3, the BA needs to identify its MSSC to determine its base contingency reserve. Because there is no forgiveness for this minimum amount of contingency reserve not deployed when called upon, the individual entity could consider additional amounts based on risk analyses. To be effective, contingency reserves should be able to be deployed (including activation or communication needs) to meet the contingency event recovery period for balancing contingency events. Reserve amounts set aside as frequency responsive include unit governor reserves. These local responses are independent of control center control. If the unit is not operating at maximum output, the unit should be capable of providing frequency response. Due to the interactions of frequency reserves, these are included in the available minimum contingency reserve amounts in Interconnections composed of more than one responsible entity. At any given time, a unit may also be loaded to maximum output and unavailable to meet the reliability requirements associated with frequency response and contingency reserves.

Additionally, the responsible entity should consider an appropriate mix and coordination of FRR and contingency reserve to ensure that the responsible entity has the ability to respond to frequency events on the Interconnection as well as in its own BA area in accordance with all NERC and RE standards.

Various resources may be considered for use as contingency reserve provided, they can be deployed within the appropriate time frame. As technology and innovations occur, this list may continue to grow and may include the following:

- Unloaded/loaded generation, such as quick start CTs, hydro facilities, portions of unit ramping capabilities
- Off-line generation
- Demand resources
- Energy storage devices
- Resources like wind, solar, etc., provided that any limitations are considered

Responsible entities should consider how schedule interruption would affect their Contingency Reserves while considering the terms and conditions under which such energy schedules were arranged.

Responsible entities that choose to use energy schedules to respond to a balancing contingency event should take into account the terms and conditions under which such energy schedules were arranged and verify that they would not detract from a responsible entity's use of such schedules when meeting their contingency reserve requirements for balancing contingency events.

For RSGs, there is a prohibition against counting toward the responsible entity’s Contingency Reserve any capacity that is already included in another responsible entity’s regulating, contingency, or FRR policy. Special coordination between RSG members may be required for resources dynamically transferred between multiple responsible entities.

To assure a responsible entity can respond to a balancing contingency event in real-time, the responsible entity should plan for its available Contingency Reserves for the operating time horizon (i.e. operations planning, same day and real-time operations). The BA operator should focus their situation awareness and evaluation of reserves in a time horizon between next hour and multiple days out. The review should be flexible so that it can be updated to reflect changes available generation, load forecast, the amount of reserve available or the amount of reserve required.

Responsible entities should consider developing some form of electronic reserve monitor that would track resources available to provide the necessary response and the amount of capacity each could provide. Many EMSs currently provide this type of feature for measuring the up and down ranges of their resources. Care should be taken to recognize the up and down ranges on resources that have been made available by the purchase or sale of non-firm energy that may disappear during an event.

For a responsible entity should leverage their Replacement Reserves to meet the Contingency Reserve Restoration Period, preplanning and training of system operators may be required. Actions like the following may be considered:

- Verification of status/availability of additional resources

- Commitment of additional resources
- Implementation of demand resources, such as interruptible loads (usually prearranged contractually)
- Curtailment of recallable transactions
- Consider the effect of emergency schedules that end before recovery completion

The responsible entity should exercise prudent operating judgment in distributing Contingency Reserves, considering the effective use of capacity in an emergency, the time required to be effective, transmission limitations, and local area requirements.

Frequency Responsive Reserve

Each responsible entity should maintain an amount of resources available to respond to frequency deviations. Planned FRR (day-ahead, day of, and hour prior) should be available in addition to planned regulating and contingency reserve. For a responsible entity experiencing a frequency deviation, FRR would be deployed to arrest frequency change and remain deployed until frequency is returned to its normal range. Although response is generally expected to come from on-line rotating machines, other resources (e.g., controllable load contracted for that purpose, certain energy storage devices) can provide initial and sustained response that would help to arrest frequency change and sustain frequency at an acceptable post event-level until frequency is returned within its normal range. Each responsible entity should have a documented FRR process ensuring the responsible entity has sufficient capacity to meet the performance requirements of BAL-003-2. The process should include at least the following:

- The BAL-003-2 standard, *Frequency Response and Frequency Bias Setting*[4], specifies (in Table 1 in Attachment A) the interconnection frequency response obligation (IFRO) and the maximum delta frequency (MDF). Attachment A also provides the calculation methodology used to determine the frequency response obligation (FRO) assigned to each responsible entity in a multiple responsible entity Interconnection (the responsible entity's FRO is the same as the IFRO in a single responsible entity Interconnection). In a multiple responsible entity Interconnection, each responsible entity's FRO is its pro-rata share of the IFRO based on the sum of its annual generation MWh plus load MWh as a fraction of those for the entire Interconnection. The attachments and forms associated with the BAL-003-2 standard cover these calculations in more detail. To determine an initial target (at scheduled frequency) FRR level (in MW) for a given responsible entity, multiply 10 times the responsible entity's FRO (because FRO is in MW/0.1 Hz) by the MDF for the responsible entity's Interconnection. An example to illustrate this is as follows:

  Given: ABC responsible entity is in the Eastern Interconnection and its pro-rata portion of IFRO is 1.5%.

  Currently, the key Eastern Interconnection parameters from are: IFRO = 1015 MW/0.1 Hz and MDF = 0.420 Hz. The responsible entity's FRO is {1.5% *1015 MW/0.1 Hz} or 15.2 MW/0.1 Hz.

  The responsible entity's initial FRR target is {10 * 15.2 * 0.420} or 63.84MW.

[4] http://www.nerc.com/pa/Stand/Reliability%20Standards/BAL-003-2.pdf

The initial target may need to be modified based on several factors. For example, if actual performance indicates additional response is needed, then the target should be increased. The responsible entity also may choose to perform a risk analysis in determining the level of FRR that assures compliance at an acceptable cost.

- Any resource (generation, load, storage device, etc.) that is capable of responding to frequency can be a candidate for inclusion as part of a responsible entity's FRR; however, such resources should help to arrest the initial frequency change (also known as primary response, and often referred to as droop or governor response) and/or provide sustained support at a post-event frequency level until frequency returns to its normal range. It is prudent practice to evaluate and test units periodically. Therefore, any resource that participates in frequency response reserve should be evaluated periodically to ensure the expected response (e.g. NERC Generator Owner/Operator Survey, or internal evaluation). Moreover, the responsible entity should have an appropriate mix of both primary and secondary reserves. The Lawrence Berkeley National Laboratory report highlights this: *Use of Frequency Response Metrics to Assess the Planning and Operating Requirements for Reliable Integration of Variable Renewable Generation, Key Findings*.[5]
- As long as the total FRR amounts for each responsible entity are satisfied, any amount of FRR may be provided through contractual agreements within the same Interconnection between responsible entities. This is the basis of the concept of frequency response sharing groups. Responsible entities can also contract for demand side options that respond to frequency deviations (usually at preset thresholds) to provide FRR. Responsible entities can likewise contract for energy storage devices to supply FRR as long as applicable terms ensure that either the devices themselves or a partnered resource provide sustained response until frequency is returned to its normal range.
- Daily resource commitment plans should include considerations to provide FRR throughout the day. In real-time operations, responsible entity operators should monitor their FRR levels in much the same way that contingency and regulating reserve are monitored. To the greatest possible extent possible, review of and adherence to planned levels and actual performance should be fed back into the commitment planning process to improve both the commitment plan and actual performance. This feedback should be integrated into commitment planning as well as be available to responsible entity operators to monitor levels.
- If a responsible entity experiences a frequency deviation in conjunction with a balancing contingency event, FRR will normally be restored when Contingency Reserves have been deployed in response to the balancing contingency event, but there may be circumstances when this is not the case. The key difference between this and the noncontingent case is whether Contingency

[5] "5. Increased variable renewable generation will have … impacts on the efficacy of primary frequency control actions: … Place[ing] increased requirements on the adequacy of secondary frequency control reserve. The demands placed on slower forms of frequency control, called secondary frequency control reserve, will increase because of more frequent, faster, and/or longer ramps in net system load caused by variable renewable generation. If these ramps exceed the capabilities of secondary reserves, primary frequency control reserve (that is set- aside to respond to the sudden loss of generation) will be used to make up for the shortfall. We recommend greater attention be paid to the impact of variable renewable generation on the interaction between primary and secondary frequency control reserve than has been the case in the past because we believe this is likely to emerge as the most significant frequency-response-based impact of variable renewable generation on reliability."
https://www.ferc.gov/sites/default/files/2020-05/frequencyresponsemetrics-report.pdf

Reserves have been deployed. During a balancing contingency event, it may not be possible to restore FRR from previously designated resources until Contingency Reserves have been deployed (a key reason that reserves are additive).

For a non-contingent responsible entity experiencing a frequency deviation due to a balancing contingency event in another BA area, FRR will normally be restored when frequency returns to its normal range, but there are some exceptions where this may not be the case. If load is shed (either as a contractual resource or for other reasons) and is not restored automatically, the FRR will have served as Contingency Reserves for the contingent responsible entity (even if unintentionally) and FRR for the noncontingent responsible entity will not have been restored. If this is the case, operator action may be needed to restore the FRR by either restoring the load so that it is again available to be shed or obtaining it from other available resources.

Capability to Respond to Large Loss-of-Load Events

Because a responsible entity should be able to adjust its resources in such a manner to ensure its ACE recovers in accordance with applicable Reliability Standards, a responsible entity should identify options to respond to large loss-of-load events, meaning the ability to reduce resources or rapidly bring on additional load. In many cases, decommitment of resources is an option, but with this option comes the risk that the decommitted resource cannot be recommitted in a timely manner, resulting in the exchange of a current solution for a future reliability problem. Planning can mitigate this problem.

Each responsible entity’s planning for the possibility of a large loss-of-load event should include consideration of its energy import and export schedules with other responsible entities; how large loss-of-load events could be affected by interruption of these schedules while taking into account the terms and conditions under which such energy schedules were arranged; and the available down range on resources that have been made available by the sale of non-firm energy that may disappear during a contingency or other disturbance.

As noted previously, responsible entities should consider developing some form of electronic reserve monitor to track resources available to provide both up and down range of reserves.

Reserve Sharing Groups

RSGs are commercial arrangements among BAs to better enable them to collectively meet the requirements of BAL-001-2, BAL-002-3 and BAL-003--2. The spreading of reserve across a larger geographically dispersed group can improve reliability and provides for the opportunity to comply with the BAL performance standards while at the same time economically supplying reserve. However, the RSG should take into account the possibility of delivery being compromised by transmission constraints or generation failures when considering establishing the group’s minimum reserve requirements.

An RSG is a group whose members consist of two or more BAs that collectively maintain, allocate, and supply Contingency Reserves to enable each BA within the group to recover from balancing contingency events. The NERC Reliability Standard BAL-002-2 allows BAs to meet the requirements of the standard through participation in an RSG, something BAs have done for many years to increase efficiency and enhance reliability. The primary benefit of RSGs is that they reduce the capacity a BA is required to withhold for reserves. This can be especially impactful for smaller BAs that have a large generator within their boundaries. Without RSGs, some smaller BA's could be required to withhold 20% or more of their capacity just for Contingency Reserves in addition to all the other reserves they carry.

Compliance for an RSG is measured via monitoring individual and group performance. The RSG can meet the compliance obligations of an event if all members individually pass based upon individual ACE values. If each member of the RSG demonstrates recovery by returning its Reporting ACE to the least of the recovery value of zero or its pre-reporting contingency event ACE value, the compliance requirement is met. In addition, the RSG can also meet the compliance obligation if the collective ACE or sum of the ACE demonstrates recovery by returning the RSG's reporting ACE to the least of the recovery value of zero or its pre-reporting contingency event ACE value. An RSG can meet compliance via either method.
In order for an event to be an RSG event, the contingent BA normally has to call on reserves from the group. If it does not, then the BA is standing alone for that event. Some agreements can require that all events are RSG events by rule. Based on the agreements of the RSG, some BAs in an RSG will not have a single contingency that is a reportable event; the only possible way for them to cause a reportable event is with multiple contingencies all occurring within the 60-second period as defined BAL-002-2. For example, losing an entire generating station due to a fault that clears the bus.

The agreement among the participant BAs for the RSG should address the following:

- The minimum reserve requirement for the group
- The allocation of reserve among members
- The procedure for activating reserve in detailed terms that should include communication protocols and infrastructure, how long reserve is available, and who can call for reserve
- The method of establishing its MSSC or minimum reserve requirements for the group
- How the BAs will manage shortages in reserves and capacity
- The criteria used to determine when a member must declare an EEA
- The criteria that allow members to aid a deficient entity through the RSG by allowing BAs to contribute additional reserves to the group
- How generation and transmission contingencies may affect the deliverability of Contingency Reserves among the members
- Each member's portion of the total reserve requirement
- The methodology used to calculate the member's reserve responsibility
- Identification of valid reasons for failure to respond to a reserve-sharing request
- The reporting and record keeping for regulatory compliance

Scheduling energy from an adjacent BA to aid recovery need not constitute reserve sharing provided the transaction is ramped in over a period the supplying party could reasonably be expected to load generation in (e.g., 10 minutes). For certain RSG arrangements, if the transaction is ramped in more quickly (e.g., between 0 and 10 minutes) then, for the purposes of BAL-002-3, the BA areas are considered to be an RSG. RSGs typically flow on transmission reliability margin (TRM) and have an annual deliverability study done by all the respective transmission planners. Some BAs may have to carry a disproportionate share of reserve if some of their large units are not completely deliverable. These issues may require a special operating guide for local congestion management.

Frequency Response Sharing Group

As defined by NERC, a frequency response sharing group (FRSG) is a group whose members consist of two or more BAs that collectively maintain, allocate, and supply operating resources required to jointly meet the sum of the FRO of its members.

Frequency response has many unique characteristics that make an FRSG different from an RSG. The frequency response capability of individual generating units can change from moment to moment depending on operating point, mode of operation, type of unit, and type of control system. A steam unit that is operating at full valve but not at full capability will have no frequency response even though it appears to have additional capability above its current output. These issues may require responsible entities to develop new unit commitment processes, new operating guidelines, tools for operators, and more consistent governor settings.

The agreement among the participant responsible entities for the FRSG should address the minimum reserve requirement for the group, the allocation of reserve among members, and reporting and record keeping for regulatory compliance. The FRSGs minimum reserve requirement should be conservative to allow for conditions, such as a unit-tripping or transmission contingencies, that could affect members' ability to supply FRR to each other. The agreement should clearly state each member's portion of the total reserve requirement as well as the methodology used to calculate the member's reserve responsibility.

Also, the agreement should consider how the information is shared in real-time based on tools created for the operators.

NERC Reliability Standard BAL-003-2 allows BAs to meet their FROs by electing to form FRSGs. Attachment A of that same standard specifies that an FRSG may calculate their frequency response measure (FRM) performance in one of two ways; calculate a group NIA or aggregate the group response to all events in the reporting year as one of the two following options:

- Single FRS Form 2 utilizing a group NI_A for each event and an accompanying FRS form 1 for the FRSG
- A summary spreadsheet that contains the sum of each participant's individual event performance and an accompanying FRS Form 1 for the FRSG

This section of the guideline is intended to provide recommended practices to consider for BAs when performing the following actions:

- Establishing FRSGs
- Calculating FRSG FRM performance

The Generator Governor Frequency Response Advisory[6] issued notice to industry on the importance of resource configurations for governors and control systems to allow for the provision of primary frequency response. Subsequently, a specific description of practices necessary for resources to provide primary frequency control, including the coordination of turbine controls with plant outer loop controls and an explanation of the different components of frequency response, can be found in the *Primary Frequency Control Reliability Guideline*[7].

Existing BAL-003-2 Forms 1 and 2 provide short-term bilateral transactions of frequency response and do not require the formal establishment and registration of a long-term FRSG, so these arrangements are not addressed by this guideline. This section of the guideline focuses solely on establishment and operating practice guidelines for a multiparty FRSG.

Establishment/Structure of an FRSG

Certain minimum criteria should apply to all candidate FRSGs prior to registration and establishment. FRSG registration is necessary to provide ERO staff with sufficient information to modify the FRSG's FRO for each operating year. The FRSG FRO is the aggregate of member BAs' FROs, including the information in the tables used in Form 1, and determine unique FRSG codes (substitutes for the BA codes normally used) for use in summary Form 1.

An FRSG should have a formal agreement among its members in place prior to registration. Depending on the structure and characteristics of the member BAs, the FRSG agreement among the participant responsible entities for the FRSG may need to address the following:

- Minimum frequency-responsive reserve requirement for the group
- Each member's portion of the total frequency-responsive reserve requirement
- Requirements, if applicable, of specific resources to provide frequency response
- Members' reporting, record keeping, and accountability for regulatory compliance
- Provisions for each member's alternative minimum frequency-responsive reserve requirements in identified areas in the event of emergency scenarios, such as an islanding event
- Methodology used to calculate the member's frequency-responsive reserve responsibility
- How information is shared among members in real-time
- Tools for operators to have situational awareness of frequency-responsive reserves of the FRSG

[6] https://www.nerc.com/pa/rrm/bpsa/Alerts%20DL/2015%20Alerts/NERC%20Alert%20A-2015-02-05-01%20Generator%20Governor%20Frequency%20Response.pdf
[7] https://www.nerc.com/comm/OC/RS_GOP_Survey_DL/PFC_Reliability_Guideline_rev20190501_v2_final.pdf

- When and how to bring more frequency-responsive reserves to bear (e.g. conservative operations, periods of low inertia)

FRSGs must be pre-arranged and member participation must coincide with the BAL-003-2 operating year (i.e., December 1 through November 30 of the following year). Any member of the BA's minimum period of participation must be one BAL-003-2 operational year. Partial BAL-003-2 operating year participation is not allowed. Per-event participation with other BAs is a bilateral transaction and is not considered a formation of an FRSG. Like bilateral transactions, FRSGs can only be established prior to the analysis period, and no BA may be a member of more than one FRSG at any given time.

All FRSG member BAs must be in the same Interconnection. An FRSG can be noncontiguous, but each FRSG may be subject to a transmission security review by potentially affected BAs and Transmission Operators. In some cases, a transmission security review by potentially affected BAs and Transmission Operators may be necessary for contiguous FRSGs if, for example, parallel flows caused by individual members' responses may impact other BAs or Transmission Operators.

Operations of a FRSG

FRSGs and their constituent BAs should attempt to fully respond to each event in the BAL-003-2 operating year.

FRSG who calculate an FRSG NI_A, should properly time-align tie line data to account for data latency and difference in member BAs' EMS scan rates. To the extent possible, this adjustment should be reflected in real-time data provided to operators. The adjustment times for each alignment should be reviewed at least annually to determine if a different amount of adjustment is needed.

The FRSGs minimum frequency-responsive reserve requirement should be conservative to allow for conditions, such as a unit-tripping or transmission contingencies, that could affect members' ability to supply frequency-responsive reserve to each other.

Although an explicit frequency-responsive reserve requirement is not necessary in every case, the FRSG should account for frequency-responsive reserves among its members in real-time. Members of an FRSG should consider including such provisions in their organizational documents.

Analysis/Reporting

FRSG member BAs must select an entity to report summary information for the FRSG to NERC. As noted above, FRSG reporting is done according to Attachment A in BAL-003-2.

For tie line data not already time-aligned, the FRSG and its member BAs should properly time-align prior to completing the aggregate FRS Form 2s to account for data latency and difference in member BAs' EMS scan rates.

Changes to Form 1 necessary to allow use of appropriate adjustments of FRM will be referred to NERC staff for development and implementation and those changes will be routed through the appropriate NERC committees for any vetting/validation needed.

Regulation Reserve Sharing Group

A regulation RSG is a group whose members consist of two or more BAs that collectively maintain, allocate, and supply the regulating reserve required for all member BAs to use in meeting applicable regulating standards.

A regulation RSG may be used to satisfy the Control Performance Standard (CPS) requirement in BAL-001-2. Sharing of regulating reserve will require real-time data sharing and dynamic transfers[8] between members. The agreement among the participant BAs of the regulation RSG should contain the maximum amount of regulation to be exchanged and the medium used to communicate the regulation to be shared. The agreement should assign responsibility for arranging transmission service and posting schedules. Regulation magnitudes may at times be limited due to resource availability or transmission constraints, so the regulation RSG agreement should include mechanisms to provide for such restrictions. If a regulation RSG has many members, the members may need central data sharing to enable communication in Real-time, as well as more complex definitions of transmission paths among members and mechanisms to address transmission path limitations. Record keeping for the regulation RSG will primarily be energy schedule records (E-Tags) and Open Access Same-Time Information System postings that allow energy flow between members. The regulation RSG agreement should also have mechanisms to settle imbalances and limit the amounts of imbalances between members.

Operating Reserve Interaction

The responsible entity’s Operating Reserves definition should include three general categories: FRR, regulating reserve, and contingency reserve. NERC Reliability Standards primarily govern the deployment of these three categories.

Load Forecast Error

The BA Operating Reserve projections should consider load forecast error when establishing reserve levels. The following is a list of considerations that may be evaluated. These may change from day to day, from season to season, and should be included in the commitment of resources.

- Weather forecast
- Seasonal temperature variations
- Model error
- Speed of weather event

Fuel Constraints

[8] For a more detailed explanation of the implementation of dynamic transfers in general and for regulation sharing (discussed as supplemental regulation in the document) specifically, see the Dynamic Transfer Reference Guidelines reference document in the *NERC Operating Manual*. This document can be found at http://www.nerc.com/comm/OC/Pages/Operating-Manual.aspx

Once resources are identified, a second review should consider fuel constraints to determine if any limitations generation exits. The following is a list of considerations that may be evaluated. These may change from day to day, from season to season, and should be included as part of a BA's projection of operating reserves and contingency reserves.

- Delivery Limitations such as Operational Flow Orders – (OFOs)
- Availability of fuel (e.g. weather impacts, market, ability to purchase)
- Transportation considerations
- Fuel supply (e.g. size of coal pile, amount of fuel oil, water reserves)
- Variability (e.g. solar and wind)

Deliverability of Reserves

Deliverability of reserves is an important consideration. If reserves are undeliverable across the BA, then the BA is at increased risk of not complying with BAL-002-3. As transmission outages occur, the ability to deliver energy across the BA changes. A BA should consider any restrictions or limitations that may reduce generation capability as part of their operating and contingency reserve projections. The following may impact the deliverability of reserves:

- Transmission availability
- Transmission constraints
- Shape/size of BA
- RSG Considerations –
    - Ability to deliver with available transmission
    - Connection through an intermediate member
    - Operating procedures

Unit Commitment

When developing plans and addressing the needs of a BA or an RSG to reliability meet the demands of customers, unit commitment is a key component of successfully planning and ensuring that the needed generation is available in real-time operations. When dispatching the system, the BA operator should coordinate and consider any impacts to operating reserves and contingency reserves. The following is a list of considerations that may be included in the unit commitment process:

- Unit start-up time
- Available personnel
- Maintenance activities
- Environmental limitations:
    - Drought constraints

    - Intake constraints
- Hydrothermal limitations

For all imbalances occurring on its power system, the responsible entity will use its reserve that is addressed by the following four-step process.

Step 1: Arrest Frequency Change

The first step in recovery is to arrest the frequency change caused by the imbalance. In most circumstances, this arresting action is performed automatically by the frequency response of generators and load on the Interconnection within the first few seconds of the imbalance. If there is insufficient frequency response or FRR to arrest a frequency decline, the Interconnection frequency will reach underfrequency relay trip points before any of the other steps can be initiated. Frequency response is therefore the most important of the required responses and FRR is the most important of the reserves.

Step 2: Contingency Reserve Deployment- Returning Frequency to its Normal Range

The second step in the recovery process is to return the frequency to its normal range. Again, this is usually accomplished by applying FRR or regulating reserve in most circumstances for small imbalances, and the CPS1 portion of BAL-001-2 governs the timeliness of the aggregate of such recoveries. The timeliness of the recovery from larger imbalances is governed by BAL-002-2 as well as CPS1. For large, sudden imbalances due to loss of generation, this is usually accomplished by applying contingency reserve. Current rules in North America require the completion of this step within a fixed time, 15 minutes in most cases. The remainder of the operating reserve not used for the frequency response is available to complete this return to the normal frequency range.

Step 3: Restore Frequency Responsive Reserve

The third step in the recovery process is the restoration of the FRR. Restoration of FRR is what indicates the Interconnection is secure and, in a position, to survive the next imbalance or disturbance. The timeliness of achieving this condition affects the risk that the Interconnection faces.

Step 4: Operating Reserves Conversion–Restoring Regulating Reserve or Contingency Reserve

The fourth step is to restore any Regulating or Contingency Reserves that has been deployed to ensure that the Interconnection can recover from the next imbalance or disturbance within an appropriate time.

Interaction

This four-step process demonstrates that the Operating Reserve components (i.e. FRR, regulating reserve and contingency reserve) are used in conjunction with one another, do not function in isolation, are always interacting, and often overlap due to timing requirements.

The Operating Reserve components can be distinguished from each other by the response time it takes to convert the reserve capacity into deliverable energy. The differences in response time allow the reserves to be utilized from the reserve with the fastest response (i.e. FRR) to the reserve with the slowest response time (i.e., Contingency Reserve). The deployment of regulating reserve in some scenarios can lead to the restoration of FRR. The deployment of Contingency Reserve in some scenarios will assist in the restoration of FRR and regulating reserve.

FRR is a "sub-minute" reserve product, and governor response provides it in most cases. Typically, Regulating Reserves and Contingency Reserves cannot be deployed in the time frame to assist in keeping frequency above underfrequency relay settings. Regulating Reserve usually does not respond quickly enough to be observable in the FRM. Contingency Reserves most often takes more than a minute and can take up to 15 minutes to deploy following the start of the contingency.

Regulating Reserves are often thought of as a "minute plus" reserve product. If it is deployed by any responsible entity in an Interconnection in a direction that supports pushing frequency towards 60 Hz, it will help restore FRR within the Interconnection.
For resource losses, contingency reserve activated by the contingent responsible entity often takes a few minutes to begin to be deployed. As its deployment progresses over time and frequency approaches 60 Hz, there will be some restoration of FRR and regulating reserve for the contingent responsible entity. A noncontingent responsible entity's FRR will tend to be restored with the deployment of the contingent responsible entity's contingency reserve as well.

For a responsible entity in a multiple responsible entity Interconnection, it may coincidentally need to deploy FRR for a load greater than generation imbalance within its Interconnection at the same time that it needs to deploy its regulating reserve in the upward direction. It may also experience its MSSC, requiring the deployment of contingency reserve while the need for FRR and regulating reserve are at a maximum. The responsible entity should plan its reserve allocations to be compliant with the NERC Reliability Standards in such a coincidental scenario.

Interconnections with only one responsible entity are unique in that only they can correct their system frequency. FRR will always be deployed automatically and coincidentally when contingency reserve needs to be deployed for a large contingency. FRR and contingency reserve are inherently co-mingled, and together they must at least equal MSSC. As with a multiple responsible entity Interconnection, regulating reserve needs to be separate from FRR and contingency reserve.

There is an additional characteristic of reserve enabling the reserve categories to be ordered. Operating Reserve categories are partially substitutable for one another. FRR is the only type of reserve that could be used as the exclusive reserve that would enable an Interconnection to operate reliably. Attempts to operate an Interconnection without FRR would result eventually in the activation of frequency relays. As long as the amount of FRR available is greater than the energy imbalance on the Interconnection, the Interconnection will remain reliable.

The difficulty with operating an Interconnection with only FRR is that FRR is limited in the total amount available. FRR will arrest the frequency change but will not restore frequency to its normal range, leaving the Interconnection vulnerable to the next contingency. The FRR provided by load damping is limited and the additional FRR provided by governor response is relatively expensive to provide in large quantities.

Regulating reserve is a reserve that can be substituted on a limited basis for FRR. When regulating reserve is substituted for FRR, the regulating reserve restores the FRR by returning governor response to the plants and replacing it with dispatched energy. As frequency is returned to normal range, the FRR is restored and available for reuse. The amount of regulating reserve that can be substituted for frequency response is determined by the difference between the FRR required to manage the largest imbalance that could occur on the Interconnection and the FRR that could be required in a period shorter than the response time for regulating reserve. This ensures there is sufficient FRR available to manage any imbalance occurring before there is time to replace the FRR being used with regulating reserve. Also, it extends the effective amount of FRR available, allowing the Interconnection to operate with less governor response because the amount of load damping is not easily modified.

In all cases, the maximum imbalance that unmanageable by supplementing FRR with regulating reserve (when only FRR and regulating reserve are available) determines the minimum FRR required. In addition, the sum of the FRR and regulating reserve should exceed the largest energy imbalance occurring on the Interconnection. Thus, when substituting regulating reserve for FRR the total amount of the FRR and regulating reserve should be equal to or exceed the amount of FRR when it is used alone.

Contingency Reserves can further supplement regulating reserve and FRR and can be manually dispatched to restore any FRR currently being used to respond to declining frequency. When dispatched, it restores both FRR and regulating reserve, making them available for reuse. Therefore, contingency reserve can be substituted for a portion of the regulating reserve that could be substituted for FRR. When this substitution is implemented, the sum of the FRR, regulating reserve, and contingency reserve should exceed the sum of regulating reserve and FRR if contingency reserve is not used.

This illustrates a power system that uses many levels of substitution to improve economic efficiency and reliability. Regulating Reserve is substituted for FRR as determined by reliability needs; contingency reserve is substituted for regulating reserve as determined by reliability needs. Reliability limits for these substitutions can be quantified with a set of inequalities:

$$FRR + RRO \geq FRRO \qquad \text{Inequality (1)}$$
$$FRR + RR + CR \geq FRR + RRO \qquad \text{Inequality (2)}$$

FRRO	=	FRO, equal to MW of FRR when only FRR is used.
FRR	=	MW of FRR when another service is substituted for FRR.
RRO	=	MW of regulating reserve (RR) when nothing is substituted for RR.
RR	=	MW of RR when another service is substituted for RR.
CR	=	MW of CR when nothing is substituted for CR.

Both inequalities represent the total required reserve on both sides of the inequality.

These inequalities are used to determine the FRO in BAL-003-2 as adjusted by the base frequency error profile that results from reserve substitution. In addition, the contingency reserve requirement in R2 of BAL-002-2 determines the minimum CR when it is not in use for recovery, but it does not require that the reserve used to meet the requirement exclude FRR or regulating reserve. Since regulating reserve is unique to each responsible entity and can be determined only by evaluating the characteristics of their load and generation resources, a minimum regulating reserve obligation is not specified in BAL-001-2. The variations of substitution of reserve as shown above suggests that the best test for reserve adequacy is whether the total capability of resources designated to provide regulating reserve, contingency reserve, and FRR is at least equal to the amount required to meet all reserve requirements concurrently.

Additionally, during the deployment of reserves in real-time, there are only limited ways to determine whether a responsible entity is holding adequate reserves. This determination can only be based on a prospective look during operations planning when there are no deviations from the expected deployment of reserves. Because this is the case, it is also important for the responsible entity to have a feedback mechanism included in its evaluations of reserve to include the uncertainties experienced during actual reserve usage. A reserve-monitoring tool could accomplish this.

The calculation of reserve levels (including FRR, regulating reserve, and contingency reserve) begins with the calculation of the amount of each type of reserve available from each resource providing any of these three types of Operating Reserves. Once the individual resource reserve contributions have been calculated, the responsible entity's total reserves by category can be determined by the sum of the reserve contributions for all contributing resources.

The calculation for these three types of reserves (i.e., FRR, regulating reserve, and contingency reserve) may not be supported in some EMSs because the FRR calculation and the interaction between reserves requires additional data not currently maintained in many EMSs. Additional data required to support the FRR calculation includes, but is not limited to, unit droop, dead-band settings, and Interconnection underfrequency load shedding (UFLS) frequency limits. Additional data may be required for other types of resources.

Finally, any calculation of the total amount of reserve and the amount in each category can change with a change in output/use of any of the resources that provide reserve for the responsible entity. For example, dispatch of contingency reserve from a resource could also affect the FRR or regulating reserve that is available from that same resource by moving the operating point of the resource nearer to one of the resource's operating limits. This could result in a reduction of one of the other reserve types in addition to the reduction in the amount of contingency reserve resulting from the dispatch. This dynamic reserve interaction should be included in operations planning and the tools used to provide the system operator with the best information.

Related Documents and Links:

NERC Reliability and Security Technical Committee Charter

NERC Operating Manual

Use of Frequency Response Metrics to Assess the Planning and Operating Requirements for Reliable Integration of Variable Renewable Generation, Key Findings

Cited Documents

NERC Alert A-2015-02-05-01 Generator Governor Frequency Response

Primary Frequency Control Reliability Guideline

NERC Standard BAL-003-2

FERC Final Order on Third-Party Provision of Primary Frequency Response Service - FERC Docket RM15-2-000 Order No. 819

Revision History		
Date	**Version Number**	**Reason/Comments**
10/18/2013	1.0	Initial Version – "Operating Reserve Management"
12/13/2017	2.0	Revised to include more detailed description of FRSG
9/13/2020	3.0	3-year review and revisions

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Reliability Guideline

Operating Reserve Management~~—~~: Version ~~2~~3

Preamble~~:~~

It is in the public interest for NERC to develop guidelines that are useful for maintaining ~~or~~and enhancing the reliability of the Bulk Electric System (BES). ~~The~~ The subgroups of the Reliability and Security Technical ~~Committees of NERC—Operating~~ Committee (~~OC), Planning Committee (PC) and the Critical Infrastructure Protection Committee (CIPC~~RSTC)—in accordance with ~~their charters~~[1]the RSTC charter[1] are authorized by the NERC Board of Trustees ~~(Board)~~ to develop ~~Reliability (OC and PC)~~reliability and ~~Security Guidelines (CIPC).~~security guidelines. These guidelines establish a voluntary code of practice on a particular topic for consideration and use by BES users, owners, and operators. These guidelines are coordinated by the technical committees and include the collective experience, expertise, and judgment of the industry. The objective of this reliability guideline is to distribute key practices and information on specific issues critical to appropriately maintaining BES reliability. Reliability guidelines are not to be used to provide binding norms or create parameters by which compliance to standards are monitored or enforced. While the incorporation, of guideline practices ~~are~~, is strictly voluntary, reviewing, revising, or developing a program using these practices is highly encouraged to promote and achieve appropriate BES reliability.

Purpose~~:~~

This ~~Reliability Guideline~~reliability guideline is intended to provide recommended practices for the management of an appropriate mix of Operating Reserve~~,~~ as well as readiness to respond to loss of load events. It also provides guidance with respect to the management of Operating Reserve required to meet the NERC Reliability Standards.

The ~~Reliability Guideline~~reliability guideline applies primarily to Balancing Authorities (BAs) or, as appropriate, ~~[Contingency] Reserve Sharing Groups, Regulation Reserve Sharing Groups~~contingency reserve sharing groups (RSGs), regulation RSGs, or ~~Frequency Response Sharing Groups~~frequency response sharing groups. For ease of reference, this guideline uses the common term "responsible entity" for these entities, and allows the readers to make the appropriate substitution applying to them when participating or not in various groups.

Reserve planning has been practiced for a long time by NERC operating entities, dating back to Policy 1 of NERC's ~~Operating Policies.~~operating policies. This ~~Reliability Guideline guides~~reliability guideline leads responsible entities toward the best practices for management of the ~~Operating Reserve~~operating reserve types by dividing them into individual components to provide visibility and accountability. While the incorporation of guideline practices is strictly voluntary, reviewing,

[1] https://www.nerc.com/comm/RSTC/RelatedFiles/RSTC_Charter_approved20191105.pdf

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revising, or developing a process using these practices is highly encouraged to promote and achieve reliability for the BES.

~~1~~ ~~http://www.nerc.com/docs/docs/oc/OC_Charter_approved_02.16.10.pdf~~ ~~http://www.nerc.com/docs/cip/CIPC_Charter_Aug2010.pdf~~ ~~http://www.nerc.com/docs/pc/Board%20Approved%20PC%20Charter%20August%204%202011.pdf~~

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Assumptions~~:~~

- There can be a variety of methods that responsible entities use to ensure that sufficient Operating Reserves are available to deploy in order to support reliability. This guideline does not specify or prescribe how the need for sufficient operating reserves are met.

- ~~A.~~ NERC, as the FERC certified ~~ERO[2]~~ERO,[2] is responsible for the reliability of the BES and has a suite of tools to accomplish this responsibility, including but not limited to~~:~~ lessons learned, reliability and security guidelines, assessments and reports, the Event Analysis ~~program~~Program, the Compliance Monitoring and Enforcement Program, and mandatory NERC Reliability Standards.

- ~~B.~~ Each ~~entity as~~ registered entity in the NERC compliance registry is responsible and accountable for maintaining reliability and compliance with the mandatory standards to maintain the reliability of the BES.

- ~~C.~~ Entities should review this ~~Reliability Guideline~~reliability guideline in detail in conjunction with the periodic review of their internal processes and procedures and make any needed changes to their procedures based on their system design, configuration, and business practices.

Background

There is often confusion when operators and planners talk about reserves. One major reason for misunderstanding is a lack of common definitions; NERC's definitions have changed over time. In addition, most NERC Regional Entities (REs) developed their own definitions. Capacity obligations have historically been the purview of state and provincial regulatory bodies, meaning that there are many different expectations and obligations across North America.

The second area of confusion concerning reserves deals with the limitations of each BA's energy management system (EMS). Common problems include the following:

- Counting all "headroom" of on-line units as spinning reserve even though it may not be available in 10 minutes (i.e., lag from adding mills or fan speed changes)
- No intelligence in the EMS regarding load management resources
- No corrections for "temperature sensitive" resources, such as natural gas turbines
- Inadequate information on resource limitations and restrictions
- Reserves that may exist and are deployed outside the purview of the EMS system

[2] http://www.ferc.gov/whats-new/comm-meet/072006/E-5.pdf

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Definitions

Capitalized terms used within this guideline are defined as part of the NERC Glossary. Terms which are not capitalized are used as references within this guideline.

Contingency Reserve: This is the provision of capacity deployed by the BA to respond to a balancing contingency event and other contingency requirements, such as energy emergency alerts (EEAs) as specified in the associated NERC Reliability Standards.

Contingency Event Recovery Period: A period that begins at the time that the resource output begins to decline within the first one-minute interval of a Reportable Balancing Contingency Event and extends for fifteen minutes thereafter.

Contingency Reserve Restoration Period: A period not exceeding 90 minutes following the end of the Contingency Event Recovery Period.

Frequency-Responsive Reserve (FRR): On-line generation with headroom that has been tested and verified to be capable of providing droop as described in the *Primary Frequency Control Reliability Guideline Reliability Guideline.*[3] Variable load that mirrors governor droop and dead-band may also be considered FRR.

Interruptible Load: Demand that the end-use customer makes available to its load-serving entity via contract or agreement for curtailment. Note: If the load can be interrupted within 10 minutes, it may be included in Contingency Reserve; otherwise, this load is generally included in Operating Reserves - Supplemental.

Most Severe Single Contingency (MSSC): The Balancing Contingency Event, due to a single contingency that was identified using system models maintained within the RSG or a BA's area that is not part of an RSG, that would result in the greatest loss (measured in megawatt (MW) of resource output used by the RSG or a BA that is not participating as a member of an RSG at the time of the event to meet firm demand and export obligation (excluding export obligation for which contingency reserve obligations are being met by the sink BA).

Operating Reserve: Operating reserve is the capability above firm system demand required to provide for regulation, load forecasting error, equipment forced and scheduled outages, and local area protection. It consists of spinning and non-spinning reserve.

Operating Reserve–Spinning: This includes generation synchronized to the system and fully available to serve load within the Disturbance Recovery Period following the contingency event or load fully removable from the system within the Disturbance Recovery Period disturbance recovery period following the contingency event deployable in 10 minutes.

[3] https://www.nerc.com/comm/OC_Reliability_Guidelines_DL/PFC_Reliability_Guideline_rev20190501_v2_final.pdf

Operating Reserve–Supplemental: This includes generation (synchronized or capable of being synchronized to the system) that is fully available to serve load within the disturbance recovery period following the contingency event or load fully removable from the system within the disturbance recovery period following the contingency event that can be removed from the system within 10 minutes.

Other Reserve Resources: This includes resources that can be used outside the continuum of Operation Reserves *Figure: 1* (i.e., on four hours' notice).

Planning Reserve: This is the difference between a BA's expected annual peak capability and its expected annual peak demand expressed as a percentage of the annual peak demand.

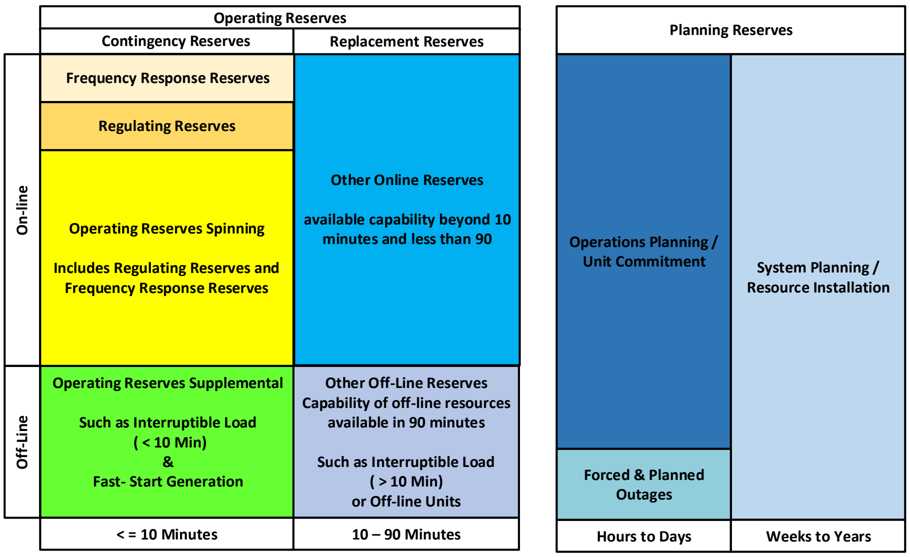
Projected Operating Reserve: This includes resources expected to be deployed for the point in time in question.

Regulating Reserve: This is an amount of Operating Reserve – Spinning that is responsive to automatic generation control (AGC) sufficient to provide normal regulating margin.

Replacement Reserve: Resources used to replace designated Contingency Reserve that have been deployed to respond to a contingency event. Each NERC RE sets times for Contingency Reserve restoration, typically in the 60–90-minute range. The NERC default Contingency Reserve restoration period is 90 minutes after the Disturbance Recovery Period.

Supplemental Reserve Service: Supplemental reserve service provides additional capacity from electricity generators that can be used to respond to a contingency within a short period, usually 10 minutes. This is an ancillary service identified in FERC Order 888 as necessary to affect a transfer of electricity between purchasing and selling entities and is effectively FERC's equivalent to NERC's Operating Reserve.

Figure 1: Operating Reserves



Guideline Details~~:~~

An effective Operating Reserve program should address the following components: ~~(I)~~

- Management ~~Roles~~roles and ~~Expectations; (II) ~~expectation
- System ~~Operator Roles; (III) ~~operator roles
- Regulating ~~Reserve; (IV) ~~reserve
- Contingency ~~Reserve; (V) frequency~~reserve
- Frequency responsive reserve~~; (VI) capability~~
- Capability to respond to large loss-of-load events~~; (VII)~~
- Reserve ~~Sharing Groups; and (VIII) ~~sharing groups
- Operating ~~Reserve Interaction. ~~reserve interaction
- Load forecast error
- Fuel constraints
- Deliverability of reserves
- Unit commitment

Each individual component should address ~~(1) Safety; (2) Processes and Procedures; (3) Evaluation~~safety; processes and procedures; evaluation of any issues or problems along with

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~~**Definition:**~~
~~**Frequency Responsive Reserve:** An amount of reserve automatically responsive to locally sensed frequency deviation.~~

Each responsible entity should evaluate the total reserve needed to meet its obligations under NERC Reliability Standards, namely frequency response reserves, regulating reserves up, regulating reserves down, contingency reserves, and ~~frequency responsive reserve.~~operating reserves. Given ~~the~~that different reserves may be difficult to separate in actual operation, the system operator will need an understanding of the quantity of each type of reserve required. Each responsible entity should consider the types of resources and the associated portion of their capacity capable of reducing the ~~Balancing Authority's Area Control Error~~BA's area control error (ACE) in either direction in response to each of the following:

- ~~1.~~ Frequency deviations~~,~~
- Bottoming out conditions
- Ramping requirements
- ~~2.~~ A Balancing Contingency Event~~,~~
- ~~3.~~ Events associated with ~~Energy Emergency Alert~~EEA 2~~,~~
- ~~4.~~ Events associated with ~~Energy Emergency Alert~~EEA 3~~, and~~
- ~~5.~~ ~~Large~~A large loss-of-load event~~.~~

~~[2] http://www.ferc.gov/whats-new/comm-meet/072006/E-5.pdf~~

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~~I.~~ Management Roles and Expectations

Management plays an important role in maintaining an effective Operating Reserve program. The management role and expectations below provide a high-level overview of the core management responsibilities related to each Operating Reserve program. The management of each responsible entity should tailor these roles and expectations to fit within its own structure~~.~~:

- Set expectations for safety, reliability, and operational performance~~.~~
- Assure that an Operating Reserve program exists for each responsible entity and is current~~.~~
- Provide annual training on the Operating Reserve program and its purpose and requirements~~.~~
- Ensure the proper expectation of Operating Reserve program performance~~.~~
- Share insights across industry associations~~.~~

~~I. System Operator Roles~~

- ~~Participate in appropriate System Operator training.~~
- ~~Ensure the Operating Reserve information is always current.~~

- Conduct an evaluation of the effectiveness of the Operating Reserve program and incorporate lessons learned~~.~~

System Operator Roles

BA Operator

It is important for the system operator know the specifics of their BA reserve strategy and maintain situation awareness through the following:

- Participate in appropriate system operator training
- Ensure the Operating Reserve information is always current
- Maintain situation awareness and projection of reserves for a 2-hour to 6-hour horizon
- Review and validate reserve plan while considering load forecast, unit commitment, fuel supply, weather conditions, and reserve requirements
- Implement the BA Operating Reserve program in ~~Real~~real-time~~.~~ that should
  - Ensure adequate reserves are available to address loss of MSSC or Frequency deviations in real-time
  - Coordinate communications with RC if inadequate reserves are forecasted or experienced
  - Adhere to EOP Operating Standards
  - Issue the proper EEA is called when a reserve short fall is forecasted or experienced

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RC Operator

It is important for the system operator to look at other indicators to determine the ultimate course of action, such as the following:

- Is the BA or BAs' ACE predominantly negative for an extended period?
- Is frequency low (i.e., more than 0.03 Hz below scheduled frequency)?
- Are reserves low in multiple BAs?
- Is load trending upward or higher than anticipated?

Based on the duration and severity of the situation, action steps may include the following:

- Verify reserve levels
- Follow EEA–review and understand individual BA EEA plans
- Direct BA(s) to take action to restore reserves
- Direct the identification of load to shed to withstand the next contingency for a post contingent action.
- Redistribute reserves
- Shed load where appropriate if the BA or Transmission Operator cannot withstand the next contingency

~~II.~~ Regulating Reserve

The responsible entity's balance between demand, supply (generation minus metered interchange) and frequency support is measured by its ~~Area Control Error (~~ACE~~)~~. Because changes in supply and demand cannot be predicted precisely, there will be a mismatch between them, resulting in a ~~non-zero~~nonzero ACE.

Each responsible entity should have a documented ~~Regulating Reserve~~regulating reserve process ~~ensuring~~that ensures that the responsible entity has sufficient capacity to meet the performance requirements of BAL-001-2. The responsible entity's process should include the following at a minimum:

~~1.~~ • **A method for determining its regulating needs**~~.~~: This method should ~~take into account~~consider the entity's generation mix, type of load, the variability in both generation and load, and the probability of extreme influences ~~such as~~(e.g., weather~~.~~).

~~2.~~ • ~~Types~~**Knowing what types of resources and the portion of their capacity that can be made available for regulation**~~.~~: The responsible entity should have resources that will respond to the entity's need to balance supply and demand to meet the performance requirements of NERC Reliability Standards.

~~3.~~ • **The** ~~responsible entity should incorporate into its regulating needs consideration~~**incorporation of contractual arrangements into regulating needs,** such as

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exports and imports~~.~~: Changes to contractual arrangements should be assessed and accounted for in the responsible entity’s ability to respond and meet the performance requirements~~.~~

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Evaluation of

~~6.~~ • ~~The responsible entity should evaluate~~ **its planned** ~~Regulating Reserve (based on changing system conditions, such as the current load, forecast errors, and generation mix)~~**regulating reserve needs over the operating time horizon and gauge its ability to meet its** ~~Regulating Reserve~~**regulating reserve needs on at least an hourly basis**: This should be based on changing system conditions, such as the current load, forecast errors, and generation mix.

~~7.~~ • ~~The responsible entity should plan~~**Planning and** ~~implement~~ **implementation of the ability to restore its** ~~ability to restore its Regulating Reserve~~**regulating reserve as needed**~~.~~: This may include the ability to restore ~~Regulating Reserve~~regulating reserve in either direction.

~~8.~~ • ~~The responsible entity's Regulating Reserve~~**Ensuring that the regulating reserve is used by only one entity:** The regulating reserve process should include a method whereby its ~~Regulating Reserve~~regulating reserve is not included in another responsible entity's Operating Reserve (~~Regulating, Contingency~~i.e. regulating, contingency, or ~~frequency responsive reserve~~FRR) policy.

~~III.~~ Contingency Reserve

When a responsible entity experiences an event~~,~~ (i.e., loss of supply or significant scheduling problems~~, which~~ that can cause frequency disturbances~~,~~), it should be able to adjust its resources in such a manner to assure its ACE recovers in accordance with the requirements of the applicable Reliability Standards.

~~1. Responsible entity's Contingency Reserve need:~~

~~In order for~~For a responsible ~~entities~~entity to meet the requirements of the NERC Reliability Standards ~~they need~~BAL-002-3, the BA needs to identify ~~their Most Severe Single Contingency (~~its MSSC~~)~~ to determine ~~their~~its base ~~Contingency Reserve.~~contingency reserve. Because there is no forgiveness for this minimum amount of ~~Contingency Reserve~~ contingency reserve not deployed when called upon, the individual entity could consider additional amounts ~~could be considered~~ based on ~~the individual entity's~~ risk analyses. To be effective, ~~Contingency Reserve~~contingency reserves should be able to be deployed (including activation or communication needs) to meet the ~~Contingency Event Recovery Period~~contingency event recovery period for ~~Balancing Contingency Events.~~balancing contingency events. Reserve amounts set aside as frequency responsive ~~reserve~~include unit governor reserves. These local responses are independent of control center control. If the unit is not operating at maximum output, the unit should ~~notbe~~be capable of providing frequency response. Due to the interactions of frequency reserves, these are included in the available minimum ~~Contingency Reserve~~contingency reserve amounts in Interconnections composed of more than one responsible entity~~, because at~~. At any given time, ~~they~~a unit may also be ~~deployed~~loaded to maximum output and unavailable to meet the reliability requirements associated with ~~Contingency Reserve~~frequency response and contingency reserves.

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Additionally, the responsible entity should consider an appropriate mix and coordination of ~~frequency responsive reserve and Contingency Reserve should be considered~~FRR and contingency reserve to ensure that the responsible entity has the ability to respond to frequency events on the Interconnection as well as in its own ~~Balancing Authority Area,~~BA area in accordance with all NERC and ~~Regional~~RE standards.

~~**Definition:**~~

~~**Most Severe Single Contingency (MSSC):** The Balancing Contingency Event, due to a single contingency identified using system models maintained within the Reserve Sharing Group (RSG) or a Balancing Authority's area that is not part of a Reserve Shaing Group, that would result in the greatest loss (measured in MW) of resource output used by the RSG or a Balancing Authority that is not participating as a member of a RSG at the time of the event to meet Firm Demand and export obligation (excluding export obligation for which Contingency Reserve obligations are being met by the sink Balancing Authority).~~

~~6.~~ ~~Many types of~~ Various resources ~~can~~may be considered for use as ~~Contingency Reserve~~contingency reserve provided, they can be deployed within the appropriate ~~timeframe~~time frame. As technology and innovations occur, this list may continue to grow~~, but~~ and may include the following:

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~~c.~~ Unloaded/loaded generation, such as quick start CTs, hydro facilities, portions of unit ramping capabilities

~~d.~~ Off-line generation

~~e.~~ Demand resources

~~f.~~ Energy ~~Storage Devices~~storage devices

~~g.~~ Resources ~~such as~~like wind, solar, etc., provided that any limitations are ~~taken into account.~~considered

~~7.~~ Responsible entities should consider how schedule interruption would affect their Contingency ~~Reserve would be affected by interruption of schedules, taking into account~~Reserves while considering the terms and conditions under which such energy schedules were arranged.

Responsible entities that choose to use energy schedules to respond to a ~~Balancing Contingency Event~~balancing contingency event should take into account the terms and conditions under which such energy schedules were arranged and verify that they would not detract from a responsible entity's use of such schedules when meeting their ~~Contingency Reserve~~contingency reserve requirements for ~~Balancing Contingency Events~~balancing contingency events.

~~8.~~ ~~A~~For RSGs, there is a prohibition against counting toward the responsible entity's Contingency Reserve any capacity ~~which~~that is already included in another responsible entity's ~~Regulating, Contingency~~regulating, contingency, or ~~frequency responsive reserve~~FRR policy. Special coordination between RSG members may be required for resources ~~that are~~ dynamically transferred between multiple responsible entities.

~~9.~~ To assure a responsible entity ~~has the ability to~~ can respond to a ~~Balancing Contingency Event during Real~~balancing contingency event in real-time, the responsible entity should plan for its available Contingency ~~Reserve~~Reserves for the operating time horizon (~~Operations Planning, Same Day~~i.e. operations planning, same day and ~~Real~~real-time ~~Operations). This~~operations). The BA operator should focus their situation awareness and evaluation of reserves in a time horizon ~~could be~~between next hour and multiple days ~~to a review of the next hour's available reserve.~~out. The review should be flexible so that it can be updated to reflect changes ~~in~~available generation, load forecast, the amount of reserve available or the amount of reserve required.

~~10.~~ Responsible entities should consider developing some form of electronic reserve monitor~~, which~~ that would track resources available to provide the necessary response and the amount of capacity each could provide. Many ~~energy management systems (EMS)~~EMSs currently provide this type of feature for measuring the up and down ranges of their resources. Care should be taken to recognize the up and down ranges on resources ~~which~~that have been made available by the purchase or sale of non-firm energy ~~which~~that may disappear during an event.

~~11.~~ ~~In order for~~For a responsible entity should leverage their Replacement Reserves to meet the Contingency Reserve Restoration Period, ~~pre-planning~~preplanning and training of ~~System Operators~~system operators may be required. Actions ~~such as~~like the following may be considered:

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~~a.~~ Verification of status/availability of additional resources

~~b.~~ Commitment of additional resources

~~c.~~ Implementation of demand resources, such as interruptible loads (usually ~~pre-arranged~~prearranged contractually)

~~d.~~ Curtailment of recallable transactions

~~e.~~ Consider the effect of emergency schedules that end before recovery completion

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~~14.~~ The responsible entity should exercise prudent operating judgment in distributing Contingency ~~Reserve, taking into account~~Reserves, considering the effective use of capacity in an emergency, the time required to be effective, transmission limitations, and local area requirements.

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~~IV.~~ Frequency Responsive Reserve

Each responsible entity should maintain an amount of resources available to respond to frequency deviations. Planned ~~frequency responsive reserve~~FRR (day-ahead, day of, and hour prior) should be available in addition to planned ~~Regulating~~regulating and ~~Contingency Reserve.~~contingency reserve. For a responsible entity experiencing a frequency deviation, ~~frequency responsive reserve~~FRR would be deployed to arrest frequency change and remain deployed until frequency is returned to its normal range. Although response is generally expected to come from on-line rotating machines, other resources (e.g., controllable load contracted for that purpose, certain energy storage devices~~, etc.)~~) can provide initial and sustained response that would help to arrest frequency change and sustain frequency at an acceptable post event-level until frequency is returned within its normal range. Each responsible entity should have a documented ~~frequency responsive reserve~~FRR process ensuring the responsible entity has sufficient capacity to meet the performance requirements of BAL-003-~~1.1~~2. The process should include at least the following:

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- ~~1.~~ The BAL-003-~~1.1~~2 standard, *Frequency Response and Frequency Bias Setting*[4], specifies (in Table 1 in Attachment A) the ~~Interconnection Frequency Response Obligation~~interconnection frequency response obligation (IFRO) and the maximum delta frequency (MDF). Attachment A also provides the calculation methodology used to determine the ~~Frequency Response Obligation~~frequency response obligation (FRO) assigned to each responsible entity in a multiple responsible entity Interconnection (the responsible entity's FRO is the same as the IFRO in a single responsible entity Interconnection). In a multiple responsible entity Interconnection, each responsible entity's FRO is its pro-rata share of the IFRO based on the sum of its annual generation MWh plus load MWh as a fraction of those for the entire Interconnection. The attachments and forms associated with the BAL-003-~~1.1~~2 standard cover these calculations in more detail. To determine an initial target (at scheduled frequency) ~~frequency responsive reserve~~FRR level (in MW) for a given responsible entity, ~~simply~~ multiply 10 times the responsible entity's FRO (because FRO is in MW/0.1 Hz) by the MDF for the responsible entity's Interconnection. An example to illustrate this is as follows:

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Given: ABC responsible entity is in the Eastern Interconnection ~~(EI)~~ and its pro-rata portion of IFRO is 1.5%.

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[4] http://www.nerc.com/pa/Stand/Reliability%20Standards/BAL-003-2.pdf

~~The~~Currently, the key ~~EI~~Eastern Interconnection parameters from ~~Table 1~~ are: IFRO = ~~1002~~1015 MW/0.1 Hz and MDF = 0.~~449~~420 Hz. The responsible entity's FRO is {1.5% *~~1002~~1015 MW/0.1 Hz} or 15.2 MW/0.1 Hz.

The responsible entity's initial ~~frequency responsive reserve~~FRR target is {10 * 15.2 * 0.~~449~~420} or ~~68.248 MW~~63.84MW.

The initial target may need to be modified based on several factors~~, most of which are addressed later in this section~~. For example, if actual performance indicates additional response is needed, then the target should be increased. The responsible entity also may choose to perform a risk analysis in determining the level of ~~frequency responsive reserve~~FRR that assures compliance at an acceptable cost.

- ~~4.~~ Any resource (generation, load, storage device, etc.) that is capable of responding to frequency can be a candidate for inclusion as part of a responsible entity's ~~frequency responsive reserve~~FRR; however, such resources should help to arrest the initial frequency change (also known as primary response, and often referred to as droop or governor response) and/or provide sustained support at a post-event frequency level until frequency returns to its normal range. It is prudent practice to evaluate and test units periodically. Therefore, any resource that participates in frequency response reserve should be evaluated periodically to ensure the expected response (e.g. NERC Generator Owner/Operator Survey, or internal evaluation). Moreover, the responsible entity should have an appropriate mix of both primary and secondary reserves. ~~This is highlighted in the~~The Lawrence Berkeley National Laboratory ~~(LBNL) Report -~~report highlights this: *Use of Frequency Response Metrics to Assess the Planning and Operating Requirements for Reliable Integration of Variable Renewable Generation, Key Findings.*~~[3]~~[5]

- ~~5.~~ As long as the total ~~of the frequency responsive reserve~~FRR amounts for each responsible entity are satisfied, any amount of ~~frequency responsive reserve~~FRR may be provided through contractual agreements ~~(~~within the same Interconnection~~)~~ between responsible entities. This is the basis of the concept of ~~Frequency Response Sharing Groups.~~frequency response sharing groups. Responsible entities can also contract for ~~sheddable load~~demand side options that ~~responds~~respond to frequency deviations (usually at ~~pre-set~~preset thresholds) to provide ~~frequency responsive reserve.~~FRR. Responsible entities can likewise contract for energy storage devices to supply ~~frequency responsive reserve,~~FRR as long as applicable terms ensure that either the devices themselves or a partnered resource provide sustained response until frequency is returned to its normal range.

- ~~6.~~ Daily resource commitment plans should include considerations to provide ~~frequency responsive reserve~~ FRR throughout the day. In real-time operations, responsible entity operators should monitor their ~~frequency responsive reserve~~FRR levels in much the same way that ~~Contingency~~contingency and ~~Regulating Reserve~~ regulating reserve are monitored. To the greatest possible extent possible, review of and adherence to planned levels and actual performance should be fed back into the commitment planning process to improve both the commitment plan and actual performance. This feedback should be integrated into commitment planning as well as be available to responsible entity operators to monitor levels.

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[5] "5. Increased variable renewable generation will have … impacts on the efficacy of primary frequency control actions: … Place[ing] increased requirements on the adequacy of secondary frequency control reserve. The demands placed on slower forms of frequency control, called secondary frequency control reserve, will increase because of more frequent, faster, and/or longer ramps in net system load caused by variable renewable generation. If these ramps exceed the capabilities of secondary reserves, primary frequency control reserve (that is set- aside to respond to the sudden loss of generation) will be used to make up for the shortfall. We recommend greater attention be paid to the impact of variable renewable generation on the interaction between primary and secondary frequency control reserve than has been the case in the past because we believe this is likely to emerge as the most significant frequency-response-based impact of variable renewable generation on reliability." https://www.ferc.gov/sites/default/files/2020-05/frequencyresponsemetrics-report.pdf

~~7.~~ • If a responsible entity experiences a frequency deviation in conjunction with a ~~Balancing Contingency Event, frequency responsive reserve~~balancing contingency event, FRR will normally be restored when Contingency ~~Reserve has~~ Reserves have been deployed in response to the ~~Balancing Contingency Event. There~~balancing contingency event, but there may ~~at times~~ be circumstances ~~in which~~when this is not the case. The key difference between this and the ~~non- contingent~~noncontingent case is whether Contingency ~~Reserve has~~ Reserves have been deployed. During a ~~Balancing Contingency Event~~balancing contingency event, it may not be possible to restore ~~frequency responsive reserve~~FRR from previously designated resources until Contingency ~~Reserve has~~Reserves have been deployed (a key reason that reserves are additive).

~~[3] "5. Increased variable renewable generation will have … impacts on the efficacy of primary frequency control actions: … Place[ing] increased requirements on the adequacy of secondary frequency control reserve. The demands placed on slower forms of frequency control, called secondary frequency control reserve, will increase because of more frequent, faster, and/or longer ramps in net system load caused by variable renewable generation. If these ramps exceed the capabilities of secondary reserves, primary frequency control reserve (that is set- aside to respond to the sudden loss of generation) will be used to make up for the shortfall. We recommend greater attention be paid to the impact of variable renewable generation on the interaction between primary and secondary frequency control reserve than has been the case in the past because we believe this is likely to emerge as the most significant frequency response-based impact of variable renewable generation on reliability."~~

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For a non-contingent responsible entity experiencing a frequency deviation due to a ~~Balancing Contingency Event~~balancing contingency event in another ~~Balancing Authority Area, frequency responsive reserve will~~ BA area, FRR will normally be restored when frequency returns to its normal range~~. There~~, but there are some exceptions ~~in which~~where this may not be the case. If load is shed (either as a contractual resource or for other reasons) and is not restored automatically, the ~~frequency responsive reserve~~FRR will have served as Contingency ~~Reserve~~Reserves for the contingent responsible entity (even if unintentionally) and ~~frequency responsive reserve~~FRR for the ~~non-contingent~~noncontingent responsible entity will not have been restored. If this is the case, operator action may be needed to restore the ~~frequency responsive reserve~~FRR by either restoring the load ~~(~~so that it is again available to be shed~~)~~ or obtaining it from other available resources.

~~V.~~ Capability to Respond to Large Loss-of-Load Events

Because a responsible entity should be able to adjust its resources in such a manner to ensure its ACE recovers in accordance with applicable Reliability Standards, a responsible entity should identify options to respond to large loss-of-load events~~—that is,~~, meaning the ability to reduce resources or rapidly bring on additional load. In many cases, decommitment of resources is an option, but with this option comes the risk that the decommitted resource cannot be recommitted in a timely manner, resulting in the exchange of a current solution for a future reliability problem. Planning can mitigate this problem.

Each responsible entity's planning for the possibility of a large loss-of-load event should include consideration of ~~(a)~~ its energy import and export schedules with other responsible entities~~, (b)~~; how large loss-of-load events could be affected by interruption of these schedules~~,~~ while taking into account the terms and conditions under which such energy schedules were arranged~~,~~; and ~~(c)~~ the available down range on resources ~~which~~that have been made available by the sale of non-firm energy ~~which~~that may disappear during a ~~Contingency~~contingency or other ~~Disturbance.~~disturbance.

As noted previously, responsible entities should consider developing some form of electronic reserve monitor to track resources available to provide both up and down range of reserves.

~~VI.~~ Reserve Sharing Groups

~~Reserve Sharing Groups (RSG)~~RSGs are commercial arrangements among ~~Balancing Authorities~~BAs to better enable them to collectively meet the requirements of BAL-001-2, BAL-002-~~2~~3 and BAL-003~~-1.1~~-2. The spreading of reserve across a larger geographically dispersed group can improve reliability and provides for the opportunity to comply with the BAL performance standards while at the same time economically supplying reserve. However, the RSG should take into account the possibility of delivery being compromised by transmission constraints or generation failures when considering establishing the group's minimum reserve requirements.

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~~1. Reserve Sharing Group (RSG)~~

~~A~~

An RSG is a group whose members consist of two or more ~~Balancing Authorities~~BAs that collectively maintain, allocate, and supply Contingency ~~Reserve~~Reserves to enable each ~~Balancing Authority~~BA within the group to recover from ~~Balancing Contingency Events.~~balancing contingency events. The NERC Reliability Standard BAL-002-2 allows ~~Balancing Authorities~~BAs to meet the requirements of the standard through participation in ~~a~~

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an RSG, ~~which Balancing Authorities~~something BAs have done for many years to increase efficiency and enhance reliability. The primary benefit of RSGs is that they reduce the capacity a BA is required to withhold for reserves. This can be especially impactful for smaller BAs that have a large generator within their boundaries. Without RSGs, some smaller BA's could be required to withhold 20% or more of their capacity just for Contingency Reserves in addition to all the other reserves they carry.

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Compliance for an RSG is measured via monitoring individual and group performance. The RSG can meet the compliance obligations of an event if all members individually pass based upon individual ACE values. If each member of the RSG demonstrates recovery by returning its Reporting ACE to the least of the recovery value of zero or its pre-reporting contingency event ACE value, the compliance requirement is met. In addition, the RSG can also meet the compliance obligation if the collective ACE or sum of the ACE demonstrates recovery by returning the RSG's reporting ACE to the least of the recovery value of zero or its pre-reporting contingency event ACE value. An RSG can meet compliance via either method.

In order for an event to be an RSG event, the contingent BA normally has to call on reserves from the group. If it does not, then the BA is standing alone for that event. Some agreements can require that all events are RSG events by rule. Based on the agreements of the RSG, some BAs in an RSG will not have a single contingency that is a reportable event; the only possible way for them to cause a reportable event is with multiple contingencies all occurring within the 60-second period as defined BAL-002-2. For example, losing an entire generating station due to a fault that clears the bus.

The agreement among the participant BAs for the RSG should address the following:

- The minimum reserve requirement for the group
- The allocation of reserve among members
- The procedure for activating reserve in detailed terms that should include communication protocols and infrastructure, how long reserve is available, and who can call for reserve
- The method of establishing its MSSC or minimum reserve requirements for the group
- How the BAs will manage shortages in reserves and capacity
- The criteria used to determine when a member must declare an EEA
- The criteria that allow members to aid a deficient entity through the RSG by allowing BAs to contribute additional reserves to the group
- How generation and transmission contingencies may affect the deliverability of Contingency Reserves among the members
- Each member's portion of the total reserve requirement
- The methodology used to calculate the member's reserve responsibility

- Identification of valid reasons for failure to respond to a reserve-sharing request
- The reporting and record keeping for regulatory compliance

Scheduling energy from an ~~Adjacent Balancing Authority~~adjacent BA to aid recovery need not constitute reserve sharing provided the transaction is ramped in over a period the supplying party could reasonably be expected to load generation in (e.g., ~~ten~~10 minutes). For certain RSG arrangements, if the transaction is ramped in more quickly (e.g., between ~~zero~~0 and ~~ten~~10 minutes) then, for the purposes of BAL-002-~~2~~3, the ~~Balancing Authority Areas~~BA areas are considered to be an RSG ~~for that event.~~.

~~The agreement among the participant Balancing Authorities for the RSG should address the minimum reserve requirement for the group, the allocation of reserve among members, and the procedure for activating reserve. In setting its Most Severe Single Contingency (MSSC) or minimum reserve requirements for the group, the RSG should consider how reasonable generation and transmission contingencies may affect the deliverability of Contingency Reserve among the members. The agreement should clearly state each member's portion of the total reserve requirement as well as the methodology used to calculate the member's reserve responsibility. The activation and recall of reserve should be defined in detailed terms which should include communication protocols and infrastructure, how long reserve is available, who can call for reserve, and valid reasons for failure to respond to a reserve-sharing request. The agreement also should cover reporting and record keeping for regulatory compliance.~~

RSGs typically flow on transmission reliability margin (TRM) and have an annual deliverability study done by all the respective transmission planners. Some BAs may have to carry a disproportionate share of reserve if some of their large units are not completely deliverable. These issues may require a special operating guide for local congestion management.

~~2.~~ Frequency Response Sharing Group

~~A Frequency Response Sharing Group~~ As defined by NERC, a frequency response sharing group (FRSG) is a group whose members consist of two or more ~~Balancing Authorities~~BAs that collectively maintain, allocate, and supply operating resources required to jointly meet the sum of the ~~Frequency Response Obligations~~FRO of its members.

Frequency ~~Response~~response has many unique characteristics ~~which makes~~that make an FRSG different from ~~a~~an RSG. The frequency response capability of individual generating units can change from moment to moment depending on operating point, mode of operation, type of unit, and type of control system. A steam unit ~~which~~that is operating at full valve but not at full capability will have no frequency response even though it appears to have additional capability above its current output. These issues may require responsible entities to develop new unit

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commitment processes, new operating guidelines, tools for operators, and more consistent governor settings.

The agreement among the participant responsible entities for the FRSG should address the minimum reserve requirement for the group, the allocation of reserve among members, and reporting and record keeping for regulatory compliance. ~~–~~The FRSGs minimum reserve requirement should be conservative to allow for conditions, such as a unit-tripping or transmission contingencies, that could affect members' ability to supply ~~frequency responsive reserve~~FRR to each other.~~-~~ The agreement should clearly state each member's portion of the total reserve requirement as well as the methodology used to calculate the member's reserve responsibility.

Also, the agreement should consider how the information is shared in ~~Real~~real-time based on tools created for the operators.

NERC Reliability Standard BAL-003-~~1.1~~2 allows ~~Balancing Authorities (~~BAs~~)~~ to meet their ~~Frequency Response Obligations (~~FROs~~)~~ by electing to form ~~Frequency Response Sharing Groups (~~FRSGs~~)~~. Attachment

A of that same ~~Standard~~standard specifies that an FRSG may ~~legitimately~~ calculate their ~~Frequency Response Measure~~ frequency response measure (FRM) performance in one of two ways~~. Calculate~~; calculate a group NIA ~~and measure~~or aggregate the group response to all events in the reporting year ~~on a~~as one of the two following options:

- Single FRS Form ~~1, or~~2 utilizing a group NI_A for each event and an accompanying FRS form 1 for the FRSG
- ~~a~~A summary spreadsheet that contains the sum of each participant's individual event performance~~.~~ and an accompanying FRS Form 1 for the FRSG

This section of the guideline is intended to provide recommended practices to consider for BAs when performing the following actions:

- Establishing FRSGs~~, and~~
- Calculating FRSG FRM performance~~.~~

~~This section of the guideline applies primarily to BAs and FRSGs. For ease of reference, this guideline, as noted earlier, uses the common term "responsible entity" for these entities, and allows the readers to make the appropriate substitution applying to them when participating or not in various groups.~~

The Generator Governor Frequency Response Advisory[6] issued notice to industry on the importance of ~~resources configuring their~~resource configurations for governors and control systems to allow for the provision of primary frequency response ~~was noticed to the industry in the Generator Governor Frequency Response Industry Advisory.~~. Subsequently, a specific description of practices necessary for ~~Resources~~resources to provide primary frequency control, including the coordination of turbine controls with plant outer loop controls~~, as well as~~ and an explanation of the different components of frequency response, can be found in the *Primary Frequency Control Reliability Guideline*[7].

~~Short~~Existing BAL-003-2 Forms 1 and 2 provide short-term ~~bi-lateral~~bilateral transactions of frequency response ~~are provided for in existing BAL-003-1.1 Form 1 and Form 2~~ and do not require the formal establishment and registration of a long-term FRSG, so ~~those~~these arrangements are not addressed by this guideline. This section of the guideline focuses solely on establishment and operating practice guidelines for a ~~multi-party Frequency Response Sharing Group~~multiparty FRSG.

[6] https://www.nerc.com/pa/rrm/bpsa/Alerts%20DL/2015%20Alerts/NERC%20Alert%20A-2015-02-05-01%20Generator%20Governor%20Frequency%20Response.pdf
[7] https://www.nerc.com/comm/OC/RS_GOP_Survey_DL/PFC_Reliability_Guideline_rev20190501_v2_final.pdf

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Establishment/Structure of an FRSG

Certain minimum criteria should apply to all candidate FRSGs prior to registration and establishment. FRSG registration is necessary to provide ~~NERC~~ERO staff with sufficient information to modify the FRSG's ~~Frequency Response Obligation (~~FRO~~, the~~ for each operating year. The FRSG FRO is the aggregate of member BAs' FROs~~), include that~~, including the information in the tables used in Form 1, and determine unique FRSG codes (substitutes for the BA codes normally used) for use in summary Form ~~1s~~1.

An FRSG should have a formal agreement among its members in place prior to registration. ~~The~~Depending on the structure and characteristics of the member BAs, the FRSG agreement among the participant responsible entities for the FRSG ~~should~~may need to address the following:

- Minimum frequency-responsive reserve requirement for the group
- Each member's portion of the total frequency-responsive reserve requirement

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- Requirements, if applicable, of specific resources to provide frequency response
- Members' reporting, record keeping, and accountability for regulatory compliance
- Provisions for each member's alternative minimum frequency-responsive reserve requirements in identified areas in the event of emergency scenarios, such as an islanding event
- Methodology used to calculate the member's frequency-responsive reserve responsibility
- How information is shared among members in ~~Real~~real-time
- Tools for operators to have situational awareness of frequency-responsive reserves of the FRSG
- When and how to bring more frequency-responsive reserves to bear (e.g. conservative operations, periods of low inertia~~, etc.).~~)

FRSGs must be pre-arranged and member participation must coincide with the BAL-003-~~1.1~~2 operating year (i.e., December 1 through November 30 of the following year~~-November 30~~). Any member of the BA's minimum period of participation must be one ~~(1)~~ BAL-003-~~1.1~~2 operational year. Partial BAL-003-~~1.1~~2 operating year participation is not ~~be~~ allowed. Per-event participation with other BAs is a ~~bi-lateral~~bilateral transaction and is not considered a formation of an FRSG. Like ~~bi-lateral~~bilateral transactions, FRSGs can only be established prior to the analysis period~~.~~ ~~No~~, and no BA may be a member of more than one FRSG at any given time.

All FRSG member BAs must be in the same Interconnection. An FRSG can be ~~non-contiguous~~noncontiguous, but each FRSG ~~should~~may be subject to a transmission security review by potentially affected BAs and Transmission Operators~~ (TOPs)~~. In some cases, a transmission security review by potentially affected BAs and Transmission Operators may be necessary for contiguous FRSGs if, for example, parallel flows caused by individual members' responses may impact other BAs or ~~TOPs~~Transmission Operators.

Operations of a FRSG

FRSGs and their constituent BAs should attempt to fully respond to each event in the BAL-003-~~1.1~~2 operating year.

FRSG ~~member BAs~~who calculate an FRSG NI_A, should properly time-align tie line data to account for data latency and difference in member BAs' ~~Energy Management System (~~EMS~~)~~ scan rates. To the extent possible, this adjustment should be reflected in ~~Real~~real-time data provided to operators. The adjustment times for each alignment should be reviewed at least annually to determine if a different amount of adjustment is needed.

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The FRSGs minimum frequency-responsive reserve requirement should be conservative to allow for conditions, such as a unit-tripping or transmission contingencies, that could affect members' ability to supply frequency-responsive reserve to each other.

Although an explicit frequency-responsive reserve requirement is not necessary in every case, the FRSG should account for frequency-responsive reserves among its members in real-time. Members of an FRSG should consider including such provisions in their organizational documents.

Analysis/Reporting

FRSG member BAs ~~should~~must select an entity to report summary information for the FRSG to NERC. As noted above, FRSG reporting is done according to Attachment A in BAL-003-~~1.1~~2.

For tie line data not already time-aligned, the FRSG and its member BAs should properly time-align prior to completing the aggregate FRS Form 2s to account for data latency and difference in member BAs' EMS scan rates.

Changes to Form 1 necessary to allow use of appropriate adjustments of FRM will be referred to NERC staff for development and implementation and those changes will be routed through the appropriate NERC committees for any vetting/validation needed.

~~1.~~

Regulation Reserve Sharing Group

A ~~Regulation Reserve Sharing Group (RRSG)~~regulation RSG is a group whose members consist of two or more ~~Balancing Authorities~~BAs that collectively maintain, allocate, and supply the regulating reserve required for all member ~~Balancing Authorities~~BAs to use in meeting applicable regulating standards.

A ~~RRSG~~regulation RSG may be used to satisfy the Control Performance Standard (CPS) requirement in BAL-001-2. Sharing of ~~Regulating Reserve~~regulating reserve will require real-time data sharing and dynamic ~~transfers[4]~~transfers[8] between members. The agreement among the participant BAs of the ~~RRSG~~regulation RSG should contain the maximum amount of regulation to be exchanged and the medium used to communicate the regulation to be shared. The agreement should assign responsibility for arranging transmission service and posting schedules. Regulation magnitudes may at times be limited due to resource availability or transmission constraints, so the ~~RRSG~~regulation RSG agreement should include mechanisms to provide for such restrictions. If a ~~RRSG~~regulation RSG has many members, the members may need central data sharing to enable communication in Real-time, as well as more complex definitions of transmission paths among members and mechanisms to address transmission path limitations. Record keeping for the ~~RRSG~~regulation RSG will primarily be energy schedule records (E-~~TAGS~~Tags) and Open Access Same-Time Information System ~~(OASIS)~~ postings that allow energy flow between members. The ~~RRSG~~regulation RSG agreement should also have mechanisms to settle imbalances and limit the amounts of imbalances between members.

~~VII.~~ Operating Reserve ~~Use and~~ Interaction

The responsible entity's Operating ~~Reserve~~ Reserves definition should include three general categories: ~~frequency responsive~~FRR, regulating reserve, ~~Regulating Reserve and Contingency~~

[8] For a more detailed explanation of the implementation of dynamic transfers in general and for regulation sharing (discussed as supplemental regulation in the document) specifically, see the Dynamic Transfer Reference Guidelines reference document in the *NERC Operating Manual*. This document can be found at http://www.nerc.com/comm/OC/Pages/Operating-Manual.aspx

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~~Reserve. The~~ and contingency reserve. NERC Reliability Standards primarily govern the deployment of these three categories~~.~~.

Load Forecast Error

The BA Operating Reserve projections should consider load forecast error when establishing reserve levels. The following is ~~governed primarily by NERC Reliability Standards.~~ a list of considerations that may be evaluated. These may change from day to day, from season to season, and should be included in the commitment of resources.

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~~[4] For a more detailed explanation of the implementation of dynamic transfers in general and for regulation sharing (discussed as supplemental regulation in the document) specifically, see the "Dynamic Transfer Reference Guidelines" reference document in the NERC Operating Manual. This document can be found at http://www.nerc.com/comm/OC/Pages/Operating-Manual.aspx.~~

~~USE~~

- Weather forecast
- Seasonal temperature variations
- Model error
- Speed of weather event

Fuel Constraints

Once resources are identified, a second review should consider fuel constraints to determine if any limitations generation exits. The following is a list of considerations that may be evaluated. These may change from day to day, from season to season, and should be included as part of a BA's projection of operating reserves and contingency reserves.

- Delivery Limitations such as Operational Flow Orders – (OFOs)
- Availability of fuel (e.g. weather impacts, market, ability to purchase)
- Transportation considerations
- Fuel supply (e.g. size of coal pile, amount of fuel oil, water reserves)
- Variability (e.g. solar and wind)

Deliverability of Reserves

Deliverability of reserves is an important consideration. If reserves are undeliverable across the BA, then the BA is at increased risk of not complying with BAL-002-3. As transmission outages occur, the ability to deliver energy across the BA changes. A BA should consider any restrictions or limitations that may reduce generation capability as part of their operating and contingency reserve projections. The following may impact the deliverability of reserves:

- Transmission availability
- Transmission constraints
- Shape/size of BA
- RSG Considerations –
  - Ability to deliver with available transmission
  - Connection through an intermediate member
  - Operating procedures

Unit Commitment

When developing plans and addressing the needs of a BA or an RSG to reliability meet the demands of customers, unit commitment is a key component of successfully planning and ensuring that the needed generation is available in real-time operations. When dispatching the system, the BA operator should coordinate and consider any impacts to operating reserves and contingency reserves. The following is a list of considerations that may be included in the unit commitment process:

- Unit start-up time
- Available personnel
- Maintenance activities
- Environmental limitations:
  - Drought constraints
  - Intake constraints
- Hydrothermal limitations

For all imbalances occurring on its power system, the responsible entity will use its reserve ~~which~~that is addressed by the following four-step process.

Step 1:~~-~~ Arrest Frequency Change

The first step in recovery is to arrest the frequency change caused by the imbalance. In most circumstances, this arresting action is performed automatically by the frequency response of generators and load on the Interconnection within the first few seconds of the imbalance. If there is insufficient frequency response or ~~frequency responsive reserve~~FRR to arrest a frequency decline, the Interconnection frequency will reach underfrequency relay trip points before any of the other steps can be initiated. Frequency response is therefore the most important of the required responses and ~~frequency responsive reserve~~FRR is the most important of the reserves.

Step 2: ~~Return~~Contingency Reserve Deployment- Returning Frequency to its Normal Range

The second step in the recovery process is to return the frequency to its normal range. Again ~~in most circumstances, for small imbalances,~~ , this is usually accomplished by applying ~~frequency responsive~~FRR or regulating reserve ~~or Regulating Reserve,~~ in most circumstances for small imbalances, and the CPS1 portion of BAL-001-2 governs the timeliness of the aggregate of such recoveries ~~is governed by the CPS1 portion of BAL-001-2.~~. The timeliness of the recovery from larger imbalances is governed by BAL-002-2~~,~~ as well as CPS1. For large, sudden imbalances due to loss of generation, this is usually accomplished by applying ~~Contingency Reserve.~~contingency reserve. Current rules in North America require the completion of this step within a fixed time, 15 minutes in most cases ~~15 minutes~~. The remainder of the operating reserve not used for the frequency response is available to complete this return to the normal frequency range.

Step 3: Restore Frequency Responsive Reserve

The third step in the recovery process is the restoration of the ~~frequency responsive reserve.~~FRR. Restoration of ~~frequency responsive reserve~~FRR is what indicates the Interconnection is secure

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and, in a position, to survive the next imbalance or disturbance. The timeliness of achieving this condition affects the risk that the Interconnection faces.

Step 4: ~~Restore~~Operating Reserves Conversion–Restoring Regulating Reserve or Contingency Reserve

The fourth step is to restore ~~the~~ any Regulating or Contingency ~~Reserve~~Reserves that has been deployed to ensure that the Interconnection can recover from the next imbalance or disturbance within an appropriate time.

Interaction

This four-step process demonstrates that the Operating Reserve components ~~—frequency responsive~~ (i.e. FRR, regulating reserve~~, Regulating Reserve~~ and ~~Contingency Reserve—~~contingency reserve) are used in conjunction with one another, do not function in isolation ~~but~~, are always interacting, and ~~are~~ often ~~used in conjunction with one another~~overlap due to timing requirements.

The Operating Reserve components can be distinguished from each other by the response time it takes to convert the reserve capacity into deliverable energy. The differences in response time allow the reserves to be utilized from the reserve with the fastest response (~~frequency responsive reserve~~i.e. FRR) to the reserve with the slowest response time (i.e., Contingency Reserve). The deployment of ~~Regulating~~regulating reserve in some scenarios can lead to the restoration of FRR. The deployment of Contingency Reserve in some scenarios will assist in the restoration of FRR and regulating reserve.

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~~can lead to the restoration of frequency responsive reserve. The deployment of Contingency Reserve in some scenarios will assist in the restoration of frequency responsive reserve and Regulating Reserve.~~

~~Frequency responsive reserve~~

FRR is a "sub-minute" reserve product~~.~~, and governor response provides it in most cases. Typically, Regulating ~~Reserve~~Reserves and Contingency ~~Reserve~~Reserves cannot be deployed in the ~~timeframe~~time frame to assist in keeping frequency above ~~under- frequency~~underfrequency relay settings. Regulating Reserve usually does not respond quickly enough to be observable in the ~~Frequency Response Measure (~~FRM~~)~~. Contingency ~~Reserve~~Reserves most often takes more than a minute and can take up to 15 minutes to deploy following the start of the contingency.

Regulating ~~Reserve is~~Reserves are often thought of as a "minute plus" reserve product. If it is deployed by any responsible entity in an Interconnection in a direction that supports pushing frequency towards 60 Hz, it will help restore ~~frequency responsive reserve~~FRR within the Interconnection.

For resource losses, ~~Contingency Reserve~~contingency reserve activated by the contingent responsible entity often takes a few minutes to begin to be deployed. As its deployment progresses over time and frequency approaches 60 Hz, there will be some restoration of ~~frequency responsive~~FRR and regulating reserve ~~and Regulating Reserve~~ for the contingent responsible entity. ~~Non-contingent~~A noncontingent responsible entity's ~~frequency responsive reserve~~FRR will tend to be restored with the deployment of the contingent responsible entity's ~~Contingency Reserve~~contingency reserve as well.

For a responsible entity in a multiple responsible entity Interconnection, it may coincidentally need to deploy ~~frequency responsive reserve~~FRR for a load greater than generation imbalance within its Interconnection at the same time that it needs to deploy its ~~Regulating Reserve~~ regulating reserve in the upward direction. It may also experience its MSSC, requiring the deployment of ~~Contingency Reserve~~contingency reserve while the need for ~~frequency responsive reserve~~ FRR and ~~Regulating Reserve~~regulating reserve are at a maximum. The responsible entity should plan its reserve allocations to be compliant with the NERC Reliability Standards in such a coincidental scenario.

Interconnections with only one responsible entity are unique in that only they can correct their system frequency. ~~Frequency responsive reserve~~ FRR will always be deployed automatically and coincidentally when ~~Contingency Reserve~~ contingency reserve needs to be deployed for a large contingency. ~~In a single responsible entity Interconnection, frequency responsive~~FRR and contingency reserve ~~and Contingency Reserve~~ are inherently co-mingled, and together they must at least equal MSSC. As with a multiple responsible entity Interconnection, ~~Regulating Reserve~~ regulating reserve needs to be separate from ~~frequency responsive reserve~~ FRR and ~~Contingency Reserve~~contingency reserve.

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There is an additional characteristic of reserve enabling the reserve categories to be ordered. Operating Reserve categories are partially substitutable for one another. ~~Frequency responsive reserve~~FRR is the only type of reserve that could be used as the exclusive reserve that would enable an Interconnection to operate reliably. Attempts to operate an Interconnection without ~~frequency responsive reserve~~FRR would result eventually in the activation of frequency relays. As long as the amount of ~~frequency responsive reserve~~FRR available is greater than the energy imbalance on the Interconnection, the Interconnection will remain reliable.

The difficulty with operating an Interconnection with only ~~frequency responsive reserve~~FRR is that ~~frequency responsive reserve~~FRR is limited in the total amount available. ~~Frequency responsive reserve~~FRR will arrest the

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frequency change but will not restore frequency to its normal range, leaving the Interconnection vulnerable to the next contingency. The ~~frequency responsive reserve~~FRR provided by load damping is limited and the additional ~~frequency responsive reserve~~FRR provided by governor response is relatively expensive to provide in large quantities.

Regulating ~~Reserve~~reserve is a reserve that can be substituted on a limited basis for ~~frequency responsive reserve.~~FRR. When ~~Regulating Reserve~~regulating reserve is substituted for ~~frequency responsive reserve~~FRR, the ~~Regulating Reserve~~ regulating reserve restores the ~~frequency responsive reserve~~ FRR by returning governor response to the plants and replacing it with dispatched energy. As frequency is returned to normal range, the ~~frequency responsive reserve~~FRR is restored and available for reuse. The amount of ~~Regulating Reserve~~ regulating reserve that can be substituted for ~~Frequency Response~~ frequency response is determined by the difference between~~, (1)~~ the ~~frequency responsive reserve~~FRR required to manage the largest imbalance that could occur on the Interconnection~~,~~ and ~~(2)~~ the ~~frequency responsive reserve~~FRR that could be required in a period shorter than the response time for ~~Regulating Reserve.~~regulating reserve. This ensures there is sufficient ~~frequency responsive reserve~~ FRR available to manage any imbalance occurring before there is time to replace the ~~frequency responsive reserve~~ FRR being used with ~~Regulating Reserve.~~regulating reserve. Also, it extends the effective amount of ~~frequency responsive reserve~~FRR available, allowing the Interconnection to operate with less governor response because the amount of load damping is not easily modified.

In all cases, the ~~minimum frequency responsive reserve required, when only frequency responsive reserve and Regulating Reserve are available, is determined by the~~ maximum imbalance that ~~cannot be managed~~unmanageable by supplementing ~~frequency responsive reserve~~FRR with ~~Regulating Reserve.~~regulating reserve (when only FRR and regulating reserve are available) determines the minimum FRR required. In addition, the sum of the ~~frequency responsive~~FRR and regulating reserve ~~and Regulating Reserve~~ should exceed the largest energy imbalance occurring on the Interconnection. Thus, when substituting ~~Regulating Reserve for frequency responsive~~regulating reserve for FRR the total amount of the ~~frequency responsive~~FRR and regulating reserve ~~and Regulating Reserve~~ should be equal to or exceed the amount of ~~frequency responsive reserve~~FRR when it is used alone.

~~Regulating Reserve and frequency responsive reserve can be further supplemented with~~ Contingency ~~Reserve. Contingency Reserve~~ Reserves can further supplement regulating reserve and FRR and can be manually dispatched to restore any ~~frequency responsive reserve~~FRR currently being used to respond to declining frequency. When dispatched, it restores both ~~frequency responsive~~FRR and regulating reserve ~~and Regulating Reserve~~, making them available for reuse. Therefore, ~~Contingency Reserve~~ contingency reserve can be substituted for a portion of the ~~Regulating Reserve~~regulating reserve that could be substituted for ~~frequency responsive reserve.~~FRR. When this substitution is implemented, the sum of the ~~frequency responsive~~FRR, regulating reserve, ~~Regulating Reserve and Contingency Reserve~~ and contingency reserve should

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exceed the sum of ~~Regulating Reserve and frequency responsive~~regulating reserve and FRR if ~~Contingency Reserve~~contingency reserve is not used.

This illustrates a power system that uses many levels of substitution to improve economic efficiency and reliability. Regulating Reserve is substituted for ~~frequency responsive reserve~~ FRR as determined by reliability needs; ~~Contingency Reserve~~ contingency reserve is substituted for ~~Regulating Reserve~~regulating reserve as determined by reliability needs. Reliability limits for these substitutions can be quantified with a set of inequalities:

$$FRR + RRO \geq FRRO \qquad \textit{Inequality (1)}$$

$$FRR + RR + CR \geq FRR + RRO \qquad \textit{Inequality (2)}$$

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FRRO	=	~~Frequency response obligation (~~FRO~~)~~, equal to MW of ~~frequency responsive rese~~ ~~(~~FRR~~)~~ when only FRR is used.
FRR	=	MW of FRR when another service is substituted for FRR.
RRO	=	MW of ~~Regulating Reserve~~regulating reserve (RR) when nothing is substituted for RR.
RR	=	MW of RR when another service is substituted for RR.
CR	=	MW of CR when nothing is substituted for CR.

Both inequalities represent the total required reserve on both sides of the inequality.

~~This is the basis~~These inequalities are used to determine the ~~Frequency Response Obligation~~FRO in BAL-003-~~1.1~~2 as adjusted by the base frequency error profile ~~resulting~~that results from reserve substitution. In addition, the ~~Contingency Reserve Requirement~~ contingency reserve requirement in R2 of BAL-002-2 determines the minimum CR when it is not in use for recovery, but it does not require that the reserve used to meet the requirement exclude ~~frequency responsive reserve~~FRR or ~~Regulating Reserve.~~regulating reserve. Since ~~Regulating Reserve~~regulating reserve is unique to each responsible entity and can be determined only by evaluating the characteristics of their load and generation resources, a minimum ~~Regulating Reserve Obligation~~regulating reserve obligation is not specified in BAL-001-2. The variations of substitution of reserve as shown above suggests that the best test for reserve adequacy is whether the total capability of resources designated to provide ~~Regulating Reserve, Contingency Reserve, and frequency responsive reserve~~regulating reserve, contingency reserve, and FRR is at least equal to the amount required to meet all reserve requirements concurrently.

Additionally, ~~this indicates that~~ during the deployment of ~~reserve~~reserves in real-time, there are only limited ways to determine whether a responsible entity is holding adequate ~~reserve~~reserves. This determination can only be based on a prospective look during operations planning when there are no deviations from the expected deployment of ~~reserve~~reserves. Because this is the case, ~~also~~ it is also important for the responsible entity to have a feedback mechanism included in its evaluations of reserve to include the uncertainties experienced during actual reserve usage. ~~This could be accomplished with a~~A reserve~~-~~monitoring tool could accomplish this.

The calculation of reserve levels (including ~~frequency responsive~~FRR, regulating reserve, ~~Regulating Reserve~~ and ~~Contingency Reserve~~contingency reserve) begins with the calculation of the amount of each type of reserve available from each resource providing any of these three types of Operating ~~Reserve~~Reserves. Once the individual resource reserve contributions have been calculated, the responsible entity's total reserves by category can be determined by the sum of the reserve contributions for all contributing resources.

~~This type of~~The calculation for these three types of reserves (~~frequency responsive~~i.e., FRR, regulating reserve, ~~Regulating Reserve~~ and ~~Contingency Reserve) is~~contingency reserve) may not be supported in ~~many current~~some EMSs because the FRR calculation ~~of frequency responsive~~

~~reserve~~ and the interaction between reserves requires additional data not currently maintained in many EMSs. Additional data required to support the ~~frequency responsive reserve~~FRR calculation includes, but is not limited to, unit droop ~~and~~, dead-band settings, and Interconnection ~~Underfrequency Load Shedding~~underfrequency load shedding (UFLS) frequency limits. Additional data may be required for other types of resources.

Finally, any calculation of the total amount of reserve and the amount in each category can change with a change in output/use of any of the resources ~~providing~~that provide reserve for the responsible entity. For example, dispatch of ~~Contingency Reserve~~ contingency reserve from a resource could also affect the ~~frequency responsive reserve~~ FRR or

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~~Regulating Reserve~~ regulating reserve that is available from that same resource by moving the operating point of the resource nearer to one of the resource's operating limits. This could result in a reduction of one of the other reserve types in addition to the reduction in the amount of ~~Contingency Reserve~~contingency reserve resulting from the dispatch. This dynamic reserve interaction should be included in operations planning and the tools used to provide the ~~System Operator~~system operator with the best information.

Related Documents and Links:

~~NERC Operating Committee Charter~~

~~NERC Critical Infrastructure Protection Committee Charter~~

~~NERC Planning Committee Charter~~

NERC Reliability and Security Technical Committee Charter

NERC Operating Manual

Use of Frequency Response Metrics to Assess the Planning and Operating Requirements for Reliable Integration of Variable Renewable Generation, Key Findings

Cited Documents

NERC Alert A-2015-02-05-01 Generator Governor Frequency Response

Primary Frequency Control Reliability Guideline

NERC Standard BAL-003-~~1.1~~2

FERC Final Order on Third-Party Provision of Primary Frequency Response Service - FERC Docket RM15-2-000 Order No. 819

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Revision History		
Date	**Version Number**	**Reason/Comments**
10/18/2013	1.0	Initial Version – “Operating Reserve Management”
12/13/2017	2.0	Revised to include more detailed description of FRSG
9/13/2020	3.0	3-year review and revisions

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Balancing and Frequency Control Reference Document

Action
Accept to post the document for a 45-day industry comment period.

Summary
The Balancing and Frequency Control Reference Document is up for the periodic 3-year review by the NERC Resources Subcommittee (RS). The RS approved the recommendation to move this technical reference document to the RSTC for approval and posting for 45-day industry comment.

Balancing and Frequency Control

Reference Document

Prepared by the NERC Resources Subcommittee

September 29, 2020

RELIABILITY | RESILIENCE | SECURITY




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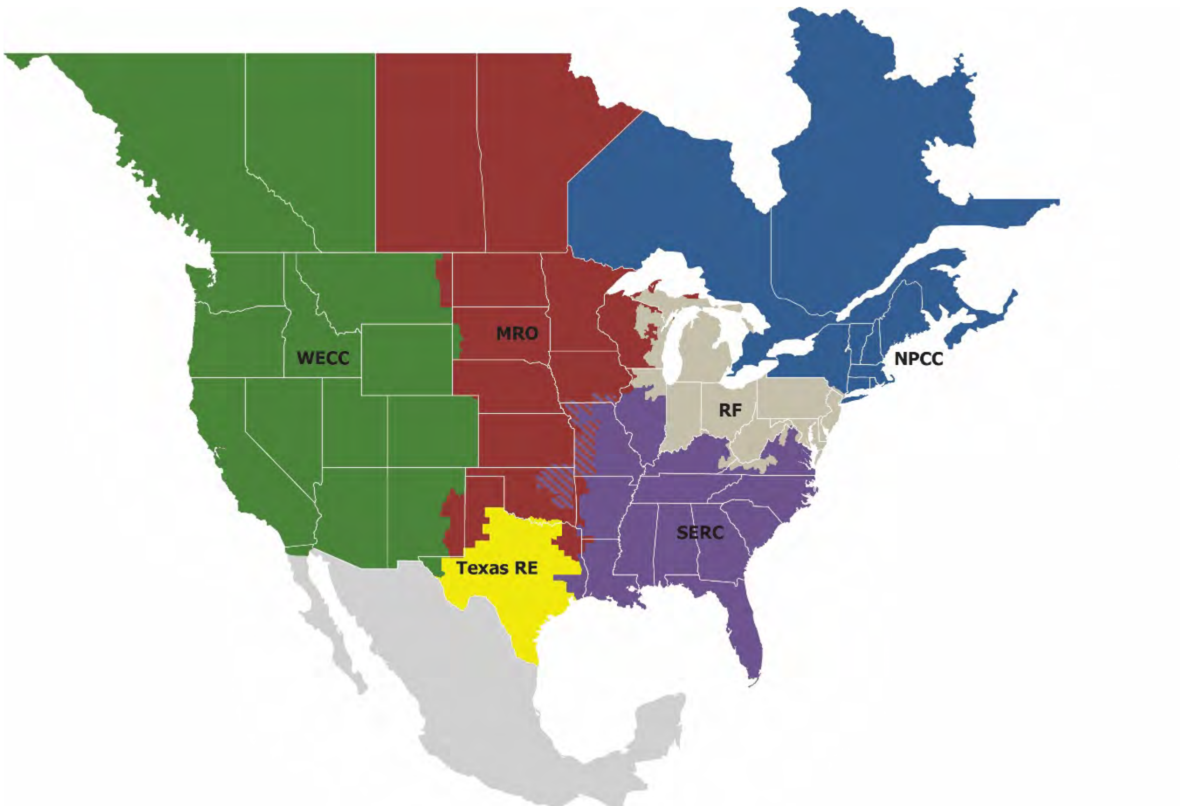
Preface

Electricity is a key component of the fabric of modern society and the Electric Reliability Organization (ERO) Enterprise serves to strengthen that fabric. The vision for the ERO Enterprise, which is comprised of the North American Electric Reliability Corporation (NERC) and the six Regional Entities (REs), is a highly reliable and secure North American bulk power system (BPS). Our mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid.

Reliability | Resilience | Security
Because nearly 400 million citizens in North America are counting on us

The North American BPS is divided into six RE boundaries as shown in the map and corresponding table below. The multicolored area denotes overlap as some load-serving entities participate in one Region while associated Transmission Owners/Operators participate in another.



The Six Regional Entities	
MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
Texas RE	Texas Reliability Entity
WECC	Western Electricity Coordinating Council

Introduction

Background

The NERC Resources Subcommittee (RS) drafted this reference document at the request of the NERC Operating Committee as part of a series on operating and planning reliability concepts. The document covers balancing and frequency control concepts, issues, and recommendations. Send questions and suggestions for changes and additions to balancing@nerc.com.

Note to Trainers

Trainers are encouraged to develop and share materials based on this reference. The RS will post supporting information on the RS website.[1]

Disclaimer

This document is intended to explain the concepts and issues of balancing and frequency control. The goal is to provide an understanding of the fundamentals. Nothing in this document is intended to be used for compliance purposes or to establish obligations.

[1] https://www.nerc.com/comm/OC/Pages/Resources-Subcommittee.aspx

Chapter 1: Balancing Fundamentals

Balancing and Frequency Control Basics

The power system of North America is divided into four major Interconnections (see **Figure 1.1**). These Interconnections can be thought of as independent electrical islands. The four Interconnections consist of the following:

- **Western:** Generally everything west of the Rockies
- **Texas:** Operated by the Electric Reliability Council of Texas (ERCOT)
- **Eastern:** Generally everything east of the Rockies except Texas and Quebec
- **Quebec:** Operated by Hydro Quebec TransEnergie

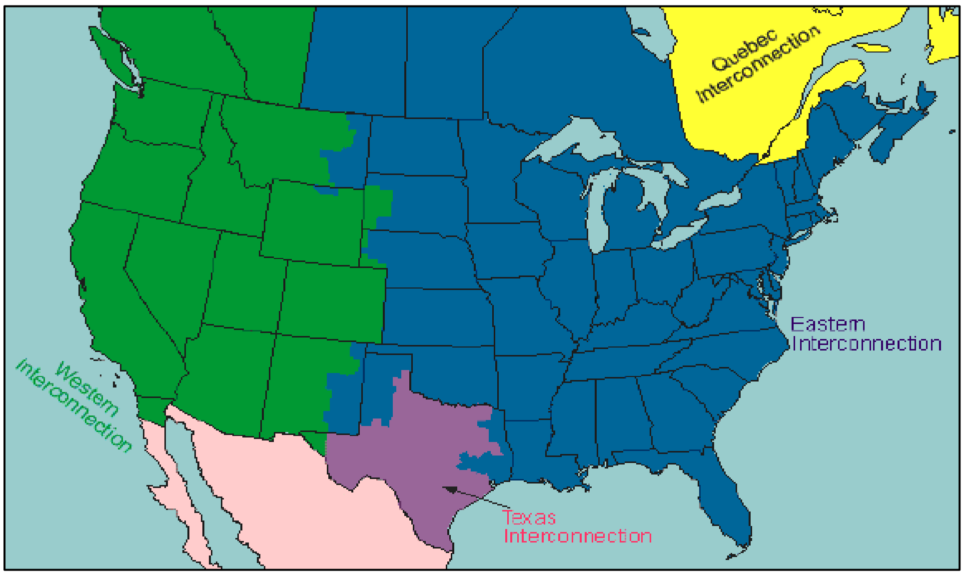


Figure 1.1: North American Interconnections

Each Interconnection can be viewed as a single large machine with every generator pulling together to supply electricity to all customers. This occurs as the electric generating units rotate (in steady-state) near synchronism. The "speed" (rotational speed) of the Interconnection is frequency measured in cycles per second, or Hertz (Hz). When the total Interconnection supply exceeds customer demand, frequency increases beyond the scheduled value (typically 60 Hz[2]) until energy balance is achieved. Conversely, when there is a temporary supply deficiency, frequency declines until a balance between supply and demand is restored.

During normal operations it is typical for there to be small mismatches between total demand and total supply, so the frequency of each Interconnection varies above and below nominal on a continuous basis. Regardless of whether the variations are above or below scheduled frequency, the supply-demand balance is restored due to frequency sensitive demands and supply resources that change output in response to frequency changes. For example, some electric devices (e.g., electric motors) use more energy if driven at a higher frequency and less at a lower frequency. Most generating units are also equipped with governors that cause the generator to inject more energy into the Interconnection when frequency is lower than nominal and slightly less energy when the frequency is higher than nominal.

[2] Nominal frequency (termed "scheduled frequency") is sometimes intentionally offset by a small amount via a mechanism called time error corrections to correct for sustained periods of high or low frequency.

Balancing Authorities (BAs) balance generation and load within their Balancing Authority Areas (BAAs) of the Interconnections. See **Figure 1.2** for an example of BAAs across North America. The BAs dispatch generating resources in order to meet their BAA demand and manage the supply/demand balance. Some BAs also control demand to maintain the supply/demand balance.

Figure 1.2: North American Balancing Authorities and Regions

The number of BAs in an Interconnection varies; Texas and Quebec are single BA Interconnections while the Eastern and the Western are multi-BA Interconnections. Each BA in an Interconnection is connected via high voltage transmission lines (called tie-lines) to neighboring BAs. The Reliability Coordinators (RCs) oversee the BA operations and coordination. BAs are responsible for the supply/demand balance within their BAA while RCs are responsible for the wide area health of the Interconnection.

Frequency will be constant in an Interconnection when there is a balance between supply and demand, including various electrical losses. This balance is depicted in **Figure 1.3**.

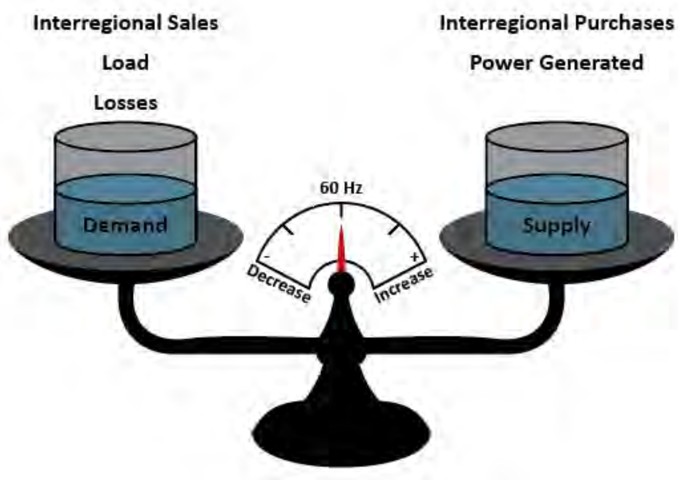


Figure 1.3: Generation | Demand Balance

Each supply resource embedded in an interconnected system has its own characteristics (e.g., ramp rates, fuel supply, output controllability and sustainability). From a simplified viewpoint, a supply resource can be analogized to a water pump with storage and control as shown in **Figure 1.4**. In this example, the pump's output fills an open storage tank similar to a swimming pool. The water depth in the tank needs to be controlled to within very tight limits: too much water accumulating will cause the pool to overflow, and too little water will cause other problems. The control valve changes average output to meet system demand in a manner analogous to automatic generation control (AGC). The surge tank on the final output is analogous to the rotational inertia of the generator.

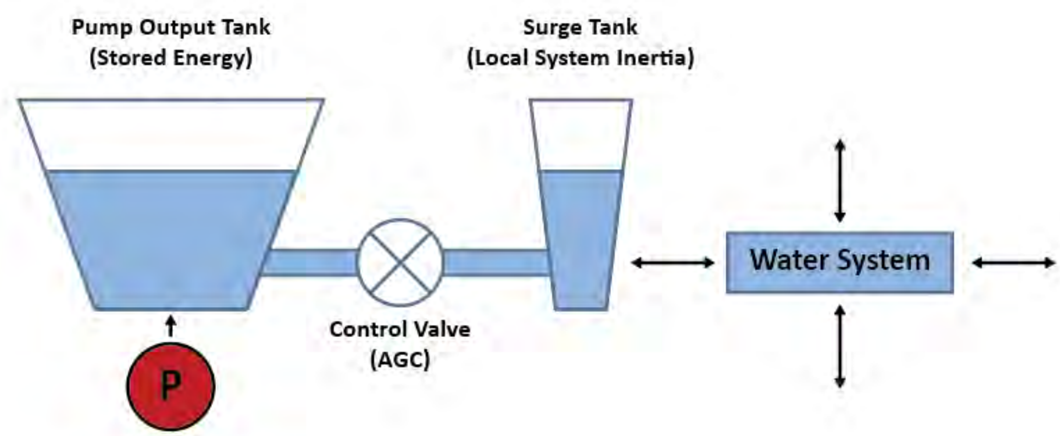


Figure 1.4: Generator | Pump Analogy

To understand how Interconnection frequency is controlled, it may help to visualize a traditional water utility that is composed of a delivery system, customers, and several pumping stations as depicted in **Figure 1.5**. If a municipality operates its own system, it needs sufficient pumps (supply) to maintain the water level in the pumping stations' storage tanks (frequency) to serve its customers. When demand exceeds supply, the water levels in the pumping station tanks will drop prompting the pumps to respond. Water level (frequency) is the primary parameter that must be controlled in an independent system.

In the early history of the power system, utilities quickly learned the benefits delivered in reliability and realized reduced expense associated with maintaining operating reserves by connecting to neighboring systems. In our water utility example, an independent utility must have pumping stations in standby that are equivalent to its largest on-line pump if it wants to maintain the water level in case there is a problem with the largest pumping station. However, if utilities are connected together via tie-lines, reliability and economics are improved because of the larger resource capacity of the combined system and the ability to share capacity when needed.

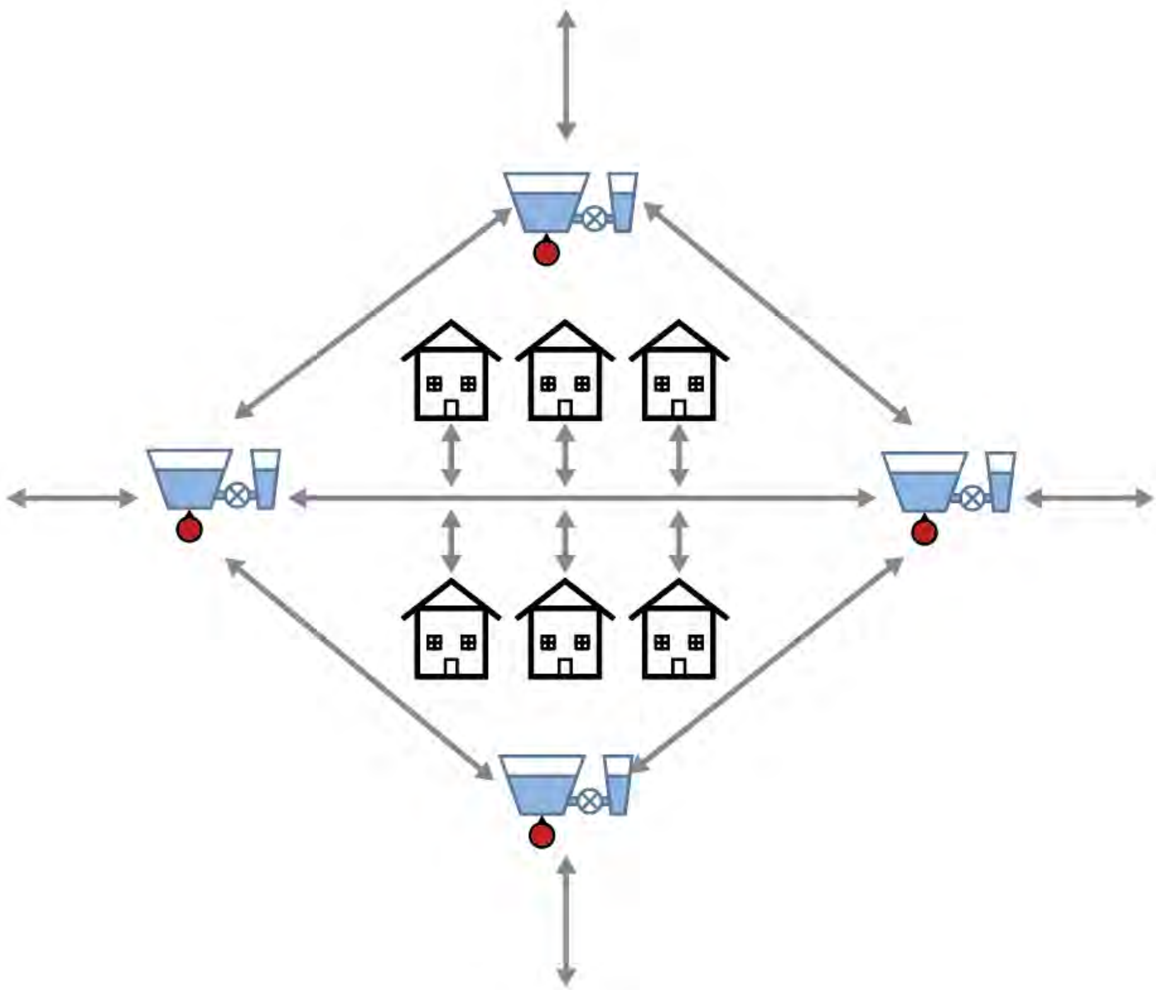


Figure 1:5: BA Analogy

Once the systems are interconnected, the steady state frequency (i.e. water level) is the same throughout. If one BA in the electric grid loses a generating resource there may be a drop in frequency but it is less than in an independent system because the overall resource capacity of the interconnected system is much greater. The BA that needed energy could purchase it from others. Purchasing and/or selling energy between BAs is known as Interchange.

There are two inputs to the BAs control process:[3]

- **Interchange Error:** the net outflow or inflow compared to the scheduled sales or purchases (The units of interchange error are in megawatts.)
- **Frequency Error:** the difference between actual and nominal frequency (The units of frequency error are hertz.)

[3] There are two control inputs in multi-BA Interconnections. Texas and Quebec are single BA Interconnections and need only control to frequency.

Frequency bias is used to translate the frequency error into megawatts. Frequency bias is the BAs obligation to provide or absorb energy to assist in maintaining frequency. In other words, if frequency goes low, each BA is asked to contribute a small amount of extra generation in proportion to its system's relative size.

Each BAA uses common meters on the tie-lines with its neighbors for control and accounting. There will be an agreed upon meter at each BA boundary that both neighboring BAs use to perform balancing operations and accounting. Thus, all supply, load, and transmission lines in an Interconnection fall within the metered bounds of a BA.

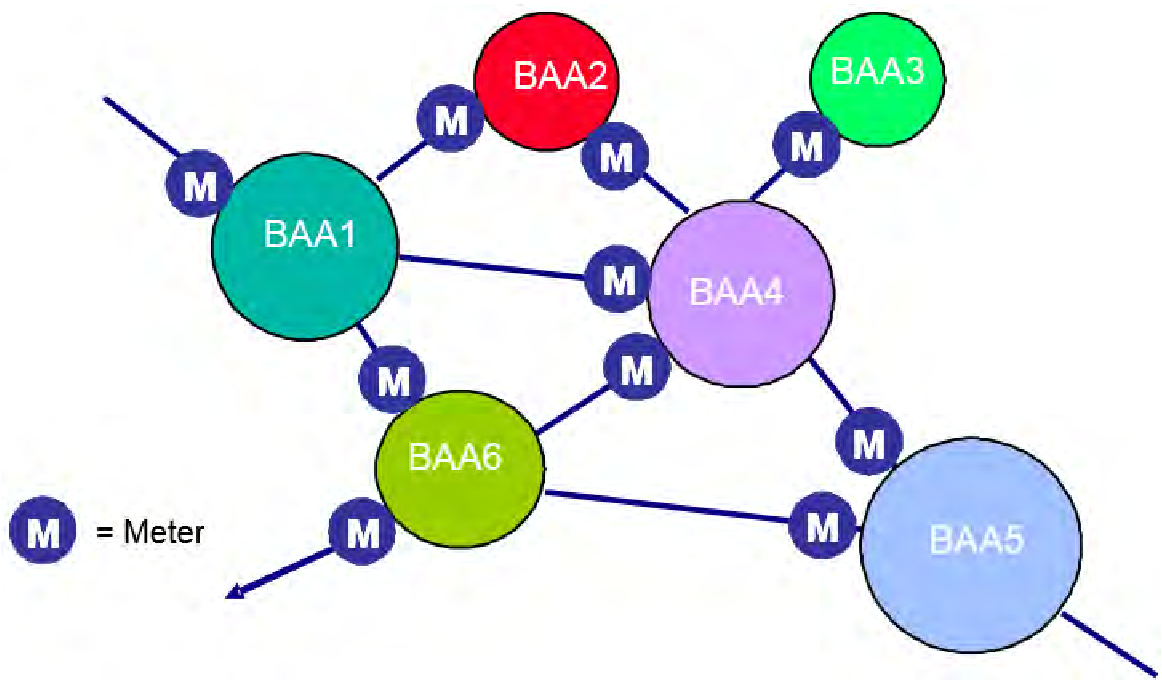


Figure 1:6: Interconnected BA Areas

If the BA is not buying or selling energy,[4] and its supply is exactly equal to the demand and losses within its metered boundary (BAA), the net of its tie line meters will be zero (assuming that the frequency of the system is at nominal). If the BA chooses to buy energy (e.g., 100 Megawatt hours (MWh)), it tells its control system to allow 100 MWh to flow in (by, for example, allowing 100 MW to flow in for one hour). Conversely, the seller will tell its control system to allow 100 MWh to flow out by allowing the corresponding 100 MW to flow out for one hour. If all BAs behave this way, the Interconnection remains in balance and frequency remains stable. Variations in the supply/demand balance cause frequency to vary from its nominal value. Problems on the grid, such as congestion, equipment faults that dictate rapid unilateral adjustments of generation, loss of load, incorrect schedules, or poor control cause changes in frequency. Maintaining Interconnection frequency near its nominal value can therefore be thought of as a fundamental indicator of the health of the power system.

Demand and supply are constantly changing within all BAAs. This means that a BA will usually have some unintentional outflow or inflow at any given instant. This mismatch in meeting a BA's internal obligations, along with the small additional "bias" obligation to maintain frequency, is represented via a real-time value called Area Control Error (ACE), with units of MW.

[4] In most cases, BA's do not buy and sell energy. Transactions now are arranged by wholesale marketing agents that represent load or generation within the BA.

System operators at each BA fulfill their NERC obligations by monitoring ACE and keeping the value within limits that are generally proportional to BA size. This balancing is typically accomplished through a combination of adjustments of supply resources, purchases and sales of electricity with other BAs, and possibly adjustments of demand.

Conceptually, ACE is to a BA what frequency is to the Interconnection. Over-generation makes ACE go positive and puts upward pressure on Interconnection frequency. A large negative ACE can cause Interconnection frequency to drop. A highly variable or "noisy" ACE tends to contribute to similarly "noisy" frequency. However, the effect of ACE on frequency depends on how ACE is correlated (or anti-correlated) with frequency error. Over-frequency error tends to be made larger when ACE indicates over-generation, and is made smaller when ACE indicates under-generation. Under-frequency error has the opposite relationship. This principle is captured in the way Control Performance Standard 1 (CPS1) measures performance. Accumulation of frequency error over time results in the Interconnection's time error. For better overall Interconnection performance, the Western Interconnection (WI) uses automatic time error correction (ATEC) that allows BAs to make incremental corrections that are caused by under/over performing ACE.

Control Continuum

Figure 1.7 demonstrates that Balancing and frequency control occur over a continuum of time using different resources that have some overlap in timeframes of occurrence.

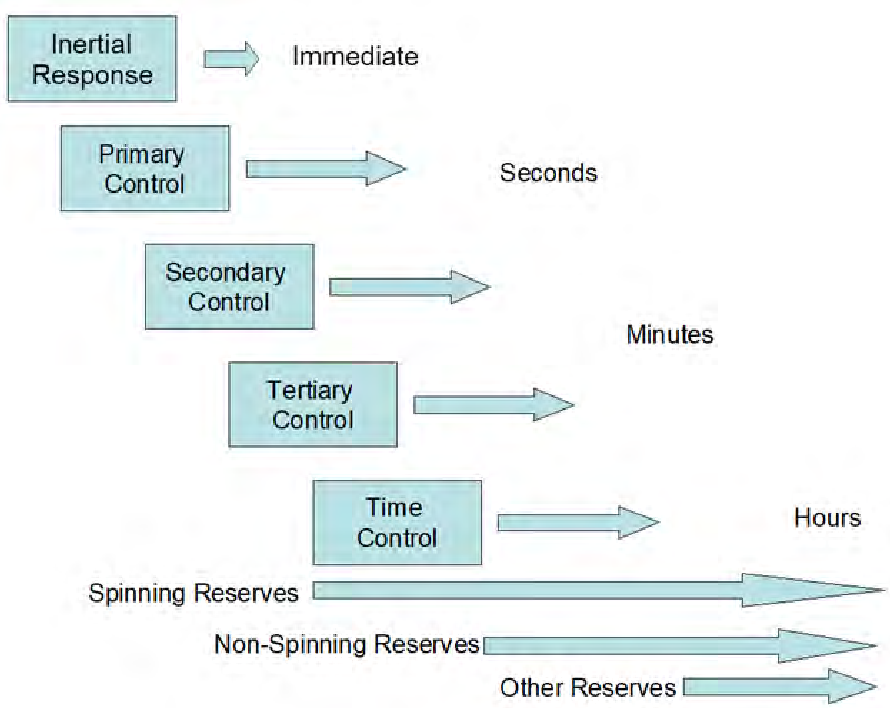


Figure 1.7: Control Continuum

A primary focus of the controls in the control continuum is to maintain nominal frequency under all conditions. One common operating condition is the loss of a (sometimes large) generator. This causes the frequency to drop which then requires the various pieces of the control continuum to recover the frequency to nominal. A stylized example is shown in figure 1.8. The frequency event is somewhat arbitrarily divided into 4 phases: the Arresting Period (when frequency decline is arrested), the Rebound Period (where frequency begins to recover towards nominal), the Stabilizing period (where frequency is stabilized), and the Recovery period (where frequency is recovered to nominal).

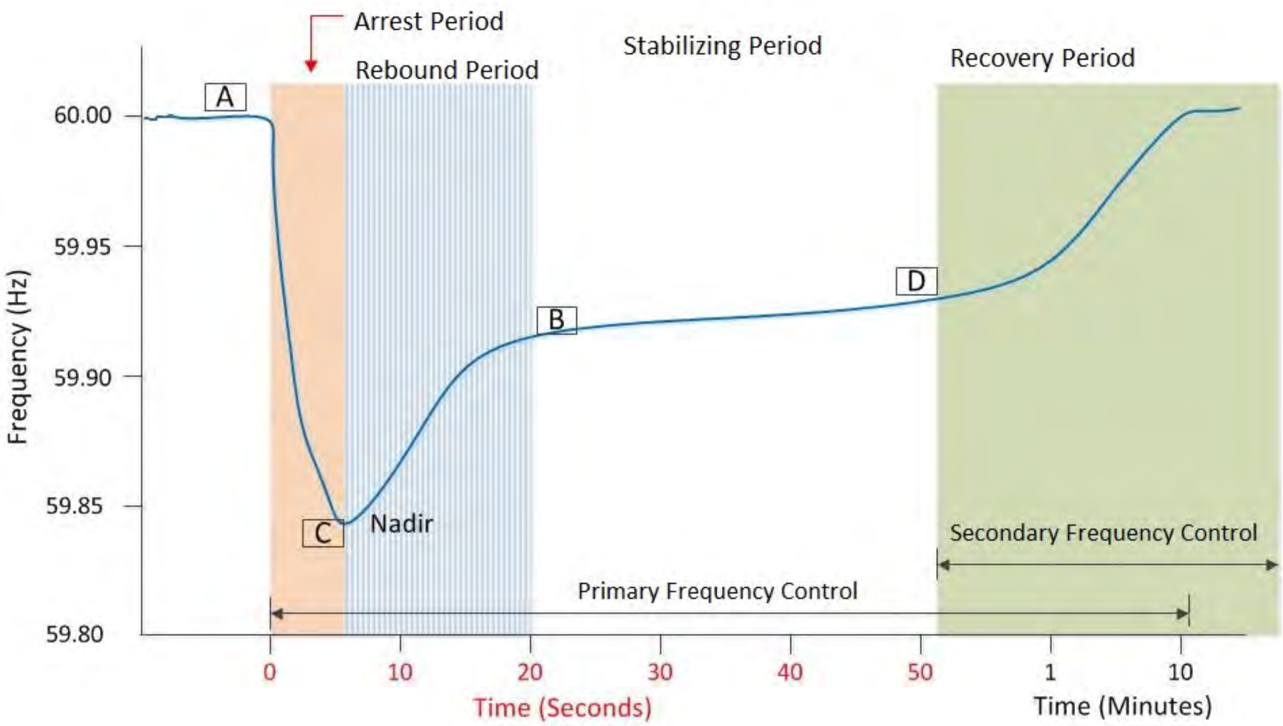


Figure 1.8: Typical Frequency Trend for the Loss of a Generating Resource

Four points of particular interest are shown in Figure 1.8: Point A is defined as the pre-disturbance frequency; Point C or Nadir is the maximum deviation due to loss of resource; Point B is defined as the stabilizing frequency and; Point D is the time the contingent BA begins the recovery from the loss of resource.

Inertial Control

Inertial control is more of an effect than an actual control since it is governed by physical principles for most resources and emulated by others. The rotating mass in a typical generator combined with the speed at which it is rotating creates a large amount of stored energy. If a decelerating force is applied (e.g., a large drop in system frequency), energy is transferred from the rotating mass and into the system. One analogy is that of a bicycle wheel and brake. If the wheel is first set spinning and then the brake is applied, the energy from the wheel flows into the braking surfaces. The contact surfaces of the brake will heat up due to the transformation of energy from the wheel into heat.

This is the same principle for the inertia effect in the power system. A sudden increase in the braking force is applied by a decrease in the amount of energy being injected into the system (e.g., losing a large generator or addition of a large load). When the mismatch between injected and consumed energy occurs, energy flows from the rotating masses of the connected resources into the power system. The propagation of this effect across an Interconnection happens within a handful of seconds.

Resources that are not directly coupled via an alternating current connection to the power system (e.g., inverter-based resources) are not typically governed by the same physical principles and therefore might not possess inertia per se from the perspective of the power system. Instead, inertia can be emulated to varying degrees of success by using sensing and control.

Primary Control

Primary control is more commonly known as primary frequency response (PFR). PFR also includes inertial response described under inertial control above as well other types of frequency response actions, as described in the Primary Frequency Control Guideline.[5] PFR is autonomous; it does not require external inputs and begins to occur within the first few seconds following a change in system frequency (disturbance) to stabilize the Interconnection. Frequency response is provided by the following:

- **Governor Action:** Resource governors are like cruise controls for cars. They sense changes in local system frequency and adjust the energy output of the resource to counteract that change. Some resources do not have "governors" per se but instead can emulate governor action to varying degrees of success by using sensing and control actions.
- **Demand Response:** The speed of directly-connected motors in an Interconnection will change in direct proportion to frequency changes. As frequency drops, motors will turn slower and consume less energy.

  Rapid reduction of system load may also be affected by automatic operation of under-frequency relays which interrupt predefined loads within fractions of seconds or within seconds of frequency reaching a predetermined value. Such reduction of load may be contractually represented as interruptible load or may be provided in the form of resources procured as reliability or Ancillary services. As a safety net, percentages of firm load may be dropped by under-frequency load shedding programs to ensure stabilization of the systems under severe disturbance scenarios.

The most common type of a frequency disturbance in an Interconnection is associated with the loss of a generator, causing a decline in frequency; this happens on a daily basis and must be considered. In general, the amount of frequency-responsive synchronized and unloaded generation with headroom in an Interconnection will directly influence the amount of available frequency response because this is the amount of supply that is connected, ready, and able to immediately increase output when needed.

It is important to note that primary control will not return frequency to nominal, but only arrest and stabilize it. Other control components are used to restore frequency to nominal.

Operating Tip: Frequency response is particularly important during disturbances and islanding situations. System operators should be aware of their frequency responsive resources. Blackstart units must be able to autonomously participate in frequency control; this is especially important during system restoration.

Secondary Control

Secondary control typically includes the balancing services deployed in the "minutes" time frame. However, some resources (e.g., hydroelectric generation or fast electrical storage) can respond faster in many cases. Secondary control is accomplished using the BA's supervisory control and data acquisition (SCADA) and energy management systems (EMSs)[6], and the manual actions taken by the dispatcher to provide additional adjustments. Secondary control also includes some initial reserve deployment for disturbances.

In short, secondary control maintains the minute-to-minute balance throughout the day and is used to keep ACE within CPS bounds and thereby maintain Interconnection frequency close to its scheduled value (usually 60 Hz) following a disturbance. Secondary control is provided by both Operating Reserve – Spinning and Supplemental. During frequency disturbances, secondary control returns the frequency to nominal once primary control has arrested and stabilized it.

[5] PFC (v 2.0 approved by the Operating Committee 6/4/2019)
[6] Terms most often associated with this are "load-frequency control" or "automatic generation control"

The most common means of exercising secondary control is through an EMS's AGC (Automatic Generation Control). AGC operates in conjunction with SCADA systems; SCADA gathers information about an electric power system, particularly system frequency, generator outputs, and actual interchange between the BA and its neighbors. Using system frequency and net actual interchange and knowledge of net scheduled interchange and upcoming changes, it is possible to determine the BA's energy balance (i.e., its ACE) within its Interconnection. Most SCADA systems poll data points sequentially for electric system data, with a typical periodicity of two to six seconds. Because of this, data is naturally slightly out of perfect time sync, but is of sufficient quality to permit balancing and good frequency control.

AGC computes a BAA's ACE from interchange and frequency data. ACE indicates whether a system is in balance or is in need of an adjustment to generation resources. AGC software generally sends signals that cause resources performing secondary control to move to oppose the ACE. Some AGC systems use pulses for raise/lower signals while other AGC systems use MW set points.

The degree of success of AGC in complying with balancing and frequency control is manifested in a BA's control performance statistics that are described in greater detail later in this document.

Tertiary Control

Tertiary Control encompasses actions taken to get resources in place to handle current and future contingencies. Reserve deployment and reserve restoration following a disturbance are common types of Tertiary Control.

Time Control

Frequency and balancing control are not perfect. There will always be occasional errors in tie-line meters whether due to instrument transducer inaccuracy, problems with SCADA hardware or software, or communications errors. Due to these errors and normal load and generation variation, ACE in an Interconnection cannot be maintained at zero. In fact, the average value of ACE over many time frames is non-zero. ACE must be managed such that its magnitude is relatively small. There is no operational reason to force ACE to be an independently randomly distributed variable. This means that frequency is never maintained at exactly 60 Hz for any appreciable length of time and average frequency over time usually is not exactly 60 Hz.

Each Interconnection has a time control process that can be used to maintain the long-term average frequency at 60 Hz. While there are some differences in process, each Interconnection designates a RC as a "time monitor" to provide Time Control.

The time monitor compares a clock driven off Interconnection frequency against the "official time"[7] provided by the National Institute of Standards and Technology. If average frequency drifts, it creates a Time Error between these two clocks. The Quebec Interconnection (QI) and Texas Interconnection (TI) operate so that Time Error is automatically minimized or eliminated while the WI operates to automatically mitigate accumulated Time Error through its ATEC. If the Time Error gets too large In the EI and WI, the Time Monitor may notify BAs in the Interconnection to manually correct the situation.

For example, if frequency has been running 2 mHz high (i.e., 60.002 Hz), a clock using Interconnection frequency as a reference will gain 1.2 seconds in a 10-hour interval:

$$\frac{(60.002\ \mathrm{Hz} - 60.000\ \mathrm{Hz})}{60\ Hz} * 10\ hr\ *\ 3600\frac{sec}{hr}\ =\ 1.2\ sec$$

[7] The Official NIST US Time: https://www.time.gov/

If the Time Error accumulates to a predetermined initiation value (e.g., +10 sec in the Eastern Interconnection (EI)) the Time Monitor will send notices for all BAs in the Interconnection to offset their scheduled frequency by -0.02 Hz (Scheduled Frequency = 59.98 Hz). This offset, known as Time Error Correction, will be maintained until Time Error has decreased below the termination threshold (e.g., +6 sec).

A positive offset (i.e., Scheduled Frequency = 60.02 Hz) would be used if average frequency was low and Time Error reached its initiation value (e.g., -10 seconds). Manual time error corrections are no longer required by standards but each Interconnection may elect to perform manual time error correction. See the *NERC Time Monitoring Reference Document (Version 4)* on manual time error correction for additional information.[8]

Control Continuum

Table 1.1 summarizes the discussion on the control continuum and identifies the service that provides the control and the NERC standard that addresses the adequacy of the service. Current issues, good practices, and recommendations on balancing and frequency control are discussed later.

Table 1.1: Control Continuum Summary

Control	Ancillary Service/ERS	Timeframe	NERC Measurement
Inertial Control	Inertial Control	0–12 Seconds	N/A
Primary Control	Frequency Response	10–60 Seconds	FRM
Secondary Control	Regulation	1–10 Minutes	CPS1 – DCS - BAAL
Tertiary Control	Imbalance/Reserves	10 Minutes–Hours	BAAL - DCS
Time Control	Time Error Correction	Hours	N/A

[8] NAESB WEQ Manual Time Error Correction Standards - WEQBPS – 004-000: https://www.naesb.org//pdf2/weq_bklet_011505_tec_mc.pdf

Area Control Error (ACE) Review

The CPSs are based on measures that limit the magnitude and direction of the BAs Reporting ACE. The equation for Reporting ACE is as follows:

- Reporting ACE = $(NI_A – NI_S) – 10B (F_A – F_S) – I_{ME}$
- Reporting ACE (WI) = $(NI_A – NI_S) – 10B (F_A – F_S) – I_{ME} + I_{ATEC}$

where:

- NI_A is Actual Net Interchange,
- NI_S is Scheduled Net Interchange,
- B is BA Bias Setting
- F_A is Actual Frequency,
- F_S is Scheduled Frequency,
- I_{ME} is Interchange (tie line) Metering Error
- I_{ATEC} is ATEC (WI only)

NI_A is the algebraic sum of tie line flows between the BA and the Interconnection. NI_S is the net of all scheduled transactions with other BAs. In most areas, flow into a BA is defined as negative; flow out is positive.

The difference between net actual interchange and net scheduled interchange (N_{IA} - N_{IS}) represents the so-called "inadvertent" error associated with meeting schedules without consideration for frequency error or bias. If it is used by itself for control, it would be referred to as "flat tie line" control.

The term $10B (F_A - F_S)$ is the BAs obligation to support frequency. B is the BAs frequency bias stated in MW/0.1 Hz (B's sign is negative). The "10" converts the bias setting to MW/Hz. F_S is normally 60 Hz but may be offset ± 0.02 Hz for time error corrections. Control using "$10B (F_A - F_S)$" by itself is called "flat frequency" control.

I_{ME} is a correction factor for meter error. The meters that measure instantaneous[9] flow are not always as accurate as the hourly meters on tie lines. BAs are expected to check the error between the integrated instantaneous and the hourly meter readings. If there is a metering error, a value should be added to compensate for the estimated error; this value is I_{ME}. This term should normally be very small or zero.

I_{ATEC} is an ACE offsetting term for automatic timer error correction in the WI. BAs correct for any delta Time Error that they are responsible for each hour.

Reporting ACE is calculated in Real-time, at least as frequently as every six seconds, by the responsible entity's Energy Management System (EMS) predominantly based on source data automatically collected by that system. Also, the data must be updated at least every six seconds for continuous scan telemetry and updated as needed for report-by-exception telemetry. See the Integrating Reporting ACE Guideline for more detail on the components of ACE and the calculation frequency.

Here is a simple example: Assume a BA with a bias of -50 MW/0.1 Hz is purchasing 300 MW. The actual flow into the BA is 310 MW. Frequency is 60.01 Hz. Assume no time correction, metering error or ATEC.

[9] Instantaneous, as used herein, refers to measurements that are as close to real-time as is possible within the limits of data acquisition and conversion equipment.

- ACE = (-310 – -300) – 10*(-50) * (60.01 – 60.00) = (-10) – (-5) = -5 MW.

The BA should be generating 5 MW more to meet its obligation to the Interconnection. Even though it may appear counterintuitive to increase generation when frequency is high, the reason is that this BA is more energy-deficient at this moment (-10 MW) than its bias obligation to reduce frequency (-5 MW). The decision on when or if to correct the -5 MW ACE would be driven by CPS compliance.

A distinction can be drawn between reporting ACE, which measures the effect of a BA on the Interconnection, and Control ACE. At any given time, a BA might use a control ACE that is different from reporting ACE because AGC resources respond to control ACE, and this difference might be used, for example, to cause AGC resources to assist in "paying down" accumulated inadvertent energy or some other purpose.[10]

Bias (B) vs. Frequency Response (Beta)

There is often confusion in the industry when discussing frequency bias and frequency response. Even though there are similarities between the two terms, frequency bias (B) is not the same as frequency response (β).

Frequency response, defined in the NERC Glossary,[11] is the mathematical expression of the net change in a BA's net actual interchange for a change in Interconnection frequency. It is a fundamental reliability characteristic provided by a combination of governor action and demand response. Frequency response represents the actual MW contribution by inertial control and primary control to stabilize frequency following a disturbance.

Bias is an approximation of β used in the ACE equation. Bias (B) is designed to prevent AGC withdrawal of frequency support following a disturbance. If B and β were exactly equal, a BA would see no change in ACE following a frequency decline even though it provided a MW contribution to stabilize frequency.

Bias and frequency response are both expressed as negative numbers. In other words, as frequency drops, MW output (β) or desired output (B) increases. Both are measured in MW/0.1 Hz

Important Note: When people talk about frequency response and bias, they often discuss them as positive values (e.g., as "our bias is 50MW/0.1Hz"). Frequency response and bias are actually negative values.

Early research (Cohn) found that it is better to be over-biased (i.e., absolute value of B greater than the absolute value of β) than to be under-biased.

[10] Bilateral or Unilateral payback of inadvertent is not allowed in the WI. ATEC is used by BAs in the WI to control primary inadvertent accumulation while automatically correcting time error.

[11] Select from list found at: https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf

Chapter 2: Primary Control

Background

Primary control relates to the response to a frequency deviation by generator governors (aka. speed controls) and inertia that helps stabilize Interconnection frequency whenever there is a change in load-resource balance. Primary control is provided in the first few seconds following a frequency change and is maintained until it is replaced by AGC action (secondary control). Frequency response (or Beta), which also includes rotational inertia response from resources and load response from frequency dependent loads, is the more commonly used term for primary control. Beta (β) is defined by the total of all initial responses to a frequency excursion.

Figure 2.1 shows a trace of the WI's frequency that resulted from a generating unit trip. The graph plots frequency from 5 seconds prior to the loss of a large generator until 60 seconds thereafter.

NERC references three key events to describe such a disturbance. Value A is the pre-disturbance frequency, typically close to 60 Hz. Point C is the maximum excursion point, commonly referred to as the Nadir, which occurs about 10 seconds after the loss of generation in this WI example. Value B is the settling frequency of the Interconnection.

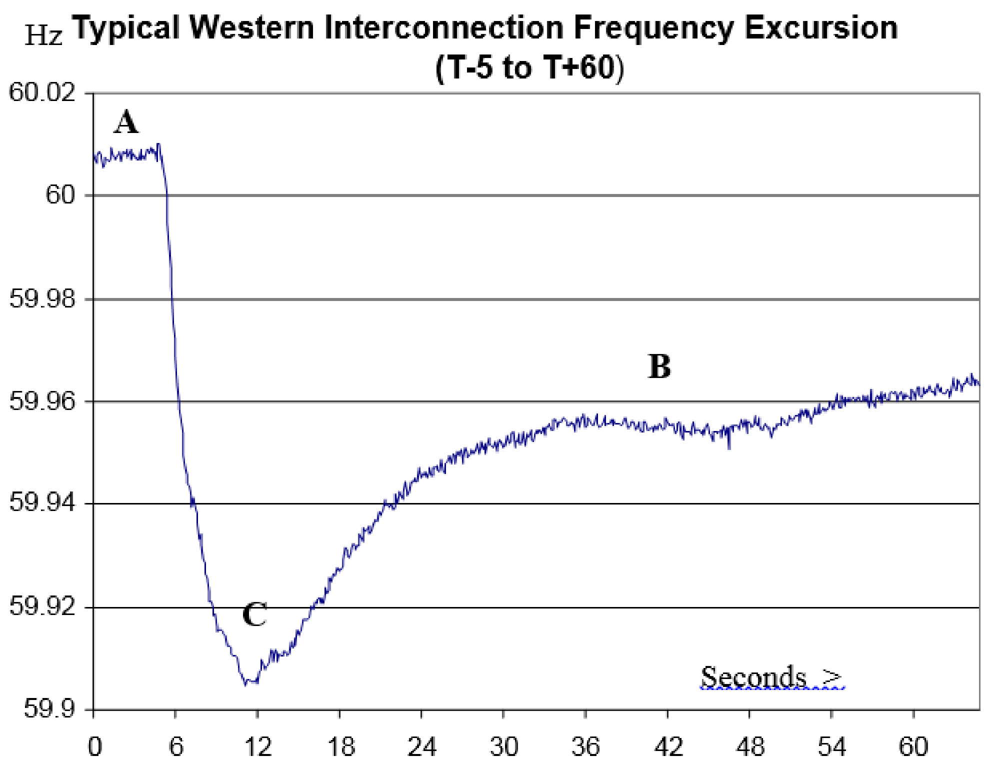


Figure 2.1: WI Frequency Excursion

As discussed earlier, there are two groups of "resources" that arrest a decline in frequency due to a loss of generation:

- A given portion of Interconnection demand is composed of motor load, which draws less energy when the motors slow down due to the lower frequency.
- Generators have governors that act much like cruise control on a car. If the generators on the Interconnection start to slow down with the frequency decline, their governors supply more energy to the generators' prime movers in order to speed them back up to nominal. The sensitivity of this response is controlled by the governor droop setting.

Inertial Response

Inertia quickly and autonomously opposes changes to both under and over frequency events. Having a large amount of inertia is useful for smoothing out power system frequency fluctuations. It is inertia combined with the response of frequency sensitive demand that determines how quickly the frequency decays following the loss of a large supply resource like a large generator or importing direct current tie-line. In an interconnection, more inertia leads to a slower drop in frequency, giving time for the other components of the control continuum to act in order to arrest, stabilize, and then recover frequency. In some sense, the inertia of the power system can be controlled by adjusting the amount and type of generators that are on-line. Inertia is commonly described in units of seconds: the energy that is stored is normalized by the electrical "size" of the resource. Since stored energy is a function of the square of the speed of rotation, low rotating mass, faster spinning resources might store more energy, yet they typically decelerate faster (thereby injecting more energy). These lighter and faster resources' contribution to slowing the fall of frequency is more "front-loaded" and they have smaller normalized inertia values than large-rotating-mass slow-spinning resources that have slower energy injection profiles. Faster response is also not always better because of interaction effects that can cause instability where resources might "bounce" in opposite directions.

For a discussion and graphical representation on how inertia opposes changes in under and over frequency excursions, see the *NERC Frequency Response Standard Background Document,* dated November 2012.[12]

Generator Governors (Speed Controls)

The most fundamental, front-line control of frequency in ac electric systems is the action of generator governors. Governors act to stabilize frequency following disturbances and act as an immediate buffer to load-resource imbalance. Governors operate in the time frame of milliseconds to seconds and operate independently from and much faster than system operator actions or those of AGC. They protect from the effects of frequency when too high, but the vast majority of their benefit comes from assisting when frequency has dropped too low, especially in cases where loss of generation causes abrupt decreases in Interconnection frequency.

Without governor action, loss of generation would result in frequency that would not stabilize until the load reduced to a point that matched the remaining generation output. As mentioned previously some load is reduced when the frequency is reduced mostly due to directly connected motors slowing down and consuming less power. This supply/demand balance point could occur at very low frequency and could result in cascading outages or complete frequency collapse, a very undesirable outcome in terms of the cost to society and potential equipment damage.

The combination of inertial response, governor response and load response – are the "beta" (β), or frequency response characteristic, of a BAA. This is the characteristic that AGC attempts to mimic in its use of the frequency bias ("B") parameter in determining ACE. The net of all BA frequency responses manifests as the Interconnection frequency response.

Droop

Governors cause generators to try and maintain a constant, stable system frequency (60 Hertz in North America). They do this by constantly governing (modulating) the amount of mechanical input energy to the shaft of the electric generator. The degree of this modulation is called "droop" and is measured in percent of frequency change to cause full generator capability to be exerted against the frequency error. A typical slope is 5%, meaning that the full output of the generator would be used (or attempt to be used) to counteract the frequency error if frequency error is 5% or 3 Hz. It should be noted that smaller droop percentages indicate increased sensitivity of response, e.g., a generator with a 4% droop would attempt to go to full output if the frequency changed by 2.4 Hz. Frequency errors are more typically in the range of 0.01% (.06 Hz, or 60 mHz), so governor action usually is a much smaller fraction of a unit's output capability. It must also be recognized that, while most generators can reduce output considerably in response

[12] https://www.nerc.com/comm/OC/RS%20Landing%20Page%20DL/Related%20Files/Bal-003-1_Background_Document_Clean_20121130.pdf

to their governor's actions, increasing output is more problematic since many generators may already be near the top of their output capability when low frequency causes their governor to request more output. Thus, if there is no "headroom" available on a generator's output, the governor will be able to do little to increase that output and help stabilize low frequency.

Deadband

The second general characteristic of governors is "deadband." This means that the governor ignores frequency error until it passes a threshold. When frequency error exceeds the threshold (which should not exceed the maximum deadband setting per Interconnection recommended in the NERC Reliability Guideline-Primary Frequency Control), the governor becomes active. It is worth noting that the deadband may be larger for older mechanical-style governors, and may have mechanical lash associated with it.

The calculated unit MW output change with a droop setting of 5% and deadband setting of 36 mHz based on the total resource capacity is shown in Figure 2.2

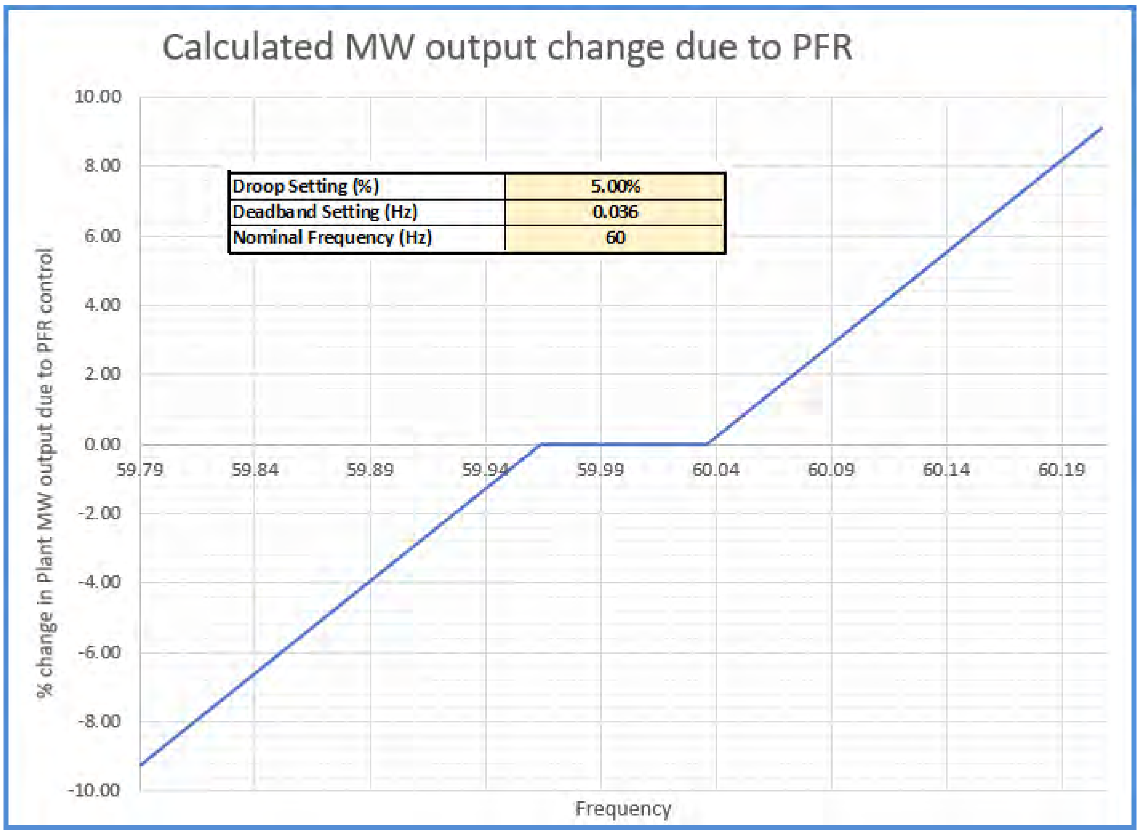


Figure 2.2: Calculated Resource % MW Output Change due to PFR

Calculating Frequency Response

Prior to current Reliability Standard requirements governing frequency response[13], calculation of frequency response was addressed by the NERC *Frequency Response Characteristic Survey Training Document*,[14] which included a form to guide the calculation for a given event. The calculation of the Frequency Response Characteristic (FRC) for a BA is to divide the change in Net Interchange Actual (NI_A) from pre-event (A point, see Figure 1.8 above) to the stabilizing period (B point, ~20-52 seconds after the event) by the change in interconnection frequency from pre-event to the stabilizing period. Although the terms in the FRC Training Document have changed over the years (e.g., Control Area is now Balancing Area), the calculation remains the same. This is often referred to as the A to B frequency response. With the advent of faster scanning tools over the years (e.g., Phasor Measurement Units), a similar response calculation can be made from the A point to the C point (nadir, if a generation loss or apex, if a load loss) of the frequency event.

Important Concept: The frequency response will normally be a negative value, reflecting the inverse relationship between the increase in MW output in response to the decrease in interconnection frequency for a frequency decline (e.g., a generator trip), or vice versa for a frequency increase (e.g., a load loss).

Under the current Reliability Standard requirements, the selection of events for evaluation and the calculation forms used to determine response are prescribed by the Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard[15], the Reliability Standard itself, its attachment and associated forms.

Frequency Response Profiles of the Interconnections

The amount of frequency decline from a generator trip varies based on a number of factors, e.g. time of day, season, and Interconnection loading. The observed frequency responses of the North American Interconnections as documented in the *2018 NERC State of Reliability* report are as follows:

- EI -2,103 MW / 0.1Hz
- TI -674 MW / 0.1 Hz
- WI -1,539 MW / 0.1 Hz
- QI -599 MW / 0.1 Hz

Important Note: These values are not normalized to adjust for starting frequency and/or resource loss size.

As noted above, the negative sign means there is an inverse relationship between generation loss and frequency. In other words, a loss of 1,000 MW would cause a frequency change (A to B) on the order of:

- EI -0.048 Hz
- TI -0.148 Hz
- WI -0.065 Hz
- QI -0.168 Hz

Conversely, if 1000 MW of load were lost in an Interconnection, the resulting frequency increase would be similar in magnitude as listed above.

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13 As of the release date of this document, the current applicable Reliability Standard is BAL-003-1.1

14 https://www.nerc.com/comm/OC/RS%20Agendas%20Highlights%20and%20Minutes%20DL/Frequency_Response_Characteristic_Survey_19890101.pdf

15 https://www.nerc.com/comm/OC/BAL0031_Supporting_Documents_2017_DL/Procedure_Clean_20121130.pdf

Figure 2.3 is a typical trace following the trip of a large generator in three of the Interconnections. Notice that governors in the East do not provide the "Point C to B" recovery of frequency as they do in the other Interconnections. The rate of frequency decline is much slower primarily due to its size, so frequency slowly drops until sufficient response stops the decline. In the early 2000s, there was typically a post-event decline in frequency, but this effect has been occurring less often.

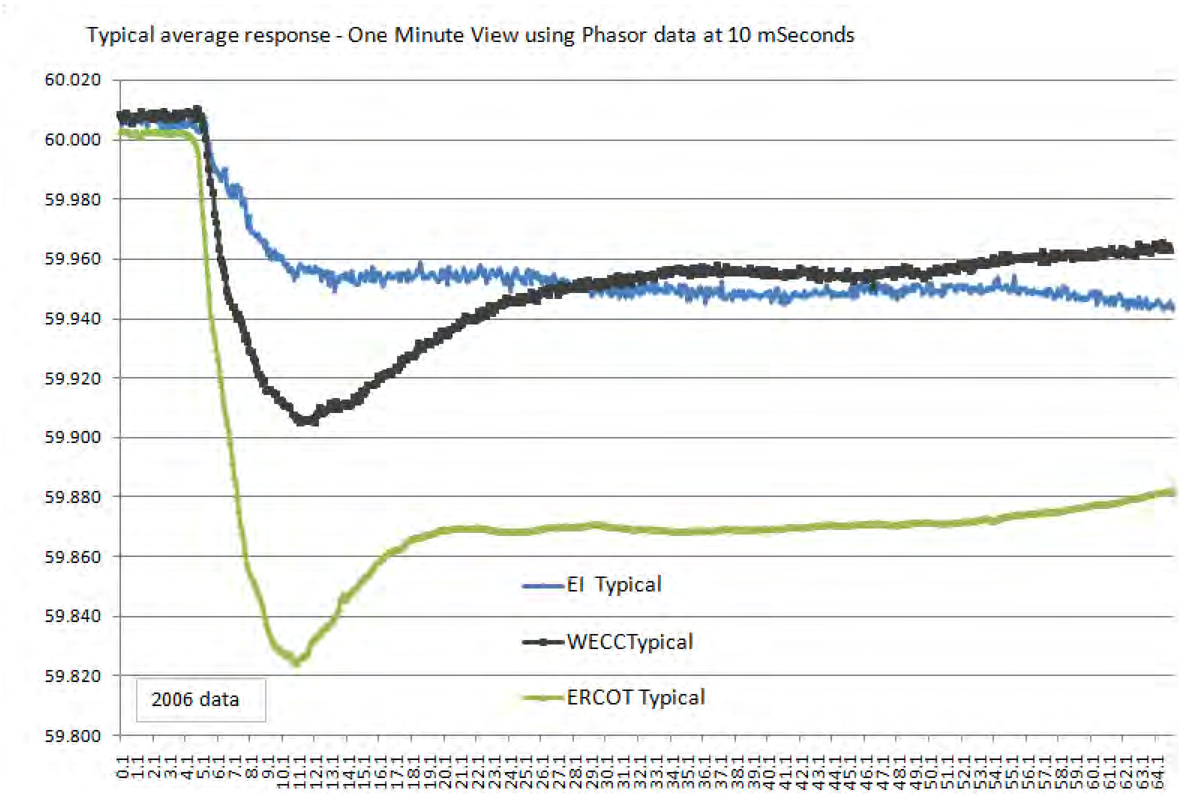

Figure 2.3: Typical Frequency Excursions

<u>Important Concept:</u> Following a large generator trip, frequency response will only stabilize the frequency of an Interconnection, arresting its decline. Frequency will not recover to scheduled frequency until the contingent BA replaces the lost generation through AGC and reserve deployment.

Figure 2.4 Shows the frequency at measured at various locations across the EI after a large generator trip. Note that the frequency disturbance is a chaotic event with complex dynamics, including fast transients bouncing about a much longer term trend. Also note that the time-scale tick-marks are every 5 seconds: the whole event has reached a stabilized frequency within 20 seconds.

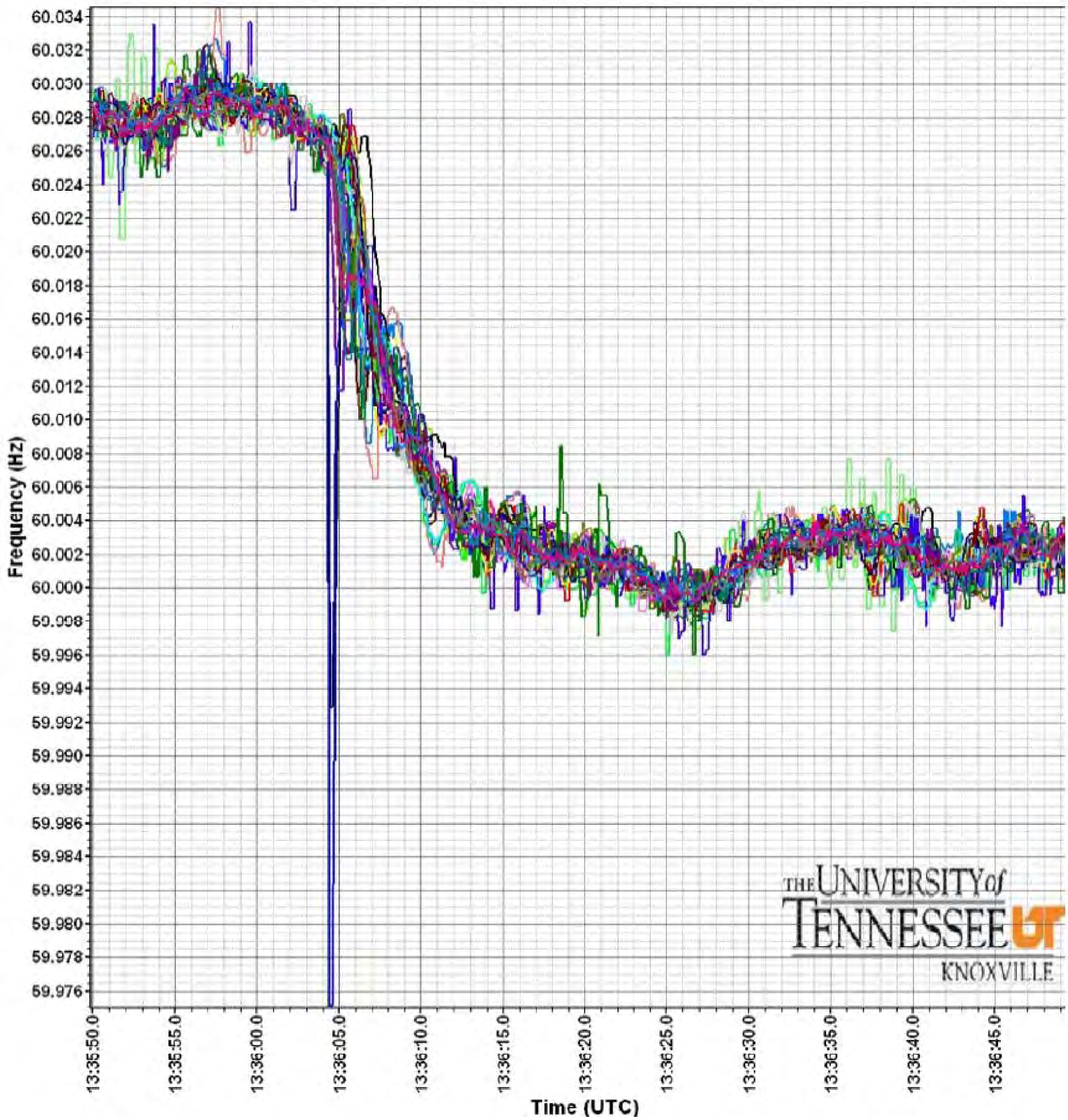

Figure 2.4: Frequency Excursion Measured at various locations in the EI

Annual Bias Calculation

The value in a BA properly stating its bias is to ensure its AGC control system does not cause unnecessary over-control of its generation.

The NERC RS posts quarterly lists of excursions that are available to the industry for everyone's use for evaluating frequency response during the year. The subcommittee refines these quarterly lists into an official event list that is used in BAL-003 FRS forms.

Guidelines the RS uses in selecting and evaluating events for calculating bias and BAL-003 performance include the following:

- Events are dispersed throughout the year to get a good representation of “average” response.
- Pick frequency excursions large enough to actuate generator governors.
- The events should be relatively clean and generally have continuous drop from A to C.
- Starting frequency should be relatively stable and close to 60 Hz.

Estimating Load’s Frequency Response

As discussed previously, motor load provides frequency response to the Interconnection. The rule of thumb is that this response is equal to 1–2% of load. Techniques have been developed to observe approximately how much “load” frequency response a BA has available. This technique is explained in **Figure 2.5**.

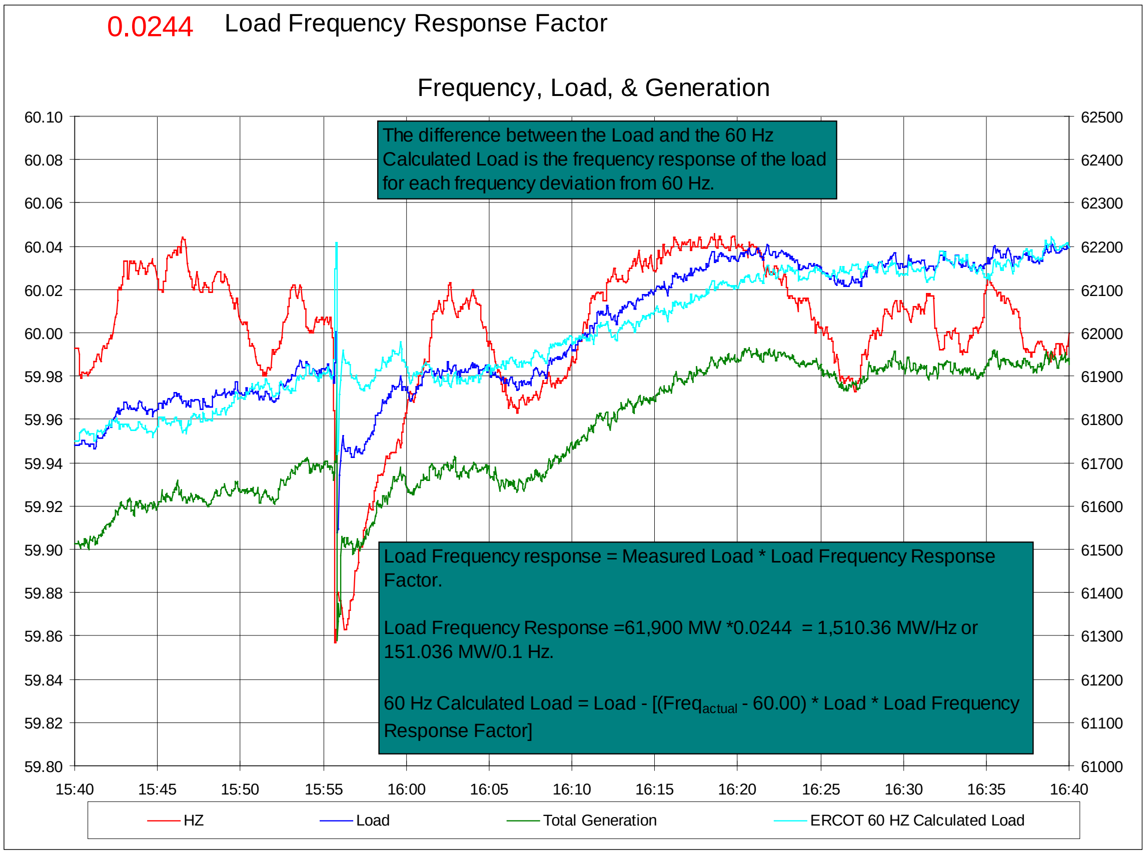

Figure 2.5: Observing Frequency Response of Load

The cyan trend in **Figure 2.5** above represents how much load would exist if frequency could be controlled to exactly 60.000 Hz all the time. The difference between the measured load, blue trend, and the cyan trend is the frequency response of load. For this event, a 759 MW resource was lost producing a frequency deviation of -0.118 Hz. This calculates to be

$$\frac{759\ MW}{0.118\ Hz * \left(\frac{10 * 0.1\ Hz}{Hz}\right)} = \frac{643\ MW}{0.1\ Hz} \text{ of frequency response.}$$

Of this response, 151.036 MW/0.1 Hz was provided by the load by multiplying the load by .00244, leaving the remainder (492.184 MW/0.1 Hz) provided by resource governor response. The post contingency total generation settled at 61,510 MW a difference of 178.222 MW below the pre-contingency generation. The generation-to-load mismatch post event is 178.222 MW plus replacement of the 580.777 MW of governor response (492.184 * 1.18 = 580.777) that will be withdrawn as frequency returns to 60.00 Hz. If this BA's bias in the ACE equation had been set exactly at 643 MW/0.1 Hz, ACE would equal -759 MW at the B point of this event. AGC would dispatch 759 MW to replace the frequency response of the governors and load, returning the Interconnection to balance at 60.00 Hz. This example is of a "single" BA Interconnection but the math works for multiple BA Interconnections as well.

By observing multiple events and adjusting the factor to produce a "60 Hz Load" value that maintains the pre- and post-event slope of load, a proper value can be determined. Larger deviation frequency events are beneficial to get a clear observation in addition to looking at many events. A factor between 0.010 and 0.025 would be reasonable depending on the ratio of motor load vs. non-motor load within the BAA boundaries.

The key points of primary control are as follows:

- Steady-state frequency is common throughout an Interconnection.
- If frequency is off schedule, generation is not in balance with total load.
- Arresting frequency deviations is the job of all BAs. This is achieved by provision of frequency response through the action of operating governors on generation and other resources able to provide frequency response (e.g., controllable load, storage, etc.).
- Frequency response is the sum of a BAs inertial response, natural load response and governor response of generators to frequency deviation within the BA Area.
- Frequency response arrests a frequency decline but does not bring it back to scheduled frequency. Returning to scheduled frequency occurs when the contingent BA restores its load-resource balance by using secondary control.
- Generators should be operated with their governors free to assist in stabilizing frequency.
- Frequency control during restoration is extremely important. That is why system operators should have knowledge of the generators' governor response capabilities during black start.
- All BAs have a frequency response characteristic based on the governor response of their units and the frequency-responsive nature of their load.
- The amount and rate of frequency deviation depends on the amount of imbalance in relation to the size of the Interconnection.
- Frequency bias is a negative number expressed in MW/0.1Hz.
- The typical (best) way to calculate frequency response is to observe the change in BA output for multiple events over a year.
- Under BAL-003-1.1 BA's should set its fixed bias to no less than the 100–125% of its natural frequency response or its percentage share of 0.9% of the Interconnection's non-coincidental peak load based upon all of the BAs within an Interconnection's non-coincident peak load values (whichever method is greater in absolute terms).
- BAs are allowed to employ variable frequency bias that more accurately reflects real-time operating condition.
- Governors were the first form of frequency control and remain in effect today; they act to oppose large changes in frequency.
- AGC supplements governor control by controlling actual tie flows and maintaining scheduled interchange at its desired value. It performs this function in the steady-state, seconds-to-minutes time frame after transient

effects, including governor action, have taken place. If bias is greater than actual frequency response, AGC will supplement this response.

- ACE, the main input to AGC, requires frequency and energy interchange data (both actual and scheduled).
- While frequency response was declining in the 1990s, actions taken by the Industry appear to have stabilized the trend.
- BA or Interconnection frequency response should be measured for two reasons:
  - To gauge the area response to frequency deviations.
  - As a basis for setting B.

Chapter 3: Secondary Control

Background

Secondary control is the combination of AGC and manual dispatch actions to maintain energy balance and scheduled frequency. In general, AGC utilizes maneuvering room while manual operator actions (e.g., phone calls to generators, purchases and sales, load management actions) keep repositioning the BAA so that AGC can respond to the remainder of the load and interchange schedule changes. NERC CPSs are intended to be the indicator of sufficiency of secondary control.

Maintaining an Acceptable Frequency Profile

One indicator of proper secondary control action is the distribution profile of steady-state Interconnection frequency. When the transition was made from the "A" criteria to CPS in 1997, the directive of the NERC Operating Committee was to not allow frequency variation to become any greater than it had been in the past. One measure of this is the root mean square (RMS) of frequency error from schedule. This by itself, however, is a measurement over an indefinite term and may not reveal problems at all averaging intervals. To adequately measure the frequency profile of an Interconnection, a statistical method was adopted in which period averages of RMS frequency error were measured and cataloged for periods of a large number of different values. In other words, the average of rolling N-minute RMS averages was computed for many values of N. This results in a defining profile as shown in **Figure 3.1** and **Figure 3.2.** Although other values could have been selected and ideally ALL values should be considered, the decision was made that the general profile would be maintained if the profile was anchored at two points in time (originally 1 minute and 10 minutes).

To set values for frequency performance, each Interconnection's frequency error was observed by using the above method, and each one was characterized, particularly at their 10-minute interval average RMS frequency deviation from schedule. The EI measured 5.7 mHz at the 10-minute point. The 1-minute point used to set the CPS standard was derived from an "ideal" error characteristic by the ratio of square roots. This yields $5.7 * \sqrt{10} = 18.025$ mHz. This value was rounded to the value in use today for the East, 18 mHz.

The same technique was used for the WI and TI. It is important to realize that CPS1 performance is only measured at this one "slice" (one-minute averaging) of the Interconnection's frequency error characteristic. Because of this, there is no assurance that frequency variation will be constrained at other averaging points or converge on the ideal characteristic and become more random.

Initially, a 10-minute metric called CPS2 was developed to keep average ACE within specific bounds. CPS2 was originally used to help prevent excessive transmission flows due to large values of ACE. The problem with CPS2 was that it was not dependent on ACE's impact on frequency. Additionally, CPS2 could cause control actions that moved against frequency. If a BA had very bad performance in one direction for five minutes, the BA could correct this by having equally bad performance in the opposite direction for the next five minutes. Finally, ACE could be totally unbounded for 10% of the month and it didn't matter whether it was 1 or 1000 MW over the limit. CPS2 did not provide the correct signal for maintaining frequency. Ultimately, the industry adopted a frequency-sensitive longer term (i.e., 30 minute) measure called the BA ACE Limit (BAAL).

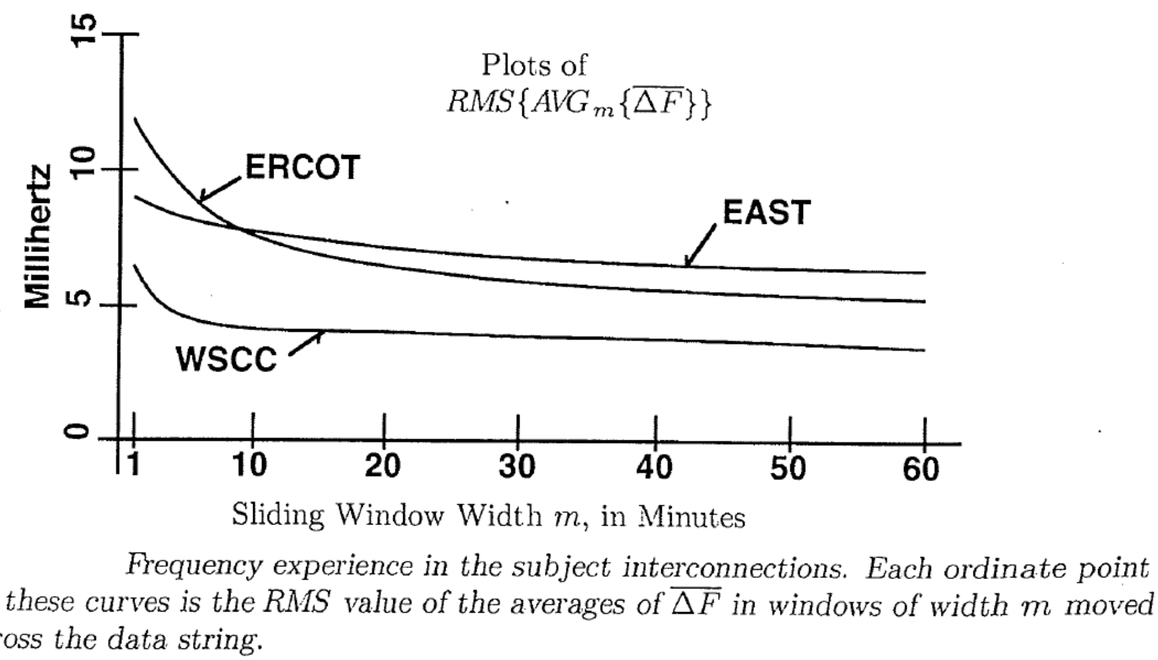

Figure 3.1: Interconnections with CPS actual-measured ΔF "period average"

Figure 3.1 Illustrates the actual-measured ΔF "period average" characteristic of the Interconnections with CPS was designed (EPRI report RP-3550, August, 1996). Note that these curves are flatter than what was ultimately selected as the epsilon limits in CPS1. The reason for this is that the standard needed to bound acceptable performance but not raise the bar and make it difficult to comply. For example, the 1-minute frequency variation in the East was about 10 mHz; if 10 mHz were chosen as Epsilon 1 in the East as opposed to the 18 mHz that was actually selected, it would mean that half the BAs in the East would have been out of compliance when the standard became active. Random (i.e., non-coincident) behavior of BAs in total is important in the above assumptions because the curves from which epsilon 1s were extrapolated start to deviate from the shape and predictability of the curves used to derive them as behavior becomes coincident (i.e., behaviors happening at the same time). Another way of saying this is that it becomes less and less valid to try to control frequency and measure performance at just one point on the sliding window continuum as coincidence creeps in. Prior to the adoption of the BAAL, the Interconnections would see wider frequency swings at specific times of day, particularly in the low direction. The swings, due primarily to load changes and large block Interchange Schedules, could occur under CPS2. The number and magnitude of frequency swings were reduced through a combination of tools that identified the contributing BAs as well as the adoption of BAAL.

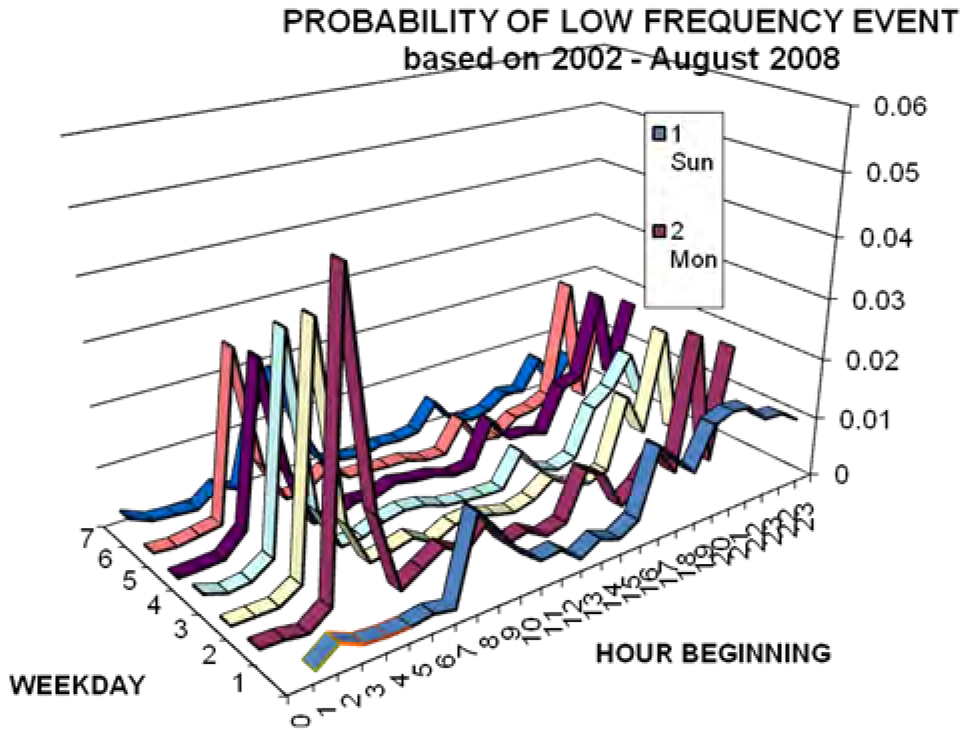

Figure 3.2: Probability Distribution for Low-Frequency Events vs. Time of Day

Control Performance Standard 1

In simple terms, CPS1 assigns each BA a share of the responsibility for control of steady-state Interconnection frequency. The amount of responsibility is directly related to BA frequency bias.

As mentioned previously, ACE is to a BA what frequency is to the Interconnection. Over-generation makes ACE go positive and frequency increase while negative ACE "drags" on Interconnection and decreases frequency. "Noisy" ACE tends to cause "noisy" frequency. CPS1 captures these relationships using statistical measures to determine each BA's contribution to such "noise" relative to what is deemed permissible.

The CPS1 equation can be simplified as follows:

- CPS1 (in percent) = 100* [2 – (a Constant[16])* (frequency error)*(ACE)]

Frequency error is deviation from scheduled frequency, normally 60Hz. Scheduled frequency is different during a time correction, but for the purposes of this discussion, assume scheduled frequency is 60 Hz.

Refer to the equation above. Any minute where the average frequency is exactly on schedule or BA ACE is zero, the quantity ((frequency error)*(ACE)) is zero. Therefore, CPS1 = 100* (2-0), or 200%. This is true whenever frequency is on schedule or ACE is zero.

For any one-minute average where ACE and frequency error are "out of phase," CPS1 is greater than 200%. For example, if frequency is low, but ACE is positive (tending to correct frequency error), the BA gets extra CPS1 points.

[16] The size of this constant changes over time for BAs with variable bias, but the effect can be ignored when considering minute-to-minute operation. It is equal to -10 * B / ε_1^2

Operating Tip: Frequency is generally low when load is increasing and high when load is dropping. Anticipating and staying slightly "ahead of the load" and on the assistive side of frequency correction with your generation will give your BA high CPS1 scores over the long run.

Conversely, if ACE is aggravating the frequency error, CPS1 will be less than 200%. CPS1 can even go negative.

TI and QI Note: The TI and QI operate as single BA's. ACE for a single BA Interconnection will always be "in phase" with frequency error; refer to the ACE review for verification. This means the largest CPS1 these BA's can achieve is 200%. This occurs whenever ACE or frequency error is zero. CPS1 for these BA's is a function of "frequency squared."

The CONSTANT in the equation above is sized such that the BA will get a CPS1 of 100% if the BA's ACE is proportionally as "noisy" as a benchmark frequency noise. The minimum acceptable rolling twelve-month score for CPS1 is 100%.

When CPS was established, each Interconnection was given a target or benchmark "frequency noise." This target noise is called Epsilon 1(ε1). Epsilon 1 is nothing more than a statistician's variable that means the RMS value of the one-minute averages of frequency.

The target values (in mHz of frequency noise) for each Interconnection are shown in **Table 3.1** below. The NERC RS monitors each Interconnection's frequency performance and can adjust the ε1 values should an Interconnection's frequency performance decline.

Table 3.1: Target Values of "One Minute Frequency Noise"

Interconnection	Epsilon 1 (ε1)
Eastern	18.0 mHz
Quebec	21.0 mHz
Western	22.8 mHz
Texas	30.0 mHz

The Epsilon 1 target initially set for each Interconnection was on the order of 1.6 times the historic frequency noise. This means a typical BAs performance would be around 160% for CPS1. If every BA in an Interconnection were performing with a CPS1 of 100%, it would result in an observed Interconnection frequency performance of ε1 (i.e.18mHz in the East).

Let's review how CPS1 data can be applied to measure the adequacy of control performance and the deployment of resource-provided services to meet load. NERC previously referred to these resources as interconnected operating services (ERSs). More recently, the term essential reliability services is used. These align somewhat to what FERC calls "ancillary services."

Figure 3.3 depicts ACE charts for one hour for four different BAs. Compare the charts for BAs 1 and 2. Both BAs show good performance for the hour. The difference between them is that the load in BA 2 is "noisier."

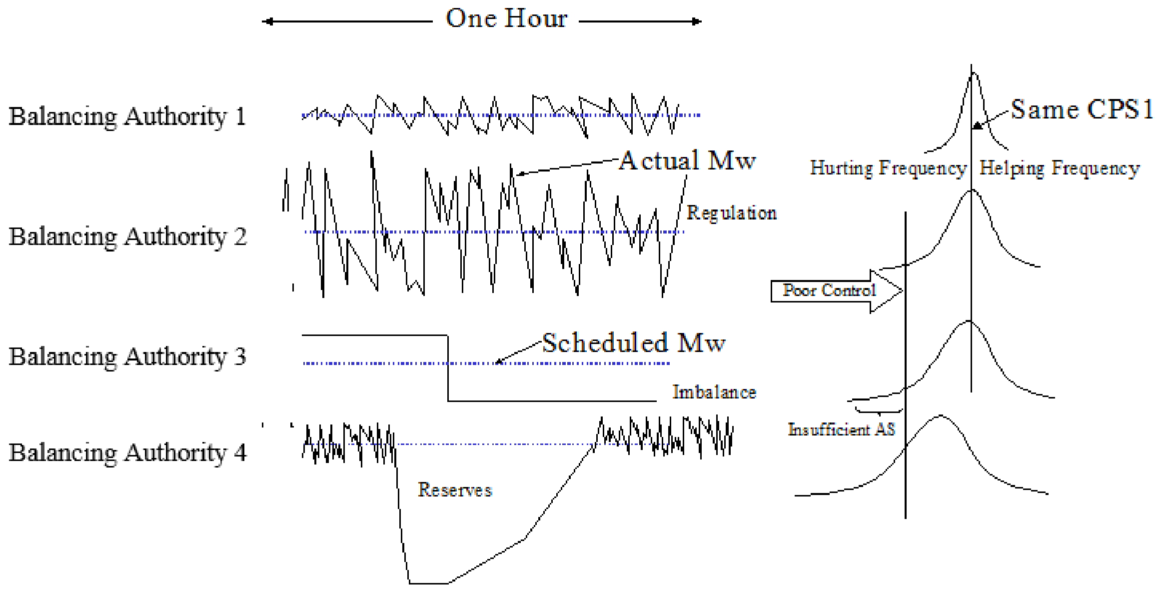

Figure 3.3: ERS/Ancillary Service Measured via CPS

The distributions to the right of the ACE charts show the individual one-minute CPS1 for both BAs for the hour. If frequency followed a normal pattern whereby it fluctuated +/- a few mHz from 60 Hz, the CPS1 curves for BA 1 and 2 would look like the distributions to the right of their ACE charts. Both curves would have the same average (about 160 percent CPS1), but BA 2's curve would be "wider."

Even though the average effect of BA 1 and 2 on the Interconnection is the same, BA 2 sometimes places a greater burden on the Interconnection as demonstrated by the size of the "left hand tail" of the CPS1 curve. A very long left tail implies poor control of some type (regulation in this case).

Now look at BA 3. It is a "generation only" BA that is selling 100 MW for the hour. The problem is that it is meeting this requirement by generating 200 MW for the first 30 minutes and 0 MW for the last half hour. Again, if frequency conditions are normal, half the time the BA will be helping frequency back towards 60 Hz and half the time the BA will be hurting frequency. This means the BA will get an "Interconnection average" CPS1 score of about 160% for the hour. The graph of its CPS1 for the hour will have wider tails, much like BA 2. The underlying problem in this case is imbalance, not regulation.

The ACE chart for BA 4 shows that a generator tripped offline during the hour. If the CPS1 one-minute averages are plotted, the curve will also have wider tails. If the unit that was lost was large, the curve will be "skewed" to the left even further. This is because the unit loss will pull frequency down while ACE is a large negative value.

In each case above, there was a deficiency in one of the energy-based ERSs. The "left tail" of the underlying CPS1 curve captured each situation.

Balancing Authority ACE Limit

In simple terms, BAAL assigns each BA a share of the responsibility for control of steady-state Interconnection frequency. The amount of responsibility is directly related to BA frequency bias and any deviation of Interconnection frequency from the Interconnections scheduled frequency.

The BAAL is calculated from the clock minutes averages of the data as follows:

Frequency Trigger Limits:

- FTL_{High} = Scheduled Frequency + 3*ε1
- FTL_{Low} = Scheduled Frequency - 3*ε1

As an example, for the EI (where epsilon1 = 0.018 mHz) and when the Interconnection is not in a time error correction (TEC) the FTL's are:

- FTL_{High} = 60.054 Hz
- FTL_{Low} = 59.946 Hz

Calculating the BAAL limits when actual frequency <> scheduled frequency:
As an example, for a BA with a frequency bias Setting = -1000MW/0.1Hz

- $BAAL_{Low} = (-10 * B * (FTL_{Low} - F_S)) * ((FTL_{Low} - F_S)/ (F_A - F_S))$
- $BAAL_{Low} = (-10*-1000* (59.946 – 60)) * (59.946 – 60)/ (F_A – 60))$
- $BAAL_{High} = (-10 * B * (FTL_{High} - F_S)) * ((FTL_{High} - F_S)/ (F_A - F_S))$
- $BAAL_{High} = (-10*-1000* (60.054 – 60)) * (60.054 – 60)/ (F_A – 60))$

Results with actual varying frequency are shown in **Table 3.2.**

Table 3.2: Varying Frequency Results

Actual Frequency	$BAAL_{High}$	$BAAL_{Low}$
60.09	324	NA
60.081	360	NA
60.072	405	NA
60.063	463	NA
60.054	540	NA
60.045	648	NA
60.036	810	NA
60.027	1080	NA
60.018	1620	NA
59.982	NA	-1080
59.973	NA	-720
59.964	NA	-540
59.955	NA	-432

Table 3.2: Varying Frequency Results		
Actual Frequency	**$BAAL_{High}$**	**$BAAL_{Low}$**
59.946	NA	-360
59.937	NA	-309
59.928	NA	-270
59.919	NA	-240
59.91	NA	-216

The BAAL limits plotted in **Figure 3.4** detail the acceptable operating area and the BAAL limit exceedance area.

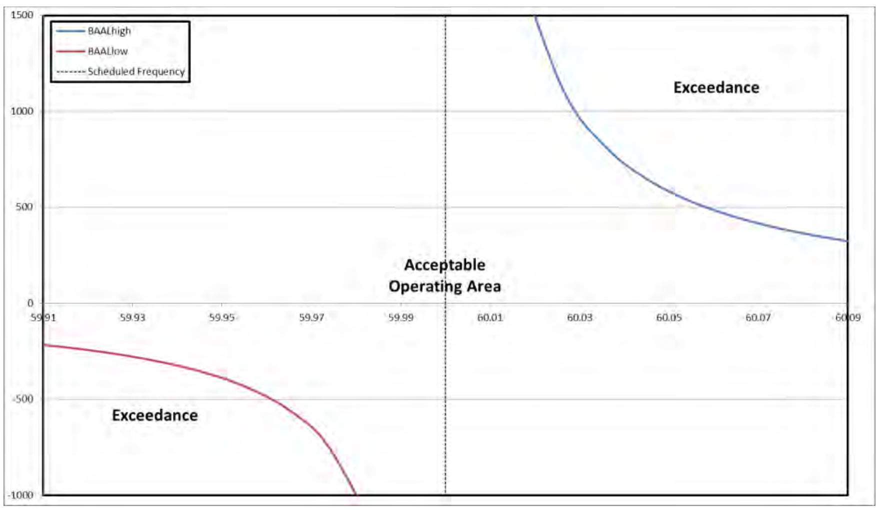

Figure 3.4: Acceptable Operating Area and the BAAL limit exceedance area

As a BA is operating and managing its ACE, the clock-minute averages of ACE are being evaluated against the BAAL limits.

CPS1 Equivalent Limit Derivation

BAAL is mathematically related to CPS1 as shown below:

- By definition; CF = (RACE/(-10B) *(F_A - F_S))/ ($\varepsilon_1{}^2$), and CPS1 = 2-CF
- Substituting for CF; CPS1 = 2-(RACE/(-10B) *(F_A - F_S))/ ($\varepsilon_1{}^2$))
- Regrouping terms; CPS1 = 2 - RACE * ((F_A - F_S)/ (-10B* $\varepsilon_1{}^2$))
- Substituting BAAL for RACE; CPS1 = 2 - 9 * (-10B* $\varepsilon_1{}^2$) / (F_A - F_S) * ((F_A - F_S)/(-10B* $\varepsilon_1{}^2$))
- Cancelling out terms; CPS1 = 2 – 9= -7 = -700%

Therefore, a one-minute CPS1 score more negative than -700% will equate to a BAAL exceedance for that one-minute period.

The minimum acceptable time frame for continuous BAAL minute exceedances shall not continue for greater than thirty minutes.

Quick Review

- CPS1 assigns each BA a share of the responsibility for control of Interconnection frequency.
- CPS1 is a yearly (i.e., rolling twelve month) standard that measures impact on frequency error with a 100% minimum allowable score.
- BAAL is a 30-minute standard intended to bind a BAs real-time impact on frequency.

Chapter 4: Tertiary Control

Tertiary Control generally follows disturbances and reserve deployment to reestablish resources for future contingencies. Reserve deployment and reserve restoration following a disturbance are common types of Tertiary Control. See the Operating Reserve Management Reliability Guideline for more information.

Understanding Reserves

There is often confusion when operators and planners talk about reserves. One major reason for misunderstanding is a lack of common definitions; NERC's definitions have changed over time. In addition, most NERC Regions developed their own definitions. Capacity obligations have historically been the purview of state and provincial regulatory bodies, meaning that there are many different expectations and obligations across North America.

In order to foster discussion and develop a more uniform understanding of the reserve data, the following definitions are provided in this reference. Refer to **Figure 4.1** to better understand the definitions.

Definitions:

(Capitalized terms are taken from NERC Glossary and lower case are not.)

Contingency Reserve: The provision of capacity deployed by the BA to meet respond to a Balancing Contingency Event and other contingency requirements (such as Energy Emergency Alerts as specified in the associated NERC Standards). This is the left column of Operating Reserves in Figure 4.1

frequency-responsive reserve: On-line generation with headroom that has been tested and verified to be capable of providing droop as described in the Primary Frequency Response guideline. Variable load that mirrors governor droop and dead-band may also be considered frequency responsive reserve.

Interruptible Load: Demand that the end-use customer makes available to its Load-Serving Entity via contract or agreement for curtailment that can be interrupted within 10 minutes.

Operating Reserve: That capability above firm system demand required to provide for regulation, load forecasting error, equipment forced and scheduled outages, and local area protection.

Operating Reserve–Spinning: Generation synchronized to the system and fully available to serve load within the Disturbance Recovery Period following the contingency event or Load fully removable from the system within the Disturbance Recovery Period following the contingency event deployable in 10 minutes.

Operating Reserve Supplemental: Generation (synchronized or capable of being synchronized to the system) that is fully available to serve load within the Disturbance Recovery Period following the contingency event or Load fully removable from the system within the Disturbance Recovery Period following the contingency event that can be removed from the system, within 10 minutes.

planning reserve: The difference between a BA's expected annual peak capability and its expected annual peak demand expressed as a percentage of the annual peak demand.

Regulating Reserve: An amount of Operating Reserve – Spinning responsive to Automatic Generation Control, which is sufficient to provide normal regulating margin.

replacement reserve: NOTE: Each NERC Region sets times for reserve restoration, typically in the 60–90-minute range. The NERC default contingency reserve restoration period is 90 minutes after the disturbance recovery period.

Supplemental Reserve Service: Provides additional capacity from electricity generators that can be used to respond to a contingency within a short period, usually ten minutes. An ancillary service identified in FERC Order 888 as necessary to affect a transfer of electricity between purchasing and selling entities. This is effectively FERC's equivalent to NERC's Operating Reserve.

Much like parts kept in a storeroom, reserves are meant to be used when the need arises. Reserves can be low for short periods of time due to plant equipment problems and unit trips and can also be misstated

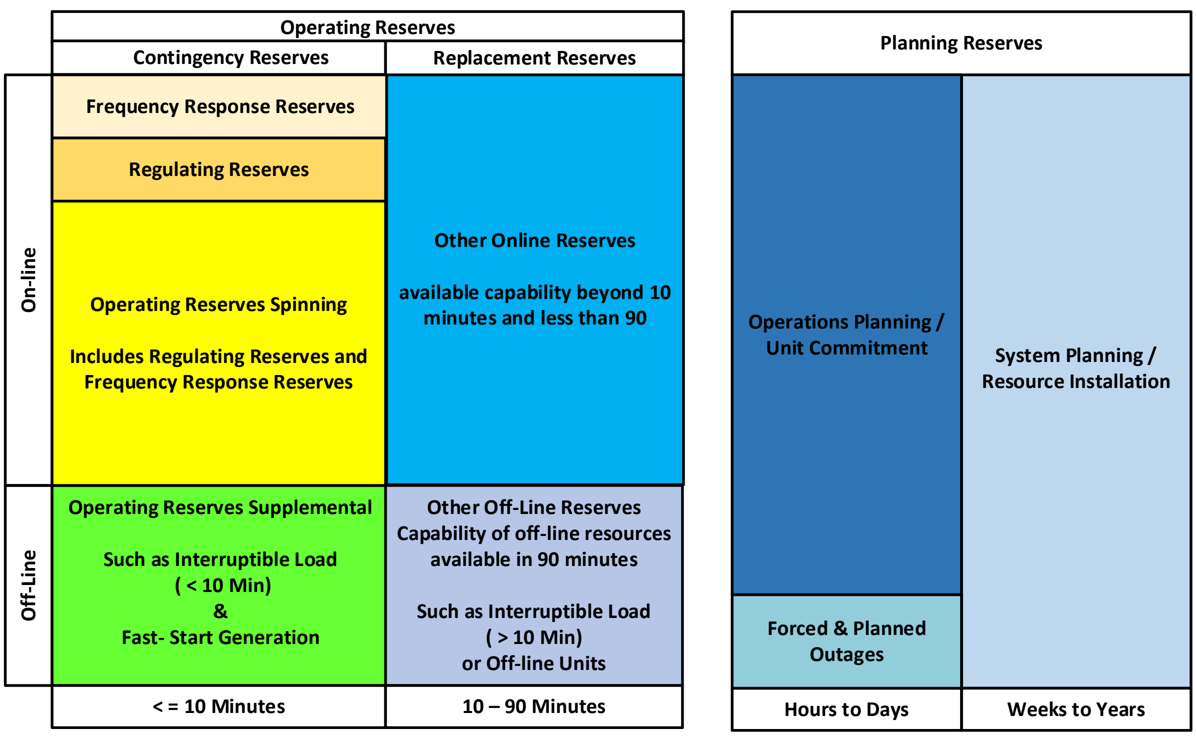

Figure 4.1: Reserves Continuum

Chapter 5: Time Control and Inadvertent Interchange

Background

There is a strong interrelationship between control of time error and Inadvertent Interchange (aka. "inadvertent"). Time error occurs when one or more BAs has imprecise control or large resource losses occur, causing average actual frequency to deviate from scheduled frequency. The bias term in the ACE equation of the remaining BAs causes control actions that result in flows between BAAs in the opposite direction. The net accumulation of all these interchange errors is referred to as Inadvertent Interchange. Inadvertent interchange represents the amount by which actual flows between BAAs and the remainder of the Interconnection differs from the intended or scheduled flows.

Time Control

As noted earlier, frequency control and balancing control are not perfect. There will always be some errors in tie-line meters. Due to load and generation variation, net ACE in an Interconnection cannot be maintained at zero. This means that frequency will vary from 60 Hz over time.

An Interconnection may have a time control process to maintain the long-term average frequency at 60 Hz. While there are some differences in process, each Interconnection that exercises time control designates an RC as a "time monitor" to coordinate time control.

Time error corrections are initiated when long-term average frequency drifts from 60 Hz. In the EI, a 0.02Hz offset to scheduled frequency corrects 1.2 seconds on the clock for each hour of the time error correction, provided the offset scheduled frequency is achieved.

There has been an ongoing debate on the need for time error corrections. The numbers of time error corrections do provide a benchmark for the quality of frequency control and provide an early warning of chronic balancing problems. While the value of time control is debatable from a reliability perspective, nobody can say with assurance who or what would be impacted if NERC and NAESB halted the practice of manual time error corrections. This practice was removed from the standards in 2017.

Inadvertent Interchange

Inadvertent interchange is net imbalance of energy between a BA and the Interconnection. The formula for inadvertent interchange is:

- $NI_I = NI_A - NI_S$

where,

NI_A is net actual interchange. It is the algebraic sum of the hourly integrated energy on a BAs tie lines. Net actual interchange is positive for power leaving the system and negative for power entering.

NI_S is net scheduled interchange. It is defined as the mutually prearranged net energy to be delivered or received on a BAs tie lines. Net scheduled interchange is positive for power scheduled to be delivered from the system and negative for power scheduled to be received into the system.

Inadvertent interchange and can be divided into two categories, described below.

Primary Inadvertent

Primary inadvertent interchange is caused by problems or action from within a given BA. Primary inadvertent interchange occurs due to the following:

- Error in scheduled interchange
  - Improper entry of data (time, amount, direction, duration, etc.…)
  - Improper update in real-time (TLR miscommunication etc.…)
  - Ramp procedures
  - Miscellaneous (phantom schedules, selling off the ties, etc.…)
- Error in actual interchange (meter error)
  - Loss of telemetry
  - Differences between real-time power (MW, for ACE), and energy (MWh), integrated values
- Control error or offset
  - Load volatility and unpredictability
  - Generation outages
  - Generation uninstructed deviations
  - Physical rate-of-change-of-production limitations
  - Deliberate control offset (i.e. unilateral payback) to reduce inadvertent energy balances

Hourly primary inadvertent can be calculated for each BA by using the following formula:

$(PII_{hourly}) = (1\text{-}Y) * (II_{actual} - Bi * \Delta TE/6)$

- PII_{hourly} is the BAs primary inadvertent for an operating hour expressed in MWh
- Y is the ratio between a BAs frequency bias setting and the sum of all BAs frequency bias setting within an Interconnection
- Bi is the BAs frequency bias
- ΔTE is the change in time error within the Interconnection that occurred during the operating hour

Secondary Inadvertent

Balancing problems external to a BA will cause off-schedule frequency. If frequency is low, the bias term of the ACE equation will cause a BA to slightly over-generate after initial effects, such as governor response and load damping, stabilize frequency. Conversely, if frequency is high, the bias term of the ACE equation will cause slight under generation. This intentional outflow or inflow to stabilize frequency due to problems outside the BA causes deviation from the schedule and is called secondary inadvertent interchange.

Hourly secondary inadvertent can be derived by subtracting a BA's hourly primary inadvertent from their hourly total inadvertent.

Quick Review: If one or more BAs have a control problem, it could result in a large primary inadvertent interchange. This may also cause off-nominal frequency, potentially spreading Secondary inadvertent interchange to the other BAs. The off-normal frequency then results in accumulated time error, potentially triggering time error corrections.

Chapter 6: Frequency Correction and Intervention

Background

There are several requirements in NERC reliability standards that tell the BA, Transmission Operator, and RC to monitor and control frequency. The standards do not provide specific guidance on what is normal frequency and under what conditions the operator should intervene. The trigger points below are designed for the EI. There may be differences in the other Interconnections based on their field trial experience.

As noted earlier in this document, this information is provided for guidance and understanding. It should not be used for compliance purposes and does not establish new requirements or obligations.

The BAAL is the ACE-frequency combination equivalent to instantaneous CPS1 of -700%. In general, if one or more of the RC's BAs is beyond the BAAL for more than 15 minutes, the RC should contact the BA to determine the underlying cause. As frequency diverges more from 60 Hz, the RC and BA should be more aggressive in their actions.

The primary responsibility of the RCs is frequency protection. Suggested actions are outlined below.

1. Identify BAs within your area beyond BAAL. Direct correction and log. RCs to notify BAs.
2. Call Other RCs, communicate problem if known. Search for cause if none reported. Notify time monitor of findings. Time monitor to log. Direct BAs beyond BAAL to correct ACE.
3. Direct all BAs with ACE hurting frequency to correct. Time monitor to notify RS after the fact.
4. Evaluate whether still interconnected. Direct emergency action.

Revision History

Date	Version Number	Reason/Comments
4-5-2011	1.0	Initial Version
9-29-2020	2.0	Resources Subcommittee Review

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NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

~~BALANCING AND FREQUENCY CONTROL~~

~~A Technical Document~~

~~Prepared by the NERC Resources Subcommittee~~

~~Chapter 1~~
~~Chapter 2~~
~~Chapter 3~~
~~Chapter 4~~
~~Chapter 5~~
~~Chapter 6~~
~~Chapter 7~~
~~Chapter 8~~

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Balancing and Frequency Control

Reference Document

Prepared by the NERC Resources Subcommittee

September 29, 2020

Table of Contents

Preface

Electricity is a key component of the fabric of modern society and the Electric Reliability Organization (ERO) Enterprise serves to strengthen that fabric. The vision for the ERO Enterprise, which is comprised of the North American Electric Reliability Corporation (NERC) and the six Regional Entities (REs), is a highly reliable and secure North American bulk power system (BPS). Our mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid.

Reliability | Resilience | Security
Because nearly 400 million citizens in North America are counting on us

The North American BPS is divided into six RE boundaries as shown in the map and corresponding table below. The multicolored area denotes overlap as some load-serving entities participate in one Region while associated Transmission Owners/Operators participate in another.

The Six Regional Entities	
MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
Texas RE	Texas Reliability Entity
WECC	Western Electricity Coordinating Council

Introduction

Background

The NERC Resources Subcommittee (RS) drafted this reference document at the request of the NERC Operating Committee as part of a series on operating and planning reliability concepts. The document covers balancing and frequency control concepts, issues, and recommendations. Send questions and suggestions for changes and additions to balancing@nerc.com.

Note to Trainers

Trainers are encouraged to develop and share materials based on this reference. The ~~NERC Resources Subcommittee~~RS will post supporting information ~~at:~~on the RS website.[1]

Disclaimer

This document is intended to explain the concepts and issues of balancing and frequency control. The goal is to provide ~~a better~~an understanding of the fundamentals. Nothing in this document is intended to be used for compliance purposes or to establish obligations.

[1] https://www.nerc.com/comm/OC/Pages/Resources-Subcommittee.aspx

~~Chapter 9~~Chapter 1: Balancing Fundamentals

Balancing and Frequency Control Basics

The power system of North America is divided into four major Interconnections~~.~~ (see **Figure 1.1**). These Interconnections can be thought of as ~~(frequency-)~~ independent electrical islands. The four Interconnections ~~are~~consist of the following:

- **Western**~~—~~: Generally everything west of the Rockies~~.~~
- **Texas**~~— Also known as~~: Operated by the Electric Reliability Council of Texas (ERCOT~~).~~)
- **Eastern**~~—~~: Generally everything east of the Rockies except Texas and Quebec~~.~~
- **Quebec**: Operated by Hydro Quebec TransEnergie

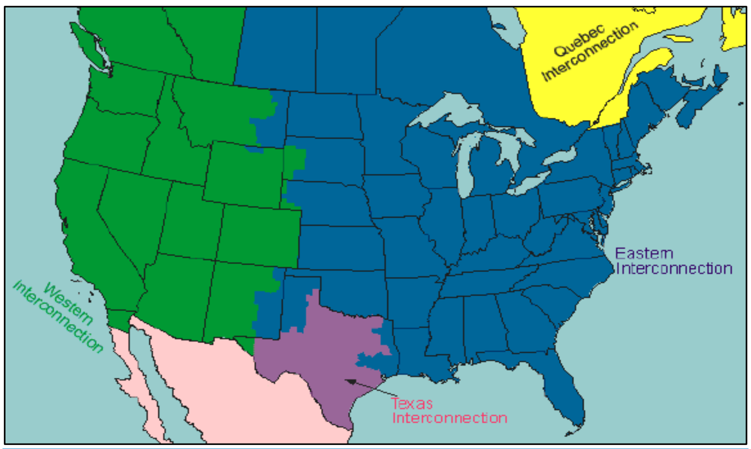


Figure 1.1: North American Interconnections

Each Interconnection ~~is actually~~ can be viewed as a single large machine~~, as~~ with every generator ~~within the island is~~ pulling ~~in tandem with the others~~together to supply electricity to all customers. This occurs as the ~~rotation of~~ electric generating units~~, nearly all~~ rotate (in ~~(~~steady-state) near synchronism. The "speed" (~~of rotation~~rotational speed) of the Interconnection is frequency~~,~~ measured in cycles per second, or Hertz (Hz). ~~If~~When the total Interconnection ~~generation~~supply exceeds customer demand, frequency increases beyond the ~~target~~scheduled value~~,~~ (typically 60 Hz[2]~~,~~) until energy balance is achieved. Conversely, ~~if~~when there is a temporary ~~generation~~supply deficiency, frequency declines until a balance between supply and demand is restored.

During normal operations it is typical for there to be small mismatches between total demand and total supply, so the frequency of each Interconnection varies above and below nominal on a continuous basis. Regardless of whether the variations are above or below scheduled frequency,

[2] Nominal frequency (termed "scheduled frequency") is sometimes intentionally offset by a small amount via a mechanism called time error corrections to correct for sustained periods of high or low frequency.

the supply-demand balance is ~~again restored at a point below the scheduled frequency. Balance is initially~~ restored ~~in each case~~ due to ~~load that varies with~~ frequency sensitive demands and ~~generator governors~~supply resources that change ~~generator~~ output in response to frequency changes. For example, some electric devices~~, such as~~ (e.g., electric motors~~,~~) use more energy if driven at a higher frequency and less at a lower frequency. Most generating units are also equipped with governors that cause the generator to inject more energy into the Interconnection when frequency is lower than nominal and slightly less energy when the frequency is higher than nominal.

~~Figure — North American Interconnections~~

~~Balancing~~Balancing Authorities (BAs) balance generation and load within their Balancing Authority Areas (BAAs) of ~~generation and load within~~ the Interconnections. See **Figure 1.2** ~~is handled by entities called Balancing Authorities.~~ for an example of BAAs across North America. The ~~Balancing Authorities~~BAs dispatch ~~generators~~generating resources in order to meet their ~~individual needs. Some Balancing Authorities~~BAA demand and manage the supply/demand balance. Some BAs also control ~~load~~demand to maintain the ~~load – generation~~supply/demand balance.

Figure 1.2: North American Balancing Authorities and Regions

~~There are over 100 Balancing Authorities of varying size in North America. Each Balancing Authority~~The number of BAs in an Interconnection varies; Texas and Quebec are single BA Interconnections while the Eastern and the Western are multi-BA Interconnections. Each BA in an

Interconnection is connected via high voltage transmission lines (called tie-lines) to neighboring ~~Balancing Authorities. Overseeing the Balancing Authorities are wide-area operators called Reliability Coordinators. The relationship between Reliability Coordinators and Balancing Authorities is similar to that between air traffic controllers and pilots.~~ BAs. The Reliability Coordinators (RCs) oversee the BA operations and coordination. BAs are responsible for the supply/demand balance within their BAA while RCs are responsible for the wide area health of the Interconnection.

Frequency ~~does not change~~will be constant in an Interconnection ~~as long as~~when there is a balance between ~~resources~~supply and ~~customer~~ demand ~~(~~, including various electrical losses~~).~~. This balance is depicted in **Figure 1.3**~~Figure 3a.~~.

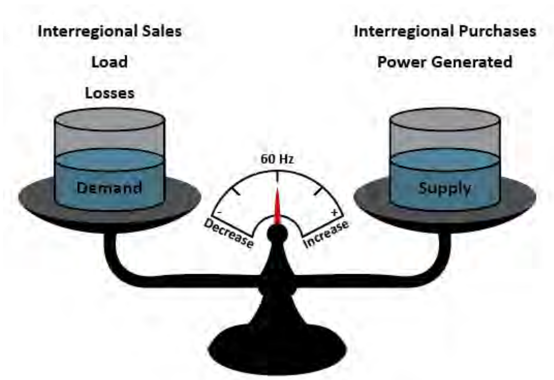


Figure 1.3~~3a —~~: Generation ~~/~~| Demand Balance

Each ~~generator~~supply resource embedded in an interconnected system has its own characteristics~~, which~~ (e.g., ramp rates, fuel supply, output controllability and sustainability). From a simplified viewpoint, a supply resource can be analogized to a water pump with storage and control~~,~~ as shown in **Figure 1.4**~~Figure 3b. Here,~~. In this example, the pump's output fills ~~a~~an open storage tank ~~(~~similar to a ~~steam drum~~swimming pool. The water depth in ~~a thermal-steam unit).~~ the tank needs to be controlled to within very tight limits: too much water accumulating will cause the pool to overflow, and too little water will cause other problems. The control valve ~~acts like an AGC input, changing~~changes average output to meet system demand~~.~~ in a manner analogous to automatic generation control (AGC). The surge tank on the final output is analogous to the rotational inertia of the generator.

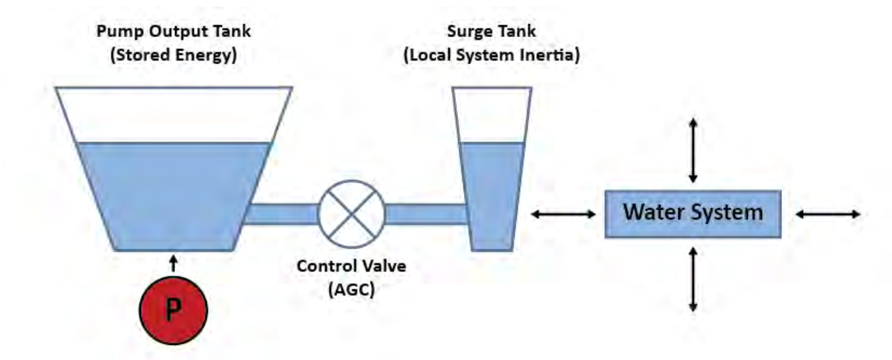


Figure 1.4~~3b~~: Generator ~~/~~| Pump Analogy

To understand how Interconnection frequency is ~~actually~~ controlled, it may help to visualize a traditional water utility~~,~~ that is composed of a delivery system, customers, and several ~~pumps~~pumping stations as depicted ~~above.~~ in **Figure 1.5**. If a municipality ~~operated~~operates its own system, it ~~would need~~needs sufficient pumps (~~generation~~supply) to maintain the water level in ~~a~~ the pumping stations' storage ~~tank~~tanks (frequency) to serve its customers. ~~If~~When demand ~~exceeded~~exceeds supply, the ~~level would~~water levels in the pumping station tanks will drop~~.~~ prompting the pumps to respond. Water level (frequency) is the primary parameter ~~to control~~ that must be controlled in an independent system.

In the early history of the power system, utilities quickly learned the benefits delivered in reliability and realized reduced expense associated with maintaining operating reserves ~~expense~~ by connecting to neighboring systems. In our water utility example, an independent utility must have ~~pumps~~pumping stations in standby that are equivalent to its largest ~~online~~on-line pump if it wants to maintain the water level~~.~~ in case there is a problem with the largest pumping station. However, if utilities are connected together via ~~pipelines (~~tie-lines~~)~~, reliability and economics are improved~~, both~~ because of the larger ~~storage capability~~ resource capacity of the combined system and the ability to share ~~pump~~ capacity when needed.

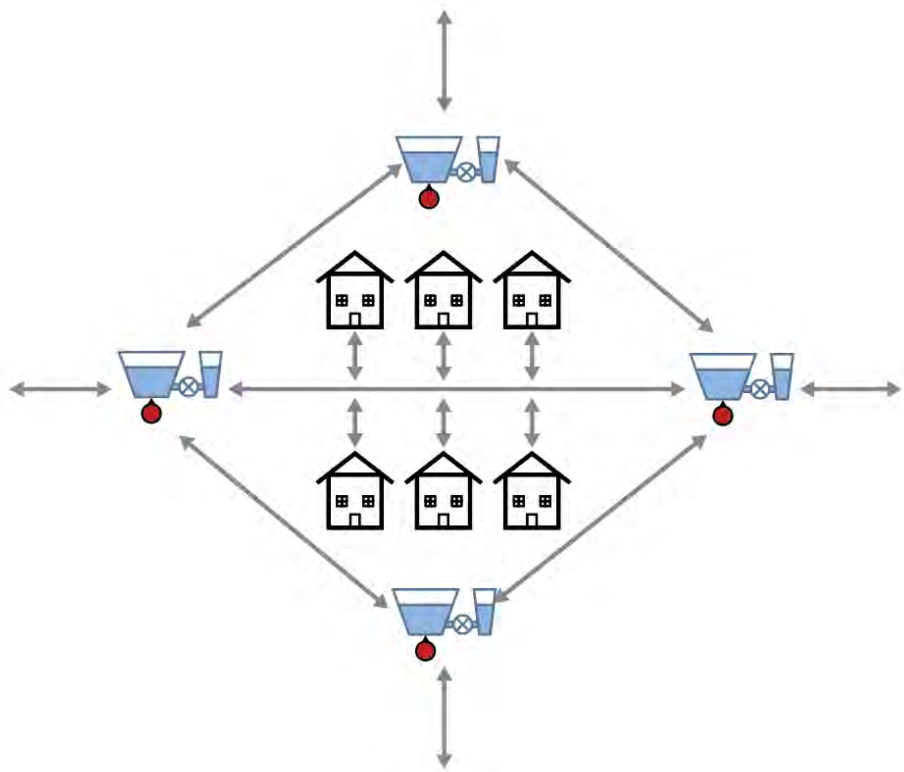


Figure 1:5~~— Balancing Authority~~: BA Analogy

Once the systems are interconnected, the ~~level (~~steady state frequency (i.e. water level) is the same throughout. If one ~~utility (Balancing Authority)~~BA in the electric grid loses a ~~pump,~~generating resource there ~~is~~may be a drop in ~~level, although~~frequency but it is ~~now much~~ less than in an independent system~~. The Balancing Authority~~ because the overall resource capacity of the interconnected system is much greater. The BA that needed ~~water (~~energy~~)~~ could purchase ~~output~~it from others. Purchasing and/or selling energy between BAs is known as Interchange.

~~Thus,~~ There are two inputs to the ~~Balancing Authorities'~~BAs control process:[3]~~:~~

- **Interchange Error**~~, which is~~: the net outflow or inflow compared to ~~what it is~~the scheduled ~~to be buying or selling.~~sales or purchases (The units of interchange error are in megawatts.)

[3] There are two control inputs in multi-BA Interconnections. Texas and Quebec are single BA Interconnections and need only control to frequency.

- **Frequency** ~~Bias, which is the Balancing Authority's~~**Error:** the difference between actual and nominal frequency (The units of frequency error are hertz.)

Frequency bias is used to translate the frequency error into megawatts. Frequency bias is the BAs obligation to provide or absorb energy to assist in ~~stabilizing~~maintaining frequency. In other words, if frequency goes low, each ~~Balancing Authority~~BA is asked to contribute a small amount of extra generation in proportion to its system's ~~established bias~~relative size.

Each ~~Balancing Authority~~BAA uses common meters on the tie-lines with its neighbors for control and accounting. ~~In other words,~~ There will be ~~a~~an agreed upon meter ~~on one end of~~ at each ~~tie-line~~BA boundary that both neighboring ~~Balancing Authorities~~BAs use ~~against which they control and~~to perform balancing operations and accounting. Thus, all ~~generators~~supply, load, and transmission lines in an Interconnection fall within the metered bounds of a ~~Balancing Authority.~~ BA.

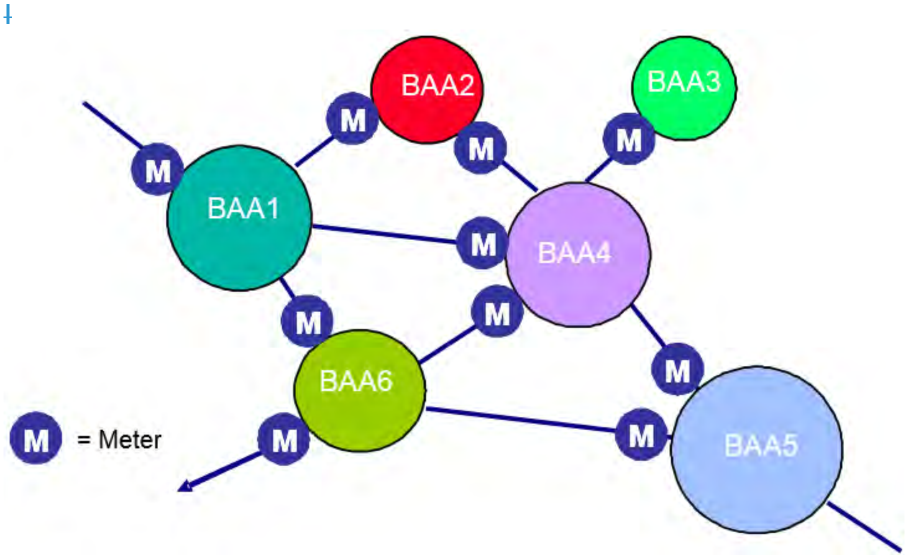


Figure 1:6~~—~~: Interconnected ~~Balancing Authorities~~BA Areas

If the ~~Balancing Authority~~BA is not buying or selling energy,[4]~~,~~ and its ~~generation~~supply is exactly equal to the ~~load~~demand and losses within its metered boundary~~, and interconnection frequency is exactly on schedule then~~ (BAA), the net of its tie line meters will be zero~~. If the Balancing Authority~~ (assuming that the frequency of the system is at nominal). If the BA chooses to buy energy~~, say~~ (e.g., 100 ~~Megawatts (MW),~~Megawatt hours (MWh)), it tells its control system to allow 100 MWh to flow in (by, for example, allowing 100 MW to flow in~~.~~ for one hour). Conversely, the seller will tell its control system to allow 100 MWh to flow out by allowing the corresponding

[4] In most cases, BA's do not buy and sell energy. Transactions now are arranged by wholesale marketing agents that represent load or generation within the BA.

100 MW to flow out~~.~~ for one hour. If all ~~Balancing Authorities~~BAs behave this way, the Interconnection remains in balance and frequency remains stable. ~~If an error in control (and a resulting imbalance) occurs, it will show up~~Variations in the supply/demand balance cause frequency to vary from its nominal value. Problems on the grid, such as congestion, equipment faults that dictate rapid unilateral adjustments of generation, loss of load, incorrect schedules, or poor control cause changes in frequency. Maintaining Interconnection frequency near its nominal value can therefore be thought of as a ~~change in frequency~~fundamental indicator of the health of the power system.

~~Customer~~ Demand and ~~generation~~supply are constantly changing within all ~~Balancing Authorities.~~ BAAs. This means ~~Balancing Authorities~~that a BA will usually have some unintentional outflow or inflow at any given instant. This mismatch in meeting a ~~Balancing Authority's~~BA's internal obligations, along with the small additional "bias" obligation to maintain frequency, is represented via a real-time value called Area Control Error (ACE), ~~estimated in~~with units of MW.

~~Dispatchers~~System operators at each ~~Balancing Authority~~BA fulfill their NERC obligations by monitoring ACE and keeping the value within limits that are generally proportional to ~~Balancing Authority~~BA size. This balancing is typically ~~is~~ accomplished through a combination of ~~computer-controlled adjustment~~adjustments of ~~generators, telephone calls to power plants and through~~supply resources, purchases and sales of electricity with other ~~Balancing Authorities, and possible emergency actions such as automatic or manual load shedding~~BAs, and possibly adjustments of demand.

Conceptually, ACE is to a ~~Balancing Authority~~BA what frequency is to the Interconnection. Over-generation makes ACE go positive and puts upward pressure on Interconnection frequency. A large negative ACE ~~causes~~can cause Interconnection frequency to drop. A highly variable~~,~~ or "noisy~~",~~," ACE tends to contribute to similarly "noisy" frequency. However, the effect of ACE on frequency depends on ~~whether~~how ACE is ~~coincident~~correlated (or anti-correlated) with frequency error. Over-frequency error tends to be made larger when ACE ~~is of the same sign as the error~~indicates over-generation, and is made smaller when ACE ~~is of~~ indicates under-generation. Under-frequency error has the opposite ~~sign to the frequency error.~~ relationship. This principle is captured in the way Control Performance Standard 1 (CPS1) measures performance.

~~Failure to maintain a balance between load and resources causes frequency to vary from its target value. Other problems on the grid, such as congestion or equipment faults which dictate rapid unilateral adjustments of generation or loss of load cause changes~~Accumulation of frequency error over time results in ~~frequency. Frequency can therefore be thought of as the pulse of the grid and a fundamental indicator of the health of the power system~~the Interconnection's time error. For better overall Interconnection performance, the Western Interconnection (WI) uses automatic time error correction (ATEC) that allows BAs to make incremental corrections that are caused by under/over performing ACE.

Control Continuum

Figure 1.7 demonstrates that Balancing and frequency control occur over a continuum of time using different resources~~, represented~~ that have some overlap in ~~.~~

timeframes of occurrence.

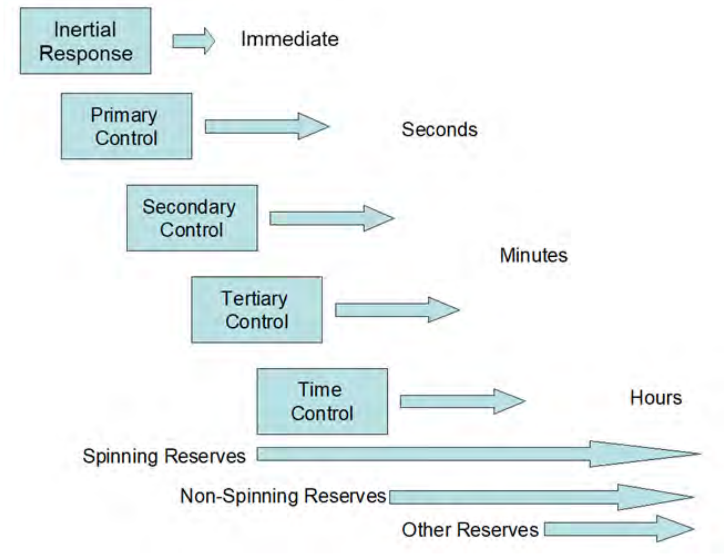


Figure 1.7: Control Continuum

A primary focus of the controls in the control continuum is to maintain nominal frequency under all conditions. One common operating condition is the loss of a (sometimes large) generator. This causes the frequency to drop which then requires the various pieces of the control continuum to recover the frequency to nominal. A stylized example is shown in figure 1.8. The frequency event is somewhat arbitrarily divided into 4 phases: the Arresting Period (when frequency decline is arrested), the Rebound Period (where frequency begins to recover towards nominal), the Stabilizing period (where frequency is stabilized), and the Recovery period (where frequency is recovered to nominal).

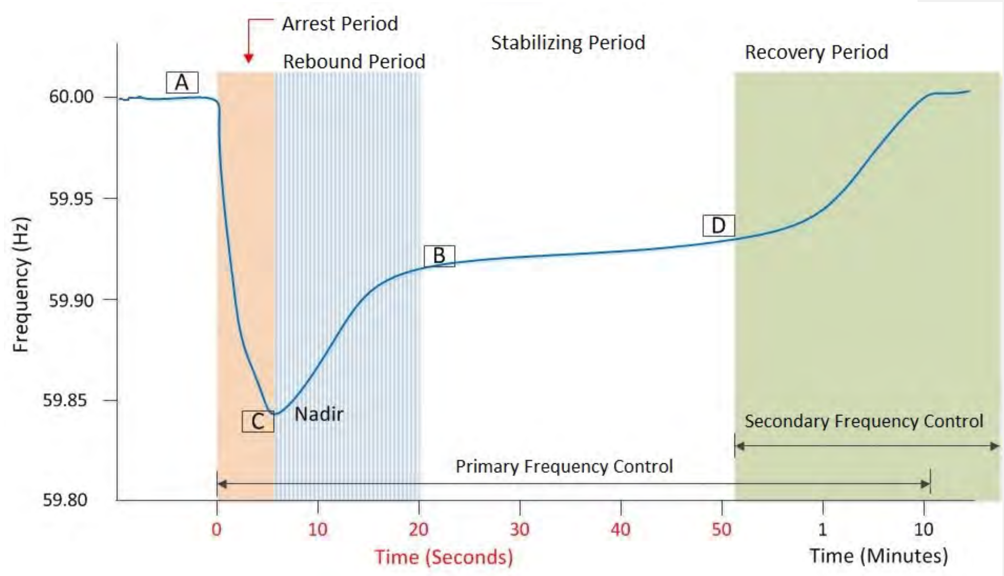


Figure 1.8: Typical Frequency Trend for the Loss of a Generating Resource

Four points of particular interest are shown in Figure 1.8: Point A is defined as the pre-disturbance frequency; Point C or Nadir is the maximum deviation due to loss of resource; Point B is defined as the stabilizing frequency and; Point D is the time the contingent BA begins the recovery from the loss of resource.

Inertial Control

Inertial control is more of an effect than an actual control since it is governed by physical principles for most resources and emulated by others. The rotating mass in a typical generator combined with the speed at which it is rotating creates a large amount of stored energy. If a decelerating force is applied (e.g., a large drop in system frequency), energy is transferred from the rotating mass and into the system. One analogy is that of a bicycle wheel and brake. If the wheel is first set spinning and then the brake is applied, the energy from the wheel flows into the braking surfaces. The contact surfaces of the brake will heat up due to the transformation of energy from the wheel into heat.

This is the same principle for the inertia effect in the power system. A sudden increase in the braking force is applied by a decrease in the amount of energy being injected into the system (e.g., losing a large generator or addition of a large load). When the mismatch between injected and consumed energy occurs, energy flows from the rotating masses of the connected resources into the power system. The propagation of this effect across an Interconnection happens within a handful of seconds.

Resources that are not directly coupled via an alternating current connection to the power system (e.g., inverter-based resources) are not typically governed by the same physical principles and therefore might not possess inertia per se from the perspective of the power system. Instead, inertia can be emulated to varying degrees of success by using sensing and control.

Primary Control

Primary control is more commonly known as primary frequency response (PFR). PFR also includes inertial response described under inertial control above as well other types of frequency response actions, as described in the Primary Frequency ~~Response. Frequency Response occurs~~Control Guideline.[5] PFR is autonomous; it does not require external inputs and begins to occur within the first few seconds following a change in system frequency (disturbance) to stabilize the Interconnection. Frequency response is provided by the following:

- **Governor Action**~~. Governors on generators~~**:** Resource governors are ~~similar to~~like cruise ~~control on your car.~~ controls for cars. They sense ~~a change~~changes in ~~speed~~local system frequency and adjust the energy ~~input into~~output of the ~~generators' prime mover.~~ resource to counteract that change. Some resources do not have "governors" per se but instead can emulate governor action to varying degrees of success by using sensing and control actions.
- ~~Load.~~ **Demand Response:** The speed of directly-connected motors in an Interconnection will change in direct proportion to frequency~~.~~ changes. As frequency drops, motors will turn slower and ~~draw~~consume less energy.

  Rapid reduction of system load may also be ~~effected~~affected by automatic operation of under-frequency relays which interrupt ~~pre-defined~~predefined loads within fractions of seconds or within seconds of frequency reaching a predetermined value. Such reduction of load may be contractually represented as interruptible load or may be provided in the form of resources procured as reliability ~~(~~or Ancillary~~)~~ services. As a safety net, percentages of firm load may be dropped by under-frequency load shedding programs to ensure stabilization of the systems under severe disturbance scenarios.
  ~~These load characteristics assist in stabilizing frequency following a disturbance.~~

The most common type of a frequency disturbance in an Interconnection is associated with the loss of a generator, ~~which causes~~causing a decline in frequency~~.~~; this happens on a daily basis and must be considered. In general, the amount of ~~(~~frequency-responsive~~) Spinning Reserve~~ synchronized and unloaded generation with headroom in an Interconnection will ~~determine~~directly influence the amount of available frequency response~~.~~ because this is the amount of supply that is connected, ready, and able to immediately increase output when needed.

It is important to ~~remember~~note that primary control will not return frequency to ~~normal~~nominal, but only arrest and stabilize it. Other control components are used to restore frequency to ~~normal~~nominal.

[5] PFC (v 2.0 approved by the Operating Committee 6/4/2019)

Operating Tip: Frequency response is particularly important during disturbances and islanding situations. System operators should be aware of their frequency responsive resources. Blackstart units must be able to autonomously participate in frequency control; this is especially important during system restoration.

Secondary Control

Secondary control typically includes the balancing services deployed in the “minutes” time frame. However, some resources ~~however, such as~~(e.g., hydroelectric generation~~,~~, or fast electrical storage) can respond faster in many cases. ~~This~~Secondary control is accomplished using the ~~Balancing Authority’s~~BA’s supervisory control ~~computer~~and data acquisition (SCADA) and energy management systems (EMSs)[6], and the manual actions taken by the dispatcher to provide additional adjustments. Secondary control also includes some initial reserve deployment for disturbances.

In short, secondary control maintains the minute-to-minute balance throughout the day and is used to ~~restore~~keep ACE within CPS bounds and thereby maintain Interconnection frequency close to its scheduled value~~, –~~ (usually 60 Hz~~,~~) following a disturbance. Secondary control is provided by both Operating Reserve – Spinning and ~~Non-Spinning Reserves.~~Supplemental. During frequency disturbances, secondary control returns the frequency to nominal once primary control has arrested and stabilized it.

The most common means of exercising secondary control is through an EMS’s AGC (Automatic Generation Control~~ (AGC). ~~). AGC operates in conjunction with ~~Supervisory Control and Data Acquisition (~~SCADA~~)~~ systems~~. –~~; SCADA gathers information about an electric power system, ~~in particular~~particularly system frequency, generator outputs, and actual interchange between the ~~system~~BA and ~~adjacent systems.~~ its neighbors. Using system frequency and net actual interchange~~, plus~~ and knowledge of net scheduled interchange and upcoming changes, it is possible to determine the ~~system’s~~BA’s energy balance ~~with its interconnection in near-real-time.~~ (i.e., its ACE) within its Interconnection. Most SCADA systems poll data points sequentially for electric system data, with a typical periodicity of ~~four~~two to six seconds. Because of this, data is naturally slightly out of perfect time sync, but is of sufficient quality to permit balancing and good frequency control.

AGC computes a ~~Balancing Area’s Area Control Error (~~BAA’s ACE~~, further described below)~~ from interchange and frequency data. ACE ~~tells~~indicates whether a system is in balance or ~~needs to make adjustments~~is in need of an adjustment to generation~~. –~~ resources. AGC software~~, while observing ACE, automatically determines the most economical output for generating resources while observing energy balance and frequency~~ generally sends signals that cause resources performing secondary control~~, usually by sending setpoints~~ to move to ~~generators.~~ oppose the ACE. Some ~~generators also~~AGC systems use ~~pulse accumulator methodology to derive a setpoint from~~ pulses ~~sent by AGC, but these have become less common over time~~for raise/lower signals while other AGC systems use MW set points.

The degree of success of AGC in complying with balancing and frequency control is manifested in a ~~Balancing Area’s~~BA’s control performance ~~compliance~~ statistics~~, which~~ that are described in greater detail later in this document.

[6] Terms most often associated with this are “load-frequency control” or “automatic generation control”

Tertiary Control

Tertiary Control encompasses actions taken to get resources in place to handle current and future contingencies. Reserve deployment and reserve restoration following a disturbance are common types of Tertiary Control.

Time Control

Frequency and balancing control are not perfect. There will always be occasional errors in tie-line meters~~,~~ whether due to instrument transducer inaccuracy, problems with SCADA hardware or software, or communications errors. Due to these errors~~, plus~~ and normal load and generation variation, ~~net~~ ACE in an Interconnection cannot be maintained at zero. In fact, the average value of ACE over many time frames is non-zero. ACE must be managed such that its magnitude is relatively small. There is no operational reason to force ACE to be an independently randomly distributed variable. This means that frequency ~~cannot always be~~ is never maintained at exactly ~~60Hz, and that~~60 Hz for any appreciable length of time and average frequency over time usually is not exactly 60 Hz.

Each Interconnection has a time control process that can be used to maintain the long-term average frequency at 60 Hz. While there are some differences in process, each Interconnection designates a ~~Reliability Coordinator~~RC as a “time monitor” to provide Time Control.

The time monitor compares a clock driven off Interconnection frequency against ~~“”~~the “official time”[7] provided by the National Institute of Standards and Technology ~~(NIST).~~ . If average frequency drifts, it creates a Time Error between these two clocks. ~~In the Western~~The Quebec Interconnection~~, time-error-correction is done~~ (QI) and Texas Interconnection (TI) operate so that Time Error is automatically minimized or eliminated while the WI operates to automatically mitigate accumulated Time Error through ~~software maintained by the Time Monitor known as Automatic Time Error Correction. In the other interconnections,~~its ATEC. If the Time Error gets too large In the EI and WI, the Time Monitor ~~will~~may notify ~~Balancing Authorities~~BAs in the Interconnection to manually correct the situation.

For example, if frequency has been running 2 mHz high (i.e., 60.~~002Hz~~002 Hz), a clock using Interconnection frequency as a reference will gain 1.2 seconds in a 10-hour interval ~~(i.e., 60.002 Hz-60.000 Hz)/60 Hz * 10 hrs * 3600 s/hr = 1.2 s).~~ :

$$\frac{(60.002\text{ Hz} - 60.000\text{ Hz})}{60\,Hz} * 10\,hr * 3600\frac{sec}{hr} = 1.2\,sec$$

If the Time Error accumulates to a ~~pre-determined~~predetermined initiation value (~~for this example,~~e.g., +10 ~~seconds~~sec in the Eastern Interconnection~~),~~ (EI)) the Time Monitor will send notices for all ~~Balancing Authorities~~BAs in the Interconnection to offset their scheduled frequency by -0.~~02Hz~~02 Hz (Scheduled Frequency = 59.~~98Hz).~~ 98 Hz). This offset, known as Time Error Correction, will be maintained until Time Error has decreased below the termination threshold (~~which would be +6 seconds for our example in the eastern interconnection).~~ e.g., +6 sec).

[7] The Official NIST US Time: https://www.time.gov/

A positive offset (i.e., Scheduled Frequency = 60.~~02Hz~~02 Hz) would be used if average frequency was low and Time Error reached its initiation value ~~(~~ (e.g., -10 seconds ~~for the Eastern~~). Manual time error corrections are no longer required by standards but each Interconnection~~).~~ may elect to perform manual time error correction. See the *NERC Time Monitoring Reference Document (Version 4)* on manual time error correction for additional information.[8]

Control Continuum

Table 1.1~~Summary Table 1~~ summarizes the discussion on the control continuum and identifies the service that provides the control and the NERC standard that addresses the adequacy of the service.

~~Table Control Continuum Summary~~

Current issues, good practices, and recommendations on balancing and frequency control are discussed later.

Table 1.1: Control Continuum Summary

Control	Ancillary Service/ERS	Timeframe	NERC Measurement
Inertial Control	Inertial Control	0–12 Seconds	N/A
Primary Control	Frequency Response	10–60 Seconds	FRM
Secondary Control	Regulation	1–10 Minutes	CPS1 – DCS - BAAL
Tertiary Control	Imbalance/Reserves	10 Minutes–Hours	BAAL - DCS
Time Control	Time Error Correction	Hours	N/A

[8] NAESB WEQ Manual Time Error Correction Standards - WEQBPS – 004-000: https://www.naesb.org//pdf2/weq_bklet_011505_tec_mc.pdf

Area Control Error (ACE) Review

Commented [sjr1]: This has already been previously defined, nonetheless Troy did you want to see it again here?

The ~~Control Performance Standards~~CPSs are based on measures that limit the magnitude and direction of the ~~Balancing Authority's Area Control Error (~~BAs Reporting ACE~~)~~. The equation for Reporting ACE is as follows:

- Reporting ACE = (NI_A – NI_S) – 10B (F_A – F_S) – I_{ME}

~~Where:~~

- Reporting ACE (WI) = (NI_A – NI_S) – 10B (F_A – F_S) – I_{ME} +I_{ATEC}

where:

- NI_A is Actual Net Interchange, ~~Actual~~
- NI_S is Scheduled Net Interchange, ~~Scheduled~~
- B is ~~Balancing Authority~~BA Bias Setting
  F_A is ~~Frequency,~~ Actual
- ~~F_S is~~ Frequency,
- F_S is Scheduled Frequency,
- I_{ME} is Interchange (tie line) Metering Error
- I_{ATEC} is ATEC (WI only)

NI_A is the algebraic sum of tie line flows between the ~~Balancing Authority~~BA and the Interconnection. NI_S is the net of all scheduled transactions with other ~~Balancing Authorities.~~ BAs. In most areas, flow into a ~~Balancing Authority~~BA is defined as negative~~.~~; flow out is positive.

The ~~combination of the two~~difference between net actual interchange and net scheduled interchange (N_{IA} - N_{IS}) represents the ~~ACE~~ so-called "inadvertent" error associated with meeting schedules~~,~~ without consideration for frequency error or bias~~, and if~~. If it is used by itself for control, it would be referred to as "flat tie line" control.

The term 10B (F_A - F_S) is the ~~Balancing Authority's~~BAs obligation to support frequency. B is the ~~Balancing Authority's~~BAs frequency bias stated in MW/0.~~1Hz~~1 Hz (B's sign is negative). The "10" converts the bias setting to MW/Hz. F_S is normally 60 Hz but may be offset ± 0.02 Hz for time error corrections. Control using "10B (F_A - F_S)" by itself is called "flat frequency" control.

I_{ME} is a correction factor for meter error. The meters that measure instantaneous[9] flow are not always as accurate as the hourly meters on tie lines. ~~Balancing Authorities~~BAs are expected to check the error between the integrated instantaneous and the hourly meter readings. If there is a metering error, a value should be added to compensate for the estimated error~~.~~; this value is I_{ME}. This term should normally be very small or zero.

I_{ATEC} is an ACE offsetting term for automatic timer error correction in the WI. BAs correct for any delta Time Error that they are responsible for each hour.

[9] Instantaneous, as used herein, refers to measurements that are as close to real-time as is possible within the limits of data acquisition and conversion equipment.

Reporting ACE is calculated in Real-time, at least as frequently as every six seconds, by the responsible entity's Energy Management System (EMS) predominantly based on source data automatically collected by that system. Also, the data must be updated at least every six seconds for continuous scan telemetry and updated as needed for report-by-exception telemetry. See the Integrating Reporting ACE Guideline for more detail on the components of ACE and the calculation frequency.

Here is a simple example~~. ~~: Assume a ~~Balancing Authority~~BA with a bias of -50 MW~~ / ~~/0.1 Hz is purchasing 300 MW. The actual flow into the ~~Balancing Authority~~BA is 310 MW. Frequency is 60.01 Hz. Assume no time correction~~ or~~, metering error~~. — ~~ or ATEC.

- ACE = (-310 ~~– –~~ – -300) – 10~~* (-~~*(-50) * (60.01 – 60.00) = (-10) – (-5) = -5 MW.

The ~~Balancing Authority~~BA should be generating 5 MW more to meet its obligation to the Interconnection. Even though it may appear counterintuitive to increase generation when frequency is high, the reason is that this ~~Balancing Area~~BA is more energy-deficient at this moment (-10 MW) than its bias obligation to reduce frequency (-5 MW). The decision on when or if to correct the -5 MW ACE would be driven by ~~control performance standard (~~CPS~~)~~ compliance. A distinction can be drawn between reporting ACE, which measures the effect of a BA on the Interconnection, and Control ACE. At any given time, a BA might use a control ACE that is different from reporting ACE because AGC resources respond to control ACE, and this difference might be used, for example, to cause AGC resources to assist in "paying down" accumulated inadvertent energy or some other purpose.[10]

Bias (B) vs. Frequency Response (Beta)

There is often confusion in the industry when discussing frequency bias and frequency response. Even though there are similarities between the two terms, frequency bias (B) is not the same as frequency response (β).

Frequency response, defined in the NERC Glossary,[11]~~,~~ is the mathematical expression of the net change in a ~~Balancing Area's~~BA's net actual interchange for a change in Interconnection frequency. It is a fundamental reliability ~~service~~characteristic provided by a combination of governor action and ~~load~~demand response. Frequency response represents the actual MW ~~primary response~~ contribution by inertial control and primary control to stabilize frequency following a disturbance.

Bias is an approximation of β used in the ACE equation. Bias ~~prevents~~(B) is designed to prevent AGC withdrawal of frequency support following a disturbance. If B and β were exactly equal, a ~~Balancing Authority~~BA would see no change in ACE following a frequency decline~~,~~ even though it provided a MW contribution to stabilize frequency.

Bias and frequency response are both expressed as negative numbers. In other words, as frequency drops, MW output (β) or desired output (B) increases. Both are measured in MW/0.1 Hz

[10] Bilateral or Unilateral payback of inadvertent is not allowed in the WI. ATEC is used by BAs in the WI to control primary inadvertent accumulation while automatically correcting time error.

[11] Select from list found at: https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf

Important Note: When people talk about frequency response and bias, they often discuss them as positive values (e.g., as “our bias is 50MW/0.1Hz”). Frequency response and bias are actually negative values.

Early research (Cohn) found that it is better to be over-biased (i.e., absolute value of B greater than the absolute value of β) than to be under-biased.

~~Chapter 10Detailed Discussion~~

~~Chapter 11~~Chapter 2: Primary Control~~ (Frequency Response)~~

Background

Primary control relates to the ~~supply and load responses, including~~response to a frequency deviation by generator governors (aka. speed controls) and inertia that helps stabilize Interconnection frequency whenever there is a change in load-resource balance. Primary control is provided in the first few seconds following a frequency change and is maintained until it is replaced by AGC action~~.~~ (secondary control). Frequency response (or Beta~~)~~), which also includes rotational inertia response from resources and load response from frequency dependent loads, is the more ~~common~~commonly used term for primary control. Beta (β) is defined by the total of all initial responses to a frequency excursion.

Figure 2.1 shows a trace of the ~~Western Interconnection's~~WI's frequency ~~resulting~~that resulted from a generating unit trip. The graph plots frequency from 5 seconds prior to the loss of a large generator until 60 seconds thereafter.

NERC references three key events to describe such a disturbance. ~~Point~~Value A is the pre-disturbance frequency, typically close to 60 Hz. Point C is the maximum excursion point, commonly referred to as the Nadir, which ~~in this WECC example~~ occurs about ~~5–8~~10 seconds after the loss of generation~~. Point~~ in this WI example. Value B is the settling frequency of the Interconnection.

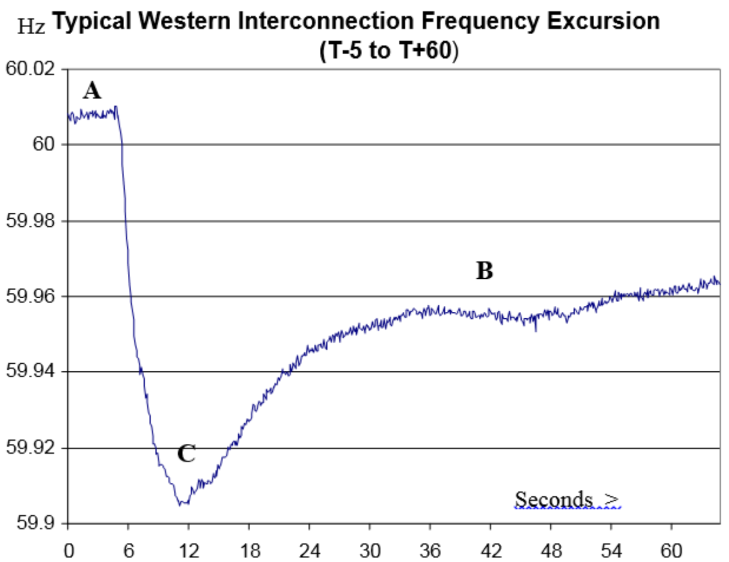


Figure 2.1~~ WECC~~: WI Frequency Excursion

As discussed earlier, there are two groups of "resources" that arrest a decline in frequency due to a loss of generation~~.~~:

- A given portion of Interconnection demand is composed of motor load, which draws less energy when the motors slow down due to the lower frequency.

- Generators have governors that act much like cruise control on a car. If the generators on the Interconnection start to slow down with the frequency decline, their governors supply more energy to the generators' prime movers in order to speed them back up to nominal. The sensitivity of this response is controlled by the governor droop setting.

Inertial Response

Inertia quickly and autonomously opposes changes to both under and over frequency events. Having a large amount of inertia is useful for smoothing out power system frequency fluctuations. It is inertia combined with the response of frequency sensitive demand that determines how quickly the frequency decays following the loss of a large supply resource like a large generator or importing direct current tie-line. In an interconnection, more inertia leads to a slower drop in frequency, giving time for the other components of the control continuum to act in order to arrest, stabilize, and then recover frequency. In some sense, the inertia of the power system can be controlled by adjusting the amount and type of generators that are on-line. Inertia is commonly described in units of seconds: the energy that is stored is normalized by the electrical "size" of the resource. Since stored energy is a function of the square of the speed of rotation, low rotating mass, faster spinning resources might store more energy, yet they typically decelerate faster (thereby injecting more energy). These lighter and faster resources' contribution to slowing the fall of frequency is more "front-loaded" and they have smaller normalized inertia values than large-rotating-mass slow-spinning resources that have slower energy injection profiles. Faster response is also not always better because of interaction effects that can cause instability where resources might "bounce" in opposite directions.

For a discussion and graphical representation on how inertia opposes changes in under and over frequency excursions, see the *NERC Frequency Response Standard Background Document,* dated November 2012.[12]

Generator Governors (Speed Controls)

The most fundamental, front-line control of frequency in ac electric systems is the action of generator governors. ~~Because of the sensitivity of generators and loads~~Governors act to stabilize frequency~~, and~~ following disturbances and act as an immediate buffer to ~~prevent frequency instability and possible collapse, it is important to maintain stability of the interconnection operating frequency and responses to changes in it.~~ load-resource imbalance. Governors operate in the ~~timeframe~~time frame of milliseconds to seconds and operate independently from ~~(~~and much faster than~~)~~ system operator actions or those of AGC. They protect from the effects of frequency when too high, but the vast majority of their benefit comes from assisting when frequency has dropped too low, especially in cases where loss of generation causes abrupt decreases in Interconnection frequency.

~~**Slope –**~~ Without governor action, loss of generation would result in frequency that would not stabilize until the load reduced to a point that matched the remaining generation output. As mentioned previously some load is reduced when the frequency is reduced mostly due to directly connected motors slowing down and consuming less power. This supply/demand balance point could occur at very low frequency and could result in cascading outages or complete frequency collapse, a very undesirable outcome in terms of the cost to society and potential equipment damage.

The combination of inertial response, governor response and load response – are the "beta" (β), or frequency response characteristic, of a BAA. This is the characteristic that AGC attempts to mimic in its use of the frequency bias ("B") parameter in determining ACE. The net of all BA frequency responses manifests as the Interconnection frequency response.

Droop

Governors ~~act to~~ cause generators to try and maintain a constant, stable system frequency (60 Hertz in North America). They do this by constantly ~~regulating~~governing (modulating) the amount of mechanical input energy to the

[12] https://www.nerc.com/comm/OC/RS%20Landing%20Page%20DL/Related%20Files/Bal-003-1_Background_Document_Clean_20121130.pdf

shaft of the electric generator. The degree of this modulation is called “~~slope”,~~droop” and is measured in percent of frequency change to cause full generator capability to be exerted against the frequency error. A typical slope is 5%, ~~which means~~meaning that ~~if frequency error is 5% (or 3 Hz)~~ the full output of the generator would be used (or attempt to be used) to counteract the frequency error~~.~~ if frequency error is 5% or 3 Hz. It should be noted that smaller droop percentages indicate increased sensitivity of response, e.g., a generator with a 4% droop would attempt to go to full output if the frequency changed by 2.4 Hz. Frequency errors are more typically in the range of 0.01% (.06 Hz, or 60 mHz), so governor action usually is a much smaller fraction of a unit’s output capability. It must also be recognized that, while most generators can reduce output considerably in response to their governor’s actions, increasing output is more problematic since many generators may already be near the top of their output capability when low frequency causes their governor to request more output. Thus, if there is no “headroom” available on a generator’s output, the governor will be able to do little to increase that output and help stabilize low frequency.

Deadband

~~—~~The second general characteristic of governors is “deadband~~”.~~.” This ~~simply~~ means that ~~until frequency error is beyond a threshold,~~ the governor ignores frequency error until it~~.~~ passes a threshold. When frequency error exceeds the threshold ~~(.036 Hz, or 36 mHz by convention)~~(which should not exceed the maximum deadband setting per Interconnection recommended in the NERC Reliability Guideline-Primary Frequency Control), the governor becomes active. It is worth noting that the deadband may be larger for older~~,~~ mechanical-style governors ~~the deadband may be larger~~~~,~~ and ~~has~~ may have mechanical lash associated with it ~~the mechanical lash that exists in mechanically-coupled devices~~.

The calculated unit MW output change with a droop setting of 5% and deadband setting of 36 mHz based on the total resource capacity is shown in Figure 2.2

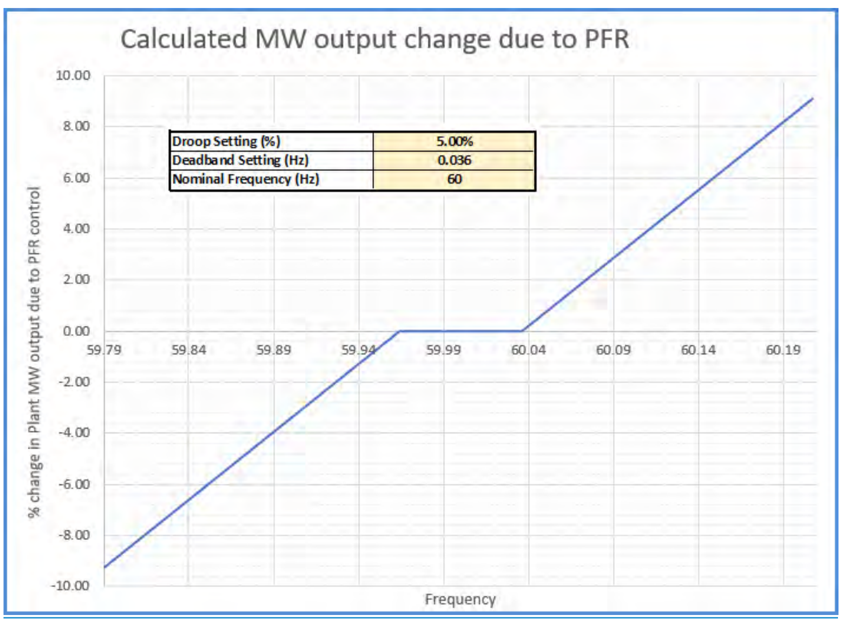


Figure 2~~Without governor action, loss of generation would result in frequency that would not stabilize until the interconnection load – frequency characteristic resulted in a (reduced) load that matched the remaining generation output. This point could be at very low frequency and could result in cascading outages or complete frequency collapse, a very undesirable outcome in terms of the cost to society and potential equipment damage.~~

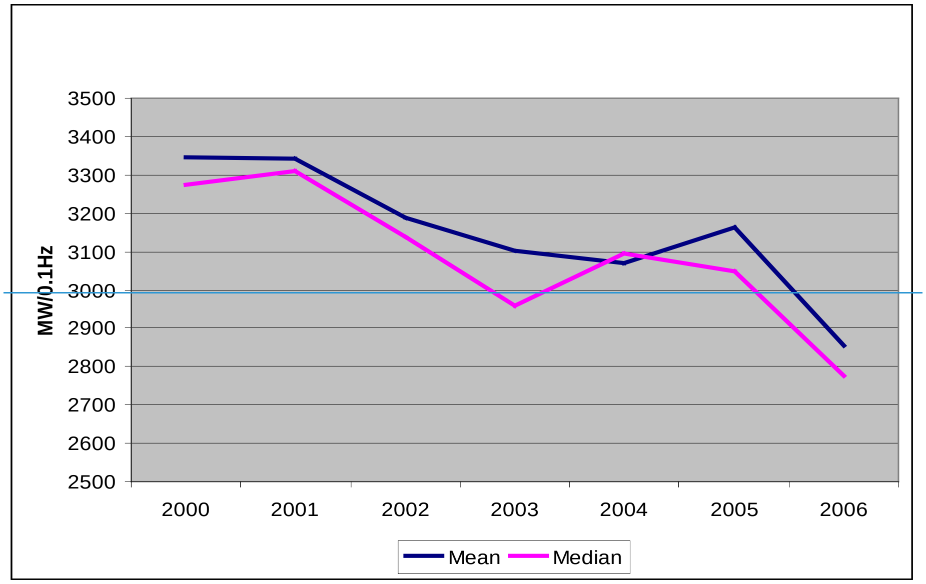
~~The combination of governor response and load – frequency response - is the "beta" (β), or frequency response characteristic, of a Balancing Area. This is the characteristic which AGC attempts to mimic in its use of the frequency bias ("B") parameter in determining ACE. The net of all Balancing Area frequency responses manifests as the interconnection frequency response, discussed in Frequency Response Trends.~~

~~Frequency Response Trends~~

~~Studies over the past 30 years have shown a general decline in Frequency Response in the Eastern Interconnection, and mixed results in other interconnections. In theory it should be increasing with increasing load and generation. Since 1994, Eastern Interconnection Beta has declined roughly 20 percent even though it should have been increasing in proportion to a 20 percent increase in customer demand. shows the recent trend in Beta.~~

~~While this trend is of concern, some caution is needed. Early studies were based on limited samples of generally large events. Such events would generally trigger more Primary Control.~~

~~The underlying reason for the proposed is to develop an objective method to calculate Beta for all Balancing Authorities and Interconnections. For example, it is unknown whether the general trend is global or whether there are specific areas with low Frequency Response.~~



~~Figure Recent Eastern Interconnection Frequency Response~~

~~Frequency Response Variability~~

~~Some have suggested that there should be a standard that requires a minimum amount of frequency response from all Balancing Authorities for all events. Consistency in measuring and controlling this would be problematic.~~

~~The calculated beta[13] for a Balancing Authority is based on measuring a relatively small change in Net Actual Interchange coincident with a frequency excursion. Load and generation continuously change in a Balancing Authority. Any random variation in load or generation that happens to occur at the time of the disturbance will greatly misstate the calculated beta for that event. An objective estimate of Balancing Authority beta should be based on 30 or more events dispersed throughout the year. Using the median value will eliminate the impact of misstated individual events.~~

~~There is a great deal of variability of Beta or Interconnection Frequency Response by season and day of the week. Beta may be larger during peak periods because there are more contributing generators and motors.~~

~~Most observed frequency excursions in the Eastern Interconnection are caused by:~~

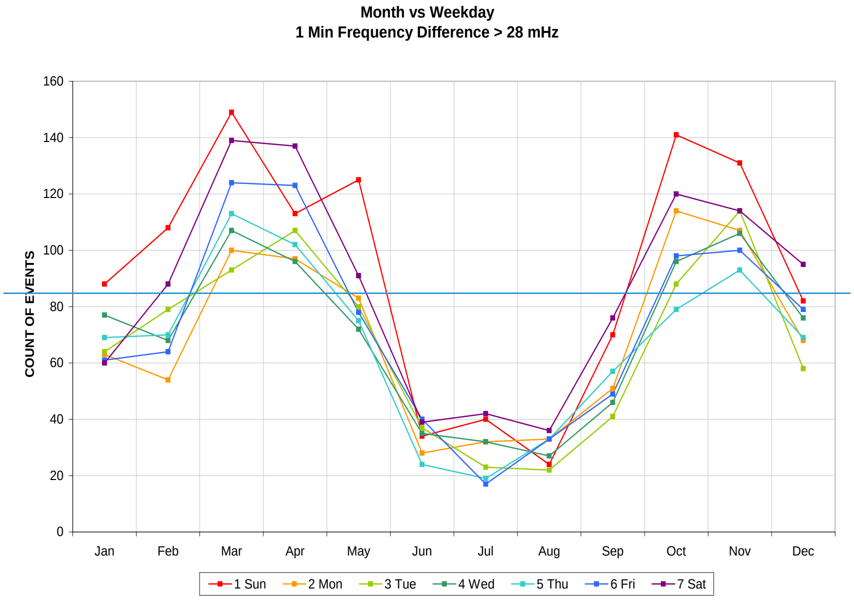
- ~~Generator trips.~~
- ~~Schedule changes (resulting in significant generation changes) at the top of the hour, particularly during the on-peak to off-peak transitions.~~
- ~~Pumped storage generation starts/stops.~~

~~A given MW-sized event will cause a larger frequency excursion during periods of low Beta than during periods when Beta is higher. As such, some events of a given size will not cause a noticeable change in frequency during peak periods that have a large Beta, yet an event of the same size might cause a significant frequency shift during periods with low Beta.~~

~~shows the variability of Interconnection Beta indirectly by tracking the number of sufficiently large[14] frequency excursions by month of the year and day of the week. Notice that there are few frequency excursions during the peak months, but many excursions on the light load months, and in particular, on weekends. This implies that an objective estimate of Beta must look at many events throughout the year.~~

[13] A capitalized Beta (which looks like a B) typically applies to the Frequency Response of an Interconnection, while small beta (β) applies to the response of a Balancing Authority.

[14] 28 mHz was chosen as a "benchmark" for frequency excursions in the Eastern Interconnection by the Resources Subcommittee when Beta was 3500MW/0.1 Hz. At this point in time, a 28 mHz excursion was typically associated with the loss of roughly 1000MW.



~~Figure —— Frequency Excursions by Month and Day of the Week~~

~~Tips on~~ .2: Calculated Resource % MW Output Change due to PFR

Calculating Frequency Response

~~The NERC Resources Subcommittee occasionally requests Frequency Response Characteristic Surveys for specific events. The NERC *Frequency Response Characteristic Survey Training Document, contained in the NERC Operating Manual,* has a form for calculating Frequency Response for a particular event.~~

~~Balancing Authorities should not rely on one or two surveys to establish a value to be used for their Bias. Statistical theory says about 30 observations are needed to give a large enough sample to have confidence in the results. The median of these samples is a better indicator of central tendency when measuring a highly variable population like Frequency Response events.~~

~~Because of the work involved, few Balancing Authorities go through a statistically rigorous approach to calculate their Bias. Most simply use the "1 percent of load" approach. The value in a Balancing Authority properly stating its Bias is to "tune" AGC to the natural response of its load and generation.~~

~~So how have Balancing Authorities obtained the observations to be used for calculating their Bias? There really has not been a standard way to do this. In some cases, Balancing Authorities have implemented automatic tools that scan for frequency events and archive data. Others just rely on their operators to spot frequency events and make a log entry somewhere so that someone can go back and pull the appropriate data (either electronic or even paper charts).~~

~~The NERC Resources Subcommittee has lists of excursions available to the industry for everyone's use for calculating Frequency Response. On request, they will post such events on their .~~

~~**Table – Frequency Response Calculator**~~

~~Table 2 demonstrates how a Balancing Authority can go about calculating its Frequency Response from several events. The table is nothing more than a spreadsheet that takes Net Actual Interchange and Frequency at points and calculates both individual and cumulative Frequency Response.~~

~~Table 2 is also an embedded spreadsheet. "Double clicking" on the table will open the spreadsheet. If you are interested in saving the sheet to calculate local Frequency Response, all you have to do is open the spreadsheet, then copy and paste it into a regular spreadsheet.~~

New Tool: NERC is implementing a Frequency Monitoring project developed by the Consortium for Electric Reliability Technology Solutions (CERTS), sponsored by the Department of Energy (DOE). As part of the project, you can receive e-mail notifications associated with frequency excursions that would be candidates for calculating responses. If you are interested, contact your NERC Resources Subcommittee representative.

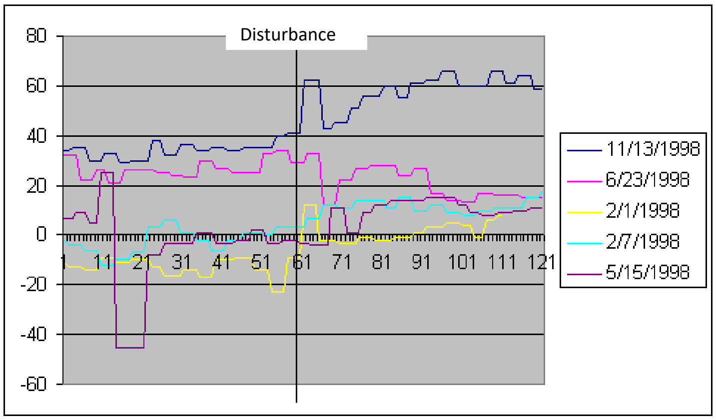
~~Once a Balancing Authority calculates its Frequency Response, it must make a decision on what Bias it will report to NERC by January 1 and use in its ACE calculation. The following are the options to consider:~~

- ~~The best approach is to use a Bias that reflects natural Frequency Response for all the observed excursions.~~
- ~~If natural Frequency Response is less than 1% of projected peak load or generation, Bias must be set such that it complies with the BAL-003 requirement that the monthly average value of Bias be at least 1% of projected peak load or generation (see standard for details).~~
- ~~The Control Performance Standard does provide some room for Balancing Authorities to select a Bias as part of a control strategy, provided they observe BAL-003 R2 and R5. For example, Balancing Authorities with large, rapidly-changing ("nonconforming") loads such as arc furnaces that cause problems meeting CPS2 may want to increase their Bias beyond their natural response. This causes their units to do more regulating (or a decline in CPS1 for the same amount of regulating) as a trade-off for getting larger L10 limits. (The size of CPS2's L10 is related to Bias.)~~

~~Unless the process is automated, there is a fair amount of effort required in objectively calculating Frequency Response.~~

~~Calculating Frequency Response is not a new requirement. Many Balancing Authorities do this in order to calculate and set their bias. Those that do this manual task understand the challenges involved.~~

~~Figure 5 shows actual scan rate response for a medium-sized Balancing Authority for five events in 1998. The chart is a graph of the Balancing Authority's "Tie Deviation" in MWs plotted against time. The chart shows the Tie Deviation from 60 seconds before a frequency excursion until 60 seconds after the excursion.~~



~~Figure – Frequency Response for 5 Events~~

~~For the time being, assume all five frequency excursions were 33 mHz. The reader can refer to the *Frequency Response Characteristic Survey Training Document* for the actual calculation, but Frequency Response is simply:~~

~~[MWs deployed /0.1 Hz of frequency deviation]~~

~~Since 33 mHz is one-third of 0.1 Hz, it seems all we have to do is multiply the change in Balancing Authority output by 3. For those familiar with the process, two problems immediately arise.~~

~~First, the *Frequency Response Characteristic Survey Training Document* says to use the interchange values "immediately before" and "immediately after" the disturbance to derive a value for MWs deployed for the event. The reader is asked to actually determine and write down the "MW deployed" for these events. It is almost certain your answer will be different than another person who reads the same graph. Given a frequency excursion of 33 mHz, a difference in calculation of 5 MW of tie deviation means a difference of 15 MWs in Frequency Response. Obviously, there is a need to be more explicit in the methodology and to find a way to take the subjectivity out of the process.~~

~~Second, a scan of Figure 5 shows that the Balancing Authority actually had a negative response for the June 23 event. This brings up another underlying problem with measuring Frequency Response. Short of measuring every generator individually, there is no way to separate Frequency Response from normal load variations for a single event. To remove the effect of load variation at the Balancing Authority level, many events should be measured and a statistical average response calculated. If enough events are captured, the effect of load variations will be reduced (because load swings are equally likely to inflate or decrease the calculated Frequency Response).~~

- ~~There is significant variation in a single Balancing Authority from event to event. This means that the selection process for events to be measured markedly affects the results. If every Balancing~~

~~Authority is not working off the same selection criteria or the same set of events, it is likely that results will be inconsistent.~~

- ~~Some Balancing Authorities calculate their response from paper "Net Interchange" charts. The scale on these charts is such that it is difficult to identify the "blip" that corresponds to the frequency excursion. CPS source data is digital to several decimal places, and thus less subjective.~~
- ~~Refer back to Figure 5 and consider the manual process that exists today. It is unlikely that given the objective data in the graph that two people calculating response for these events manually would come up with matching answers. Using CPS data takes subjectivity out of the process.~~
- ~~*The Frequency Response Characteristic Training Document* leaves room for interpretation on the time window to measure. The document talks about using the Interchange and Frequency values "immediately before" and "immediately after" the event. This is subject to interpretation. Using CPS data takes subjectivity out of the process.~~
- ~~On the average, little automatic generation control (AGC) occurs within a single minute timeframe. Even though there will be some random load and generation swings in each event, their effects will be netted out over many events.~~

Prior to current Reliability Standard requirements governing frequency response[15], calculation of frequency response was addressed by the NERC *Frequency Response Characteristic Survey Training Document*,[16] which included a form to guide the calculation for a given event. The calculation of the Frequency Response Characteristic (FRC) for a BA is to divide the change in Net Interchange Actual (NI_A) from pre-event (A point, see Figure 1.8 above) to the stabilizing period (B point, ~20-52 seconds after the event) by the change in interconnection frequency from pre-event to the stabilizing period. Although the terms in the FRC Training Document have changed over the years (e.g., Control Area is now Balancing Area), the calculation remains the same. This is often referred to as the A to B frequency response. With the advent of faster scanning tools over the years (e.g., Phasor Measurement Units), a similar response calculation can be made from the A point to the C point (nadir, if a generation loss or apex, if a load loss) of the frequency event.

Important Concept: The frequency response will normally be a negative value, reflecting the inverse relationship between the increase in MW output in response to the decrease in interconnection frequency for a frequency decline (e.g., a generator trip), or vice versa for a frequency increase (e.g., a load loss).

Under the current Reliability Standard requirements, the selection of events for evaluation and the calculation forms used to determine response are prescribed by the Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard[17], the Reliability Standard itself, its attachment and associated forms.

Frequency Response Profiles of the Interconnections

The amount of frequency decline from a ~~lost~~ generator trip varies based on a number of factors, e.g. time of day, ~~the~~ season, ~~as well as the~~ and Interconnection~~.~~ loading. The observed frequency responses of the North American Interconnections ~~are on the order of~~as documented in the *2018 NERC State of Reliability* report are as follows:

- EI -2,~~760~~103 MW / 0.1Hz ~~(Eastern Interconnection)~~
- ~~-650~~TI -674 MW / 0.1 Hz ~~(Texas Interconnection – ERCOT)~~

[15] As of the release date of this document, the current applicable Reliability Standard is BAL-003-1.1

[16] https://www.nerc.com/comm/OC/RS%20Agendas%20Highlights%20and%20Minutes%20DL/Frequency_Response_Characteristic_Survey_19890101.pdf

[17] https://www.nerc.com/comm/OC/BAL0031_Supporting_Documents_2017_DL/Procedure_Clean_20121130.pdf

- WI -1,~~482~~539 MW / 0.1 Hz ~~(Western Interconnection – WECC)~~
- ~~-120~~QI -599 MW / 0.1 Hz ~~(Quebec Interconnection)~~

Important Note: These values are not normalized to adjust for starting frequency and/or resource loss size.

As noted above, the negative sign means there is an inverse relationship between generation loss and frequency. In other words, a loss of 1,000 MW would cause a frequency change (A to B) on the order of:

- EI -0.~~036~~048 Hz ~~(East)~~
- TI -0.~~154~~148 Hz ~~(Texas)~~
- WI -0.~~067~~065 Hz ~~(West)~~
- QI -0.~~833~~168 Hz ~~(Quebec)~~

Conversely, if 1000 MW of load were lost in an Interconnection, the resulting frequency increase would be similar in magnitude as listed above. ~~In ERCOT it has been observed that typical response to high frequency events is approximately 2/3 of the frequency response for low frequency events.~~

Figure 2.~~3~~ is a typical trace following the trip of a large generator in three of the ~~Eastern Interconnection, while is a trace from ERCOT.~~ Interconnections. Notice that governors in the East do not provide the "Point C to B" recovery of frequency as they do in the other Interconnections. ~~Another observation in the East is that there is often some decline~~ The rate of frequency ~~towards the end of the first minute following the event. It is believed this is~~decline is much slower primarily due to ~~setpoint control at both generating stations and in the Balancing Authorities' control systems. More investigation is needed to specifically identify the cause of this behavior.~~its size, so frequency slowly drops until sufficient response stops the decline. In the early 2000s, there was typically a post-event decline in frequency, but this effect has been occurring less often.

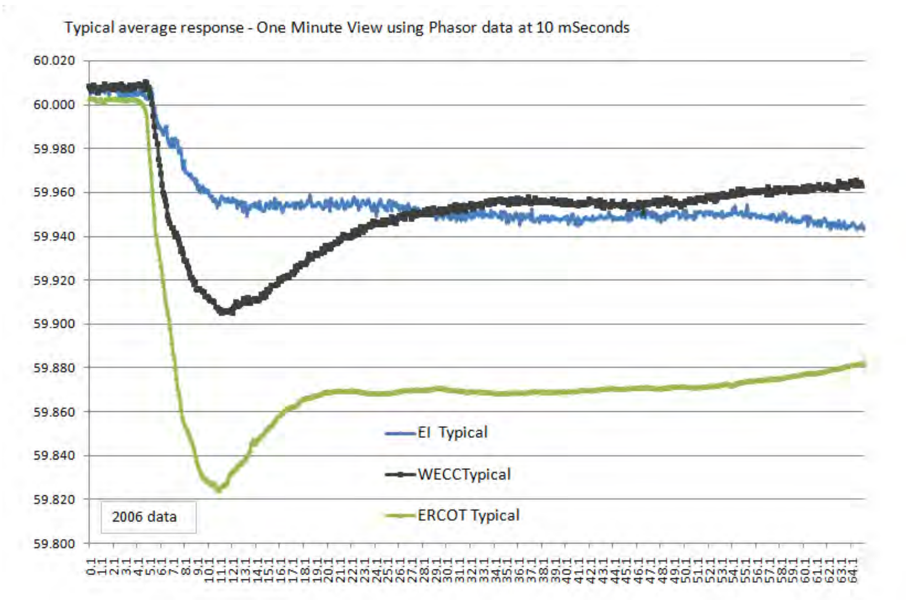


Figure 2~~—~~.3: Typical Frequency Excursions

Important Concept: Following a large generator trip, frequency response will only stabilize the frequency of an Interconnection, arresting its decline. Frequency will not recover to scheduled frequency until the contingent BA replaces the lost generation through AGC and reserve deployment.

Figure 2.~~Eastern Interconnection~~4 Shows the frequency at measured at various locations across the EI after a large generator trip. Note that the frequency disturbance is a chaotic event with complex dynamics, including fast transients bouncing about a much longer term trend. Also note that the time-scale tick-marks are every 5 seconds: the whole event has reached a stabilized frequency within 20 seconds.

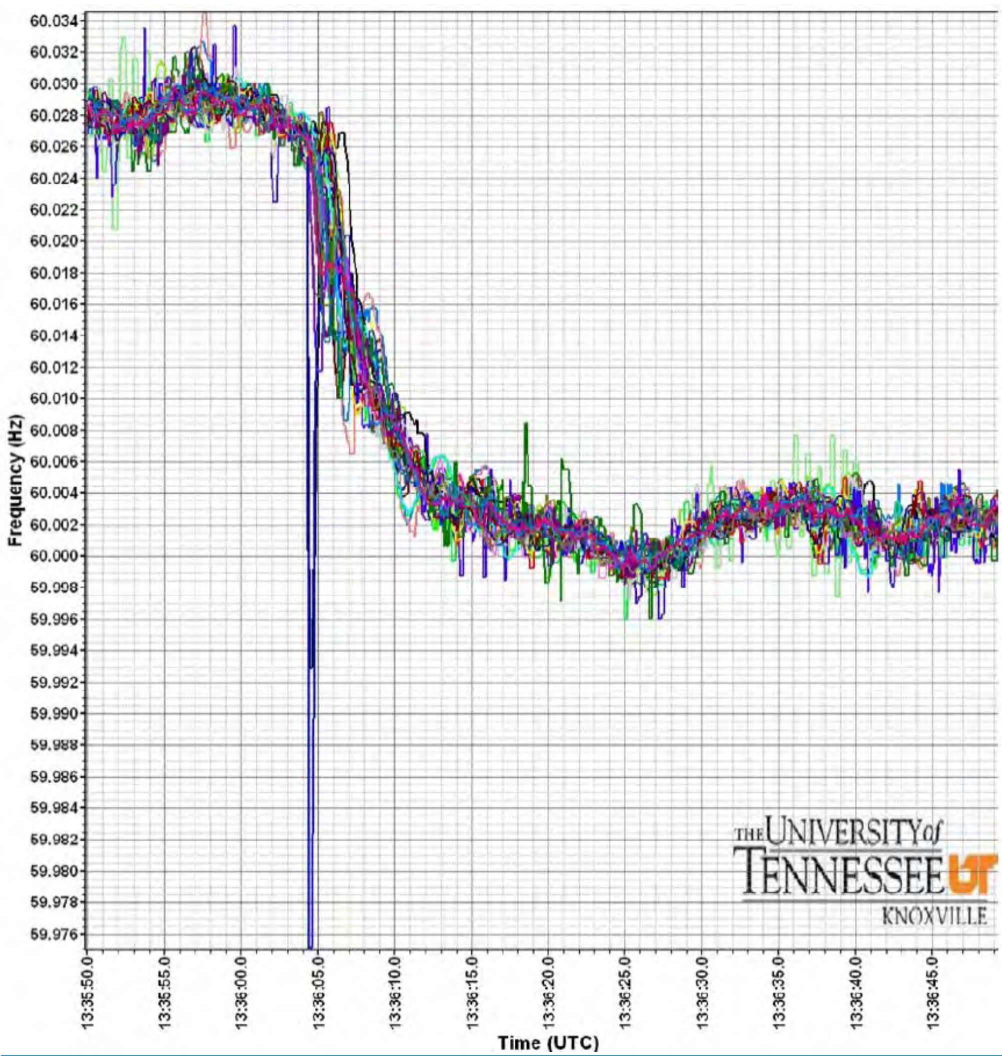


Figure 2.4: Frequency Excursion Measured at various locations in the EI

~~Figure — Typical ERCOT Frequency Excursion~~

Annual Bias Calculation

The value in a ~~Balancing Authority~~BA properly stating its bias is to ensure its AGC control system does not cause unnecessary over-control of its generation.

The NERC ~~Resources Subcommittee has~~RS posts quarterly lists of excursions that are available to the industry for everyone's use for ~~calculating Frequency Response. One may have been provided along with this document.~~ evaluating frequency response during the year. The subcommittee refines these quarterly lists into an official event list that is used in BAL-003 FRS forms.

Guidelines the RS uses in selecting and evaluating events for calculating bias and BAL-003 performance include the following:

- ~~If possible, avoid using events where you or a neighboring Balancing Authority caused the frequency decline. Tie-line data typically goes through wide swings when this is the case.~~
- ~~Ensure~~ Events are dispersed throughout the year to get a good representation of "average" response.
- Pick frequency excursions large enough to actuate generator governors.~~ This would require excursions of at least 36 mHz (.036 Hz), because some governor references use this as a deadband setting. With some older governors unable to resolve better than 50 mHz, excursions of at least this magnitude may prove even more useful.~~
- The events should be relatively clean and generally have continuous drop from A to C.
- Starting frequency should be relatively stable and close to 60 Hz.

Estimating Load's Frequency Response

As discussed previously, motor load provides frequency response to the Interconnection. The rule of thumb is that this response is equal to 1~~ to ~~–2~~ percent~~% of load. Techniques have been developed to observe approximately how much "load" frequency response a ~~Balancing Authority actually~~BA has~~.~~ available. This technique is explained in **Figure 2.5**~~below.~~.

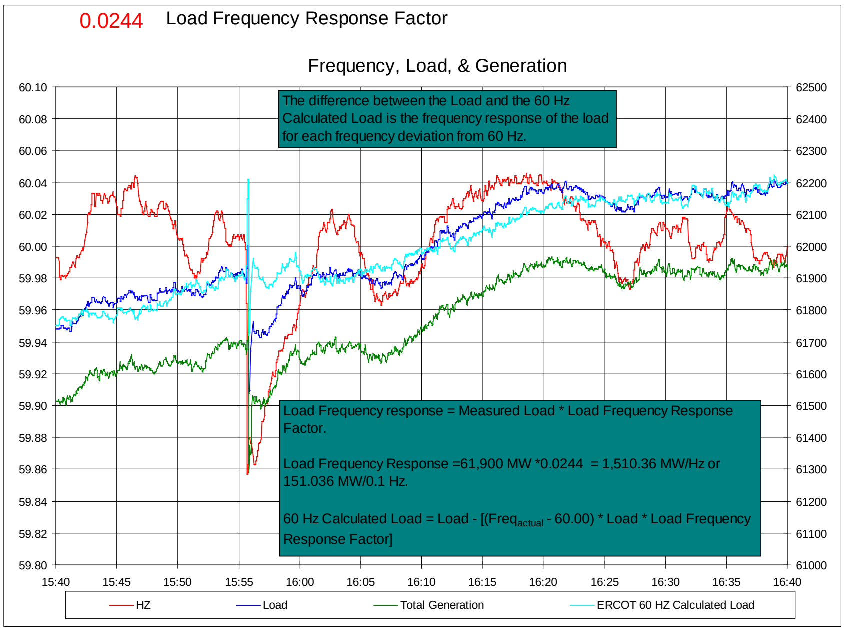


Figure 2.5: Observing Frequency Response of Load

The cyan trend in **Figure 2.5** above represents how much load would exist if frequency could be controlled to exactly 60.000 Hz all the time. The difference between the measured load, blue trend, and the cyan trend is the frequency response of load. For this event, a 759 MW resource was lost producing a frequency deviation of -0.118 Hz. This calculates to be ~~759/(0.118*10) = 643 MW/0.1 Hz~~

$$\frac{759\,MW}{0.118\,Hz*\left(\frac{10*0.1\,Hz}{Hz}\right)} = \frac{643\,MW}{0.1\,Hz}$$ of frequency response.

Of this response, 151.036 MW/0.1 Hz was provided by the load (by multiplying the load by .00244~~) which leaves~~, leaving the remainder~~,~~ (492.184 MW/0.1 Hz~~,~~) provided by resource governor response. The post contingency total generation settled at 61,510 MW a difference of 178.222 MW below the pre-contingency generation. The generation-to-load mismatch post ~~-~~event is 178.222 MW plus ~~replacing~~replacement of the 580.777 MW of governor response (492.184 * 1.18 = 580.777) that will be withdrawn as frequency returns to 60.00 Hz. If this BA's bias in the ACE equation had been set exactly at 643 MW/0.1 Hz, ACE would equal -~~759MW~~759 MW at the B point of this event. AGC would dispatch 759 MW to replace the frequency response of the governors and load~~ which would return~~, returning the Interconnection to balance at 60.00 Hz. This example is of a "single" ~~Balancing Authority~~BA Interconnection but the math works for multiple BA Interconnections as well.

By observing multiple events and adjusting the factor to produce a "60 Hz Load" value that maintains the pre- and post-event slope of load, a proper value can be determined. Larger deviation frequency events are beneficial to get a clear observation ~~as well as~~in addition to looking at many events. A factor between 0.010 and 0.025 would be reasonable depending on the ratio of motor load vs. non-motor load within the ~~BA~~BAA boundaries.

~~**Key Points (Primary Control)**~~

The key points of primary control are as follows:

- Steady-state frequency is common throughout an Interconnection.
- If frequency is off schedule, generation is not in balance with total load~~ at the load's value for scheduled frequency~~.
- Arresting frequency deviations is the job of all ~~Balancing Authorities.~~ BAs. This is achieved by provision of frequency response through the action of operating governors on generation and other resources able to provide frequency response (e.g., controllable load~~).~~, storage, etc.).
- Frequency response is the sum of a ~~Balancing Authority's~~BAs inertial response, natural load response ~~to frequency~~ and ~~the~~ governor response of generators to frequency deviation within the ~~Balancing Authority~~BA Area.
- Frequency response arrests a frequency decline~~,~~ but does not bring it back to scheduled frequency. Returning to scheduled frequency occurs when the contingent ~~Balancing Authority~~BA restores its load-resource balance by using secondary control.
- Generators should be operated with their governors free to assist in stabilizing frequency.
- Frequency control during restoration is extremely important. That is why system operators should have knowledge of the generators' governor response capabilities during black start.
- All ~~Balancing Authorities~~BAs have a frequency response characteristic based on the governor response of their units and the frequency-responsive nature of their load.
- The amount and rate of frequency deviation depends on the amount of imbalance in relation to the size of the Interconnection.
- Frequency bias is a negative number ~~(Balancing Authority output increases as frequency declines)~~ expressed in MW/0.1Hz.
- The typical (best) way to calculate frequency response is to observe the change in ~~Balancing Authority~~BA output for ~~several (many)~~multiple events over a year.
- ~~A Balancing Authority~~Under BAL-003-1.1 BA's should set its fixed bias to no less than the 100–125% of its natural frequency response ~~, and to at least 1% of predicted system peak load (~~or ~~generation) per BAL-003.~~
- ~~The Eastern Interconnection has a Frequency Response~~its percentage share of ~~roughly 2,750 MW/~~0.~~1 Hz. This means the loss~~9% of ~~a 1,000 MW generator will drop frequency roughly 0.036 Hz.~~
- ~~The Western Interconnection has a Frequency Response~~the Interconnection's non-coincidental peak load based upon all of ~~roughly 1,500 MW/0.1 Hz. This means the loss of a 1,000 MW generator will cause~~ the ~~frequency to drop approximately 0.06 to 0.07 Hz.~~
- ~~Most Balancing Authorities use the "1% of~~BAs within an Interconnection's non-coincident peak load~~"~~ values (whichever method ~~to calculate their Bias. This~~ is ~~roughly twice the observed Frequency Response~~greater in ~~the Eastern Interconnection.~~absolute terms).
- BAs are allowed to employ variable frequency bias that more accurately reflects real-time operating condition.
- Governors were the first form of frequency control~~,~~ and remain ~~at the vanguard~~in effect today~~.~~; they act to ~~mitigate~~oppose large changes in frequency ~~change~~.
- AGC supplements governor control by controlling actual tie flows and maintaining scheduled interchange at its desired value. It performs this function in the steady-state, seconds-to-minutes ~~timeframe,~~time frame after transient effects ~~(~~, including governor action~~)~~, have taken place. If bias is greater than actual frequency response, AGC will supplement this response.
- ACE, the main input to AGC, requires frequency and energy interchange data (both actual and scheduled~~)~~).

- ~~The Frequency Response is declining in the Eastern Interconnection and appears to be declining in the Western Interconnection. One underlying issue is that nobody knows if the decline is spread out among all Balancing Authorities or if there are pockets with substandard response. Neither situation is an immediate threat for steady-state reliability. However, Frequency Response is vital during disturbances and islanding.~~
- ~~Area frequency response~~ While frequency response was declining in the 1990s, actions taken by the Industry appear to have stabilized the trend.
- BA or Interconnection frequency response should be measured for two reasons~~.~~:
  - ~~Most importantly,~~ To gauge the area response to frequency ~~upsets,~~ deviations.
  - ~~Secondarily,~~ As a basis for setting B.

~~Chapter 12~~Chapter 3: Secondary Control

Background

Secondary control is the combination of ~~automatic generation control (~~AGC~~)~~ and manual dispatch actions to maintain energy balance and scheduled frequency. In general, AGC utilizes maneuvering room while manual operator actions (e.g., phone calls to generators, purchases and sales, load management actions) keep repositioning the ~~Balancing Authority Area~~BAA so that AGC can respond to the remainder of the load and interchange schedule changes. ~~The~~ NERC ~~Control Performance Standards~~CPSs are intended to be the indicator of sufficiency of secondary control.

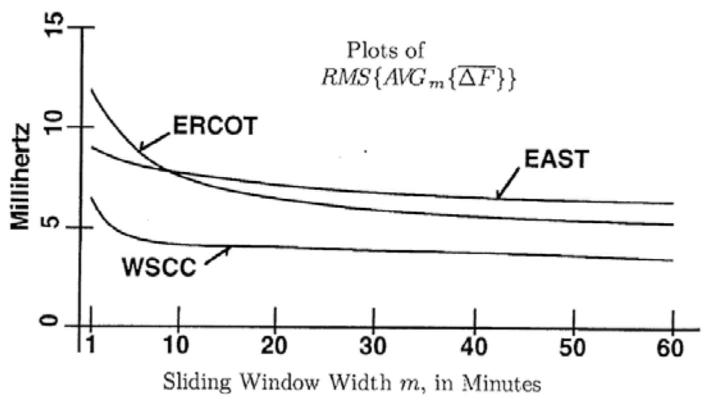
~~Whither the~~Maintaining an Acceptable Frequency Profile~~ Requirement?~~

~~The most basic~~One indicator of proper secondary control action is the ~~character~~distribution profile of steady-state Interconnection frequency. When the transition was made from the "A" criteria to CPS in 1997, the directive of the NERC Operating Committee was to not allow frequency ~~(deviation)~~variation to become any ~~worse~~greater than it had been in the past. One measure of this is the root mean square (RMS) of frequency error from schedule. This by itself, however, is a measurement over an indefinite term and may not reveal problems at all averaging intervals. To adequately measure the frequency profile of an Interconnection, a statistical method was adopted in which period averages of RMS frequency error were measured and cataloged for periods of a large number of different values. In other words, the average of rolling N-minute RMS averages was computed for many values of N. This results in a defining profile as shown in **Figure 3.1**~~figures 14a~~ and **Figure 3.2**~~14b. ~~. Although other values could have been selected~~,~~ and ideally ALL values should be considered, the ~~averaged values looked~~decision was made that the general profile would be maintained if the profile was anchored at ~~most closely were those for~~two points in time (originally 1 minute and 10 minutes~~. This was for practical reasons; computing all the interval averages would be computationally burdensome and, arguably, unnecessary if frequency performance could be made (more) random.~~).

To set values for frequency performance, each Interconnection's frequency error was observed by using the above method, and each one was characterized, particularly at their 10-minute interval average RMS frequency deviation from schedule. The ~~eastern interconnection~~EI measured 5.7 mHz at the 10-minute point. The 1-minute point used to set the CPS standard was derived from an "ideal" error characteristic by the ratio of square roots. This yields 5.~~4 * sqrt(~~7 * √(10) = 18.025 mHz. This value was rounded to the value in use today for the East, 18 mHz.

The same technique was used for the ~~WECC~~WI and ~~ERCOT interconnections. ~~TI. It is important to realize that CPS1 performance~~, described in the next section,~~ is only measured at this one "slice" (one-minute averaging) of the Interconnection's frequency error characteristic. Because of this, there is no assurance that frequency ~~error~~variation will be constrained at other averaging points or converge on the ideal characteristic and become more random. ~~CPS2 does impose limits on deviations of ACE at 10-minute averages (intended to help prevent excessive transmission flows due to ACE fluctuations), but this does not assure the desired random behavior, either.~~

Initially, a 10-minute metric called CPS2 was developed to keep average ACE within specific bounds. CPS2 was originally used to help prevent excessive transmission flows due to large values of ACE. The problem with CPS2 was that it was not dependent on ACE's impact on frequency. Additionally, CPS2 could cause control actions that moved against frequency. If a BA had very bad performance in one direction for five minutes, the BA could correct this by having equally bad performance in the opposite direction for the next five minutes. Finally, ACE could be totally unbounded for 10% of the month and it didn't matter whether it was 1 or 1000 MW over the limit. CPS2 did not provide the correct signal for maintaining frequency. Ultimately, the industry adopted a frequency-sensitive longer term (i.e., 30 minute) measure called the BA ACE Limit (BAAL).

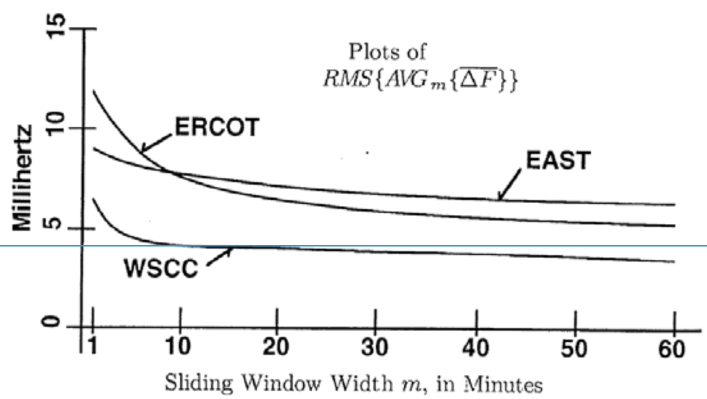


Frequency experience in the subject interconnections. Each ordinate point on these curves is the RMS value of the averages of $\overline{\Delta F}$ in windows of width m moved across the data string.

Figure 3.1: Interconnections with CPS actual-measured ΔF "period average"

Figure 3.1

~~Figure 14a – The ideal ΔF characteristic, for random behavior of Balancing Areas, shows an inverse square-root declining "noise" of frequency deviation as the length of the averaging period increases (EPRI report RP-3550, August, 1996).~~



Frequency experience in the subject interconnections. Each ordinate point on these curves is the RMS value of the averages of $\overline{\Delta F}$ in windows of width m moved across the data string.

~~Figure 14b — Illustration of actually~~ Illustrates the actual-measured ΔF "period average" characteristic of the Interconnections with CPS was designed (EPRI report RP-3550, August, 1996). Note that these curves are flatter than ~~the ideal, with frequency deviation "noise" remaining significant as the averaging period lengthens. Shown are the~~

~~actual measured characteristics for the East, WSCC, and ERCOT interconnections.~~ what was ultimately selected as the epsilon limits in CPS1. The ~~difference between these and the "ideal"~~reason for this is ~~caused by the distribution of the frequency error being non-random in the real world, while it is assumed to be random in the ideal. Hour-crossing schedule changes, diurnal load fluctuations, pumped hydro operation and other such activity drive this characteristic.~~

that the standard needed to bound acceptable performance but not raise the bar and make it difficult to comply. For example, the 1-minute frequency variation in the East was about 10 mHz; if 10 mHz were chosen as Epsilon 1 in the East as opposed to the 18 mHz that was actually selected, it would mean that half the BAs in the East would have been out of compliance when the standard became active. Random (i.e., non-coincident) behavior of ~~balancing areas,~~BAs in total~~,~~ is important in the above assumptions~~,~~ because ~~as behavior becomes coincident (behaviors happening at the same time)~~ the curves from which epsilon 1s were extrapolated start to deviate from the shape and predictability of the curves used to derive them~~.~~ as behavior becomes coincident (i.e., behaviors happening at the same time). Another way of saying this is that it becomes less and less valid to try to control frequency and measure performance at just one point on the sliding window continuum as coincidence creeps in. ~~One type of coincident behavior is illustrated in Figure 14c below, where time-of-day behaviors relating to diurnal load characteristics and scheduling practices lead to observable clustering of probability of low-frequency events~~Prior to the adoption of the BAAL, the Interconnections would see wider frequency swings at specific times of day, particularly in the low direction. The swings, due primarily to load changes and large block Interchange Schedules, could occur under CPS2. The number and magnitude of frequency swings were reduced through a combination of tools that identified the contributing BAs as well as the adoption of BAAL.

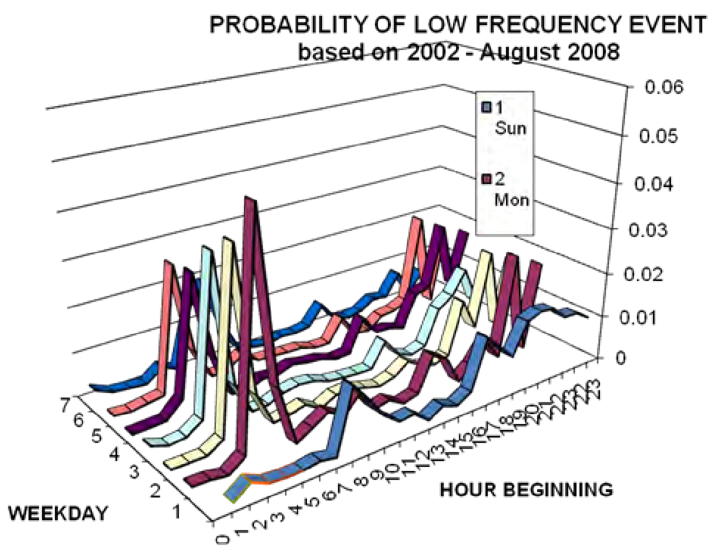


Figure 3.2~~14c –~~: Probability Distribution for Low-Frequency Events vs. Time of Day

Control Performance Standard 1 ~~(CPS1)~~

In simple terms, CPS1 assigns each ~~Balancing Authority~~BA a share of the responsibility for control of steady-state Interconnection frequency. The amount of responsibility is directly related to ~~Balancing Authority~~BA frequency bias.

As mentioned previously, ACE is to a ~~Balancing Authority~~BA what frequency is to the Interconnection. Over-generation makes ACE go positive and frequency increase~~.~~ while negative ACE "drags" on Interconnection and decreases frequency. "Noisy" ACE tends to cause "noisy" frequency. CPS1 captures these relationships using statistical measures to determine each ~~Balancing Authority's~~BA's contribution to such "noise" relative to what is deemed permissible.

The CPS1 equation can be simplified as follows:

- CPS1 (in percent) = 100* [2 – (a Constant[18])* (frequency error)*(ACE)]

Frequency error is deviation from scheduled frequency~~. Normally this is deviation from~~, normally 60Hz. Scheduled frequency is different during a time correction, but for the purposes of this discussion, assume scheduled frequency is 60 Hz.

Refer to the equation above. Any minute where the average frequency is exactly on schedule or ~~Balancing Authority~~BA ACE is zero, the quantity ((frequency error)*(ACE)) is zero. Therefore, CPS1 = 100* (2-0), or 200%. This is true whenever frequency is on schedule or ACE is zero.

For any one-minute average where ACE and frequency error are "out of phase~~",~~," CPS1 is greater than 200~~ percent.~~ %. For example, if frequency is low, but ACE is positive (tending to correct frequency error), the ~~Balancing Authority~~BA gets extra CPS1 points.

Operating Tip: Frequency is generally low when load is increasing and high when load is dropping. Anticipating and staying slightly "ahead of the load" and on the assistive side of frequency correction with your generation will give your BA high CPS1 scores over the long run.

Conversely, if ACE is aggravating the frequency error, CPS1 will be less than 200~~ percent.~~ %. CPS1 can even go negative.

TI and QI Note: The TI and QI operate as single BA's. ACE for a single BA Interconnection will always be "in phase" with frequency error; refer to the ACE review for verification. This means the largest CPS1 these BA's can achieve is 200%. This occurs whenever ACE or frequency error is zero. CPS1 for these BA's is a function of "frequency squared."

The CONSTANT in the equation above is sized such that ~~if a Balancing Authority's~~the BA will get a CPS1 of 100% if the BA's ACE is proportionally as "noisy" as a benchmark frequency noise~~, the Balancing Authority will get a CPS1 of 100 percent.~~. The minimum acceptable ~~long-term~~rolling twelve-month score for CPS1 is 100~~ percent.~~%.

When CPS was established, each Interconnection was given a target or benchmark "frequency noise~~".~~." This target noise is called ~~"~~Epsilon 1~~" or~~ (ε1~~.~~). Epsilon 1 is nothing more than a statistician's variable that means the RMS ~~(root mean square)~~ value of the one-minute averages of frequency.

The target values (in mHz ~~(millihertz)~~ of frequency noise) for each Interconnection are shown in **Table 3.1**~~Table 1~~ below. The NERC ~~Resources Subcommittee~~RS monitors each Interconnection's frequency performance and can ~~tighten (or loosen)~~adjust the ε1 values should an Interconnection's frequency performance decline~~ (improve)~~.

Table 3.1: Target Values of "One Minute Frequency Noise"	
Interconnection	**Epsilon 1 (ε1)**

[18] The size of this constant changes over time for BAs with variable bias, but the effect can be ignored when considering minute-to-minute operation. It is equal to -10 * B / ε_1^2

Eastern	18.0 mHz
Quebec	21.0 mHz
Western	22.8 mHz
Texas	30.0 mHz

~~Table Target Values of "One Minute Frequency Noise"~~

The Epsilon 1 target initially set for each Interconnection was on the order of 1.6 times the historic frequency noise. ~~This should permit Balancing Authorities, performing at historic “average” compliance, to score~~This means a typical BAs performance would be around 160% for CPS1. If every BA in an Interconnection were performing with a CPS1 of 100%, it would result in an observed Interconnection frequency performance of ε1 (i.e.18mHz in the East).

Let’s review how CPS1 data can be applied to measure the adequacy of control performance and the deployment of resource-provided services to meet load. NERC ~~refers~~previously referred to these resources as interconnected operating services (~~IOS). Although there are some differences in definitions~~ERSs). More recently, the term essential reliability services is used. These align somewhat to what FERC calls ~~these~~“ancillary services ~~Ancillary Services. ~~.”

Figure 3.3

~~Figure 15 IOS/Ancillary Service Measured via CPS~~

depicts ACE charts for one hour for four different ~~Balancing Authorities. ~~BAs. Compare the charts for ~~Balancing Authorities~~BAs 1 and 2. Both ~~Balancing Authorities~~BAs show good performance for the hour. The difference between them is that the load in ~~Balancing Authority~~BA 2 is “noisier~~”. ~~.”

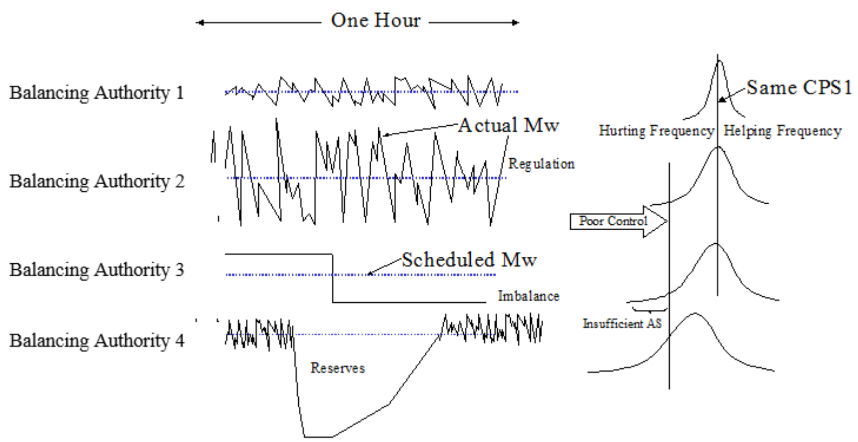


Figure 3.3: ERS/Ancillary Service Measured via CPS

The ~~"bell curves"~~distributions to the right of the ACE charts show the ~~distribution of the~~ individual one-minute CPS1 for both ~~Balancing Authorities~~BAs for the hour. If frequency followed a normal pattern~~,~~ whereby it fluctuated +/- a few mHz from 60 Hz, the CPS1 curves for ~~Balancing Authority~~BA 1 and 2 would look like the ~~"bell curves"~~distributions to the right of their ACE charts. Both curves would have the same average (about 160 percent CPS1), but ~~Balancing Authority~~BA 2's curve would be "wider~~". In other words, the larger ACE swings would sometimes help frequency back to 60 more than Balancing Authority 1, but sometimes hurt frequency more than Balancing Authority 1.~~."

Even though the average effect of ~~Balancing Authority~~BA 1 and 2 on the Interconnection is the same, ~~Balancing Authority~~BA 2 sometimes places a greater burden on the Interconnection~~,~~ as demonstrated by the size of the "left hand tail" of the CPS1 curve. A very long left tail implies poor control of some type (regulation in this case ~~regulation~~).

Now look at ~~Balancing Authority~~BA 3. It is a "generation only" ~~Balancing Authority~~BA that is selling 100 MW for the hour. The problem is that it is meeting this requirement by generating 200 MW for the first 30 minutes and 0 MW for the last half ~~of the~~ hour. Again, if frequency conditions are normal, half the time the ~~Balancing Authority~~BA will be helping frequency back towards 60 Hz and half the time the ~~Balancing Authority~~BA will be hurting frequency. This means the ~~Balancing Authority~~BA will get an "Interconnection average" CPS1 score of about 160 ~~percent~~% for the hour. The graph of its CPS1 for the hour will have wider tails, much like ~~Balancing Authority~~BA 2. The underlying problem in this case is imbalance, not regulation.

The ACE chart for ~~Balancing Authority~~ BA 4 shows that a generator tripped offline during the hour. If the CPS1 one-minute averages are plotted, the curve will also have wider tails. If the unit that was lost was large, the curve will be "skewed" to the left even further. This is because the unit loss will pull frequency down while ACE is a large negative value.

In each case above, there was a deficiency in one of the energy-based ~~IOS (sometimes called ancillary services).~~ ERSs. The "left tail" of the underlying CPS1 curve captured each situation.

~~Extremely positive CPS1 (irrational~~ Balancing Authority ACE Limit

In simple terms, BAAL assigns each BA a share of the responsibility for control~~) is achieved in one of two ways:~~

- ~~Significant over-generation during low frequency. Low frequency is generally associated with high energy prices. Creating positive inadvertent rather than selling energy into a market is irrational.~~
- ~~Significant under-generation during high frequency. If a resource is lost during a period~~ of ~~extended high frequency, there are typically many possible suppliers that can be called upon to help correct the situation.~~

~~Control Performance Standard 2 (CPS2)~~

~~CPS2 is a "safety valve" standard that was put in place when CPS was developed. There was concern that if CPS1 was the only regulating standard, a Balancing Authority could grossly over or under generate (as long as it was opposite the frequency error) and get very good CPS1, yet impact its neighbors with excessive flows.~~

~~shows the general relationship between Balancing Authority size and the size of the L_{10} band for the Eastern~~steady-state Interconnection~~.~~ frequency. The ~~table assumes the Balancing Authorities use the "1% of load" method to determine their Bias obligation.~~

~~BA Size (MW)~~	~~$L_{(10)}$ (MW)~~
~~10~~	~~2~~
~~50~~	~~5~~
~~100~~	~~7~~
~~250~~	~~12~~
~~500~~	~~17~~
~~1000~~	~~23~~
~~2500~~	~~37~~
~~5000~~	~~52~~
~~10000~~	~~74~~
~~15000~~	~~91~~

~~**Table Approximate L10 Limits vs. Balancing Authority Size (Eastern**~~ amount of responsibility is directly related to BA frequency bias and any deviation of Interconnection~~)~~ frequency from the Interconnections scheduled frequency.

The BAAL is calculated from the clock minutes averages of the data as follows:

Frequency Trigger Limits:

- FTL_{High} = Scheduled Frequency + 3*ε1
- FTL_{Low} = Scheduled Frequency - 3*ε1

As an example, for the EI (where epsilon1 = 0.018 mHz) and when the Interconnection is not in a time error correction (TEC) the FTL's are:

- FTL_{High} = 60.054 Hz
- FTL_{Low} = 59.946 Hz

Calculating the BAAL limits when actual frequency <> scheduled frequency:
As an example, for a BA with a frequency bias Setting = -1000MW/0.1Hz

- $BAAL_{Low} = (-10 * B * (FTL_{Low} - F_S)) * ((FTL_{Low} - F_S)/ (F_A-F_S))$
- $BAAL_{Low} = (-10*-1000* (59.946 – 60)) * (59.946 – 60)/ (F_A – 60))$
- $BAAL_{High} = (-10 * B * (FTL_{High} - F_S)) * ((FTL_{High} - F_S)/ (F_A-F_S))$
- $BAAL_{High} = (-10*-1000* (60.054 – 60)) * (60.054 – 60)/ (F_A – 60))$

Results with actual varying frequency are shown in **Table 3.2**.

Table 3.2: Varying Frequency Results		
Actual Frequency	$BAAL_{High}$	$BAAL_{Low}$
60.09	324	NA
60.081	360	NA
60.072	405	NA
60.063	463	NA
60.054	540	NA
60.045	648	NA
60.036	810	NA
60.027	1080	NA
60.018	1620	NA
59.982	NA	-1080
59.973	NA	-720
59.964	NA	-540
59.955	NA	-432
59.946	NA	-360
59.937	NA	-309
59.928	NA	-270
59.919	NA	-240
59.91	NA	-216

The BAAL limits plotted in **Figure 3.4**~~Balancing Authorities using variable Bias have~~ ~~L_{10}~~ ~~limits that change slightly throughout the day.~~

~~CPS2 says that for each 10-minute period, the average ACE for a 1000 MW Balancing Authority must be less than 23 MW. Any clock 10-minute period (there are six per hour) greater than 23 MW (no matter if it's 1 MW more or 100 MW more) is a violation of the limit for that 10-minute period. Performance requires that there be no violations in at least 90% of the 10-minute periods of a month and is calculated by:~~

~~**CPS2 (percent) = 100 * (periods without violations)/(all periods in the month)**~~

detail the acceptable operating area and the BAAL limit exceedance area.

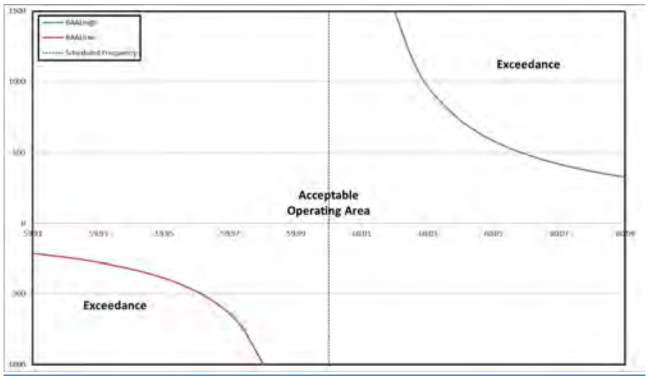


Figure 3.4: Acceptable Operating Area and the BAAL limit exceedance area

As a BA is operating and managing its ACE, the clock-minute averages of ACE are being evaluated against the BAAL limits.

CPS1 Equivalent Limit Derivation

BAAL is mathematically related to CPS1 as shown below:

- By definition; CF = $(RACE/(-10B) * (F_A - F_S))/(\varepsilon_1{}^2)$, and CPS1 = 2-CF
- Substituting for CF; CPS1 = $2-(RACE/(-10B) * (F_A - F_S))/(\varepsilon_1{}^2))$
- Regrouping terms; CPS1 = $2 - RACE * ((F_A - F_S)/(-10B * \varepsilon_1{}^2))$
- Substituting BAAL for RACE; CPS1 = $2 - 9 * (-10B * \varepsilon_1{}^2) / (F_A - F_S) * ((F_A - F_S)/(-10B * \varepsilon_1{}^2))$
- Cancelling out terms; CPS1 = 2 – 9= -7 = -700%

Therefore, a one-minute CPS1 score more negative than -700% will equate to a BAAL exceedance for that one-minute period.

The minimum acceptable ~~CPS2~~time frame for continuous BAAL minute exceedances shall not continue for greater than thirty minutes.

Quick Review

- CPS1 assigns each BA a share of the responsibility for control of Interconnection frequency.
- CPS1 is a yearly (i.e., rolling twelve month~~ is 90%. This means~~) standard that measures impact on ~~the average, a Balancing Authority may have roughly one violation ever other hour and still pass CPS2.~~ frequency error with a 100% minimum allowable score.

~~The actual L10 limits change slightly each year, based on bias calculations submitted to NERC. These limits can be found on the .~~

- BAAL is a 30-minute standard intended to bind a BAs real-time impact on frequency.

~~Chapter 13~~Chapter 4: Tertiary Control

~~The UCTE Operation Handbook defines Tertiary Control as any (automatic or) manual change in the working points of generators (mainly by re-scheduling), in order to restore an adequate SECONDARY CONTROL RESERVE at the right time. This would include actions such as adjustments to scheduled interchange and deployment of additional generation resources.~~

Tertiary Control generally follows disturbances and reserve deployment to reestablish resources for future contingencies. Reserve deployment and reserve restoration following a disturbance are common types of Tertiary Control. See the Operating Reserve Management Reliability Guideline for more information.

Understanding Reserves

There is often confusion when operators and planners talk about reserves. One major reason for ~~misunderstandings~~misunderstanding is a lack of common definitions~~.~~; NERC's definitions have changed over time. In addition, most NERC Regions developed their own definitions. Capacity obligations have historically been the purview of state and provincial regulatory bodies, ~~which means~~meaning that there are many different expectations and obligations across North America.

~~The second area of confusion concerning reserves deals with the limitations of each Balancing Authority's energy management system (EMS). Common problems include:~~

- ~~Counting all "headroom" of on-line units as spinning reserve, even though it may not be available in 10 minutes.~~
- ~~No intelligence in the EMS regarding load management resources.~~
- ~~No corrections for "temperature sensitive" resources such as gas turbines.~~
- ~~Inadequate information on resource limitations and restrictions.~~
- ~~Reserves which may exist and are deployed outside the purview of the EMS system.~~

In order to foster discussion and develop a more uniform understanding of the reserve data, the following definitions are provided in this reference. Refer to **Figure 4.1** to better understand the definitions.

Definitions:

(Capitalized terms are taken from NERC Glossary and lower case are not.)

Contingency Reserve: The provision of capacity deployed by the BA to meet respond to a Balancing ~~Authority to meet the Disturbance Control Standard (DCS)~~Contingency Event and other ~~NERC and Regional Reliability Organization~~ contingency requirements~~.~~

~~**Curtailable Load:** Load that can be disconnected from~~ (such as Energy Emergency Alerts as specified in the associated NERC Standards). This is the ~~system with assurance in less than one hour.~~ left column of Operating Reserves in Figure 4.1

frequency-responsive reserve: On-line generation with headroom that has been tested and verified to be capable of providing droop ~~<= 6% with a deadband <= 36 mHz.~~ as described in the Primary Frequency Response guideline. Variable load that mirrors governor droop and ~~deadband~~dead-band may also be considered frequency responsive reserve. ~~In most cases, only portions of a, b and c in Figure 16 qualify as Frequency Responsive Reserve.~~

Interruptible Load: Demand that the end-use customer makes available to its Load ~~under direct control of an operator~~ Serving Entity via contract or agreement for curtailment that can be interrupted within 10 minutes.

~~**Nonspinning Reserve:** Operating Reserve capable of serving demand or Interruptible Demand that can be removed from the system, within 10 minutes. (This is c in Figure 16)~~

Operating Reserve: That capability above firm system demand required to provide for regulation, load forecasting error, equipment forced and scheduled outages, and local area protection. ~~(This is a+b+c+d+e in).~~

~~Other Reserve Resources: Resources that can be brought to bear outside the continuum of (i.e. on four hours' notice).~~

Operating Reserve–Spinning: Generation synchronized to the system and fully available to serve load within the Disturbance Recovery Period following the contingency event or Load fully removable from the system within the Disturbance Recovery Period following the contingency event deployable in 10 minutes.

Operating Reserve Supplemental: Generation (synchronized or capable of being synchronized to the system) that is fully available to serve load within the Disturbance Recovery Period following the contingency event or Load fully removable from the system within the Disturbance Recovery Period following the contingency event that can be removed from the system, within 10 minutes.

planning reserve: The difference between a ~~Balancing Authority's~~BA's expected annual peak capability and its expected annual peak demand expressed as a percentage of the annual peak demand.

~~**Projected Operating Reserve:** This is a+b+c+d+e in for those resources expected to be deployed (or available in the time windows in) for the point in time in question.~~

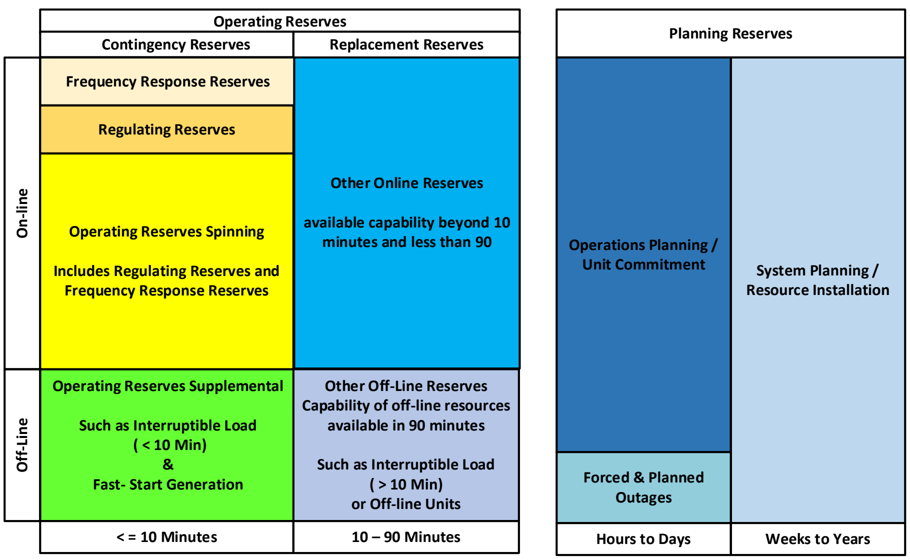
Regulating Reserve: An amount of ~~spinning reserve~~Operating Reserve – Spinning responsive to Automatic Generation Control, which is sufficient to provide normal regulating margin. ~~(This is "a" in .)~~

replacement reserve: ~~(This is d+e in).~~ NOTE: Each NERC Region sets times for reserve restoration, typically in the ~~30~~60–90-minute range. The NERC default contingency reserve restoration period is 90 minutes after the disturbance recovery period.

~~**Spinning Reserve:** Unloaded, synchronized, resource, deployable in 10 minutes. (This is b in).~~

Supplemental Reserve Service: Provides additional capacity from electricity generators that can be used to respond to a contingency within a short period, usually ten minutes. An ancillary service identified in FERC Order 888 as necessary to affect a transfer of electricity between purchasing and selling entities. ~~Also referred to as non-spinning reserve.~~ This is effectively FERC's equivalent to NERC's ~~Non-Spinning reserve (c in).~~Operating Reserve.

Much like parts kept in a storeroom, reserves are meant to be used when the need arises. Reserves can be low for short periods of time due to plant equipment problems and unit trips~~. Reserves~~ and can also be misstated~~. It is important to look at other indicators to determine the ultimate course of action, such as:~~



- ~~Is the Balancing Authority(s)' ACE predominantly negative for an extended period?~~
- ~~Is frequency low (more than 0.03 Hz below scheduled frequency)?~~
- ~~Are reserves low in multiple Balancing Authorities?~~
- ~~Is load trending upward (are higher loads anticipated)?~~

~~Based on the duration and severity of the situation, action steps would include:~~

- ~~Verify reserve levels~~
- ~~Follow EEA~~

- ~~Direct Balancing Authority(s) to take action to restore reserves~~
- ~~Redistribute reserves~~
- ~~Shed load where appropriate if the Balancing Authority or Transmission Operator cannot withstand the next contingency.~~

Figure 4.1: Reserves Continuum

~~Measuring Performance rather than the Commodity~~

~~The traditional measure of resource adequacy is to track operating reserves. A simplified calculation for reserves is Balancing Authority's generating capability minus customer demand. There are actually several different types of reserves (spinning, non-spinning, regulating, contingency, replacement), but all are intended to maintain or restore load-generation balance in different windows of time.~~

~~There are four underlying problems with determining adequacy by measuring reserves as a commodity rather than the performance or outcome (restoring load-generation balance):~~

- ~~Reserves are almost always misstated. Demand forecasts are not precise and projected generating capability may be based on ideal conditions.~~
- ~~Because of the differing requirements across the country (for example, planning reserve obligations are typically the purview of state commissions) the industry has no standard definition for reserves or process for verifying reserves.~~
- ~~Not all Balancing Authorities need the same amount and type of Operating Reserves. Balancing Authorities with large arc furnace loads need more regulating (quick maneuvering) generation than others. Balancing Authorities that can import power from multiple directions need less reserve than a Balancing Authority that has only one neighboring Balancing Authority. Balancing Authorities with less reliable generators or very large generators need more reserves. Balancing Authorities with a preponderance of one fuel source for its generation should have more reserves than neighbors with more diverse fuel supplies.~~
- ~~Rate and quality of response by reserves vary among different generators and are not always predictable. Actual rate of response is often smaller than the value specified for the unit, and other factors, such as the time delay before generators start responding needs to be considered. Balancing Authorities without methods to accurately evaluate and mitigate issues in regulation response need more reserves.~~

~~Even if a Balancing Authority has adequate reserves, it may fail or be unable to deploy them when needed. If, however, a Balancing Authority continuously balances load and resources within objective bounds, it demonstrates through performance that it has enough reserves to meet its needs and fulfill its obligations to the Interconnection.~~

~~Chapter 14~~Chapter 5: Time Control and Inadvertent Interchange

Background

There is a strong interrelationship between control of time error and Inadvertent Interchange~~.~~ (aka. “inadvertent”). Time error occurs when one or more ~~Balancing Authorities~~BAs has imprecise control or large resource losses occur, causing average actual frequency to deviate from scheduled frequency. The bias term in the ACE equation of the remaining ~~Balancing Authorities~~BAs causes control actions that result in flows between ~~Balancing Areas~~BAAs in the opposite direction. The net accumulation of all these interchange errors is referred to as Inadvertent Interchange. Inadvertent interchange represents the amount by which actual flows between ~~Balancing Authority Areas~~BAAs and the remainder of the Interconnection differs from the intended or scheduled flows.

Time Control

As noted earlier, frequency control and balancing control are not perfect. There will always be some errors in tie-line meters. Due to load and generation variation, net ACE in an Interconnection cannot be maintained at zero. This means that frequency will vary from 60 Hz over time.

An Interconnection may have a time control process to maintain the long-term average frequency at 60 Hz. While there are some differences in process, each Interconnection that exercises time control designates ~~a Reliability Coordinator~~an RC as a “time monitor” to coordinate time control.

Time error corrections are initiated when long-term average frequency drifts from 60 Hz. In the ~~Eastern Interconnection~~EI, a 0.02Hz offset to scheduled frequency corrects 1.2 seconds on the clock for each hour of the time error correction, provided the offset scheduled frequency is achieved.

There has been an ongoing debate on the need for time error corrections. The numbers of ~~TECs~~time error corrections do provide a benchmark for the quality of frequency control and ~~also~~provide an early warning of chronic balancing problems. While the value of time control is debatable from a reliability perspective, nobody can say with assurance who or what would be impacted if NERC and NAESB halted the practice of ~~TECs.~~ manual time error corrections. This practice was removed from the standards in 2017.

Inadvertent Interchange

Inadvertent interchange is net imbalance of energy between a ~~Balancing Authority~~BA and the Interconnection. The formula for inadvertent interchange is:

- $NI_I = NI_A - NI_S$

where,

NI_A is net actual interchange. It is the algebraic sum of the hourly integrated energy on a ~~Balancing Authority's~~BAs tie lines. Net actual interchange is positive for power leaving the system and negative for power entering.

NI_S is net scheduled interchange. It is defined as the mutually prearranged net energy to be delivered or received on a ~~Balancing Authority’s~~BAs tie lines. Net scheduled interchange is positive for power scheduled to be delivered from the system and negative for power scheduled to be received into the system.

Inadvertent interchange and can be divided into two categories, described below.

Primary Inadvertent

Primary inadvertent interchange is caused by problems or action from within a given ~~Balancing Authority.~~ BA. Primary inadvertent interchange occurs due to the following:

- Error in scheduled interchange
  - Improper entry of data (time, amount, direction, duration, etc~~…)~~….)
  - Improper update in real-time (TLR miscommunication etc~~…)~~….)
  - Ramp procedures
  - Miscellaneous (phantom schedules, selling off the ties, etc~~…)~~….)
- Error in actual interchange (meter error)
  - Loss of telemetry
  - Differences between real-time power (MW, for ACE), and energy (~~MWhr~~MWh), integrated values
- Control error or offset
  - Load volatility and unpredictability
  - Generation outages
  - Generation uninstructed deviations
  - Physical rate-of-change-of-production limitations
  - Deliberate control offset (i.e. unilateral payback) to reduce inadvertent energy balances

Hourly primary inadvertent can be calculated for each BA by using the following formula:

$$(PII_{hourly}) = (1-Y) * (II_{actual} - Bi * \Delta TE/6)$$

- PII_{hourly} is the BAs primary inadvertent for an operating hour expressed in MWh
- Y is the ratio between a BAs frequency bias setting and the sum of all BAs frequency bias setting within an Interconnection
- Bi is the BAs frequency bias
- ΔTE is the change in time error within the Interconnection that occurred during the operating hour

Secondary Inadvertent

Balancing problems external to a ~~Balancing Authority~~BA will cause off-schedule frequency. If frequency is low, the bias term of the ACE equation will cause a ~~Balancing Authority~~BA to slightly over-generate ~~(~~after initial effects, such as governor response and load damping, stabilize~~) to stabilize~~ frequency. Conversely, if frequency is high, the bias term of the ACE equation will cause ~~a~~ slight under ~~-~~generation. This intentional outflow or inflow to stabilize frequency due to problems outside the ~~Balancing Authority~~BA causes deviation from the schedule and is called secondary inadvertent interchange.

Hourly secondary inadvertent can be derived by subtracting a BA's hourly primary inadvertent from their hourly total inadvertent.

Quick Review: If one or more BAs have a control problem, it could result in a large primary inadvertent interchange. This may also cause off-nominal frequency, potentially spreading Secondary inadvertent interchange to the other BAs. The off-normal frequency then results in accumulated time error, potentially triggering time error corrections.

~~Chapter 15~~Chapter 6: Frequency Correction and Intervention

Background

There are several requirements in ~~the~~ NERC reliability standards that tell the ~~Balancing Authority~~BA, Transmission Operator, and ~~Reliability Coordinator~~RC to monitor ~~frequency~~ and control frequency. The standards do not provide specific guidance on what is normal frequency and under what conditions the operator should intervene. ~~This section provides guidance based on the underlying research done to support the draft Reliability Based Control Standard.~~ The trigger points below are designed for the ~~Eastern Interconnection.~~ EI. There may be differences in the other Interconnections based on their field trial experience.

As noted ~~early~~earlier in this document, this information is provided for guidance and understanding. It should not be used for compliance purposes and does not establish new requirements or obligations.

The ~~Balancing Authority ACE Limit (~~BAAL~~)~~ is the ACE-frequency combination equivalent to instantaneous CPS1 of -~~572%~~[19] ~~.~~700%. In general, if one or more of the RC's ~~Balancing Authorities~~BAs is beyond the BAAL for more than 15 minutes, the RC should contact the ~~Balancing Authority~~BA to determine the underlying cause. As frequency diverges more from 60 Hz, the RC and BA should be more aggressive in their actions.

The primary responsibility of the RCs ~~under the draft Reliability Based Control standard~~ is frequency protection ~~of frequency.~~. Suggested actions are outlined below.

[19] As a clarification, the BAAL is based on a snapshot CPS1 calculation that uses deviation from 60Hz rather than deviation from scheduled frequency.

~~Chapter 16Short-Term Triggers (Reliability Coordinators)~~
~~Chapter 17~~

1. ~~Look for~~Identify BAs within your area beyond BAAL. Direct correction and log. RCs to notify BAs.
2. Call Other RCs, communicate problem if known. Search for cause if none reported. Notify time monitor of findings. Time monitor to log. Direct BAs beyond BAAL to correct ACE.
3. Direct all BAs with ACE hurting frequency to correct. Time monitor to notify ~~Resources Subcommittee (~~RS after the fact~~)~~.
4. Evaluate whether still interconnected. Direct emergency action.

Revision History

Date	Version Number	Reason/Comments
4-5-2011	1.0	Initial Version
9-29-2020	2.0	Resources Subcommittee Review

~~Chapter 18NERC Tools~~

~~Chapter 19~~

~~Short Description of the RS-Sponsored Tools~~

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~~Chapter 20Review Questions~~

~~Chapter 21~~

~~The questions below are intended as a resource for the development of local training programs. Trainers are encouraged to submit additional questions to .~~

~~Primary Control~~

~~1) System frequency:~~

- ~~a) Measures load-resource balance in an Interconnection or island~~
- ~~b) Changes in direct relation to generator voltage~~
- ~~c) Varies from Balancing Authority to Balancing Authority~~
- ~~d) All of the above~~

~~2) How does a Balancing Authority determine the frequency Bias it should use~~

- ~~a) The same value of the previous year unless a new generator is added~~
- ~~b) The greater of generation or load multiplied by the L10 limit~~
- ~~c) Measure the actual response to several frequency deviations~~
- ~~d) None of the above~~

~~3) Generation external to your Balancing Authority has tripped. Which of the following would you expect to see?~~

- ~~a) Frequency above 60 Hz~~
- ~~b) Increased net interchange out~~
- ~~c) Reduced net generation on your system~~
- ~~d) All of the above~~

~~4) The frequency Bias setting used by a Balancing Authority may be calculated:~~

- ~~a) As a fixed value~~
- ~~b) As a variable value~~
- ~~c) Using a percentage of governor droop from jointly owned units for dynamic scheduling or pseudo-tie control~~
- ~~d) All of the above~~
- ~~e) None of the above~~

~~5) The minimum recommended frequency Bias setting used by a Balancing Authority that serves load is:~~

- ~~a) 1 percent of the annual peak demand per 0.1 Hz change~~
- ~~b) 2 percent of the annual peak demand per 0.1 Hz change~~
- ~~c) 5 MW/0.1 Hz~~
- ~~d) 5 MW/0.1 Hz~~
- ~~e) None of the above~~

~~6) The minimum recommended frequency Bias setting for a Balancing Authority that does not serve native load is:~~

- ~~a) 1 percent of the estimated maximum generation level for the upcoming year per 0.1 Hz change~~

- ~~b) 2 percent of the estimated maximum generation level for the upcoming year per 0.1 Hz change~~
- ~~c) 5 MW/0.1 Hz~~
- ~~d) –5 MW/0.1 Hz~~
- ~~e) None of the above~~

~~Use the following data to answer questions 7 and 8.~~

~~Assume a Balancing Authority's Bias setting is –50 MW/0.1 Hz. ACE is initially 0 and frequency is 60.00 Hz. Suddenly, a disturbance elsewhere drops frequency to 59.96 Hz. If the actual Frequency Response characteristic for your Balancing Authority for this event is –35 MW/0.1 Hz:~~

~~7) What direction is the instantaneous inadvertent interchange on your system at 59.96 Hz?~~

- ~~a) Received into your system~~
- ~~b) No inadvertent (0)~~
- ~~c) Delivered out of your system~~
- ~~d) None of the above~~

~~8) What is the direction of your instantaneous ACE at 59.96 Hz?~~

- ~~a) Received into your system~~
- ~~b) ACE is zero~~
- ~~c) Delivered out of your system~~
- ~~d) Not necessarily any of the above~~

~~9) All generator governors have a droop setting. NERC recommends all generator governors be set at a 5% droop. What does a 5% governor droop setting mean?~~

- ~~a) The generating unit is allowed to move 5% of its rated load for a frequency deviation of 0.1 Hz~~
- ~~b) The generating unit is set to cover 5% of the Balancing Authority system load in response to a frequency deviation of 0.1 Hz~~
- ~~c) The generating unit will cover 5% of its rated load in a ten-minute period in response to a frequency deviation of 0.1 Hz~~
- ~~d) The generating unit will cover its entire load range (0 MW to full load) for a 5% change in frequency~~
- ~~e) None of the above~~

~~10) The emergency reserve inherent in the Interconnection's Frequency Response is to be used:~~

- ~~a) Whenever a Balancing Authority cannot afford emergency assistance~~
- ~~b) Only as a temporary source of emergency energy~~
- ~~c) For a period of time not to exceed six hours in a single 24-hour period~~
- ~~d) After all neighboring systems have been polled for emergency capacity availability~~

~~11) When providing a certain type of regulation service, a Balancing Authority must incorporate the frequency Bias setting of the Balancing Authority being controlled into its ACE equation. This type of regulation service is known as:~~

a) ~~Supplemental regulation service~~

b) ~~Secondary regulation service~~

c) ~~Overlap regulation service~~

d) ~~None of the above~~

12) ~~When providing a certain type of regulation service for another Balancing Authority, the providing Balancing Authority uses only its own frequency Bias setting in its ACE equation. It does not incorporate the frequency Bias of the Balancing Authority for which it is providing regulation service. This type of regulation service is known as:~~

a) ~~Primary regulation service~~

b) ~~Supplemental regulation service~~

c) ~~Time correction regulation service~~

d) ~~Overlap regulation service~~

e) ~~None of the above~~

13) ~~A 1,100 MW generator trips in New York causing a large frequency deviation in the Eastern Interconnection. The NERC survey used to measure the response of every Balancing Authority to the deviation is called the:~~

a) ~~Area Interchange Error survey~~

b) ~~Control Performance Standard survey~~

c) ~~Frequency Response Characteristic survey~~

d) ~~None of the above~~

14) ~~If a disturbance reduced the frequency by 0.04 Hz and your Balancing Authority frequency Bias was –100 MW/0.1 Hz, how many MW would your system initially contribute to correcting the problem?~~

a) ~~400 MW~~

b) ~~0.4 MW~~

c) ~~4.0 MW~~

d) ~~40 MW~~

15) ~~Frequency Bias and Frequency Response are:~~

a) ~~Expressed in MW/0.1 Hz.~~

b) ~~One and the same.~~

c) ~~Expressed in MW/cycles of deviation.~~

d) ~~None of the above.~~

16) ~~Frequency Bias serves to:~~

a) ~~Determine the frequency “dead band” of .05 to 1.0 in establishing ACE.~~

b) ~~Determine MW of response obligation to a given change in frequency.~~

c) ~~Determine the amount of time error to be automatically corrected by AGC.~~

d) ~~None of the above is correct.~~

~~17) You are doing a perfect job of maintaining a load-resource balance. A large generator in another Balancing Authority has tripped and frequency has dropped to 59.9 Hz. Your frequency Bias is –50 MW/0.1 Hz. If you have done an equally perfect job of setting your frequency Bias, your ACE should be:~~

~~a) + 50 MW~~

~~b) 0 MW~~

~~c) –50 MW~~

~~d) None of the above~~

~~18) A 1% change in frequency will typically lead to what percent change in the total load?~~

~~a) No change~~

~~b) 0.1%~~

~~c) 1%~~

~~d) 2%~~

~~19) A governor droop setting is such that the MW output changes by 25 MW for a 0.12 Hz change in system frequency. The maximum output of the unit is 500 MW. What is the value of the droop characteristic? (Nominal frequency is 60 Hz.)~~

~~a) 1%~~

~~b) 1.2%~~

~~c) 4%~~

~~d) 5%~~

~~20) A power system has ten units on governor control. The units have different capacities (max MW output) and droop settings. The biggest adjustments in MW output in response to a frequency disturbance will be provided by units that have:~~

~~a) Large capacity; large droop setting~~

~~b) Large capacity; small droop setting~~

~~c) Small capacity; large droop setting~~

~~d) Small capacity; small droop setting~~

~~21) The frequency response characteristic of a power system is defined as:~~

~~a) The nominal frequency of the system; 60 Hz in North America~~

~~b) The change in Interconnection frequency for 100 MW changes in load or generation~~

~~c) The percentage change in system output for a 0.1% change in system frequency~~

~~The MW change in system output for a 0.1 Hz change in system frequency~~

Reliability Guideline: Generating Unit Winter Weather Readiness – Current Industry Practices – Version 3

Action
Approve

Summary
The Event Analysis Subcommittee updated the Reliability Guideline and posted it for a 45-day comment period. They have responded to the comments received and are seeking RSTC approval of the final document.

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Reliability Guideline: Generating Unit Winter Weather Readiness – Current Industry Practices

Triennial review

Richard Hackman, Sr. Event Analysis Advisor

December 3, 2020

RELIABILITY | RESILIENCE | SECURITY

Reliability Guideline Generating Unit Winter Weather Readiness V3

Three Year document review

The majority of changes initially proposed were format and organizational updates, adding wind turbine info and adding links to cold weather resources….

Revision History:

Date	Version	Reason/Comments
~~12/03/~~December 3, 2012	1.0	Initial Version – *Winter Weather Readiness* *(Approved by the Operating Committee March 5, 2013)*
~~06/05/~~June 5, 2017	2.0	Three year document review per the OC Charter *(Approved by the Operating Committee August 23, 2017)*
~~XX/XX/~~June 16, 2020	3.0	Three year document review *(Approved by the Reliability and Security Technical Committee~~RSTC~~ XX XX, 2020)*

Reliability Guideline Generating Unit Winter Weather Readiness V3

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Reliability Guideline

Generating Unit Winter Weather Readiness – Current Industry Practices – Version ~~2~~3

Preamble:

~~The NERC Operating Committee (OC), Planning Committee (PC) and Critical Infrastructure Protection Committee (CIPC) develop Reliability (OC and PC) and Security (CIPC) Guidelines, which include the collective experience, expertise and judgment of the industry.~~ The objective of the reliability guidelines is to distribute key practices and information on specific issues critical to promote and maintain a highly reliable and secure bulk power system (BPS). Reliability guidelines are not binding norms or parameters to the level that compliance to NERC's Reliability Standards are monitored or enforced. Rather, their incorporation into industry practices is strictly voluntary. Reviewing, revising, or developing a program using these practices is highly encouraged.

Footer

Reliability Guideline: Generating Unit Winter Weather Readiness – Current Industry Practices – Version ~~2~~3
Approved by the ~~Operating C~~Reliability and Security Technical Committee on ~~August 24~~XX XX, 20~~17~~20

Reliability Guideline Generating Unit Winter Weather Readiness V3

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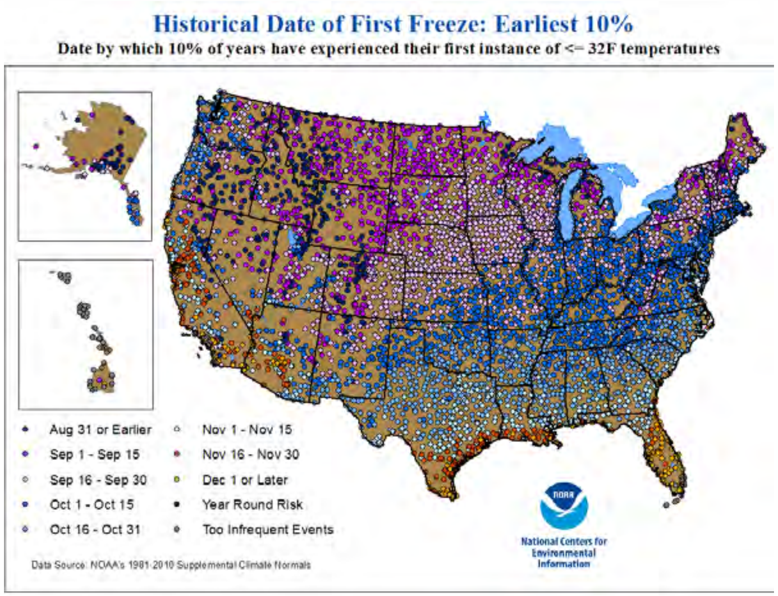
IV. Evaluation of Potential Problem Areas with Critical Components

Identify and prioritize critical components, systems, and other areas of vulnerability which may experience freezing problems or other cold weather operational issues. Schedule any ~~needed~~routine cold weather ~~related~~readiness inspections, repairs, and 'winterization' work to ~~occur~~be completed prior to the local ~~NOAA First Frost Date~~expected seasonal first freeze date. Some additional checks and winterization activities might be needed prior to forecasted extreme winter events. Un-doing winterization should wait until after the local expected seasonal last freeze date~~NOAA Last Frost Date~~ and be completed prior to summer heat arrival. -Links to the NOAA First Frost Date and NOAA Last Frost Date maps are included for reference.



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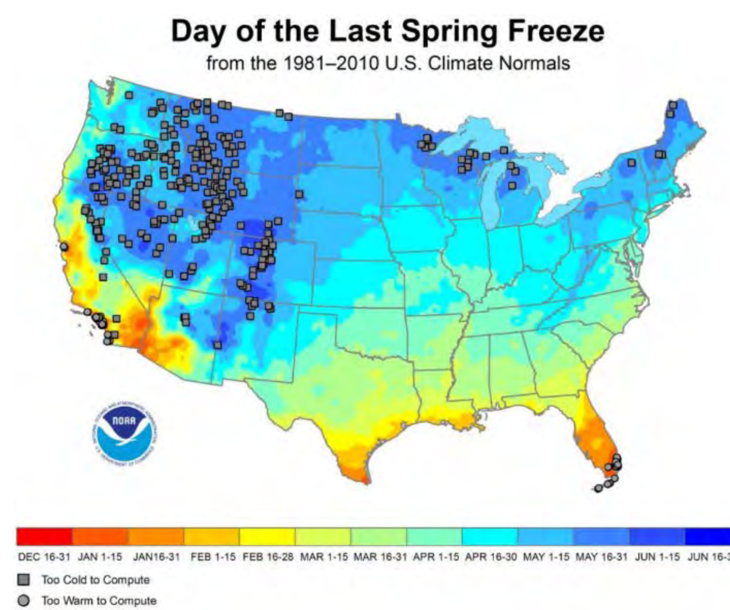

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10. Lube oil and greases for mechanical equipment necessary to support generation in locations that may be exposed to cold weather.

11. Ensure lead acid batteries or other batteries and UPS systems critical to the functioning of the facility are housed in temperature controlled locations and protected from weather.~~Lead acid batteries or other batteries and UPS systems in locations that need protected from weather.~~

12. Adequacy and functional~~l~~ity~~y~~ of heat tracing, insulation, and temperature responsive ventilation (heaters, fans, dampers, & louvers).

Page 6

3. Before and during a severe winter weather event, ~~the~~ affected ~~entity(ies)~~entities will keep ~~the~~their BA up to date on changes to plant availability, capacity, low temperature cut-offs, or other operating limitations. Depending on regional structure and market design, notification to the Reliability Coordinator (RC) and Transmission Operator (TOP) may also be necessary.

Reliability Guideline Generating Unit Winter Weather Readiness V3

Related Documents and Links:

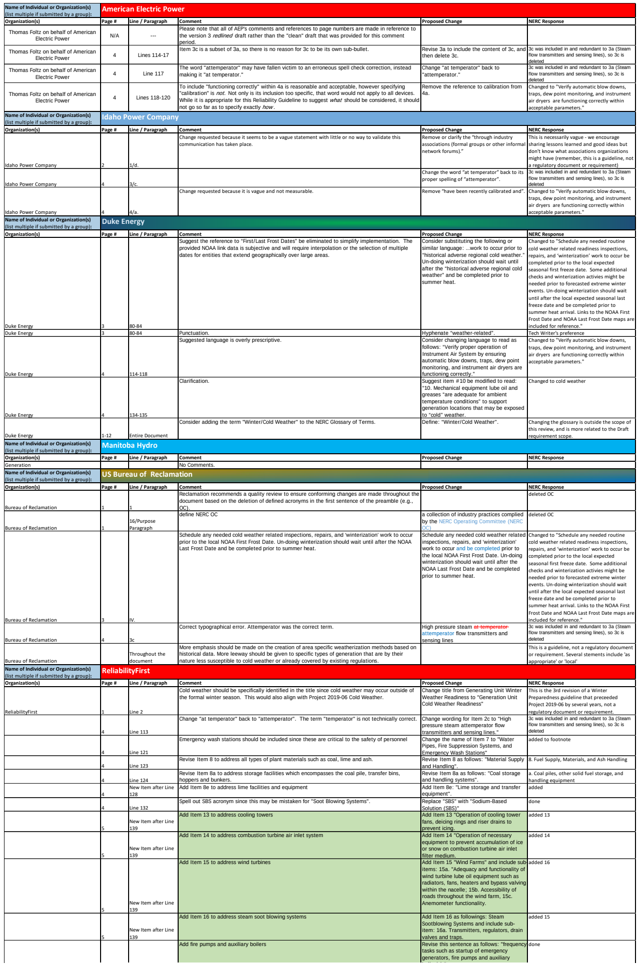
- *Report on Outages and Curtailments during the Southwest Cold Weather Event of February 1-5, 2011*, dated August 2011, Federal Energy Regulatory Commission and North American Electric Reliability Corporation
- 2019 FERC and NERC Staff Report: "The South Central United States Cold Weather Bulk Electric System Event of January 17, 2018"
- *Winter Weather Readiness for Texas Generators*, dated April 13, 2011, Calpine, CPS Energy, LCRA, Luminant, and NRG Energy
- *Electric Reliability Organization Event Analysis Process*, dated January 2017, ERO Event Analysis Process and associated Lessons Learned
- Previous Cold Weather Reports and Training Materials
- There are a number of 'sound practices' from the industry that are detailed in the Southcentral cold weather report, starting on page 100. Link to the report: https://www.ferc.gov/legal/staff-reports/2019/07-18-19-ferc-nerc-report.pdf

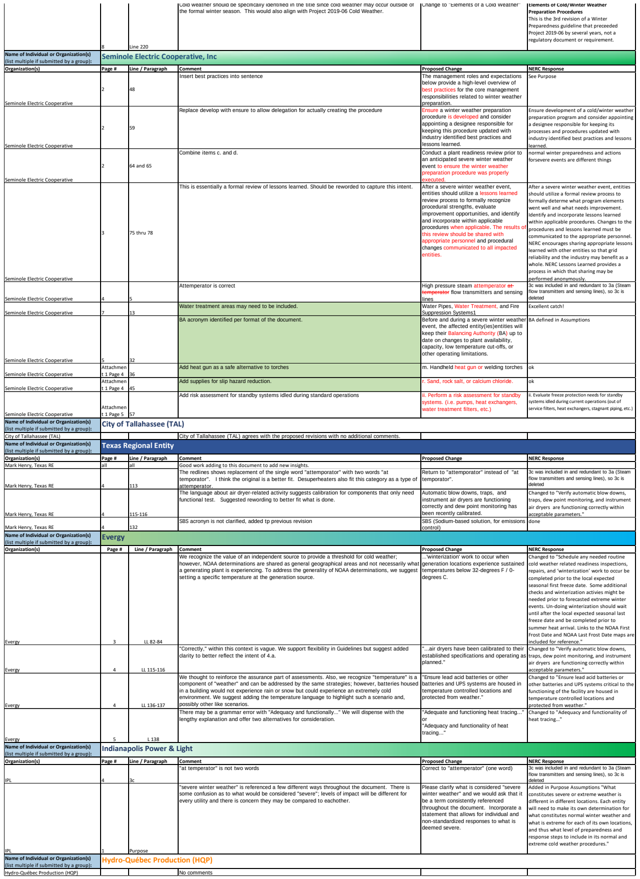
Cold weather related Lessons Learned:

- LL20110902 – "Adequate Maintenance and Inspection of Generator Freeze Protection"
- LL20110903 - "Generating Unit Temperature Design Parameters and Extreme Winter Conditions"
- LL20111001 - "Plant Instrument and Sensing Equipment Freezing Due to Heat Trace and Insulation Failures"
- LL20120101 – "Plant Onsite Material and Personnel Needed for a Winter Weather Event"
- LL20120102 – "Plant Operator Training to Prepare for a Winter Weather Event"
- LL20120103 – "Transmission Facilities and Winter Weather Operations"
- LL20120901 – "Wind Farm Winter Storm Issues"
- LL20120902 – "Transformer Oil Level Issues During Cold Weather"
- LL20120903 – "Winter Storm Inlet Air Duct Icing"
- LL20120904 – "Capacity Awareness During an Energy Emergency Event"
- LL20120905 – "Gas and Electricity Interdependency"
- LL20180702 – "Preparing Circuit Breakers for Operation in Cold Weather"
- LL20200601 – "Unanticipated Wind Generation Cutoffs during a Cold Weather Event"

Reliability Guideline Generating Unit Winter Weather Readiness V3

Most entity comments were directed at language and equipment already in version 2. There were real improvements in Program / Procedure(s) language, and recognition of generator / location differences…





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Page 1

a collection of best industry practices compiled by ~~the~~ NERC ~~OC~~. While the incorporation of these practices is strictly voluntary, developing a winter weather readiness program using these practices in keeping with local conditions is highly encouraged to promote and achieve the highest levels of reliability for these high impact weather events.

Assumptions:

1. Each BPS Generator Owner (GO) and Generator Operator (GOP) is responsible and accountable for maintaining generating unit reliability. It is recognized that nuclear power plants, in keeping with NRC regulation and INPO guidance already have more detailed Winterization and Summerization procedures than are expected by this document.

2. Balancing Authorities (BAs) and Market Operators should consider strategies to start-up and dispatch to minimum load prior to anticipated severe cold weather units that are forecasted to be needed for the surge in demand, since keeping units running through exceptional cold snaps can be accomplished much more reliably than attempting start-up of offline generation during such events. Entities should develop and apply plant-specific winter weather readiness plans, as appropriate, based on factors such as geographical location, technology and plant configuration.

~~2.~~3. What constitutes severe or extreme weather is different in different locations. Each entity will need to make its own determination for what constitutes normal winter weather and what is extreme for each of its own locations, and thus what level of preparedness and response steps to include in its normal and extreme cold weather procedures.

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Page 2

2. Plant Management

   a. Ensure ~~D~~development of a cold/winter weather preparation ~~procedure~~ program and consider appointing a designee responsible for keeping ~~this~~ its processes and procedures updated with industry identified best practices and lessons learned.

Page 3

After a severe winter weather event, entities should utilize a formal review process to ~~formally recognize procedural strengths~~ determine what program elements went well and what needs improvement.~~,~~ ~~evaluate improvement opportunities, and I~~identify and incorporate lessons learned within applicable procedures. Changes to the procedures and lessons learned must be communicated to the appropriate personnel. NERC encourages sharing appropriate lessons learned with other entities so that grid reliability and the industry may benefit as a whole. NERC Lessons Learned provides a process in which that sharing may be performed anonymously.

Reliability Guideline Generating Unit Winter Weather Readiness V3

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3. Critical Flow Transmitters
   a. Steam flow transmitters and sensing lines
   b. Feed water pump flow transmitters and sensing lines
   ~~c. High pressure steam attemperatorat temperator flow transmitters and sensing lines~~
4. Instrument Air System
   a. Verify ~~A~~automatic blow downs, traps, dew point monitoring, and instrument air dryers ~~have been recently calibrated and~~ are functioning correctly within acceptable parameters.
   b. Low point drain lines are periodically drained by operators to remove moisture during extreme cold weather.
5. Motor-Operated Valves, Valve Positioners, and Solenoid Valves
6. Drain Lines, Steam Vents, and Intake Screens
7. Water Pipes, Water Treatment, and Fire Suppression Systems[1]
   a. Low/no water flow piping systems
8. Fuel Supply, Materials, and Ash Handling
   a. Coal piles, other solid fuel storage, and ~~coal~~ handling equipment
   b. Transfer systems for backup fuel supply
   c. Gas supply regulators, other valves, and instrumentation (may require coordination with gas pipeline operator)
   d. Ash disposal systems and associated equipment

[1] For safety reasons, fire protection systems should also be included in this identification process. These problem areas should be noted in the site specific winter weather preparation procedure.

Reliability Guideline Generating Unit Winter Weather Readiness V3

~~d.~~e. Lime storage and transfer equipment

9. Tank Heaters
   a. Conduct initial tests
   b. Check availability of spare heaters
   c. Record current tanks indicators for sodium-based solution (SBS) injection systems, flue gas desulfurization systems, dibasic acid additives, mercury control additives, etc.

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10. Lube oil and greases for mechanical equipment necessary to support generation in locations that may be exposed to cold weather.
11. Ensure lead acid batteries or other batteries and UPS systems critical to the functioning of the facility are housed in temperature controlled locations and protected from weather.~~Lead acid batteries or other batteries and UPS systems in locations that need protected from weather.~~
12. Adequacy and functional~~l~~ity~~y~~ of heat tracing, insulation, and temperature responsive ventilation (heaters, fans, dampers, & louvers).
13. Adjust operation of cooling tower fans, deicing rings and riser drains to prevent icing.
14. Operation of necessary equipment to prevent accumulation of ice or snow on combustion turbine air inlet filter medium
15. Steam Sootblowing Systems (Transmitters, regulators, drain valves and traps)
16. Wind Farms
    a. Adequacy and functionality of wind turbine lube oil equipment such as radiators, fans, heaters and bypass valving within the nacelle
    b. Accessibility of roads throughout the wind farm
    c. Anemometer functionality.

Reliability Guideline Generating Unit Winter Weather Readiness V3

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~~Attachment 1~~

Attachment 1

Elements of ~~a~~ Cold/Winter Weather Preparation Procedures[3]

d. Heaters and heat lamps

i. Ensure operation of all permanently mounted and portable heaters.

ii. Evaluate plant electrical circuits to ensure they have enough capacity to handle the additional load. Circuits with ground fault interrupters (GFIs) should be continuously monitored to make sure they have not tripped due to condensation.

iii. Steps should be taken to prevent unauthorized relocation of heating elements~~Fasten heaters and heat lamps in place to prevent unauthorized relocation~~.

Reliability Guideline Generating Unit Winter Weather Readiness V3

l. Instrumentation tubing
m. Heat guns or ~~H~~handheld welding torches
n. Ice removal chemicals and equipment
o. Snow removal equipment
p. Cold weather personal protective equipment (PPE) available to personnel as appropriate.
q. Properly winterized service vehicles functioning 4WD
~~q.~~r. Supplies for slip hazard reduction such as sand, rock salt, or calcium chloride

i. Monitor room temperatures, as required, so that instrumentation and equipment in enclosed spaces (e.g. pump rooms) don't freeze.

~~i.~~ii. Evaluate freeze protection needs for standby systems idled during current operations (out of service filters, heat exchangers, stagnant piping, etc.)

Questions and Answers

NERC
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Reliability Guideline

Generating Unit Winter Weather Readiness – Current Industry Practices – Version 3

Preamble:

The objective of the reliability guidelines is to distribute key practices and information on specific issues critical to promote and maintain a highly reliable and secure bulk power system (BPS). Reliability guidelines are not binding norms or parameters to the level that compliance to NERC's Reliability Standards are monitored or enforced. Rather, their incorporation into industry practices is strictly voluntary. Reviewing, revising, or developing a program using these practices is highly encouraged.

Purpose:

This reliability guideline is applicable to electricity sector organizations responsible for the operation of the BPS. Although this guideline was developed as a result of an unusual cold weather event in an area not normally exposed to freezing temperatures, it provides a general framework for developing an effective winter weather readiness program for generating units throughout North America. The focus is on maintaining individual unit reliability and preventing future cold weather related events. This document is a collection of best industry practices compiled by NERC. While the incorporation of these practices is strictly voluntary, developing a winter weather readiness program using these practices in keeping with local conditions is highly encouraged to promote and achieve the highest levels of reliability for these high impact weather events.

Assumptions:

1. Each BPS Generator Owner (GO) and Generator Operator (GOP) is responsible and accountable for maintaining generating unit reliability. It is recognized that nuclear power plants, in keeping with NRC regulation and INPO guidance already have more detailed Winterization and Summerization procedures than are expected by this document.
2. Balancing Authorities (BAs) and Market Operators should consider strategies to start-up and dispatch to minimum load prior to anticipated severe cold weather units that are forecasted to be needed for the surge in demand, since keeping units running through exceptional cold snaps can be accomplished much more reliably than attempting start-up of offline generation during such events. Entities should develop and apply plant-specific winter weather readiness plans, as appropriate, based on factors such as geographical location, technology and plant configuration.
3. What constitutes severe or extreme weather is different in different locations. Each entity will need to make its own determination for what constitutes normal winter weather and what is extreme for each of its own locations, and thus what level of preparedness and response steps to include in its normal and extreme cold weather procedures.

Guideline Details:

An effective winter weather readiness program, which includes severe winter weather event preparedness, should generally address the following components: (I) Safety; (II) Management Roles and Expectations;

(III) Processes and Procedures; (IV) Evaluation of Potential Problem Areas with Critical Components; (V) Testing; (VI) Training; and (VII) Communications.

I. Safety

Safety remains the top priority during winter weather events. Job safety briefings should be conducted during preparation for and in response to these events. Robust safety programs to reduce risk to personnel include identifying hazards involving cold weather such as personnel exposure risk, travel conditions, and slip/fall issues due to icing. A Job Safety Analysis (JSA) should be completed to address the exposure risks, travel conditions and slips/falls related to icing conditions. Winter weather Alerts should be communicated to all impacted entities. A Business Continuity and Emergency Response Plan should also be available and communicated in the event of a severe winter weather event.

II. Management Roles and Expectations

Management plays an important role in maintaining effective winter weather programs. The management roles and expectations below provide a high-level overview of the core management responsibilities related to winter weather preparation. Each entity should tailor these roles and expectations to fit within their own corporate structure.

1. Senior Management
   a. Set expectations for safety, reliability, and operational performance.
   b. Ensure that a winter weather preparation procedure exists for each operating location.
   c. Consider a fleet-wide annual winter preparation meeting, training exercise, or both to share best practices and lessons learned.
   d. Share insights across the fleet and through industry associations (formal groups or other informal networking forums).
2. Plant Management
   a. Ensure development of a cold/winter weather preparation program and consider appointing a designee responsible for keeping its processes and procedures updated with industry identified best practices and lessons learned.
   b. Ensure the site specific winter weather preparation procedure includes processes, staffing plans, and timelines that direct all key activities before, during, and after severe winter weather events.
   c. Ensure proper execution of the winter weather preparation procedures.
   d. Conduct a plant readiness review prior to an anticipated severe winter weather event.
   e. Encourage plant staff to look for areas at risk due to winter conditions and bring up opportunities to improve readiness and response.
   f. Following each winter, conduct an evaluation of the effectiveness of the winter weather preparation procedure and incorporate lessons learned.

III. Processes and Procedures

Winter weather preparation procedure should be developed for seasonal winter preparedness. Components of effective winter weather preparation procedures are included as Attachment 1.

After a severe winter weather event, entities should utilize a formal review process to determine what program elements went well and what needs improvement. Identify and incorporate lessons learned within applicable procedures. Changes to the procedures and lessons learned must be communicated to the appropriate personnel. NERC encourages sharing appropriate lessons learned with other entities so that grid reliability and the industry may benefit as a whole. NERC Lessons Learned provides a process in which that sharing may be performed anonymously.

IV. Evaluation of Potential Problem Areas with Critical Components

Identify and prioritize critical components, systems, and other areas of vulnerability which may experience freezing problems or other cold weather operational issues. Schedule any routine cold weather readiness inspections, repairs, and 'winterization' work to be completed prior to the local expected seasonal first freeze date. Some additional checks and winterization activities might be needed prior to forecasted extreme winter events. Un-doing winterization should wait until after the local expected seasonal last freeze date and be completed prior to summer heat arrival. Links to the NOAA First Frost Date and NOAA Last Frost Date maps are included for reference.

This includes critical instrumentation or equipment that has the potential to:

1. Initiate an automatic unit trip,
2. Impact unit start-up,
3. Initiate automatic unit runback schemes or cause partial outages,
4. Cause damage to the unit,
5. Adversely affect environmental controls that could cause full or partial outages,
6. Adversely affect the delivery of fuel or water to the units,
7. Cause operational problems such as slowed or impaired field devices, or
8. Create a weather-related safety hazard

Based on previous cold weather events, a list of typical problem areas are identified below. This is not meant to be an all-inclusive list. Individual entities should review their plant design and configuration, identify areas with critical components' potential exposure to the elements, ambient temperatures, or both and tailor their plans to address them accordingly.

1. Critical Level Transmitters
   a. Drum level transmitters and sensing lines
   b. Condensate tank level transmitters and sensing lines
   c. De-aerator tank level transmitters and sensing lines

   d. Hotwell level transmitters and sensing lines
   e. Fuel oil tank level transmitters/indicators
2. Critical Pressure Transmitters
   a. Gas turbine combustor pressure transmitters and sensing lines
   b. Feed water pump pressure transmitters and sensing lines
   c. Condensate pump pressure transmitters and sensing lines
   d. Steam pressure transmitters and sensing lines
3. Critical Flow Transmitters
   a. Steam flow transmitters and sensing lines
   b. Feed water pump flow transmitters and sensing lines
4. Instrument Air System
   a. Verify automatic blow downs, traps, dew point monitoring, and instrument air dryers are functioning correctly within acceptable parameters.
   b. Low point drain lines are periodically drained by operators to remove moisture during extreme cold weather.
5. Motor-Operated Valves, Valve Positioners, and Solenoid Valves
6. Drain Lines, Steam Vents, and Intake Screens
7. Water Pipes, Water Treatment, and Fire Suppression Systems[1]
   a. Low/no water flow piping systems
8. Fuel Supply, Materials, and Ash Handling
   a. Coal piles, other solid fuel storage, and handling equipment
   b. Transfer systems for backup fuel supply
   c. Gas supply regulators, other valves, and instrumentation (may require coordination with gas pipeline operator)
   d. Ash disposal systems and associated equipment
   e. Lime storage and transfer equipment
9. Tank Heaters
   a. Conduct initial tests
   b. Check availability of spare heaters

[1] For safety reasons, fire protection systems should also be included in this identification process. These problem areas should be noted in the site specific winter weather preparation procedure.

   c. Record current tanks indicators for sodium-based solution (SBS) injection systems, flue gas desulfurization systems, dibasic acid additives, mercury control additives, etc.

10. Lube oil and greases for mechanical equipment necessary to support generation in locations that may be exposed to cold weather.
11. Ensure lead acid batteries or other batteries and UPS systems critical to the functioning of the facility are housed in temperature controlled locations and protected from weather.
12. Adequacy and functionality of heat tracing, insulation, and temperature responsive ventilation (heaters, fans, dampers, & louvers).
13. Adjust operation of cooling tower fans, deicing rings and riser drains to prevent icing.
14. Operation of necessary equipment to prevent accumulation of ice or snow on combustion turbine air inlet filter medium
15. Steam Sootblowing Systems (Transmitters, regulators, drain valves and traps)
16. Wind Farms
    a. Adequacy and functionality of wind turbine lube oil equipment such as radiators, fans, heaters and bypass valving within the nacelle
    b. Accessibility of roads throughout the wind farm
    c. Anemometer functionality.

Potential vulnerabilities associated with emergency generators, including Blackstart Resources, should be evaluated when developing the site specific winter weather preparation procedure, as they may provide critical system(s) backup.

V. Testing[2]

In addition to the typical problem areas identified above, emphasis should be placed on the testing of low frequency tasks such as startup of emergency generators, fire pumps and auxiliary boilers, where applicable.

VI. Training

Coordinate annual training in winter specific and plant specific awareness and maintenance training. This may include response to freeze protection panel alarms, troubleshooting and repair of freeze protection circuitry, identification of plant areas most affected by winter conditions, review of special inspections or rounds implemented during severe weather, fuel switching procedures, knowledge of the ambient temperature for which the freeze protection system is designed, and lessons learned from previous experiences or the NERC Lessons Learned program.

1. Consider holding a winter readiness meeting on an annual basis to highlight preparations and expectations for severe cold weather.

[2] See Attachment 1, Section 8 “Special Operations Instruction” for more information

2. Operations personnel should review cold weather scenarios affecting instrumentation readings, alarms, and other indications on plant control systems.
3. Ensure appropriate NERC Generation Availability Data Systems (GADS) coding for unit derates or trips as a result of severe winter weather events to promote lessons learned, knowledge retention, and consistency. Examples may include NERC GADS code 9036 “Storms (ice, snow, etc.)” or code 9040 “Other Catastrophe.”

VII. Winter Event Communications

Clear and timely communication is essential to an effective program. Key communication points should include the following:

1. Before a severe winter weather event, plant management should communicate with their appropriate senior management that the site specific winter weather preparation procedure, checklists, and readiness reviews have been completed.
2. Before and during a severe winter weather event, communicate with all personnel about changing conditions and potential areas of concern to heighten awareness around safe and reliable operations.
3. Before and during a severe winter weather event, affected entities will keep their BA up to date on changes to plant availability, capacity, low temperature cut-offs, or other operating limitations. Depending on regional structure and market design, notification to the Reliability Coordinator (RC) and Transmission Operator (TOP) may also be necessary.
4. After a generating plant trip, derate, or failure to start due to severe winter weather, Plant Management, as appropriate, should conduct an analysis, develop lessons learned, and incorporate good industry practices.
   a. This process should include a feedback loop to enhance current winter weather readiness programs, processes, procedures, checklists and training (continuous improvement).
   b. Sharing of technical information and lessons learned through the NERC Event Analysis Program or some other method is encouraged.

Related Documents and Links:

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- Previous Cold Weather Reports and Training Materials
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Attachment 1
Elements of Cold / Winter Weather Preparation Procedures[3]

This Attachment provides some key points to address in each of the winter weather preparation procedure elements, including severe winter weather event preparedness. These are not all inclusive lists. Individual entities should review their plant design and configuration, identify areas of potential exposure to the elements and ambient temperatures, and tailor their plans to address them accordingly.

1. Work Management System
    a. Review Work Management System to ensure adequate annual preventative work orders exist for freeze protection and winter weather preparedness.
    b. Ensure all freeze protection and winter weather preparedness preventative work orders are completed prior to the onset of the winter season.
    c. Review Work Management System for open corrective maintenance items that could affect plant operation and reliability in winter weather, and ensure that they are completed prior to the onset of the winter season.
    d. As appropriate to your climate, suspend freeze protection measures and remove freeze protection equipment after the last probable freeze of the winter. This may be a plant specific date established by senior management.
    e. Ensure all engineered modification and construction activities are performed such that the changes maintain winter readiness for the plant. Newly built plants or engineered modifications can be more susceptible to winter weather.
2. Critical instrumentation and equipment protection
    a. Ensure all critical site specific problem areas (as noted above in section IV. Evaluation of Potential Problem Areas with Critical Components) have adequate protection to ensure operability during a severe winter weather event. Emphasize the points in the plant where equipment freezing would cause a generating plant trip, derate, or failure to start.
    b. Develop a list of critical instruments and transmitters that require maintenance prior to winter and increase surveillance during severe winter weather events.
3. Insulation, heat trace, and other protection options – Ensure processes and procedures verify adequate protection and necessary functionality (by primary or alternate means) before and during winter weather. Consider the effect of wind chill when applying freeze protection. Considerations include but are not limited to:
    a. Insulation thickness, quality and proper installation

[3] Plants that will remain offline during the winter season would not need to perform winterization preparations unless it is necessary for asset protection/preservation.

   i. Verify the integrity of the insulation on critical equipment identified in the winter weather preparation procedure. Following any maintenance, insulation should be re-installed to original specifications.

b. Heat trace capability and electrical continuity/ground faults

   i. Perform a complete evaluation of all heat trace lines, heat trace power supplies (including all breakers, fuses, and associated control systems) to ensure they maintain their accuracy. Label heat tracing and insulation in the field in reference to the circuit feed panel to reduce troubleshooting and repair times. This inspection may include checking for loose connections, broken wires, corrosion, and other damage to the integrity of electrical insulation that could lead to heat trace malfunctioning. Measure heat trace amperage and voltage, if possible, to determine whether the circuits are producing the design output. If there are areas where heat tracing is not functional, an alternate means of protection should be identified in the winter weather preparation procedure.

   ii. Evaluation of heat trace and insulation on critical lines should be performed during new installation, during regular maintenance activities, or if damage or inappropriate installation is identified (i.e., wrapped around the valve and not just across the valve body).

      (1) For example, inspect heat tracing before it is covered by insulation, to confirm that the extra cable length specified by the designer, for the purpose of being concentrated at valves and supports, has not been applied as a constant-pitch spiral over the length of the line.

   iii. Re-install removed or disturbed heat tracing following any equipment maintenance to restore heat tracing integrity and equipment protection.

   iv. Update and maintain all heat tracing circuit drawings and labeling inside cabinets.

   v. Require a report of calculations from the heat tracing contractor and ensure that their design basis is consistent with the insulation that will be applied with regards to exposure of valve bonnets, actuator, and pipe supports.

c. Wind breaks

   i. Install permanent or temporary wind barriers as deemed appropriate to protect critical instrument cabinets, heat tracing and sensing lines.

d. Heaters and heat lamps

   i. Ensure operation of all permanently mounted and portable heaters.

   ii. Evaluate plant electrical circuits to ensure they have enough capacity to handle the additional load. Circuits with ground fault interrupters (GFIs) should be continuously monitored to make sure they have not tripped due to condensation.

   iii. Steps should be taken to prevent unauthorized relocation of heating elements.

e. Covers, enclosures, and buildings

   i. Enclose cold-weather sensitive critical transmitters in enclosures with local heating elements.
   ii. Install covers on valve actuators to prevent ice accumulation.
   iii. Inspect building penetrations, windows, doors, fan louvers, and other openings for potential exposure of critical equipment to the elements.

4. Supplemental equipment – Prior to the onset of the winter season, inspect and ensure adequate inventories of all commodities, equipment and other supplies that would aid in severe winter weather event preparation or response, and ensure that they are readily available to plant staff. Supplemental equipment might include:
   a. Tarps
   b. Portable heaters, heat lamps, or both
   c. Scaffolding
   d. Blankets
   e. Extension cords
   f. Kerosene/propane
   g. Temporary enclosures
   h. Temporary insulation
   i. Plastic rolls
   j. Portable generators
   k. Portable lighting
   l. Instrumentation tubing
   m. Heat guns or handheld welding torches
   n. Ice removal chemicals and equipment
   o. Snow removal equipment
   p. Cold weather personal protective equipment (PPE) available to personnel as appropriate.
   q. Properly winterized service vehicles functioning 4WD
   r. Supplies for slip hazard reduction such as sand, rock salt, or calcium chloride
5. Operational supplies – Prior to the onset of a severe winter weather event, conduct an inventory of critical supplies needed to keep the plant operational. Appropriate deliveries should be scheduled based on the severity of the event, lead times, etc. Operational supplies might include:
   a. Aluminum sulfate
   b. Anhydrous ammonia
   c. Aqueous ammonia

   d. Carbon dioxide
   e. Caustic soda
   f. Chlorine
   g. Diesel fuel
   h. Ferric chloride
   i. Gasoline (unleaded)
   j. Hydrazine
   k. Hydrogen
   l. Sulfuric acid
   m. Calibration gases
   n. Lubricating oils (lighter grades or synthetic)
   o. Welding supplies
   p. Limestone

6. Staffing (as necessary)
   a. Enhanced staffing (24x7) during severe winter weather events.
   b. Arrangements for lodging and meals.
   c. Arrangements for transportation.
   d. Arrangements for support and appropriate staffing from responsible entity for plant switchyard to ensure minimal line outages.
   e. Arrangements for storage of in-house food inventories for extended work shifts.
   f. Arrangements for on-site lodging during severe winter weather events.

7. Communications
   a. Identify appropriate communication protocols to follow during a severe winter weather event.
   b. Identify and verify operations of a back-up communication option in case the Interpersonal Communications capability is not available (i.e. satellite phone).
   c. Include availability of Interpersonal Communication capability and available back-up communication options in job safety briefing for severe winter weather events.

8. Special operations instruction (just prior to or during a severe winter weather event) as appropriate.
   a. Utilize the “buddy system” during severe winter weather events to promote personnel safety.
   b. Utilize cold weather checklists to verify critical equipment is protected – i.e. pumps running, heaters operating, igniters tested, barriers in place, temperature gauges checked, etc.

i. Monitor room temperatures, as required, so that instrumentation and equipment in enclosed spaces (e.g. pump rooms) don't freeze.

ii. Evaluate freeze protection needs for standby systems idled during current operations (out of service filters, heat exchangers, stagnant piping, etc.)

c. Test dual fuel capability where applicable. Identify alternate suppliers of fuel as necessary. Ensure that alternate fuel suppliers are capable of delivering required quantities of fuel during adverse winter conditions

d. Initiate pre-warming and/or early start-up, of scheduled units prior to a forecasted severe winter weather event.

e. Run emergency generators immediately prior to severe winter weather events to help ensure availability. Review fuel quality and quantity.

f. Place in service critical equipment such as intake screen wash systems, cooling towers, auxiliary boilers, and fuel handling equipment, where freezing weather could adversely impact operations or forced outage recovery.

Reliability Guideline

Generating Unit Winter Weather Readiness – Current Industry Practices – Version ~~2~~3

Preamble:
~~The NERC Operating Committee (OC), Planning Committee (PC) and Critical Infrastructure Protection Committee (CIPC) develop Reliability (OC and PC) and Security (CIPC) Guidelines, which include the collective experience, expertise and judgment of the industry.~~ The objective of the reliability guidelines is to distribute key practices and information on specific issues critical to promote and maintain a highly reliable and secure bulk power system (BPS). Reliability guidelines are not binding norms or parameters to the level that compliance to NERC's Reliability Standards are monitored or enforced. Rather, their incorporation into industry practices is strictly voluntary. Reviewing, revising, or developing a program using these practices is highly encouraged.

Purpose:
This reliability guideline is applicable to electricity sector organizations responsible for the operation of the BPS. Although this guideline was developed as a result of an unusual cold weather event in an area not normally exposed to freezing temperatures, it provides a general framework for developing an effective winter weather readiness program for generating units throughout North America. The focus is on maintaining individual unit reliability and preventing future cold weather related events. This document is a collection of best industry practices compiled by ~~the~~ NERC ~~OC~~. While the incorporation of these practices is strictly voluntary, developing a winter weather readiness program using these practices in keeping with local conditions is highly encouraged to promote and achieve the highest levels of reliability for these high impact weather events.

Assumptions:

1. Each BPS Generator Owner (GO) and Generator Operator (GOP) is responsible and accountable for maintaining generating unit reliability. It is recognized that nuclear power plants, in keeping with NRC regulation and INPO guidance already have more detailed Winterization and Summerization procedures than are expected by this document.
2. Balancing Authorities (BAs) and Market Operators should consider strategies to start-up and dispatch to minimum load prior to anticipated severe cold weather units that are forecasted to be needed for the surge in demand, since keeping units running through exceptional cold snaps can be accomplished much more reliably than attempting start-up of offline generation during such events. Entities should develop and apply plant-specific winter weather readiness plans, as appropriate, based on factors such as geographical location, technology and plant configuration.
3. ~~2.~~3. What constitutes severe or extreme weather is different in different locations. Each entity will need to make its own determination for what constitutes normal winter weather and what is extreme for each of its own locations, and thus what level of preparedness and response steps to include in its normal and extreme cold weather procedures.

Guideline Details:

An effective winter weather readiness ~~procedure~~program, which includes severe winter weather event preparedness, should generally address the following components: (I) Safety; (II) Management Roles and Expectations; (III) Processes and Procedures; (IV) Evaluation of Potential Problem Areas with Critical Components; (V) Testing; (VI) Training; and (VII) Communications.

I. Safety

Safety remains the top priority during winter weather events. Job safety briefings should be conducted during preparation for and in response to these events. Robust safety programs to reduce risk to personnel include identifying hazards involving cold weather such as personnel exposure risk, travel conditions, and slip/fall issues due to icing. A Job Safety Analysis (JSA) should be completed to address the exposure risks, travel conditions and slips/falls related to icing conditions. Winter weather Alerts should be communicated to all impacted entities. A Business Continuity and Emergency Response Plan should also be available and communicated in the event of a severe winter weather event.

II. Management Roles and Expectations

Management plays an important role in maintaining effective winter weather programs. The management roles and expectations below provide a high-level overview of the core management responsibilities related to winter weather preparation. Each entity should tailor these roles and expectations to fit within their own corporate structure.

1. Senior Management
    a. Set expectations for safety, reliability, and operational performance.
    b. Ensure that a winter weather preparation procedure exists for each operating location.
    c. Consider a fleet-wide annual winter preparation meeting, training exercise, or both to share best practices and lessons learned.
    d. Share insights across the fleet and through industry associations (formal groups or other informal networking forums).
2. Plant Management
    a. Ensure ~~D~~development of a cold/winter weather preparation ~~procedure~~ program and consider appointing a designee responsible for keeping ~~this~~ its processes and procedures updated with industry identified best practices and lessons learned.
    b. Ensure the site specific winter weather preparation procedure includes processes, staffing plans, and timelines that direct all key activities before, during, and after severe winter weather events.
    c. Ensure proper execution of the winter weather preparation procedures.
    d. Conduct a plant readiness review prior to an anticipated severe winter weather event.
    e. Encourage plant staff to look for areas at risk due to winter conditions and bring up opportunities to improve readiness and response.

f. Following each winter, conduct an evaluation of the effectiveness of the winter weather preparation procedure and incorporate lessons learned.

III. Processes and Procedures

~~A w~~Winter weather preparation procedure should be developed for seasonal winter preparedness. Components of ~~an~~ effective winter weather preparation procedures are included as Attachment 1.

After a severe winter weather event, entities should utilize a formal review process to ~~formally recognize procedural strengths~~ determine what program elements went well and what needs improvement.~~,~~ ~~evaluate improvement opportunities, and I~~identify and incorporate lessons learned within applicable procedures. Changes to the procedures and lessons learned must be communicated to the appropriate personnel. NERC encourages sharing appropriate lessons learned with other entities so that grid reliability and the industry may benefit as a whole. NERC Lessons Learned provides a process in which that sharing may be performed anonymously.

IV. Evaluation of Potential Problem Areas with Critical Components

Identify and prioritize critical components, systems, and other areas of vulnerability which may experience freezing problems or other cold weather operational issues. Schedule any ~~needed~~routine cold weather ~~related~~readiness inspections, repairs, and 'winterization' work to ~~occur~~be completed prior to the local ~~NOAA First Frost Date~~expected seasonal first freeze date. Some additional checks and winterization activities might be needed prior to forecasted extreme winter events. Un-doing winterization should wait until after the local expected seasonal last freeze date~~NOAA Last Frost Date~~ and be completed prior to summer heat arrival. ~~-~~Links to the NOAA First Frost Date and NOAA Last Frost Date maps are included for reference.

This includes critical instrumentation or equipment that has the potential to:

1. Initiate an automatic unit trip,
2. Impact unit start-up,
3. Initiate automatic unit runback schemes or cause partial outages,
4. Cause damage to the unit,
5. Adversely affect environmental controls that could cause full or partial outages,
6. Adversely affect the delivery of fuel or water to the units,
7. Cause operational problems such as slowed or impaired field devices, or
8. Create a weather-related safety hazard

Based on previous cold weather events, a list of typical problem areas are identified below. This is not meant to be an all-inclusive list. Individual entities should review their plant design and configuration, identify areas with critical components' potential exposure to the elements, ambient temperatures, or both and tailor their plans to address them accordingly.

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1. Critical Level Transmitters
    a. Drum level transmitters and sensing lines
    b. Condensate tank level transmitters and sensing lines
    c. De-aerator tank level transmitters and sensing lines
    d. Hotwell level transmitters and sensing lines
    e. Fuel oil tank level transmitters/indicators
2. Critical Pressure Transmitters
    a. Gas turbine combustor pressure transmitters and sensing lines
    b. Feed water pump pressure transmitters and sensing lines
    c. Condensate pump pressure transmitters and sensing lines
    d. Steam pressure transmitters and sensing lines
3. Critical Flow Transmitters
    a. Steam flow transmitters and sensing lines
    b. Feed water pump flow transmitters and sensing lines
    ~~c. High pressure steam attemperatorat temperator flow transmitters and sensing lines~~
4. Instrument Air System
    a. Verify ~~A~~automatic blow downs, traps, dew point monitoring, and instrument air dryers ~~have been recently calibrated and~~ are functioning correctly within acceptable parameters.
    b. Low point drain lines are periodically drained by operators to remove moisture during extreme cold weather.
5. Motor-Operated Valves, Valve Positioners, and Solenoid Valves
6. Drain Lines, Steam Vents, and Intake Screens
7. Water Pipes, Water Treatment, and Fire Suppression Systems[1]
    a. Low/no water flow piping systems
8. Fuel Supply, Materials, and Ash Handling
    a. Coal piles, other solid fuel storage, and ~~coal~~ handling equipment
    b. Transfer systems for backup fuel supply
    c. Gas supply regulators, other valves, and instrumentation (may require coordination with gas pipeline operator)
    d. Ash disposal systems and associated equipment

[1] For safety reasons, fire protection systems should also be included in this identification process. These problem areas should be noted in the site specific winter weather preparation procedure.

~~d.~~e. Lime storage and transfer equipment

9. Tank Heaters

   a. Conduct initial tests

   b. Check availability of spare heaters

   c. Record current tanks indicators for sodium-based solution (SBS) injection systems, flue gas desulfurization systems, dibasic acid additives, mercury control additives, etc.

10. Lube oil and greases for mechanical equipment necessary to support generation in locations that may be exposed to cold weather.

11. Ensure lead acid batteries or other batteries and UPS systems critical to the functioning of the facility are housed in temperature controlled locations and protected from weather.~~Lead acid batteries or other batteries and UPS systems in locations that need protected from weather.~~

12. Adequacy and functional~~l~~ity~~y~~ of heat tracing, insulation, and temperature responsive ventilation (heaters, fans, dampers, & louvers).

13. Adjust operation of cooling tower fans, deicing rings and riser drains to prevent icing.

14. Operation of necessary equipment to prevent accumulation of ice or snow on combustion turbine air inlet filter medium

15. Steam Sootblowing Systems (Transmitters, regulators, drain valves and traps)

16. Wind Farms

   a. Adequacy and functionality of wind turbine lube oil equipment such as radiators, fans, heaters and bypass valving within the nacelle

   b. Accessibility of roads throughout the wind farm

   c. Anemometer functionality.

Potential vulnerabilities associated with emergency generators, including Blackstart Resources, should be evaluated when developing the site specific winter weather preparation procedure, as they may provide critical system(s) backup.

V. Testing[2]

In addition to the typical problem areas identified above, emphasis should be placed on the testing of low frequency tasks such as startup of emergency generators, fire pumps and auxiliary boilers, where applicable.

[2] See Attachment 1, Section 8 "Special Operations Instruction" for more information

VI. Training

Coordinate annual training in winter specific and plant specific awareness and maintenance training. This may include response to freeze protection panel alarms, troubleshooting and repair of freeze protection circuitry, identification of plant areas most affected by winter conditions, review of special inspections or rounds implemented during severe weather, fuel switching procedures, knowledge of the ambient temperature for which the freeze protection system is designed, and lessons learned from previous experiences or the NERC Lessons Learned program.

1. Consider holding a winter readiness meeting on an annual basis to highlight preparations and expectations for severe cold weather.
2. Operations personnel should review cold weather scenarios affecting instrumentation readings, alarms, and other indications on plant control systems.
3. Ensure appropriate NERC Generation Availability Data Systems (GADS) coding for unit derates or trips as a result of severe winter weather events to promote lessons learned, knowledge retention, and consistency. Examples may include NERC GADS code 9036 “Storms (ice, snow, etc.)” or code 9040 “Other Catastrophe.”

VII. Winter Event Communications

Clear and timely communication is essential to an effective program. Key communication points should include the following:

1. Before a severe winter weather event, plant management should communicate with their appropriate senior management that the site specific winter weather preparation procedure, checklists, and readiness reviews have been completed.
2. Before and during a severe winter weather event, communicate with all personnel about changing conditions and potential areas of concern to heighten awareness around safe and reliable operations.
3. Before and during a severe winter weather event, ~~the~~ affected ~~entity(ies)~~entities will keep ~~the~~their BA up to date on changes to plant availability, capacity, low temperature cut-offs, or other operating limitations. Depending on regional structure and market design, notification to the Reliability Coordinator (RC) and Transmission Operator (TOP) may also be necessary.
4. After a generating plant trip, derate, or failure to start due to severe winter weather, Plant Management, as appropriate, should conduct an analysis, develop lessons learned, and incorporate good industry practices.
   a. This process should include a feedback loop to enhance current winter weather readiness programs, processes, procedures, checklists and training (continuous improvement).
   b. Sharing of technical information and lessons learned through the NERC Event Analysis Program or some other method is encouraged.

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Attachment 1

Elements of ~~a~~ Cold / Winter Weather Preparation Procedures[3]

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   b. Ensure all freeze protection and winter weather preparedness preventative work orders are completed prior to the onset of the winter season.
   c. Review Work Management System for open corrective maintenance items that could affect plant operation and reliability in winter weather, and ensure that they are completed prior to the onset of the winter season.
   d. As appropriate to your climate, suspend freeze protection measures and remove freeze protection equipment after the last probable freeze of the winter. This may be a plant specific date established by senior management.
   e. Ensure all engineered modification and construction activities are performed such that the changes maintain winter readiness for the plant. Newly built plants or engineered modifications can be more susceptible to winter weather.
2. Critical instrumentation and equipment protection
   a. Ensure all critical site specific problem areas (as noted above in section IV. Evaluation of Potential Problem Areas with Critical Components) have adequate protection to ensure operability during a severe winter weather event. Emphasize the points in the plant where equipment freezing would cause a generating plant trip, derate, or failure to start.
   b. Develop a list of critical instruments and transmitters that require maintenance prior to winter and increase surveillance during severe winter weather events.
3. Insulation, heat trace, and other protection options – Ensure processes and procedures verify adequate protection and necessary functionality (by primary or alternate means) before and during winter weather. Consider the effect of wind chill when applying freeze protection. Considerations include but are not limited to:
   a. Insulation thickness, quality and proper installation

[3] Plants that will remain offline during the winter season would not need to perform winterization preparations unless it is necessary for asset protection/preservation.

   i. Verify the integrity of the insulation on critical equipment identified in the winter weather preparation procedure. Following any maintenance, insulation should be re-installed to original specifications.

b. Heat trace capability and electrical continuity/ground faults

   i. Perform a complete evaluation of all heat trace lines, heat trace power supplies (including all breakers, fuses, and associated control systems) to ensure they maintain their accuracy. Label heat tracing and insulation in the field in reference to the circuit feed panel to reduce troubleshooting and repair times. This inspection may include checking for loose connections, broken wires, corrosion, and other damage to the integrity of electrical insulation that could lead to heat trace malfunctioning. Measure heat trace amperage and voltage, if possible, to determine whether the circuits are producing the design output. If there are areas where heat tracing is not functional, an alternate means of protection should be identified in the winter weather preparation procedure.

   ii. Evaluation of heat trace and insulation on critical lines should be performed during new installation, during regular maintenance activities, or if damage or inappropriate installation is identified (i.e., wrapped around the valve and not just across the valve body).

      (1) For example, inspect heat tracing before it is covered by insulation, to confirm that the extra cable length specified by the designer, for the purpose of being concentrated at valves and supports, has not been applied as a constant-pitch spiral over the length of the line.

   iii. Re-install removed or disturbed heat tracing following any equipment maintenance to restore heat tracing integrity and equipment protection.

   iv. Update and maintain all heat tracing circuit drawings and labeling inside cabinets.

   v. Require a report of calculations from the heat tracing contractor and ensure that their design basis is consistent with the insulation that will be applied with regards to exposure of valve bonnets, actuator, and pipe supports.

c. Wind breaks

   i. Install permanent or temporary wind barriers as deemed appropriate to protect critical instrument cabinets, heat tracing and sensing lines.

d. Heaters and heat lamps

   i. Ensure operation of all permanently mounted and portable heaters.

   ii. Evaluate plant electrical circuits to ensure they have enough capacity to handle the additional load. Circuits with ground fault interrupters (GFIs) should be continuously monitored to make sure they have not tripped due to condensation.

   iii. Steps should be taken to prevent unauthorized relocation of heating elements~~Fasten heaters and heat lamps in place to prevent unauthorized relocation~~.

e. Covers, enclosures, and buildings

    i. Enclose cold-weather sensitive critical transmitters in enclosures with local heating elements.
    ii. Install covers on valve actuators to prevent ice accumulation.
    iii. Inspect building penetrations, windows, doors, fan louvers, and other openings for potential exposure of critical equipment to the elements.

4. Supplemental equipment – Prior to the onset of the winter season, inspect and ensure adequate inventories of all commodities, equipment and other supplies that would aid in severe winter weather event preparation or response, and ensure that they are readily available to plant staff. Supplemental equipment might include:
    a. Tarps
    b. Portable heaters, heat lamps, or both
    c. Scaffolding
    d. Blankets
    e. Extension cords
    f. Kerosene/propane
    g. Temporary enclosures
    h. Temporary insulation
    i. Plastic rolls
    j. Portable generators
    k. Portable lighting
    l. Instrumentation tubing
    m. Heat guns or ~~H~~handheld welding torches
    n. Ice removal chemicals and equipment
    o. Snow removal equipment
    p. Cold weather personal protective equipment (PPE) available to personnel as appropriate.
    q. Properly winterized service vehicles functioning 4WD
    ~~q.~~r. Supplies for slip hazard reduction such as sand, rock salt, or calcium chloride
5. Operational supplies – Prior to the onset of a severe winter weather event, conduct an inventory of critical supplies needed to keep the plant operational. Appropriate deliveries should be scheduled based on the severity of the event, lead times, etc. Operational supplies might include:
    a. Aluminum sulfate
    b. Anhydrous ammonia
    c. Aqueous ammonia

d. Carbon dioxide
e. Caustic soda
f. Chlorine
g. Diesel fuel
h. Ferric chloride
i. Gasoline (unleaded)
j. Hydrazine
k. Hydrogen
l. Sulfuric acid
m. Calibration gases
n. Lubricating oils (lighter grades or synthetic)
o. Welding supplies
p. Limestone

6. Staffing (as necessary)
   a. Enhanced staffing (24x7) during severe winter weather events.
   b. Arrangements for lodging and meals.
   c. Arrangements for transportation.
   d. Arrangements for support and appropriate staffing from responsible entity for plant switchyard to ensure minimal line outages.
   e. Arrangements for storage of in-house food inventories for extended work shifts.
   f. Arrangements for on-site lodging during severe winter weather events.
7. Communications
   a. Identify appropriate communication protocols to follow during a severe winter weather event.
   b. Identify and verify operations of a back-up communication option in case the Interpersonal Communications capability is not available (i.e. satellite phone).
   c. Include availability of Interpersonal Communication capability and available back-up communication options in job safety briefing for severe winter weather events.
8. Special operations instruction (just prior to or during a severe winter weather event) as appropriate.
   a. Utilize the "buddy system" during severe winter weather events to promote personnel safety.
   b. Utilize cold weather checklists to verify critical equipment is protected – i.e. pumps running, heaters operating, igniters tested, barriers in place, temperature gauges checked, etc.

i. Monitor room temperatures, as required, so that instrumentation and equipment in enclosed spaces (e.g. pump rooms) don't freeze.

~~i.~~ii. Evaluate freeze protection needs for standby systems idled during current operations (out of service filters, heat exchangers, stagnant piping, etc.)

c. Test dual fuel capability where applicable. Identify alternate suppliers of fuel as necessary. Ensure that alternate fuel suppliers are capable of delivering required quantities of fuel during adverse winter conditions

d. Initiate pre-warming and/or early start-up, of scheduled units prior to a forecasted severe winter weather event.

e. Run emergency generators immediately prior to severe winter weather events to help ensure availability. Review fuel quality and quantity.

f. Place in service critical equipment such as intake screen wash systems, cooling towers, auxiliary boilers, and fuel handling equipment, where freezing weather could adversely impact operations or forced outage recovery.

Name of Individual or Organization(s) (list multiple if submitted by a group):	**Exelon**				
Organization(s)	**Page #**	**Line / Paragraph**	**Comment**	**Proposed Change**	**NERC Response**
Exelon	1	Preamble	Clarify that this guidance may be most useful for those entities which have been adversely affected by cold weather in the past, or are commencing operation of a new facility and lack historical experience. However for those entities that do have a history of successful severe cold weather operation, or for those facilities subject to other inspections and winter guidance (for example the Institute of Nuclear Power Operations for nuclear generators) this guidance is provided as a supplement, and not a replacement of those seasonal preparation guidelines and practices already in place.		**Added in Assumptions** "It is recognized that nuclear power plants, in keeping with NRC regulation and INPO guidance already have more detailed Winterization and Summerization procedures than are expected by this document."
Exelon	1	Purpose	Suggest re-wording to make clear that there is a difference between normal seasonal cold weather preparation and extra steps that might be required for extreme cold. For example, ensuring installed insulation or heat tracing is functional would be part of routine seasonal preparation. Consideration of placing additional heaters in areas history has shown are vulnerable is an extra step taken when extreme cold is predicted.		**Added in Assumptions** "What constitutes severe or extreme weather is different in different locations. Each entity will need to make its own determination for what constitutes normal winter weather and what is extreme for each of its own locations, and thus what level of preparedness and response steps to include in its normal and extreme cold weather procedures."
Exelon	1	Purpose	Suggest re-wording to distinguish between seasonal cold weather, and extreme cold weather "events", and clarify if a cold weather event is the cold itself, or the impact on / loss of the facility due to cold. Specifically the wording "preventing future cold weather related events" appears to suggest that somehow the cold weather itself can be prevented. Wording should be added that "cold weather" and "severe cold weather" are not specific temperatures but are locale specific and will differ between regions of the country, proximity to lakes and oceans, etc.		**Added in Assumptions** "What constitutes severe or extreme weather is different in different locations. Each entity will need to make its own determination for what constitutes normal winter weather and what is extreme for each of its own locations, and thus what level of preparedness and response steps to include in its normal and extreme cold weather procedures."
Exelon	1	Guideline Details	"An effective winter weather readiness procedure…." Comment: replace "procedure" with either "procedure(s)" or "program". The process of winterization may be embodied in multiple procedures applicable to different pertinent groups such as work planning, operations, maintenance, and engineering. Putting everything in one procedure would create an impractically cumbersome document. Further, routine seasonal cold weather preparation may appear in one procedure, with extra steps taken for extreme cold in more of an "emergency" type procedure.		Changed procedure to program
Exelon	2	Safety	The guidelines regarding safety are good, but typical of any hazardous weather work activity. The guideline should make clear that it is the intent that these types of safety precautions be taken, preferably embodied in a work practices document, but there does not need to be a separate "severe cold weather safety precautions" document.		**Added in Assumptions** "What constitutes severe or extreme weather is different in different locations. Each entity will need to make its own determination for what constitutes normal winter weather and what is extreme for each of its own locations, and thus what level of preparedness and response steps to include in its normal and extreme cold weather procedures."
Exelon	2	Processes and Procedures	"A winter weather preparation procedure should be developed for seasonal winter preparedness. Components of an effective winter weather preparation procedure are included as Attachment 1." Similar to prior comment regarding a single procedure. The components listed in Att. 1 of the draft guideline may appear in the entity's collection of procedures that direct winter weather preparation and do not necessarily need to be located in a single procedure.		pluralized
Exelon	3	Section IV: Evaluation of Potential Problem Areas	Tying completion of seasonal winter preparation activities to the NOAA frost dates is impractical and unnecessary. For some stations the time period between the last frost date in May and the first frost date in September results in an impractically short time frame to perform seasonal readiness preparation, and is unnecessarily restrictive. While such dates may be of extreme interest to some industries, they do not signal significant impact on generating stations located in northern parts of the United States. Typical winterization processes begin almost immediately after the conclusion of a winter season with review of lessons learned and planning for the subsequent winter. The winterization process continues in a count-down fashion up to and through the historical on-set of cold weather. Long lead time and critical components are considered first, with commodity procurement and final walkdowns and management reviews of preparations toward the end. The winterization process has evolved over the decades that these plants have operated in cold weather conditions and has resulted in excellent performance during the cold weather months. Suggest re-wording to provide the frost dates as a reference, however stress that in areas where cold, and severe cold, is routine, that historical experience can be used as a guide. The wording of Attachment 1, 1- Work Management, d: "As appropriate to your climate... This may be a plant specific date established by senior management …." is more appropriate.		Changed to "Schedule any needed routine cold weather related readiness inspections, repairs, and 'winterization' work to occur be completed prior to the local expected seasonal first freeze date. Some additional checks and winterization activies might be needed prior to forecasted extreme winter events. Un-doing winterization should wait until after the local expected seasonal last freeze date and be completed prior to summer heat arrival. Links to the NOAA First Frost Date and NOAA Last Frost Date maps are included for reference."
Exelon	Attachment 1	General	Title appears to be mis-typed, i.e., "Elements of a Winter Weather Preparation Procedure5", i.e., 5 should be an s. However agree that the word should be plural, "Procedures" and not "Procedure", consistent with prior comments.		Footnote 3 was not a 5 or an s, but the change to plural is a good idea

Exelon	Attachment 1	General	Attachment is overly prescriptive and reads more like a check list of items that must be proceduralized and less like a collection of best practices to consider. Concern is that this document will be taken into the field by auditors, or picked up by industry facility owners, who then try to force every facility to have "one of these" in their procedures to satisfy the checklist, regardless of necessity. The use of the words "might include" in Att. 1 Sects 4 and 5 is good, and suggest including similar wording ("could consider", "as appropriate", etc.) in other Att. 1 sections.		**See the preamble:** "The objective of the reliability guidelines is to distribute key practices and information on specific issues critical to promote and maintain a highly reliable and secure bulk power system (BPS). Reliability guidelines are not binding norms or parameters to the level that compliance to NERC's Reliability Standards are monitored or enforced. Rather, their incorporation into industry practices is strictly voluntary. Reviewing, revising, or developing a program using these practices is highly encouraged." **Also in the Assumptions:** "2.3. Entities should develop and apply plant-specific winter weather readiness plans, as appropriate, based on factors such as geographical location, technology and plant configuration. What constitutes severe or extreme weather is different in different locations. Each entity will need to make its own determination for what constitutes normal winter weather and what is extreme for each of its own locations, and thus what level of preparedness and response steps to include in its normal and extreme cold weather procedures.
Exelon	Attachment 1	2.b	"Develop a list of critical instruments and transmitters that require maintenance prior to winter and increase surveillance during severe winter weather events." This guidance is overly prescriptive. That is, critical instrumentation may be identified in system descriptions, system operating instructions, station operating procedures, etc. The general requirement that critical instrumentation be reviewed to ensure winter readiness is sufficient. Creating a single list of hundreds of equipment items creates an overhead burden and potential confusion factor by removing from or duplicating what is already in place for use by those most familiar with their operation.		Critical instruments are those important to the functioning of the generating plant. Winterization is applicable only to those that are / could be exposed to low termerature. That should not be hundreds of items. Why wouldn't there already be a list of those?
Exelon	Attachment 1	3.b Heat Trace Capability	In general this section is overly prescriptive and fails to account for practices that have been in place for long periods of time and have been shown to be sufficient for severe cold weather operation. For example, requiring calculations from heat trace contractors (section v) may be acceptable for new installations, but is impractical and unnecessary for installations that have been in service for long periods of time. Subsections 3.b.i and ii are sufficient. Although even in section i the suggested checking of heat trace amperage and voltage could be considered overly restrictive, i.e., use of thermal cameras or other means may be used to ensure adequate heat trace function.		See the Preamble, Purpose and Assumptions. A non-binding list of things to considere should not be viewed as prescriptive. There are still entities who are new at the generation business and those who are surprised at equipment limitations during cold snaps who can benefit from this information. Thanks for the thermal camera mention.
Exelon	Attachment 1	3.b Heaters and Heat Lamps	Item ii "Evaluate plant electrical circuits to ensure they have enough capacity to handle the additional load. Circuits with ground fault interrupters (GFIs) should be continuously monitored to make sure they have not tripped due to condensation." Phrasing implies each season an electrical circuit evaluation will be conducted, e.g., a calculation. This guidance is too prescriptive. Suggest re-wording as ""Ensure electrical circuits have enough capacity…" and allow facility operators to determine best method to do so. Wording of "… continuously monitored…." is vague and implies that either a person or dedicated monitoring circuit is continuously in place to monitor each GFI. Experience has shown that such constant monitoring is not necessary and that room temperature monitors, operator rounds, other such options are sufficient to detect tripped circuit protection. Item iii "Fasten heaters and heat lamps in place to prevent unauthorized relocation" is again too prescriptive. The intent is understood, but fails to accommodate the needs of adjusting heating elements as conditions change. For example, fixing a portable heater in place in a nuclear station may trigger an extensive modification process which would be repeated each time the heater is located to accommodate changing conditions, e.g., wind direction, in a storm. In practice, use of signage that directs that heating element positioning is only to be performed by certain personnel is sufficient. Suggest re-phrasing to state that "steps should be taken to prevent unauthorized relocation of heating elements".		3.d. Changed to "Steps should be taken to prevent unauthorized relocation of heating elements"
Exelon	Attachment 1	8 Special Operations Instruction	Revise to include wording such as "as appropriate" or "as applicable". As written the section is overly prescriptive. For example, "Run emergency generators immediately prior to severe winter weather events …." is not necessary or practical for such facilities as nuclear generators which have very detailed emergency diesel maintenance practices and already prescribed operational testing. Unnecessary starts create additional wear on the machines which are relied upon during losses off-site power.		as appropriate (remember, this is a guideline, not a regulatory document or requirement)
Name of Individual or Organization(s) (list multiple if submitted by a group):	**American Electric Power**				
Organization(s)	**Page #**	**Line / Paragraph**	**Comment**	**Proposed Change**	**NERC Response**
Thomas Foltz on behalf of American Electric Power	N/A	---	Please note that all of AEP's comments and references to page numbers are made in reference to the version 3 *redlined* draft rather than the "clean" draft that was provided for this comment period.		

Organization(s)	Page #	Line / Paragraph	Comment	Proposed Change	NERC Response
Thomas Foltz on behalf of American Electric Power	4	Lines 114-17	Item 3c is a subset of 3a, so there is no reason for 3c to be its own sub-bullet.	Revise 3a to include the content of 3c, and then delete 3c.	3c was included in and redundant to 3a (Steam flow transmitters and sensing lines), so 3c is deleted
Thomas Foltz on behalf of American Electric Power	4	Line 117	The word "attemperator" may have fallen victim to an erroneous spell check correction, instead making it "at temperator."	Change "at temperator" back to "attemperator."	3c was included in and redundant to 3a (Steam flow transmitters and sensing lines), so 3c is deleted
Thomas Foltz on behalf of American Electric Power	4	Lines 118-120	To include "functioning correctly" within 4a is reasonable and acceptable, however specifying "calibration" is *not.* Not only is its inclusion too specific, that word would not apply to all devices. While it is appropriate for this Reliability Guideline to suggest *what* should be considered, it should not go so far as to specify exactly *how*.	Remove the reference to calibration from 4a.	Changed to "Verify automatic blow downs, traps, dew point monitoring, and instrument air dryers are functioning correctly within acceptable parameters."
Name of Individual or Organization(s) (list multiple if submitted by a group):	**Idaho Power Company**				
Organization(s)	**Page #**	**Line / Paragraph**	**Comment**	**Proposed Change**	**NERC Response**
Idaho Power Company	2	1/d.	Change requested because it seems to be a vague statement with little or no way to validate this communication has taken place.	Remove or clarify the "through industry associations (formal groups or other informal network forums)."	This is necessarily vague - we encourage sharing lessons learned and good ideas but don't know what associations organizations might have (remember, this is a guideline, not a regulatory document or requirement)
Idaho Power Company	4	3/c.		Change the word "at temperator" back to its proper spelling of "attemperator".	3c was included in and redundant to 3a (Steam flow transmitters and sensing lines), so 3c is deleted
Idaho Power Company	4	4/a.	Change requested because it is vague and not measurable.	Remove "have been recently calibrated and".	Changed to "Verify automatic blow downs, traps, dew point monitoring, and instrument air dryers are functioning correctly within acceptable parameters."
Name of Individual or Organization(s) (list multiple if submitted by a group):	**Duke Energy**				
Organization(s)	**Page #**	**Line / Paragraph**	**Comment**	**Proposed Change**	**NERC Response**
Duke Energy	3	80-84	Suggest the reference to "First/Last Frost Dates" be eliminated to simplify implementation. The provided NOAA link data is subjective and will require interpolation or the selection of multiple dates for entities that extend geographically over large areas.	Consider substituting the following or similar language: ...work to occur prior to "historical adverse regional cold weather." Un-doing winterization should wait until after the "historical adverse regional cold weather" and be completed prior to summer heat.	Changed to "Schedule any needed routine cold weather related readiness inspections, repairs, and 'winterization' work to occur be completed prior to the local expected seasonal first freeze date. Some additional checks and winterization activies might be needed prior to forecasted extreme winter events. Un-doing winterization should wait until after the local expected seasonal last freeze date and be completed prior to summer heat arrival. Links to the NOAA First Frost Date and NOAA Last Frost Date maps are included for reference."
Duke Energy	3	80-84	Punctuation.	Hyphenate "weather-related".	Tech Writer's preference
Duke Energy	4	114-118	Suggested language is overly prescriptive.	Consider changing language to read as follows: "Verify proper operation of Instrument Air System by ensuring automatic blow downs, traps, dew point monitoring, and instrument air dryers are functioning correctly."	Changed to "Verify automatic blow downs, traps, dew point monitoring, and instrument air dryers are functioning correctly within acceptable parameters."
Duke Energy	4	134-135	Clarification.	Suggest item #10 be modified to read: "10. Mechanical equipment lube oil and greases "are adequate for ambient temperature conditions" to support generation locations that may be exposed to "cold" weather.	Changed to cold weather
Duke Energy	1-12	Entire Document	Consider adding the term "Winter/Cold Weather" to the NERC Glossary of Terms.	Define: "Winter/Cold Weather".	Changing the glossary is outside the scope of this review, and is more related to the Draft requirement scope.
Name of Individual or Organization(s) (list multiple if submitted by a group):	**Manitoba Hydro**				
Organization(s)	**Page #**	**Line / Paragraph**	**Comment**	**Proposed Change**	**NERC Response**
Generation			No Comments.		
Name of Individual or Organization(s) (list multiple if submitted by a group):	**US Bureau of Reclamation**				
Organization(s)	**Page #**	**Line / Paragraph**	**Comment**	**Proposed Change**	**NERC Response**
Bureau of Reclamation	1	1	Reclamation recommends a quality review to ensure conforming changes are made throughout the document based on the deletion of defined acronyms in the first sentence of the preamble (e.g., OC).		deleted OC
Bureau of Reclamation	1	16/Purpose Paragraph	define NERC OC	a collection of industry practices complied by the NERC Operating Committee (NERC OC)	deleted OC

Bureau of Reclamation	3	IV.	Schedule any needed cold weather related inspections, repairs, and 'winterization' work to occur prior to the local NOAA First Frost Date. Un-doing winterization should wait until after the NOAA Last Frost Date and be completed prior to summer heat.	Schedule any needed cold weather related inspections, repairs, and 'winterization' work to occur and be completed prior to the local NOAA First Frost Date. Un-doing winterization should wait until after the NOAA Last Frost Date and be completed prior to summer heat.	Changed to "Schedule any needed routine cold weather related readiness inspections, repairs, and 'winterization' work to occur be completed prior to the local expected seasonal first freeze date. Some additional checks and winterization activies might be needed prior to forecasted extreme winter events. Un-doing winterization should wait until after the local expected seasonal last freeze date and be completed prior to summer heat arrival. Links to the NOAA First Frost Date and NOAA Last Frost Date maps are included for reference."
Bureau of Reclamation	4	3c	Correct typographical error. Attemperator was the correct term.	High pressure steam ~~at temperator~~ attemperator flow transmitters and sensing lines	3c was included in and redundant to 3a (Steam flow transmitters and sensing lines), so 3c is deleted
Bureau of Reclamation		Throughout the document	More emphasis should be made on the creation of area specific weatherization methods based on historical data. More leeway should be given to specific types of generation that are by their nature less susceptible to cold weather or already covered by existing regulations.		This is a guideline, not a regulatory document or requirement. Several stements include 'as appropriate' or 'local'
Name of Individual or Organization(s) (list multiple if submitted by a group):	**ReliabilityFirst**				
Organization(s)	**Page #**	**Line / Paragraph**	**Comment**	**Proposed Change**	**NERC Response**
ReliabilityFirst	1	Line 2	Cold weather should be specifically identified in the title since cold weather may occur outside of the formal winter season. This would also align with Project 2019-06 Cold Weather.	Change title from Generating Unit Winter Weather Readiness to "Generation Unit Cold Weather Readiness"	This is the 3rd revision of a Winter Preparedness guideline that preceeded Project 2019-06 by several years, not a regulatory document or requirement.
	4	Line 113	Change "at temperator" back to "attemperator". The term "temperator" is not technically correct.	Change wording for Item 2c to "High pressure steam attemperator flow transmitters and sensing lines."	3c was included in and redundant to 3a (Steam flow transmitters and sensing lines), so 3c is deleted
	4	Line 121	Emergency wash stations should be included since these are critical to the safety of personnel	Change the name of Item 7 to "Water Pipes, Fire Suppression Systems, and Emergency Wash Stations"	added to footnote
	4	Line 123	Revise Item 8 to address all types of plant materials such as coal, lime and ash.	Revise Item 8 as follows: "Material Supply and Handling".	8. Fuel Supply, Materials, and Ash Handling
	4	Line 124	Revise Item 8a to address storage facilities which encompasses the coal pile, transfer bins, hoppers and bunkers.	Revise Item 8a as follows: "Coal storage and handling systems".	a. Coal piles, other solid fuel storage, and handling equipment
	4	New Item after Line 128	Add Item 8e to address lime facilities and equipment	Add Item 8e: "Lime storage and transfer equipment".	added
	4	Line 132	Spell out SBS acronym since this may be mistaken for "Soot Blowing Systems".	Replace "SBS" with "Sodium-Based Solution (SBS)"	done
	5	New Item after Line 139	Add Item 13 to address cooling towers	Add Item 13 "Operation of cooling tower fans, deicing rings and riser drains to prevent icing	added 13
	5	New Item after Line 139	Add Item 14 to address combustion turbine air inlet system	Add Item 14 "Operation of necessary equipment to prevent accumulation of ice or snow on combustion turbine air inlet filter medium	added 14
	5	New Item after Line 139	Add Item 15 to address wind turbines	Add Item 15 "Wind Farms" and include sub-items: 15a. "Adequacy and functionality of wind turbine lube oil equipment such as radiators, fans, heaters and bypass valving within the nacelle; 15b. Accessibility of roads throughout the wind farm, 15c. Anemometer functionality.	added 16
	5	New Item after Line 139	Add Item 16 to address steam soot blowing systems	Add Item 16 as followings: Steam Sootblowing Systems and include sub-item: 16a. Transmitters, regulators, drain valves and traps	added 15
	5	Line 147	Add fire pumps and auxiliary boilers	Revise this sentence as follows: "frequency tasks such as startup of emergency generators, fire pumps and auxiliary boiler(s)."	done
	8	Line 220	Cold weather should be specifically identified in the title since cold weather may occur outside of the formal winter season. This would also align with Project 2019-06 Cold Weather.	Change to "Elements of a Cold Weather"	**Elements of Cold/Winter Weather Preparation Procedures** This is the 3rd revision of a Winter Preparedness guideline that preceeded Project 2019-06 by several years, not a regulatory document or requirement.
Name of Individual or Organization(s) (list multiple if submitted by a group):	**Seminole Electric Cooperative, Inc**				
Organization(s)	**Page #**	**Line / Paragraph**	**Comment**	**Proposed Change**	**NERC Response**

Seminole Electric Cooperative	2	48	Insert best practices into sentence	The management roles and expectations below provide a high-level overview of best practices for the core management responsibilities related to winter weather preparation	See Purpose
Seminole Electric Cooperative	2	59	Replace develop with ensure to allow delegation for actually creating the procedure	Ensure a winter weather preparation procedure is developed and consider appointing a designee responsible for keeping this procedure updated with industry identified best practices and lessons learned.	Ensure development of a cold/winter weather preparation program and consider appointing a designee responsible for keeping its processes and procedures updated with industry identified best practices and lessons learned.
Seminole Electric Cooperative	2	64 and 65	Combine items c. and d.	Conduct a plant readiness review prior to an anticipated severe winter weather event to ensure the winter weather preparation procedure was properly executed.	normal winter preparedness and actions forsevere events are different things
Seminole Electric Cooperative	3	75 thru 78	This is essentially a formal review of lessons learned. Should be reworded to capture this intent.	After a severe winter weather event, entities should utilize a lessons learned review process to formally recognize procedural strengths, evaluate improvement opportunities, and identify and incorporate within applicable procedures when applicable. The results of this review should be shared with appropriate personnel and procedural changes communicated to all impacted entities.	After a severe winter weather event, entities should utilize a formal review process to formally determe what program elements went well and what needs improvement. Identify and incorporate lessons learned within applicable procedures. Changes to the procedures and lessons learned must be communicated to the appropriate personnel. NERC encourages sharing appropriate lessons learned with other entities so that grid reliability and the industry may benefit as a whole. NERC Lessons Learned provides a process in which that sharing may be performed anonymously.
Seminole Electric Cooperative	4	5	Attemperator is correct	High pressure steam attemperator ~~at temperator~~ flow transmitters and sensing lines	3c was included in and redundant to 3a (Steam flow transmitters and sensing lines), so 3c is deleted
Seminole Electric Cooperative	7	13	Water treatment areas may need to be included.	Water Pipes, Water Treatment, and Fire Suppression Systems1	Excellent catch!
Seminole Electric Cooperative	5	32	BA acronym identified per format of the document.	Before and during a severe winter weather event, the affected entity(ies)entities will keep their Balancing Authority (BA) up to date on changes to plant availability, capacity, low temperature cut-offs, or other operating limitations.	BA defined in Assumptions
Seminole Electric Cooperative	Attachment 1 Page 4	36	Add heat gun as a safe alternative to torches	m. Handheld heat gun or welding torches	ok
Seminole Electric Cooperative	Attachment 1 Page 4	45	Add supplies for slip hazard reduction.	r. Sand, rock salt, or calcium chloride.	ok
Seminole Electric Cooperative	Attachment 1 Page 5	57	Add risk assessment for standby systems idled during standard operations	ii. Perform a risk assessment for standby systems. (i.e. pumps, heat exchangers, water treatment filters, etc.)	ii. Evaluate freeze protection needs for standby systems idled during current operations (out of service filters, heat exchangers, stagnant piping, etc.)
Name of Individual or Organization(s) (list multiple if submitted by a group):	**City of Tallahassee (TAL)**				
City of Tallahassee (TAL)			City of Tallahassee (TAL) agrees with the proposed revisions with no additional comments.		
Name of Individual or Organization(s) (list multiple if submitted by a group):	**Texas Regional Entity**				
Organization(s)	**Page #**	**Line / Paragraph**	**Comment**	**Proposed Change**	**NERC Response**
Mark Henry, Texas RE	all	all	Good work adding to this document to add new insights.		
Mark Henry, Texas RE	4	113	The redlines shows replacement of the single word "attemporator" with two words "at temporator". I think the original is a better fit. Desuperheaters also fit this category as a type of attemperator.	Return to "attemporator" instead of "at temporator".	3c was included in and redundant to 3a (Steam flow transmitters and sensing lines), so 3c is deleted
Mark Henry, Texas RE	4	115-116	The language about air dryer-related activity suggests calibration for components that only need functional test. Suggested rewording to better fit what is done.	Automatic blow downs, traps, and instrument air dryers are functioning correctly and dew point monitoring has been recently calibrated.	Changed to "Verify automatic blow downs, traps, dew point monitoring, and instrument air dryers are functioning correctly within acceptable parameters."
Mark Henry, Texas RE	4	132	SBS acronyn is not clarified, added tp previous revision	SBS (Sodium-based solution, for emissions control)	done
Name of Individual or Organization(s) (list multiple if submitted by a group):	**Evergy**				
Organization(s)	**Page #**	**Line / Paragraph**	**Comment**	**Proposed Change**	**NERC Response**

Evergy	3	LL 82-84	We recognize the value of an independent source to provide a threshold for cold weather; however, NOAA determinations are shared as general geographical areas and not necessarily what a generating plant is experiencing. To address the generality of NOAA determinations, we suggest setting a specific temperature at the generation source.	...'winterization' work to occur when generation locations experience sustained temperatures below 32-degrees F / 0-degrees C.	Changed to "Schedule any needed routine cold weather related readiness inspections, repairs, and 'winterization' work to occur be completed prior to the local expected seasonal first freeze date. Some additional checks and winterization activies might be needed prior to forecasted extreme winter events. Un-doing winterization should wait until after the local expected seasonal last freeze date and be completed prior to summer heat arrival. Links to the NOAA First Frost Date and NOAA Last Frost Date maps are included for reference."
Evergy	4	LL 115-116	"Correctly," within this context is vague. We support flexibility in Guidelines but suggest added clarity to better reflect the intent of 4.a.	"...air dryers have been calibrated to their established specifications and operating as planned."	Changed to "Verify automatic blow downs, traps, dew point monitoring, and instrument air dryers are functioning correctly within acceptable parameters."
Evergy	4	LL 136-137	We thought to reinforce the assurance part of assessments. Also, we recognize "temperature" is a component of "weather" and can be addressed by the same strategies; however, batteries housed in a building would not experience rain or snow but could experience an extremely cold environment. We suggest adding the temperature language to highlight such a scenario and, possibly other like scenarios.	"Ensure lead acid batteries or other batteries and UPS systems are housed in temperature controlled locations and protected from weather."	Changed to "Ensure lead acid batteries or other batteries and UPS systems critical to the functioning of the facility are housed in temperature controlled locations and protected from weather."
Evergy	5	L 138	There may be a grammar error with "Adequacy and functionally..." We will dispense with the lengthy explanation and offer two alternatives for consideration.	"Adequate and functioning heat tracing..." or "Adequacy and functionality of heat tracing..."	Changed to "Adequacy and functionality of heat tracing..."
Name of Individual or Organization(s) (list multiple if submitted by a group):	**Indianapolis Power & Light**				
Organization(s)	**Page #**	**Line / Paragraph**	**Comment**	**Proposed Change**	**NERC Response**
IPL	4	3c	"at temperator" is not two words	Correct to "attemperator" (one word)	3c was included in and redundant to 3a (Steam flow transmitters and sensing lines), so 3c is deleted
IPL	1	Purpose	"severe winter weather" is referenced a few different ways throughout the document. There is some confusion as to what would be considered "severe"; levels of impact will be different for every utility and there is concern they may be compared to eachother.	Please clarify what is considered "severe winter weather" and we would ask that it be a term consistently referenced throughout the document. Incorporate a statement that allows for individual and non-standardized responses to what is deemed severe.	Added in Purpose Assumptions "What constitutes severe or extreme weather is different in different locations. Each entity will need to make its own determination for what constitutes normal winter weather and what is extreme for each of its own locations, and thus what level of preparedness and response steps to include in its normal and extreme cold weather procedures."
Name of Individual or Organization(s) (list multiple if submitted by a group):	**Hydro-Québec Production (HQP)**				
Hydro-Québec Production (HQP)			No comments		

Reliability Assessments Subcommittee (RAS) Scope and Probabilistic Assessments Working Group (PAWG) Scope

Action
Approve

Summary
The RAS and PAWG revised their scope documents as part of the RSTC transition planning activities. A redline for each is included in the agenda package. The RAS and PAWG are seeking approval of the scope documents.

NERC

NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Reliability Assessment Subcommittee

Scope Revisions

Lewis De La Rosa, RAS Chair
Reliability and Security Technical Committee Meeting
December 16, 2020

RELIABILITY | RESILIENCE | SECURITY




Reliability Assessment Subcommittee Scope

- RAS requests RSTC Approval of revised scope
- Last approved in June 2018
- In November 2020 RAS revised the scope by replacing “Planning Committee (PC)” with “RSTC”
  - Added RSTC Sponsor to the list of liaison participants

Probabilistic Assessment Working Group Scope

- RAS and PAWG request RSTC approval of revised scope
- Last approved December 2016
- Summary of changes
  - Formatted to reflect similar Working Groups under Subcommittees
  - Eliminated superfluous references
  - Clarified purpose, activities, and membership
  - Replaced old committee references with RSTC in accordance with the RSTC Charter

PAWG Scope - Purpose

Old Scope

- Contained multiple references to 2016 and older probabilistic initiatives.
- Relied on knowledge of previous group work or previous work scopes.
- Contained work scope statements opposed to purpose statements

Revised Scope

- Focuses on the PAITF report that provided recommendation for Working Group
- Focuses on purpose statements and moves specific work into "Scope of Activities"

PAWG Scope – Scope of Activities

Old Scope

- Did not contain the largest work PAWG does (Biennial ProbA)
- Contained work plan items.
- Did not detail broad activities or initiatives.

Revised Scope

- References current procedure for work.
- Provides specific examples like old scope, but in context of broader activity.
  - Focuses on probabilistic components of reliability assessments
  - Development of documents that identify and evaluate probabilistic approaches

PAWG Scope – Membership

Old Scope

- Focuses on membership structure
- Contained work plan items opposed to scope of activities.
- Did not touch on decision making or minority opinions

Revised Scope

- Open to technical support from non-regional representation.
- Describes member qualities and structure
- Details Chair, Vice-Chair, and NERC Coordinator(s).
- Consensus-based decisions
  - Minority views can be included in work product

Action

- RAS is requesting RSTC approval of the RAS scope
- RAS and PAWG are requesting RSTC approval of the PAWG scope

Subgroups

Committee Subgroups				
	Scope	Duration	Approvals	Leadership
Subcommittee	• Oversee broad processes • Manage cyclical deliverables	Long-term	Consensus seeking; vote as specified by its scope	Nominated by subcommittee; Approved by RSTC Leadership
Working Group	• Oversee specific data systems • Support specific initiatives with broader interaction with other subgroups/topics • Support a cyclical process • Support parent subcommittee	Long-term/ mid-term	Consensus seeking; non-voting	Nominated by working group, parent subcommittee, or direct appointment by the NERC Technical Committees; approved by RSTC Leadership
Task Force	• Support a specific initiative • Direct, often only one deliverable • Support parent subcommittee	Short-term	Consensus seeking; non-voting	Nominated by task force, parent subcommittee, or direct appointment by the NERC Technical Committees; approved by RSTC Leadership

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Reliability Assessment Subcommittee Scope

Purpose

The Reliability Assessment Subcommittee (RAS) reviews, assesses, and reports on the overall reliability (adequacy and security) impacting the bulk power systems, both existing and as planned. Those reviews and assessments verify that each Assessment Area conforms to its own planning criteria, guides, and the applicable NERC Reliability Standards. Further guidance for any reliability assessment is provided in the *NERC Rules of Procedure: Section 800*.

In addition to supporting the peer review process for NERC's reliability assessments, the RAS will also provide input and guidance on the development of assessment data collections forms. Specifically, the RAS will serve as a platform for collaborative enhancements of current data collection processes to improve the accuracy, consistency, transparency, and efficiency of NERC's reliability assessments. This effort will involve collaboration with the U.S. Department of Energy's (DOE's) Energy Information Administration (EIA) and other governmental agencies with a goal of reducing duplicative reporting while promoting consistent data definitions.

Scope of Activities

1. Evaluate bulk power systems' conformance to respective Assessment Area planning criteria and guides, along with pertinent NERC Reliability Standards over the assessment period.
2. Support the annual review of each Assessment Area's long-term and short-term resource adequacy plans. This includes:
   a. Identifying and monitor the key issues, risks, and uncertainties that may impact or have the potential to impact bulk power system reliability;
   b. Coordinating timely submittals of Assessment Area narratives and responses to questions developed by NERC with support from the RAS.
3. Address and resolve any potential reliability issues or differences between the subcommittee's assessment and the assessment area's internal or interregional reliability assessment(s). Report any unresolved issues or differences to the NERC Reliability and Security Technical Committee (RSTC).
4. Upon request of the RSTC, conduct special reliability assessments, as conditions warrant (in addition to those defined above). Present results and findings to the RSTC and others as appropriate.

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[1] Based on existing ISO/RTO footprints; otherwise, based on individual Planning Coordinator or group of Planning Coordinators. NERC collects data for seasonal and long-term assessments based on these footprints that align with how the system is planned and operated.

[2] NERC Rules of Procedure.

5. Facilitate data collection efforts of the Regional Entities and stakeholders for NERC's reliability assessments and identify and propose recommendations for improved RAS data collection efforts.
6. Seek feedback on any new data definitions approved by the RSTC and provide recommendations to the RSTC for consideration.
7. Develop recommendations for new data development and presentation options in NERC's reliability assessments.
8. Collaborate with EIA to promote efficiency, consistent data definitions, eliminate duplicative data collection, and improve overall data quality, including, but not limited to: EIA-860, and EIA-860M.
9. Coordinate review of assigned Essential Reliability Services forward looking measures with the applicable reporting entities for inclusion in NERC's assessments.
   a. ERS Framework Measure 6: Forward-Looking Net Demand Ramping Variability
   b. ERS Framework Measures 1,2, and 4: Forward Looking Frequency Analysis
10. Establish working groups, as required, to support analysis and work products.

Working Groups

Working groups report to the RAS. Working group's scope, objectives, duration, deliverables, and other related documents will be endorsed by the RAS for approval in accordance with the RSTC charter.

Representation

The RAS chair and vice chair will be appointed by the NERC RSTC leadership for a two-year term. The vice chair should be available to succeed to the chair.

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

Any member category as defined above that does not provide a representative in a timely fashion is requested to formally decline its invitation to participate in the subcommittee in writing to the chair of the RAS.

Reporting

The RAS will report to the RSTC for the completion of work associated with the scope items outlined above, and final work products of the RAS will be reviewed and considered by the RSTC and or the NERC Board of Trustees. The RAS chair will periodically apprise the RSTC on the subcommittee's activities, assignments, and recommendations.

Membership

The subcommittee is comprised of the following:

- Chair
- Vice chair
- One representative and one alternate from each Regional Entity – at least one of which must be Regional Entity staff (May also be the chair or vice-chair).
- One representative and one alternate from each Assessment Area that is not a Region
- One member-at-large from Canada
- At least one representative from each sector listed below:
    - Investor-Owned Utilities
    - Areas where there are no organized markets
- Additional members can be added:
    - At the request of the RSTC sector representatives, or
    - As requested by Regional Entity or Assessment Area staff, and upon approval by the NERC staff coordinator
- NERC staff coordinator(s)

Liaison members include, but not limited to:

- Federal Energy Regulatory Commission (FERC)
- United States Department of Energy (DOE)
- National Energy Board, Canada
- RSTC (Sponsor)_

Additional guest participation of industry experts may be requested to support RAS activities.

Order of Business

In general, the desired, normal tone of RAS business is to strive for constructive technically sound solutions which also achieve consensus. On the relatively few occasions where desired outcome cannot be achieved, the RAS will defer to the RSTC to settle the issue. If strong minority opinions develop, those opinions may be documented as desired by the minority and forwarded to the RAS Chair and RSTC Chair for future meeting consideration.

NERC staff advice should be about what the ERO needs to be successful. The above normal tone of the RAS to seek a technically sound consensus is very important. NERC staff and RAS observers are also expected to strive for constructive technically sound solutions and seek consensus.

Meetings

Four to six open meetings per year, or as needed.

Reliability Assessment Subcommittee Scope

~~June 2018~~

Purpose

The Reliability Assessment Subcommittee (RAS) reviews, assesses, and reports on the overall reliability (adequacy and security) impacting the bulk power systems, both existing and as planned. Those reviews and assessments verify that each Assessment Area[1] conforms to its own planning criteria, guides, and the applicable NERC Reliability Standards. Further guidance for any reliability assessment is provided in the *NERC Rules of Procedure: Section 800*.[2]

In addition to supporting the peer review process for NERC's reliability assessments, the RAS will also provide input and guidance on the development of assessment data collections forms. Specifically, the RAS will serve as a platform for collaborative enhancements of current data collection processes to improve the accuracy, consistency, transparency, and efficiency of NERC's reliability assessments. This effort will involve collaboration with the U.S. Department of Energy's (DOE's) Energy Information Administration (EIA) and other governmental agencies with a goal of reducing duplicative reporting while promoting consistent data definitions.

Scope of Activities

1. Evaluate bulk power systems' conformance to respective Assessment Area planning criteria and guides, along with pertinent NERC Reliability Standards over the assessment period.
2. Support the annual review of each Assessment Area's long-term and short-term resource adequacy plans. This includes:
    a. Identifying and monitor the key issues, risks, and uncertainties that may impact or have the potential to impact bulk power system reliability;
    b. Coordinating timely submittals of Assessment Area narratives and responses to questions developed by NERC with support from the RAS.
3. Address and resolve any potential reliability issues or differences between the subcommittee's assessment and the assessment area's internal or interregional reliability assessment(s). Report any unresolved issues or differences to the NERC ~~Planning Committee~~Reliability and Security Technical Committee ~~ ~~(~~PC~~RSTC).
4. Upon request of the ~~PC or Operating Committee~~RSTC, conduct special reliability assessments, as conditions warrant (in addition to those defined above). Present results and findings to the ~~PC, Operating Committee,~~RSTC and others as appropriate.

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[1] Based on existing ISO/RTO footprints; otherwise, based on individual Planning Coordinator or group of Planning Coordinators. NERC collects data for seasonal and long-term assessments based on these footprints that align with how the system is planned and operated.

[2] NERC Rules of Procedure.

5. Facilitate data collection efforts of the Regional Entities and stakeholders for NERC's reliability assessments and identify and propose recommendations for improved RAS data collection efforts.
6. Seek feedback on any new data definitions approved by the ~~PC~~ RSTC and provide recommendations to the ~~PC~~ RSTC for consideration.
7. Develop recommendations for new data development and presentation options in NERC's reliability assessments.
8. Collaborate with EIA to promote efficiency, consistent data definitions, eliminate duplicative data collection, and improve overall data quality, including, but not limited to: ~~Forms EIA-411,~~ EIA-860, and EIA-860M.
9. Coordinate review of assigned Essential Reliability Services forward looking measures with the applicable reporting entities for inclusion in NERC's assessments.
   a. ERS Framework Measure 6: Forward-Looking Net Demand Ramping Variability
   b. ERS Framework Measures 1,2, and 4: Forward Looking Frequency Analysis
10. Establish working groups, as required, to support analysis and work products.

Working Groups

Working groups report to the RAS. Working group's scope, objectives, duration, deliverables, and other related documents will be endorsed by the RAS for approval in accordance with the ~~PC~~ RSTC charter.

Representation

The RAS chair and vice chair will be appointed by the NERC ~~PC~~ RSTC leadership for a two-year term. The vice chair should be available to succeed to the chair.

~~The Operating Committee representatives are appointed by the chair of the Operating Committee. Representation on this Subcommittee follows established PC guidelines for representatives.~~

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

Any member category as defined above that does not provide a representative in a timely fashion is requested to formally decline its invitation to participate in the subcommittee in writing to the chair of the RAS.

Reporting

The RAS will report to the ~~PC~~ RSTC for the completion of work associated with the scope items outlined above, and final work products of the RAS will be reviewed and considered by the ~~PC~~ RSTC and or the NERC Board of Trustees. The RAS chair will periodically apprise the ~~PC, Operating Committee, and Board of Trustees, as required,~~ RSTC on the subcommittee's activities, assignments, and recommendations.

Membership

The subcommittee is comprised of the following:

- Chair
- Vice chair
- One representative and one alternate from each Regional Entity – at least one of which must be Regional Entity staff (May also be the chair or vice-chair).
- One representative and one alternate from each Assessment Area that is not a Region
- ~~At least two representatives from the NERC Operating Committee~~
- One member-at-large from Canada
- At least one representative from each sector listed below:
  - Investor-Owned Utilities
  - Areas where there are no organized markets
- Additional members can be added:
  - At the request of the ~~PC~~ RSTC sector representatives, or
  - As requested by Regional Entity or Assessment Area staff, and upon approval by the NERC staff coordinator
- NERC staff coordinator(s)

Liaison members include, but not limited to:

- Federal Energy Regulatory Commission (FERC)
- United States Department of Energy (DOE)
- National Energy Board, Canada
- RSTC (Sponsor)

Additional guest participation of industry experts may be requested to support RAS activities.

Order of Business

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

NERC staff advice should be about what the ERO needs to be successful. The above normal tone of the RAS to seek a technically sound consensus is very important. NERC staff and RAS observers are also expected to strive for constructive technically sound solutions and seek consensus.

Meetings

Four to six open meetings per year, or as needed.

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Probabilistic Assessment Working Group Scope

Purpose

The primary function of the NERC Probabilistic Assessment Working Group (PAWG) is to advance and continually improve the probabilistic components of the resource adequacy work of the ERO Enterprise in assessing the reliability of the North American Bulk Power System. The group's origins and ongoing activities stem from work initiated by the Probabilistic Assessment Improvement Task Force (PAITF)[1] with the Probabilistic Assessment Improvement Plan.[2] Specifically, the group researches, identifies and details probabilistic analytical enhancements that apply to resource adequacy. The group's long-term focus addresses relevant aspects of the ERO Enterprise Long-Term Strategy[3] and the Reliability Issues Steering Committee (RISC) report[4] in conjunction with the NERC Reliability Assessment Subcommittee (RAS).

Scope of Activities

The PAWG serves as a stakeholder group focusing on probabilistic components of reliability assessments and the development of documents that identify and evaluate different probabilistic approaches and analyses. Specific activities of the PAWG include, but are not limited to:

- Leading the biennial NERC Core Probabilistic Assessment (ProbA), any annual probabilistic assessments, and supporting the development of NERC-coordinated special probabilistic assessments;
- Coordinating and promoting alignment of probabilistic resource adequacy assessments, to include transmission constraints, conducted by NERC, the Regions, and the industry at large;
- Identify improvement opportunities for NERC based probabilistic assessments;
- Implement and report on feasibility of identified improvements, as directed by the NERC Reliability Assessment Subcommittee (RAS);
- Develop detailed guidelines and recommended best practices regarding reliability and measures for probabilistic resource adequacy assessment.

1 https://www.nerc.com/comm/PC/PAITF/ProbA%20Technical%20Guideline%20Document%20-%20Final.pdf

2 https://www.nerc.com/comm/PC/Reliability%20Assessment%20Subcommittee%20RAS%202013/ProbA%20%20Summary%20and%20Recommendations%20final%20Dec%2017.pdf#search=GTRPMTF

3 See Focus Areas 1 and 4: https://www.nerc.com/AboutNERC/StrategicDocuments/ERO%20Enterprise%20Long-Term%20Strategy%20(Approved%20December%2012,%202019).pdf

4 See Risk 1: https://www.nerc.com/comm/RISC/Related%20Files%20DL/RISC%20ERO%20Priorities%20Report_Board_Accpeted_November_5_2019.pdf

Membership

The PAWG will include members who have technical or policy level expertise in at least one or more of the following areas:

- Probabilistic Resource Adequacy Analysis and Metrics
- Development of a probabilistic reliability study
- Stochastic representation of BPS elements

The PAWG Leadership will consist of a Chair and Vice Chair appointed by the RAS. Additionally, membership will include at least one representative from each Regional Entity (RE) or Planning Coordinator (PC). At least one representative from Canada is also expected. NERC staff are assigned as Coordinator(s). Decisions will be consensus-based of the membership, led by PAWG Leadership and Coordinators. Any minority views can be included in an addendum or in the reporting of the work products.

Any RE or stakeholder representatives may name alternate representative(s) who may attend PAWG meetings on their behalf.

Reporting

The PAWG reports to and conducts all activities through the RAS. The PAWG Scope and final work products are reviewed by the RAS and recommended for approval by the RSTC. The PAWG Chair will periodically update the RAS and the RSTC (or other committees) on PAWG activities, as requested and appropriate.

Meetings

The PAWG will meet according to a meeting schedule to be developed by the PAWG, subject to RAS review and approval; estimated to be four to six meetings per year.

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Probabilistic Assessment Working Group ~~(PAWG)~~ Scope

~~December 2016~~

Purpose

The primary function of the NERC Probabilistic Assessment Working Group (PAWG) is to advance and continually improve the probabilistic components of the resource adequacy work of the ERO Enterprise in assessing the reliability of the North American Bulk Power System. The group's origins and ongoing activities stem from work initiated by the ~~Generation & Transmission Reliability Planning Models Task Force (GTRPMTF) [1] and the~~ Probabilistic Assessment Improvement Task Force (PAITF)[1] with the Probabilistic Assessment Improvement Plan~~[2]~~~~.The primary function of the Probabilistic Assessment Working Group (PAWG) is to further advance the work initiated by the Generation & Transmission Reliability Planning Models Task Force (GTRPMTF) [1] and the Probabilistic Assessment Improvement Task Force (PAITF)[2] in the conduct of NERC's Core probabilistic assessments. The PAITF recently developed two reports to enhance probabilistic assessments. The *NERC Probabilistic Assessment Improvement Plan* was published in December 2015, and included possible recommendations by the PAITF based on 2015 Long-Term Reliability Assessment (LTRA) key findings regarding NERC core and proposed coordinated special probabilistic assessment reports. The *NERC ProbA Technical Guideline Document*, published in August 2016, [3] provided probabilistic modeling guidelines and technical recommendations to serve as a platform for detailing probabilistic analytical enhancements that apply to resource adequacy assessments.~~.[3] Specifically, the group researches, identifies and details probabilistic analytical enhancements that apply to resource adequacy. The group's long-term focus addresses relevant aspects of the ERO Enterprise Long-Term Strategy[4] and the Reliability Issues Steering Committee (RISC) report[5] in conjunction with the NERC Reliability Assessment Subcommittee (RAS).

~~The PAWG will develop Technical Reference documents that identify and evaluate more~~

[1] https://www.nerc.com/comm/PC/PAITF/ProbA%20Technical%20Guideline%20Document%20-%20Final.pdf

[3] https://www.nerc.com/comm/PC/Reliability%20Assessment%20Subcommittee%20RAS%202013/ProbA%20%20Summary%20and%20Recommendations%20final%20Dec%2017.pdf#search=GTRPMTF

[4] See Focus Areas 1 and 4: https://www.nerc.com/AboutNERC/StrategicDocuments/ERO%20Enterprise%20Long-Term%20Strategy%20(Approved%20December%2012,%202019).pdf

[5] See Risk 1: https://www.nerc.com/comm/RISC/Related%20Files%20DL/RISC%20ERO%20Priorities%20Report_Board_Accpeted_November_5_2019.pdf

~~probabilistic approaches for ongoing analyses that will provide further insights into resource adequacy assessment. The objectives of the PAWG include:~~

- ~~Conducting the biennial NERC Core Probabilistic Assessment and supporting the development of NERC coordinated Special Probabilistic Assessment reports, including the development of proposed data and information requests; and,~~

~~1. Coordinating and promoting alignment of probabilistic resource adequacy assessments conducted by NERC, the Regions, and the industry at large.~~

Scope of Activities

~~These following PAWG activities support the above objectives:~~

The PAWG serves as a stakeholder group focusing on probabilistic components of reliability assessments and the development of documents that identify and evaluate different probabilistic approaches and analyses. Specific activities of the PAWG include, but are not limited to:

- Leading the biennial NERC Core Probabilistic Assessment (ProbA), any annual probabilistic assessments, and supporting the development of NERC-coordinated special probabilistic assessments;
- Coordinating and promoting alignment of probabilistic resource adequacy assessments, to include transmission constraints, conducted by NERC, the Regions, and the industry at large;
- Identify improvement opportunities for NERC based probabilistic ~~resource adequacy assessment, including the objectives outlined above.~~assessments;
- ~~Provide and maintain a work plan to implement~~Implement and report on feasibility of identified ~~proposed~~ improvements, as directed by the NERC Reliability Assessment Subcommittee~~.~~ (RAS);

  ~~1. Recommend common data collection approaches to support a robust NERC probabilistic resource adequacy assessment, including modeling of:~~
     ~~a. Generation outages;~~
     ~~b. Operating procedures (e.g., maintaining operating reserves, load relief from public appeals);Load shape correlation with weather;~~
     ~~c. Grid connected variable resources (wind and solar);~~
     ~~d. Demand-Side Management Programs;~~
     ~~e. Behind the meter resources; and,~~
     ~~f. Transmission modeling.~~
- Develop ~~NERC Technical Document(s)~~detailed guidelines and recommended best practices regarding reliability and measures for probabilistic resource adequacy assessment ~~for consideration of the NERC PC~~.

Membership

The PAWG ~~membership will consist of subject matter experts that~~ will include members who have ~~demonstrated knowledge~~technical or policy level expertise in at least one or more of the following areas:

- Probabilistic Resource Adequacy Analysis and Metrics

- Development of a probabilistic ~~analysis with following structure:~~reliability study
- Stochastic representation of BPS elements

  - The PAWG Leadership will consist of a Chair ~~(two-year term)~~ and Vice Chair ~~(available to succeed to the chair) as~~ appointed by the RAS ~~and approved by the PC;~~
  - ~~At~~. Additionally, membership will include at least one representative from each Regional Entity~~;~~
  - ~~NERC staff coordinator(s); and,~~
  - (RE) or Planning Coordinator (PC). At least one representative from Canada~~.~~
  - ~~Additional members may include:~~
    - ~~Planning Authority representatives;~~
    - ~~Representative(s) from~~ is also expected. NERC staff are assigned as Coordinator(s). Decisions will be consensus-based of the membership, led by PAWG Leadership and Coordinators. Any minority views can be included in an addendum or in the ~~NERC Operating Committee~~

~~Representatives requested by~~reporting of the ~~RAS; and,~~work products.

    - ~~Representatives requested by the NERC coordinators.~~
  - ~~Observer members may include, but not limited to:~~
    - ~~Federal Energy Regulatory Commission;~~
    - ~~United States Department of Energy;~~
    - ~~Canadian Provincial Energy Boards; and,~~
    - ~~State regulatory authorities.~~

Any ~~Regional Entity~~RE or ~~electric industry sector~~stakeholder representatives may name alternate representative(s) who may attend PAWG meetings on their behalf.

Reporting

The PAWG reports to ~~the Reliability Assessment Subcommittee.~~and conducts all activities through the RAS. The PAWG Scope ~~is approved by the Planning Committee. Final PAWG~~and final work products are reviewed by the RAS~~,~~ and recommended for approval by the ~~PC (and the OC if required).~~RSTC. The PAWG Chair will periodically update the RAS~~,~~ and the ~~PC (and OC~~RSTC (or other committees) on PAWG activities, as requested and appropriate~~) of the status of working group activities~~.

Meetings

~~Meeting~~The PAWG will meet according to a meeting schedule to be developed by the PAWG, subject to RAS review and approval; estimated to be four to six meetings per year.

Guideline for the Electricity Sector: Supply Chain Procurement Language

Action
Approve

Summary
This guideline was posted for a 45-day industry comment period and conforming revisions were made. The response to comments received is included in the agenda package for this item. The SCWG is seeking approval of the guideline.

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Supply Chain Working Group

Tony Eddleman, NPPD and SCWG Chair
Reliability and Security Technical Committee
December 15-16, 2020

RELIABILITY | RESILIENCE | SECURITY




RSTC Status Report – Supply Chain Working Group (SCWG)

On Track
Schedule at risk
Milestone delayed

Chair: Tony Eddleman
Vice-Chair: Charles Abell | November 19, 2020

Purpose: Enhancing Bulk Electric System (BES) reliability by implementing the goals and objectives of the RSTC Strategic Plan with respect to issues in the area of supply chain risk management.

Items for RSTC Approval/Discussion:

- **Approve:** Security Guideline on Supply Chain Procurement Language
- **Approve**: SCWG Scope

Recent Activity

- Completed Security Guideline on Supply Chain Procurement Language
- Updated the SCWG Scope

Upcoming Activity

- Guidance documentation on supply chain risk management issues and topics
- Input and feedback associated with the development of supply chain documents to NERC staff

Workplan Status *(6 month look-ahead)*

Milestone	Status	Comments
Guidance documentation on supply chain risk management issues and topics	On Track	In progress
Input and feedback associated with the development of supply chain documents to NERC staff	On Track	In progress

Good Business Practices Provided in Security Guidelines

- Use the experience and expertise of the small team and the SCWG to identify best practices and challenges to the reader.
  - What are the pitfalls the reader should know about and avoid?
  - How does the reader learn about a specific topic and move forward to implement a solid program to improve reliability?
- Security Guidelines are approximately three (3) pages each.
  - The papers are written to convey general guidance to the reader without having to read a lengthy document.
  - Not trying to make the reader an expert.
- Provide references – reader can research for more information.

Security Guidelines are not compliance implementation guidance

Supply Chain Procurement Language

- A core measurement of any supply chain cybersecurity risk management program is proof of its value in risk-reducing terms.
  - Remedies applied through the inclusion of targeted controls in the procurement of cyber systems, components, maintenance, and related services can assist in the development of a “risk-based” approach to cybersecurity.

Supply Chain Procurement Language

- Procurement language within contracts is one among several means at an entity's disposal to formalize risk mitigation for the relationship between the entity and vendor
- Examples of supply chain cybersecurity risks and procurement language considerations include:
  - Energy Sector Control Systems Working Group (ESCSWG), "Cybersecurity Procurement Language for Energy Delivery Systems"
  - Utilities Technology Council (UTC), "Cyber Supply Chain Risk management for Utilities – Roadmap for Implementation"
  - Model Procurement Contract Language Addressing Cybersecurity Supply Chain Risk , developed by the Edison Electric Institute (EEI), May 2020
  - SP 800-161 Supply Chain Risk Management Practices for Federal Information Systems and Organization , National Institute of Standards and Technology (NIST)

Supply Chain Procurement Language

- Non-Contractual Purchases
  - Non-contractual purchases should be documented, assessed for risk, and include steps taken to mitigate identified risks.
  - Purchases, made without a contract, perhaps in response to an emergency to obtain something quickly, pose risks and lack formal oversight.
  - In some cases, the means of acquisition may affect the support that the entity will receive from the equipment manufacturer, or may impose additional requirements to obtain support, thereby requiring additional steps to mitigate risk.
    - Consider, for instance, the risk of using credit cards without the protections of procurement language.

Supply Chain Procurement Language

- NERC Webinar provided on the Guideline on April 27, 2020
  - Recording available on the NERC SCWG website
- July 15 – NERC SCWG finalized draft
- Reliability and Security Technical Committee (RSTC) Executive Committee reviewed the initial draft and approved posting it for industry comment
  - Comment Period: August 6, 2020 – September 21, 2020
- September 21 - NERC SCWG performed initial review and discussion of comments
- October 19 – NERC SCWG reviewed responses to comments and updated language
- November 16 – NERC SCWG final review
- Request NERC RSTC approval to post publicly

Subgroups

Committee Subgroups				
	Scope	Duration	Approvals	Leadership
Subcommittee	• Oversee broad processes • Manage cyclical deliverables	Long-term	Consensus seeking; vote as specified by its scope	Nominated by subcommittee; Approved by RSTC Leadership
Working Group	• Oversee specific data systems • Support specific initiatives with broader interaction with other subgroups/topics • Support a cyclical process • Support parent subcommittee	Long-term/ mid-term	Consensus seeking; non-voting	Nominated by working group, parent subcommittee, or direct appointment by the NERC Technical Committees; approved by RSTC Leadership
Task Force	• Support a specific initiative • Direct, often only one deliverable • Support parent subcommittee	Short-term	Consensus seeking; non-voting	Nominated by task force, parent subcommittee, or direct appointment by the NERC Technical Committees; approved by RSTC Leadership

SCWG Scope

- Supply Chain Working Group (SCWG) Scope updated to reflect changes to the RSTC
  - Enhance Bulk Electric System (BES) reliability by implementing the goals and objectives of the RSTC Strategic Plan with respect to issues in the area of supply chain risk management
- Large membership (> 125 members; > 90 observers)
- Partnership with industry
  - Registered Entities
  - Service Providers
  - Consultants
  - Product Providers
  - FERC, NERC, and Regional Entities
  - EEI, EPRI, and NATF
- Exceptional Experience and Knowledge

Questions and Answers

Guideline for the Electricity Sector

Supply Chain Procurement Language

The objective of the reliability guidelines is to distribute key practices and information on specific issues critical to promote and maintain a highly reliable and secure bulk power system (BPS). Reliability guidelines are not binding norms or parameters to the level that compliance to NERC's Reliability Standards are monitored or enforced. Rather, their incorporation into industry practices are strictly voluntary.

Introduction

A core measurement of any supply chain cybersecurity risk management program is proof of its value in risk-reducing terms. Regulators have challenged the levels of rigor regarding risk management practices that organizations claim to have attained. Remedies applied through the inclusion of targeted controls in the procurement of cyber systems, components, maintenance, and related services can assist in the development of a "risk-based" approach to cybersecurity.

Target Audience

Procurement language, beginning at the planning stage and at each step of an acquisition, is a critical element of a supply chain cybersecurity risk management program. Procurement language includes negotiated agreements that formalize the division of responsibilities, performance requirements, and expectations for compliance monitoring. This language is expressed in the form of contract clauses developed during the procurement of industrial control system hardware, software, and computing and networking services associated with bulk electric system (BES) operations. This paper highlights considerations for developing and maintaining risk based procurement language for electrical sector supply chain purposes.

Risk Identification

A NERC entity's supply chain cybersecurity risk management program efforts begin by identifying important risks to the cybersecurity of the BES supply chain; this process is described in the guideline "*Vendor Risk Management Lifecycle*"[1]. A thorough understanding of the risks associated with vendor relationships to critical cyber systems and particularly BES cyber systems, determines the type and quantity of conditions and stipulations appropriate to include in the procurement language to achieve cybersecurity and reliability goals. The risk assessment should include an analysis of likelihood and magnitude of harm and consider threats, vulnerabilities, and impact to organizational operations and assets, individuals, and the BES.

Procurement language within contracts is one among several means at an entity's disposal to formalize risk mitigation for the relationship between the entity and vendor. Acceptance or transfer of risk and the mitigating controls afforded or needing to be implemented as it relates to a third party may carry specific

[1] https://www.nerc.com/comm/CIPC_Security_Guidelines_DL/Security_Guideline-Vendor_Risk_Management_Lifecycle.pdf

liability and should be defined in entity's processes; and/or authorized by an appropriate senior manager or executive with a solid understanding of the risk being transferred or accepted.

Procurement language should also enable the audit mechanisms and metrics necessary for an entity to ensure that its vendors are meeting the contractual requirements and changes relevant to industry risks. Procurement contracts should be reviewed and updated as appropriate to ensure that an entity is identifying, assessing, and mitigating risks posed by vendors. Entity risk management controls for vendors should monitor contracts, master agreements, service level agreements and other documents associated with vendor procurements for:

- Change in product(s) or service(s)
- Vendor mergers or acquisitions
- Termination dates
- Renewal dates
- Automatic renewal clause dates
- Other significant contract terms

Procurement Language Examples

In the "*Letter to the Electric Industry Vendor Community*"[2] from the Critical Infrastructure Protection Committee (CIPC) on 03/06/2019, CIPC encouraged product and service vendors to provide several reasonable controls. The list attached to that letter is not intended to be all-inclusive but should be considered during lifecycles of supply chain vendors along with other sources noted below.

Examples of supply chain cybersecurity risks and procurement language considerations include:

- Energy Sector Control Systems Working Group (ESCSWG), "*Cybersecurity Procurement Language for Energy Delivery Systems*"[3]
- Utilities Technology Council (UTC), "*Cyber Supply Chain Risk management for Utilities – Roadmap for Implementation*"[4]
- *Model Procurement Contract Language Addressing Cybersecurity Supply Chain Risk*[5], developed by the Edison Electric Institute (EEI), May 2020
- *SP 800-161 Supply Chain Risk Management Practices for Federal Information Systems and Organization*[6], National Institute of Standards and Technology (NIST)

[2] https://www.nerc.com/pa/comp/Documents/Supply_Chain_Cyber_Security_Practices_20190306.pdf
[3] https://www.energy.gov/sites/prod/files/2014/04/f15/CybersecProcurementLanguage-EnergyDeliverySystems_040714_fin.pdf
[4] https://utc.org/wp-content/uploads/2018/02/SupplyChain2015-2.pdf
[5] https://www.eei.org/issuesandpolicy/Documents/EEI Law - Model Procurement Contract Language.pdf
[6] https://nvlpubs.nist.gov/nistpubs/SpecialPublications/NIST.SP.800-161.pdf

Additional information sources

- *Cyber Security Supply Chain Risk Management Guidance*[7], developed by the North American Transmission Forum (NATF), 2018
- *North American Generator Forum Cyber Security Supply Chain Management White Paper*[8], developed by the North American Generator Forum (NAGF)
- CIPC approved guideline / letter to industry – *Supply Chain Cyber Security Practices*[9]
- *NERC Frequently Asked Questions Supply Chain – Small Group Advisory Sessions Version: February 18, 2020 NERC Frequently Asked Questions Supply Chain*[10]

Non-Contractual Purchases

Non-contractual purchases should be documented, assessed for risk, and include steps taken to mitigate identified risks. Purchases, made without a contract, perhaps in response to an emergency to obtain something quickly, pose risks and lack formal oversight. In some cases, the means of acquisition may affect the support that the entity will receive from the equipment manufacturer, or may impose additional requirements to obtain support, thereby requiring additional steps to mitigate risk. Consider, for instance, the risk of using credit cards without the protections of procurement language.

The registered entity should document the emergency procurement process in a Supply Chain Risk Management (SCRM) procurement plan, along with documentation that registered entity personnel or approved contractors should also address after-the-fact risks and mitigations of the procurement. ***(See: NERC Frequently Asked Questions Supply Chain[11])***.

Closing

The most effective supply chain cybersecurity risk management program will prioritize a risk-based and tiered approach to mitigating security threats. Clear communication and expectations between vendors and entities will result in procurement language to support entity and industry security controls requirements.

[7] https://www.nerc.com/pa/comp/SupplyChainRiskMitigationProgramDL/NATF Cyber Security Supply Chain Risk Management Guidance.pdf
[8] https://www.nerc.com/pa/comp/SupplyChainRiskMitigationProgramDL/NAGF SC White Paper final.pdf
[9] https://www.nerc.com/pa/comp/Documents/Supply_Chain_Cyber_Security_Practices_20190306.pdf
[10] https://www.nerc.com/pa/comp/SupplyChainRiskMitigationProgramDL/Supply Chain Small Group Advisory Sessions FAQs %E2%80%93 October 2019.pdf
[11] https://www.nerc.com/pa/comp/SupplyChainRiskMitigationProgramDL/Supply Chain Small Group Advisory Sessions FAQs %E2%80%93 October 2019.pdf

Guideline for the Electricity Sector

Supply Chain Procurement Language

The objective of the reliability guidelines is to distribute key practices and information on specific issues critical to promote and maintain a highly reliable and secure bulk power system (BPS). Reliability guidelines are not binding norms or parameters to the level that compliance to NERC's Reliability Standards are monitored or enforced. Rather, their incorporation into industry practices are strictly voluntary.

Introduction

A core measurement of any supply chain cyber security risk management program is proof of its value in risk-reducing terms. Regulators have challenged the levels of rigor regarding risk management practices that organizations claim to have attained. Remedies applied through the inclusion of targeted controls in the procurement of cyber systems, components, maintenance, and related services can assist in the development of a "risk-based" approach to cybersecurity.

Target Audience

Procurement language, beginning at the planning stage and at each step of an acquisition, is a critical element of a supply chain cyber security risk management program. Procurement language includes negotiated agreements that formalize the division of responsibilities, performance requirements, and expectations for compliance monitoring. This language is expressed in the form of contract clauses developed during the procurement of industrial control system hardware, software, and computing and networking services associated with bulk electric system (BES) operations. This paper highlights considerations for developing and maintaining risk based procurement language for electrical sector supply chain purposes.

Risk Identification

NERC entity Supply Chain Cyber Security Risk Management Program efforts begin by identifying important risks to the cyber security of the BES supply chain; this process is described in the guideline "Vendor Risk Management Lifecycle". A thorough understanding of the risks associated with vendor relationships to critical cyber systems and particularly BES cyber systems, determines the type and quantity of conditions and stipulations appropriate to include in the procurement language to achieve cyber security and reliability goals. The risk assessment should include an analysis of likelihood and magnitude of harm and consider threats, vulnerabilities, and impact to organizational operations and assets, individuals, and the BES.

Procurement language within contracts is one among several means at an entity's disposal to formalize risk mitigation for the relationship between the entity and vendor. Acceptance or transfer of risk and the mitigating controls afforded or needing to be implemented as it relates to a third party may carry specific liability and should be defined in entity's processes; and/or authorized by ~~the CIP Senior Manager~~an appropriate ~~or other similarly~~ senior manager or executive with a solid understanding of the ~~ramifications of these decisions~~risk being transferred or accepted.

Procurement language should also enable the audit mechanisms and metrics necessary for an entity to ensure that its vendors are meeting the contractual requirements and changes relevant to industry risks. Procurement contracts should be ~~treated as living documents that need to be~~ reviewed and updated ~~regularly~~ as appropriate to ensure that an entity is ~~continually~~ identifying, assessing, and mitigating risks posed by vendors. Entity risk management controls for vendors should monitor contracts, master agreements, service level agreements and other documents associated with vendor procurements for:

- Change in product(s) or service(s)
- Vendor mergers or acquisitions
- Termination dates
- Renewal dates
- Automatic renewal clause dates
- Other significant contract terms~~, including the acceptance of residual risks that procurement language does not completely address.~~

Procurement Language Examples

In the Letter to the Electric Industry Vendor Community from the Critical Infrastructure Protection Committee (CIPC) on 03/06/2019, CIPC encouraged product and service vendors to provide several reasonable controls. The list attached to that letter is not intended to be all-inclusive but should be considered during lifecycles of supply chain vendors along with other sources noted below; 55 Examples of supply chain cyber security risks and procurement language considerations include:

- Energy Sector Control Systems Working Group (ESCSWG), "Cybersecurity Procurement Language for Energy Delivery Systems"
- Utilities Technology Council (UTC), "Cyber Supply Chain Risk management for Utilities – Roadmap for Implementation"
- Model Procurement Language Addressing Cybersecurity Supply Chain Risk, developed by the Edison Electric Institute (EEI), 2019
- SP 800-161 Supply Chain Risk Management Practices for Federal Information Systems and Organization, National Institute of Standards and Technology (NIST)

Additional information sources

- Cyber Security Supply Chain Risk Management Guidance, developed by the North American Transmission Forum (NATF), 2018
- North American Generator Forum Cyber Security Supply Chain Management White Paper, developed by the North American Generator Forum (NAGF)
- CIPC approved guideline / letter to industry – Supply Chain Cyber Security Practices
- NERC Frequently Asked Questions Supply Chain – Small Group Advisory Sessions Version: February 18, 2020 NERC Frequently Asked Questions Supply Chain 74

Non-Contractual Purchases

Non-contractual purchases should be documented, assessed for risk, and include steps taken to mitigate identified risks. Purchases, made without a contract, perhaps in response to an emergency to obtain something quickly, pose risks and lack formal oversight. In some cases, the means of acquisition may affect the support that the entity will receive from the equipment manufacturer, or may impose additional requirements to obtain support, thereby requiring additional steps to mitigate risk. Consider, for instance, the risk of using credit cards without the protections of procurement language.

The registered entity should document the emergency procurement process in a Supply Chain Risk Management (SCRM) procurement plan, along with documentation that registered entity personnel or approved contractors ~~validate~~ should also address after-the-fact risks and mitigations of the procurement. ***(See Above: NERC Frequently Asked Questions Supply Chain)***.

Closing

The most effective supply chain cyber security risk management program will prioritize a risk-based and tiered approach to mitigating security threats. Clear communication and expectations between vendors and entities will result in procurement language to support entity and industry security controls requirements.

Security Guideline	Supply Chain Procurement Language
Review Period	August 6 - September 21, 2020

Consolidated Comments and Responses

Organization(s)	Page #	Line #	Comment	Proposed Change	NERC Response
Hydro-Québec TransEnergie	1	24	Use "Cyber risk management" rather than "risk based procurement language"	This paper highlights considerations for developing and maintaining procurement language for cybersecurity risk magagement for electrical sector supply chain purposes.	Thank you for your comment. The existing wording is preferred.
Hydro-Québec TransEnergie	1	33	Understanding the cyber risks of vendor relationship with critical cyber systems allows to respond to cyber security goal	A thorough understanding of the risks associated with vendor relationships to critical cyber systems and particularly BES cyber systems, determines the type and quantity of conditions and stipulations appropriate to include in the procurement language to achieve cyber security and reliability goals.	Wording in the Guideline has been updated to reflect these comments.
Georgia System Operations Corporation	1	38 - 41	The sentence contained within these lines indicates that acceptance or transfer of risk should be authorized by the CIP senior manager or a similarly senior manager or executive with a solid understanding of the ramifications of these decisions. Companies often have established procurement processes, which already address/include decision trees and authorization matrices for contract amounts and/or topics. In some cases, decisions about risk may be made by procurement or legal personnel or may be escalated to the executive level. An executive may not be fully familiar with specific risks or ramifications, but may have a solid understanding of how risks affect their business units overall. GSOC recommends the revisions indicated in the proposed change column.	"Acceptance or transfer of risk as it relates to a third party may carry specific liability and should be authorized by an appropriately senior manager or executive with a solid understanding of the risk being transferred or accepted or as defined in entity's processes "	Wording in the Guideline has been updated to reflect these comments.
Hydro-Québec TransEnergie	1	39	CIP-013 standard mandate CIP senior manager's obligation in acceptance or transfer of risk. The Guideline should be consistent with CIP-13 language.	Acceptance or transfer of risk as it relates to a third party may carry specific liability and should be authorized by the CIP Senior Manager. Other similarly senior manager or executive with a solid understanding of the ramifications of these decisions can recommende such acceptance or transfer of risk to the CIP Senior Manager	Thank you for your comment. The existing wording is preferred.
Duke Energy	1	39, 40 & 41	Delete the following "be authorized by the CIP Senior Manager or other similarly senior manager or executive with a solid understanding of the ramifications of these decisions".	Replace with "be considered during contract negotiations."	Specifically regarding, R1 Part 1.2 and its sub-parts, while the action to renegotiate or abrogate existing contracts is not required, it is expected that mitigating activities are documented and implemented to address the risks of these elements.
Georgia System Operations Corporation	2	45 - 48	The sentence contained within these lines indicates a document review cycle and associated activities that is different from the review cycles indicated within the associated reliability standard. More specifically, the terms "living document" and "continually" could be interpreted to require frequent, holistic reviews of all in-scope procurement contracts - regardless of a trigger or indicia from the vendor. GSOC recommends the revisions indicated in the proposed change column.	Procurement contracts should be reviewed and updated as appropriate to ensure that an entity is identifying, assessing, and mitigating risks posed by vendors, including the acceptance of residual risks that procurement language does not completely address.	Wording in the Guideline has been updated to reflect these comments.
Duke Energy	2	46	Delete the word "regularly"	Replace with ", when commercially possible,"	Wording in the Guideline has been updated to reflect these comments.
Duke Energy	2	47 & 48	Delete the following "including the acceptance of residual risks that procurement language does not completely address."	End the sentence after vendors on Line 47	Good point - you can't update a procurement contract to cover acceptance of risks that the procurement language doesn't address. Wording in the Guideline has been updated to reflect these comments.

U.S. Bureau of Reclamation	2	51-73	This version does not contain actual guidance. It refers the reader to many OTHER documents, at links that may or may not remain viable. Use of this document could become cumbersome because of the numerous redicrects.	Append each referenced document so the reader can use the guideline without additional navigation to other documents.	This Security Guideline was developed as a short paper of the topic and not an extensive reference document. It was developed to provide the reader an overview of the topic within approximately three pages. References are provided to the reader where they can find additional information.
U.S. Bureau of Reclamation	2	63	NERC should consider strengthening and aligning the CIP standards with NIST for all CIP-related procurement language. The NIST standards are security-focused and provide a holistic approach to cybersecurity with implementation flexibility and the ability to assess and accept risk when appropriate compensating controls are in place. The NIST standards also include security control baselines (Low, Moderate, High) that are resilient to changes to the threat-landscape. The focus should not be on adapting the CIP standards, or how to better align them to NIST, but what is right with the NIST standards, and how a convergence on a single set of standards would improve BES resilience and security.	Provide additional focus towards NIST for supply chain cyber security risk management.	NIST is referenced in the Procurement Language Examples section. This Security Guideline was developed to promote good security practices for a specific topic and not intended to address the broader issue of NIST versus CIP Reliability Standards.
Georgia System Operations Corporation	3	83 - 86	The sentences contained within these lines could give the impression that, where entities document an emergency process, the triggering of such process exempts the purchase from compliance with CIP-013. This could create confusion and result in entities being found non-compliant during an audit as the declaration of use of an emergency process could be considered subjective. Accordingly, where an entity thought the triggering of its emergency process was justified, but a regional entity did not, what would be the outcome? Further, the clause appears to suggest an after-the -fact validation, but the scope or remedies resulting therefrom are unclear- especially where a contract has already been executed or a solution purchased Here, again, there is the potential for subjectivity relative to whether risks or mitigations were properly addressed. For these reasons, GSOC recommends the revisions indicated not he proposed change column.	The registered entity should document the emergency procurement process in a Supply Chain Risk 84 Management (SCRM) procurement plan, which should also address any after-the-fact validation of the risks and mitigations of the procurement.	Wording in the Guideline has been updated to reflect these comments.
U.S. Bureau of Reclamation	All	All	NIST SP 800-37, Risk Management Framework (RMF) for Information Systems and Organizations, a System Life Cycle Approach for Security and Privacy, Revision 2 provides guidance for securing information systems and supply chain risk management development. NIST SP 800-37 and its references should be mentioned within this procurement language document and identified as a key practice for managing an entity's supply chain cyber security risk management program.	Provide additional focus towards NIST for supply chain cyber security risk management.	NIST is referenced in the Procurement Language Examples section. This Security Guideline was developed to promote good security practices for a specific topic and not intended to address the broader issue of NIST versus CIP Reliability Standards.

Agenda Item 10b
Reliability and Security Technical
Committee Meeting
December 15, 2020

Supply Chain Working Group Scope Document

Action
Approve

Summary
The SCWG revised their scope document as part of the RSTC transition planning activities. A redline is include in the agenda package. The SCWG is seeking approval of the scope document.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Supply Chain Working Group

Scope | December 15, 2020

Purpose

The Supply Chain Working Group (SCWG) assists the NERC Reliability and Security Technical Committee (RSTC) in enhancing Bulk Electric System (BES) reliability by implementing the goals and objectives of the RSTC Strategic Plan with respect to issues in the area of supply chain risk management.

Functions

The SCWG accomplishes this by:

- Maintaining a roster of technical cyber and operations security experts to address the objectives and goals outlined in this scope document.
- Identifying known supply chain risks and address though guidance documentation or other appropriate processes including input to NERC Alerts or the E-ISAC advisories.
- Assisting NERC staff by providing input and feedback associated with the development of supply chain documents.
- Assisting where possible the E-ISAC efforts to engage Department of Energy and Department of Homeland Security to explore information sharing and supply chain risk assessments.
- Coordinating with the North American Transmission Forum (NATF) and other industry groups as appropriate to ensure bulk power system (BPS) asset owner supply chain security requirements are clearly articulated.
- Partnering with national laboratories to identify vulnerabilities in cyber equipment and develop mitigation practices.
- Developing other guidance where needed under the direction of the RSTC.

Deliverables

- Guidance documentation on supply chain risk management issues and topics
- Input and feedback associated with the development of supply chain documents to NERC staff
- Reports of working group activity for the regularly scheduled RSTC meetings
- Responses to other directives and requests of the NERC RSTC.

Reporting

The SCWG reports to the NERC RSTC and shall maintain communications with other groups as necessary about supply chain risk management related issues.

Officers

The NERC RSTC Chair appoints the SCWG officers (Chair and Vice Chair) for a specific term (generally two years). The working group officers may be reappointed for additional terms. The SCWG Chair is expected to attend the regular standing committee meetings to report on assignments, provide a summary report of the group's activities as requested, and advise the RSTC on important issues. The Vice Chair position is considered important for succession planning with the anticipation that the Vice Chair will be appointed as SCWG Chair for the next term. The SCWG may recommend officer candidates for the RSTC Chair's consideration.

Membership

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

General Requirements

SCWG membership requirements are focused on expertise related to cybersecurity and specifically in the area of supply chain risk management.

Commitment and Participation

SCWG members must be committed to their service on the working group. Members must prepare for and actively participate in all working group meetings in person or on conference calls. As needed, members must also write and review draft reports, serve on standard authorization request and standard drafting teams if selected, and bring issues to their Regional Entities, trade organizations, and utilities for further discussion and insight.

Work Products and Processes

The SCWG will follow the process (processes) directed by the RSTC in the development and publication of reports, guidelines, and other documents. Unless directed otherwise, document content will be approved by consensus of the SCWG.

Guests and Observers

SCWG meetings are open to members and guests. Individuals can request to be added to the SCWG mailing list.

Meeting Procedures

General

The SCWG follows the meeting procedures explained in the following documents:

- NERC Antitrust Compliance Guidelines,
- Participant Conduct Policy Applicable to NERC Operating Committee and its Subgroups, and
- Robert's Rules of Order, Newly Revised.

Scheduled Meetings

The SCWG routinely holds virtual meetings monthly and may occasionally hold in-person meetings as needed. Advance notices of these meetings are posted on the NERC website. Other open or confidential (see below) meetings of the SCWG and/or one or more of its document development teams may be scheduled, either virtually or in person, as the need arises.

Confidential Sessions

The chair of the SCWG may limit attendance at a meeting or portion of a meeting, based on confidentiality of the information to be disclosed at the meeting. Such limitations should be applied sparingly and on a non-discriminatory basis as needed to protect information that is sensitive to one or more parties. To stay in the confidential session, participants must have a signed "NERC Confidentiality Agreement for NERC Resources Subcommittee Members" on file.

Subgroups

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

Task forces are usually ad-hoc and are not expected to exist after completing their assignments.

Task force and document development team leads (or delegates) are expected to attend the regular working group meetings to report on assignments and subgroup activity.

Agenda Item 11
Reliability and Security Technical
Committee Meeting
December 15, 2020

EMP Task force (EMPTF) Scope and Work Plan

Action
Approve

Summary
The EMPTF sponsor, leadership, and NERC Staff revised and enhanced the previous version of the draft scope for the EMPTF. They also developed a draft work plan for 2021. They are seeking approval of both the EMPTF Scope document and 2021 Work Plan.

NERC
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RELIABILITY CORPORATION

EMP Initiative

Status Update and Work Plan Endorsement

Aaron Shaw (AEP), Chair, EMP Initiative

RSTC Q4 Meeting
December 15, 2020

RELIABILITY | RESILIENCE | SECURITY

Industry Update

- DOE – Working closely with DHS on mitigation projects to:
  - Field deploy agreed upon (DOE and the partner utility) cost-effective technologies to mitigate the adverse impacts of EMP on operations and/or equipment;
  - Evaluate the extent to which they work as designed;
  - Identify any adverse impacts from the installation; make sure operators understand how to maintain the mitigation systems; and provide guidance to others in the utility industry on lessons learned from the field deployment of the technology.
- DHS – Working on addressing the Presidential executive order on EMP and Congress intent of sustainable, efficient, and cost-effective approaches to EMP mitigation[1].

[1] https://www.cisa.gov/publication/emp-program-status-report

Scope Overview

- The new EMP initiative
  - NERC BOT chartered EMP task force is complete
  - Blessing and scope expanded by NERC BOT to continue under RSTC
- Solicit new NERC Members to support new team structure
  - The team to solicit industry for additional NERC members to execute work plan (seeking a minimum of 25 additional)
- Observers
  - Participation of observers and technical advisors will be encouraged as mentors and aids to execute deliverables
  - The following are examples that would be considered Observers
    - National Labs (SNL, LANL, ORNL, etc.)
    - Government and Defense (DHS, DOE, DTRA, NASA, etc.)
    - EPRI

Scope Overview

- Summary of upcoming deliverables
  - Team to produce ~15 reports over the next 2-3 years
  - Facilitate multiple technical workshops to foster collaboration
- Teams and Team Lead Structure
  - The following teams will be assembled to execute deliverables within work plan
    - Policy
    - Research and Development
    - Vulnerability Assessments
    - Mitigation
    - Response and Recovery

Work Plan Overview

- Overview of immediate priorities of deliverables

Task	Description	Deliverables	Lead	Estimated Completion
1. Scope Document, Work Plan	Develop and recommend a multi-year work plan for NERC to pursue. This in support of NERC BOT recommendations from February 2020. Develop Scope Document	Work Plan and scope document	NERC and EMP Team	Q4, 2020
2. Expand Membership	Solicit additional membership	Expanded list	NERC and EMP Team	Q1, 2021
3. Technical workshop	NERC to host EMP Technical Workshop	Publicly available EMP workshop	NERC and EMP Team	Q1, 2021
4. Team Leader(s) Selection	Selection of five (5) team leaders, including individual team membership.	Appointment of Team Leaders	NERC and EMP Team	Q1, 2021

Work Plan Overview

- Overview of high priority deliverables as directed by NERC BOT

Policy				
5. BPS Performance Expectations	Establish performance expectations for all sectors of the BPS regarding a predefined EMP event. NERC staff will work with other agencies on areas that require coordination	Report of findings	Team 1	2021-2022
Research and Development				
8. Research Gaps	Support additional research to close existing knowledge gaps into the complete impact of an EMP event to understand vulnerabilities, develop mitigation strategies, and plan response and recovery efforts	Report of findings	Team 2	2021-2022
Vulnerability Assessment				
11. Tools and Methods	Support development of tools and methods (and make available) for system planners and equipment owners to use in assessing EMP impacts on the BPS.	Report of findings	Team 3	2021-2022
12. Critical Assets Identification	Develop guidance to the industry on how to identify and prioritize hardening of assets that are needed to maintain and restore critical BPS operations	Report of findings	Team 3	2021-2022
Response and Recovery				
14. Strategies for Supporting Recovery	Develop guidance for supporting systems and equipment (including spare equipment strategy) needed for BPS recovery in a post-EMP event	Report of findings	Team 5	2021-2022

[1] Items that NERC staff has identified with highest priority, and that need to be addressed in the near term, are provided in **bold**

Questions and Answers

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Electromagnetic Pulse Initiative

EMP Initiative Scope
November 2020

Background

A 2019 technical report[1] from the Electric Power Research Institute (EPRI)[2] outlined threats to reliability posed by a high-altitude electromagnetic pulse (HEMP) attack. The report assessed vulnerabilities and risks and made mitigation recommendations in addition to laying the groundwork for the technical basis to develop for various analyses, guides, and or assessments.

To address research findings from the EPRI report, NERC's Board of Trustees established the Electromagnetic Pulse Task Force (EMPTF), which evaluated Bulk Power System (BPS) reliability and security concerns associated with a HEMP event and made recommendations towards meeting those expectations.

In its report[3] to the NERC Board of Trustees in November 2019, the EMPTF identified several Strategic Recommendations and key points of interest that should be addressed related to HEMP impacts on the BPS. Specifically, the EMPTF developed recommendations for next steps in the following areas:

- Policy
- Research and Development
- Vulnerability Assessments
- Mitigation Guidelines
- Response and Recovery

The report further recommended that an EMP team should be maintained and expanded to provide guidance for further work, particularly projects undertaken through the NERC technical committees to develop vulnerability assessments, mitigation guidelines, and enhanced response and recovery plans.

Purpose

The purpose of the new Electromagnetic Pulse Initiative is to address aspects of the next level of key points of interest related to system planning, risks and assessments, modeling, and reliability impacts to the bulk power system (BPS) as identified in the "EMP Task Force: Strategic Recommendations" (Report) to NERC's Board of Trustees in November 2019. The EMP Team's activities and responsibilities fall under the purview of NERC's Reliability and Security Technical Committee (RSTC).

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[1] https://www.epri.com/research/products/3002014979

[2] High-Altitude Electromagnetic Pulse and the Bulk Power System: Potential Impacts and Mitigation Strategies. EPRI, Palo Alto, CA: 2019. 3002014979.

[3] https://www.nerc.com/pa/Stand/EMP Task Force Posting DL/NERC_EMP_Task_Force_Report.pdf

Activities

The EMP Team will serve as a stakeholder forum for focusing on HEMP from a transmission planning and system analysis perspectives. Some of the primary focuses of EMP Team will be data collection, modeling practices, that are to determine the bulk power system (BPS) expectations for an EMP event. Based on that information, the industry can make the necessary preparations for attempting to meet those expectations. However, several policy matters, outside of the ERO Enterprise, will severely impact the electric sector's ability to address an EMP event. Those policy matters include the lack of a cost recovery mechanism and access to classified information regarding an EMP threat.

Each of the strategic recommendations identifies suggested lead organizations, and in some cases with NERC serving a prominent role as the lead or co-lead for most of the items. Certain key items, such as access to classified EMP data/environments and cost recovery mechanisms, must be addressed elsewhere. The timing and sequencing of the recommendations and policy matters are crucial, and the need for a highly organized and coordinated effort to support EMP resilience must be emphasized.

The following items from the Report list recommendations that were designated as NERC-led efforts and which EMP Team will address:

- Policy
- Research and development
- Vulnerability assessments
- Mitigation guidelines
- Response and Recovery

For issues from the Report that are not within NERC's areas of responsibility or authority, the EMP Team will seek to coordinate and facilitate efforts to accomplish these items from the Report:

- Policy matters
  - Cost Recovery Mechanisms
  - Industry Access to Classified Information
  - Declassification of Information

Deliverables

A drafted work plan is included in Attachment 1.

Membership

General Requirements

The EMP Team must have sufficient expertise within its ranks to fully understand and provide guidance on issues relevant to industry about EMP.

- **Members**
  Members are users, owners, and operators of bulk power system assets and represent stakeholders.
- **Observers**
  Observers provide subject matter expertise to the EMP Team, particularly in areas not directly related to bulk power system planning and operation.

Commitment and Participation

Members must be committed to their service on the EMP Team and are expected to actively participate in all meetings in person or on conference calls. As needed, members must also write and review draft reports, serve on or advise other NERC technical committees/teams, and bring issues to their Regional Entities, trade organizations, and utilities for further discussion and insight.

Reporting and Duration

The EMP Team will make reports at each regular meeting of the RSTC. The detail of the report will be appropriate for the level of activity over the preceding three months, with special emphasis given to issues that require action, feedback or participation from RSTC members and other industry participants.

The EMP Team will report to the RSTC. EMP Team work products will be approved by the RSTC. The group will submit work plans as directed to the RSTC.

The EMP Team's working timeline is guided by the availability of work and other information from the various federal and state regulatory agencies, federal agencies working on the HEMP subject matters, and other non-governmental organizations working on HEMP.

Meetings

EMP Team meetings will meet at least monthly, with updates provided to members and observers at least once per quarter. Meetings can be held via conference call, webinar, and/or face to face.

Attachment 1: Work Plan

NERC, in collaboration with industry, will follow the work plan presented below.

Task	Description	Deliverables	Lead	Estimated Completion
1. Scope Document, Work Plan	Develop and recommend a multi-year work plan for NERC to pursue. This in support of NERC BOT recommendations from February 2020. Develop Scope Document	Work Plan and scope document	NERC and EMP Team	Q4, 2020
2. Expand Membership	Solicit additional membership	Expanded list	NERC and EMP Team	Q1, 2021
3. Technical workshop	NERC to host EMP Technical Workshop	Publicly available EMP workshop	NERC and EMP Team	Q1, 2021
4. Team Leader(s) Selection	Selection of five (5) team leaders, including individual team membership.	Appointment of Team Leaders	NERC and EMP Team	Q1, 2021
Policy				
5. BPS Performance Expectations[4]	Establish performance expectations for all sectors of the BPS regarding a predefined EMP event. NERC staff will work with other agencies on areas that require coordination	Report of findings	Team 1	2021-2022
6. Industry and Public Education	Develop (or reference) educational material about EMPs and their impact to intelligent electronic devices and BPS reliability to inform industry and general public	Technical reference document Publicly available webinar(s) Workshop	Team 1	2021-2022
7. Coordination with Other Sectors	Develop guidance to the electricity industry on how to coordinate with interdependent utility sectors	Report of findings	Team 1	2021-2022
Research and Development				
8. Research Gaps	Support additional research to close existing knowledge gaps into the complete impact of an EMP event to understand vulnerabilities, develop	Report of findings	Team 2	2021-2022

[4] Items that NERC staff has identified with highest priority, and that need to be addressed in the near term, are provided in **bold**

	mitigation strategies, and plan response and recovery efforts			
9. Monitor Current R&D on National Initiatives	Communicate to the industry research pertaining to EMP and EMP-related national security initiatives that impacts the BPS	Technical workshop (yearly)	Team 2	2021-2022
10. Industry Specifications for Equipment	Support efforts to design equipment specifications for the electric sector utility industry around EMP hardening and mitigation strategies	Report of findings	Team 2	2021-2022
Vulnerability Assessment				
11. Tools and Methods	Support development of tools and methods (and make available) for system planners and equipment owners to use in assessing EMP impacts on the BPS.	Report of findings	Team 3	2021-2022
12. Critical Assets Identification	Develop guidance to the industry on how to identify and prioritize hardening of assets that are needed to maintain and restore critical BPS operations	Report of findings	Team 3	2021-2022
Mitigation				
13. Hardening of Critical Assets	Develop guideline for industry to use in developing strategies for mitigating the effects of a high-altitude EMP on the BPS	Technical report	Team 4	2021-2022
Response and Recovery				
14. Strategies for Supporting Recovery	Develop guidance for supporting systems and equipment (including spare equipment strategy) needed for BPS recovery in a post-EMP event	Report of findings	Team 5	2021-2022
15. Establish National EMP Notification System	Evaluate whether it would be feasible and useful to partner with the appropriate agencies to develop a real-time national notification system for the electric sector to System Operators and Plant Operators pertaining to an EMP event and its parameters.	Report of findings	Team 5	2021-2022
16. Response Planning	Develop response planning guidelines for electric utility industry members for pre and post-contingency of an EMP event that aligns with plans of applicable regulatory authorities.	Report of findings	Team 5	2021-2022
17. Enhance Operating Plans and Procedures	Work with industry to develop criteria to incorporate into operating plans and procedures and system restoration plans pertaining to EMP event.	Report of findings	Team 5	2021-2022
18. Incorporate EMP Events into Industry	Develop training for system and plant operators about EMP events and what to anticipate and incorporate EMP events in industry exercises to test	Technical reference document	Team 5	2021-2022

Exercises and Training	response planning and system restoration recovery efforts.	Training material (recorded webinars) Incorporate into Grid Security Exercise		

Real Time Operating Subcommittee (RTOS) Scope

Action
Approve

Summary
The RTOS sponsor, leadership, and NERC Staff revised, updated, and enhanced the previous version of the Operating reliability Subcommittee (ORS) scope document. They are seeking approval of the updated RTOS Scope document.

Real Time Operating Subcommittee Scope

Purpose

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

Functions

The RTOS will:

1. **Develop guidelines and programs to facilitate operating reliability coordination. Included among the processes supported by RTOS are those related to:**
   a. Real-time communications among registered entities, especially Reliability Coordinators (RCs).
   b. Exchange of operational data and modeling data among registered entities.
2. **Disseminate operational information among the RCs and other reliability entities.**
3. **Respond to requests for technical input and guidance from the RSTC.**
   a. Maintain documents and guides created by the RTOS for the RSTC.
4. **Review reliability plans and provide recommendations to the RSTC.**
5. **Provide a forum for coordinating system operating procedures in all four Interconnections, including:**
   a. Coordinate operating Reliability Standard implementation to promote consistency across the Interconnections.
   b. Prepare for the upcoming operating peak demand season.
   c. Review significant system disturbances and abnormal transaction curtailments, or others as requested by RTOS, for "lessons learned".
   d. Review Interconnection frequency events at each meeting.
6. **Provide coordination between EIDSN, Inc. and the RSTC regarding the applications managed by EIDSN, Inc.**
7. **Provide a forum for coordination of TLR business practices and Reliability Standards.**
8. **Provide oversight and guidance on aspects of interchange scheduling, including dynamic transfers, as it applies to impacts on reliable operations.**

Working Groups

Working groups may include, and are not limited to, the following:

- Synchronous Measurement Working Group

Deliverables

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

Reporting

The RTOS reports to the RSTC and shall maintain communications with the RSTC and other groups as necessary on relevant issues.

Officers

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

Membership

1. **One member from each RC.**
2. **Up to one additional non-RC member from each Region.**
3. **No single company may have multiple non-RC members**
4. **Current non-RC RTOS members will be grandfathered as a member of the subcommittee and the subcommittee roster will indicate this grandfathered status**
5. **Once the current grandfathered members resign their position on the subcommittee the RTOS will then accept applications for non-RC membership based on the criteria in number two above. The selection process will be determined by the RTOS.**

As outlined in the RSTC's "Subcommittee Organization and Procedures," the RTOS shall have sufficient expertise and diversity to be able to speak knowledgably for the industry and provide meaningful and useful guidance to assist the industry in the carrying out of its reliability responsibilities.

Executive Committee

The Executive Committee of the RTOS is empowered by the RTOS to act on its behalf between subcommittee meetings on matters where urgent actions are crucial and full subcommittee discussion is not practical. Ultimate RTOS responsibility resides with its full membership whose decisions cannot be overturned by the Executive Committee, but retains the authority to ratify, modify or annul Executive Committee actions. The Executive Committee will be comprised of the RTOS Chair, Vice Chair, along with three at large members. The Executive Committee members are elected by the RTOS for a two year term. The Executive Committee members may be re-elected.

Meeting Procedures

1. **Quorum: 50 percent of subcommittee members eligible to vote**
2. **All other procedures follow those of the "Organization and Procedures Manual for the NERC Standing Committees."**

Confidential Sessions

The chairman of the subcommittee may limit attendance at a meeting or portion of a meeting, based on confidentiality of the information to be disclosed at the meeting. Such limitations should be applied sparingly and on a non-discriminatory basis as needed to protect information that is sensitive to one or more parties.

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

Subgroups

The RTOS may form working groups, task groups, and task forces as needed to assist the subcommittee in carrying out standing or ad hoc assignments. Task group chairs (or delegates) are expected to attend the regular subcommittee meetings to report on assignments or provide a summary report of the group's activities at a minimum.

~~Operating Reliability~~Real Time Operating Subcommittee Scope

Purpose

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

Functions

The ~~ORS~~RTOS will:

1. **Develop guidelines and programs to facilitate operating reliability coordination. Included among the processes supported by ~~ORS~~RTOS are those related to:**
    a. Real-time communications among registered entities, especially Reliability Coordinators (RCs).
    b. Exchange of operational data and modeling data among registered entities.
2. **Disseminate operational information among the RCs and other reliability entities.**
3. **Respond to requests for technical input and guidance from the ~~OC~~RSTC.**
    a. Maintain documents and guides created by the ~~ORS~~RTOS for the ~~OC~~RSTC.
4. **Review reliability plans and provide recommendations to the ~~OC~~RSTC.**
5. **Provide a forum for coordinating system operating procedures in all four Interconnections, including:**
    a. Coordinate operating Reliability Standard implementation to promote consistency across the Interconnections.
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6. **Provide coordination between EIDSN, Inc. and the ~~OC~~RSTC regarding the applications managed by EIDSN, Inc.**
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Working Groups

Working groups may include, and are not limited to, the following:

- Synchronous Measurement Working Group

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Deliverables

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

Reporting

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

Officers

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

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GMD Data Reporting

Donna Pratt, Manager of Performance Analysis, NERC

Reliability and Security Technical Committee
December 15-16, 2020

RELIABILITY | RESILIENCE | SECURITY




Topics

- Background
- Overview of GMD Data Reporting Application
- Appendix and Reference Slides

GMD Data Collection Background

- FERC Order No. 830 directed NERC to collect GMD data to "improve our collective understanding" of GMD risk NERC developed the GMD Data Request with GMD Task Force (GMDTF) and technical committee input
  - In August 2018, NERC Board approved Rules of Procedure Section 1600 data request for collecting GMD data
    - Applies to Transmission Owners (TO) and Generator Owners (GO)
- Updates were provided to the GMDTF throughout application development
- NERC deployed the GMD Data Portal in October 2020
- Reporting entities must report data annually by June 30
  - First collection deadline June 30, 2021

Types of Data

- There are three types of data to be reported :
  - GMD monitoring equipment (GIC Monitor, Magnetometer)
  - GIC measurement data for designated GMD events
  - Geomagnetic field measurement data for designated GMD events

- Data Reporting Instructions describe data fields (format, units, narrative description, etc.) and provide example data

GMD Home Page

Geomagnetic Disturbance Data System

Welcome to the NERC Geomagnetic Disturbance (GMD) Data System. Users may submit, view, and manage device information and GMD Event data. GMD System Reports provide information on data reported for individual GIC Monitors and Magnetometers. Below is a list of entities for which you have permission to view or submit data. If an entity is not listed, go to the Application Access Requests page to request access.

The User Guide for the GMD Data System is available here or on the NERC website by navigating to Program Areas & Departments > Reliability Assessment & Performance Analysis > Geomagnetic Disturbance (GMD) > GMD User Guide for Entities.

For assistance with the functionality of the GMD Data System, please email GMD@nerc.net.

The annual reporting collection period for GMD data is from April 1 – March 31. The reporting deadline for each annual reporting collection period is June 30.

NCR ↑	Entity Name	GMD Role
NCR22222	Test Company 2	GMD Read-Only
NCR33333	Test Company 3	GMD Read-Only
NCR44444	Test Company 4	GMD Submitter
NCR55555	Test Company 5	GMD Submitter

Menu

GIC Monitor Devices
View, create, manage or bulk import GIC monitor devices

Magnetometer Devices
View, create, manage or bulk import magnetometer devices

GIC Monitor Data Reporting
View and submit GIC monitor data reporting submissions

Magnetometer Data Reporting
View and submit magnetometer geomagnetic data reporting submissions

Missing Data Report Imports
Bulk import missing data reports

GMD Reporting Status
View GMD Status Reports

GMD Events
View GMD events that require reporting

Implementation Update

- Data reporting training sessions held in October
  - As of mid-November, 125 registered entities have indicated that they meet the reporting criteria for GMD
- System User training – mid-2021
  - For System Users to download GMD Data

Appendix

Process for Designating Information as Confidential Information

Order No. 830 on Data Confidentiality

…as a general matter, the Commission does not believe that GIC monitoring and magnetometer data should be treated as Confidential Information pursuant to the NERC Rules of Procedure. (P 89)

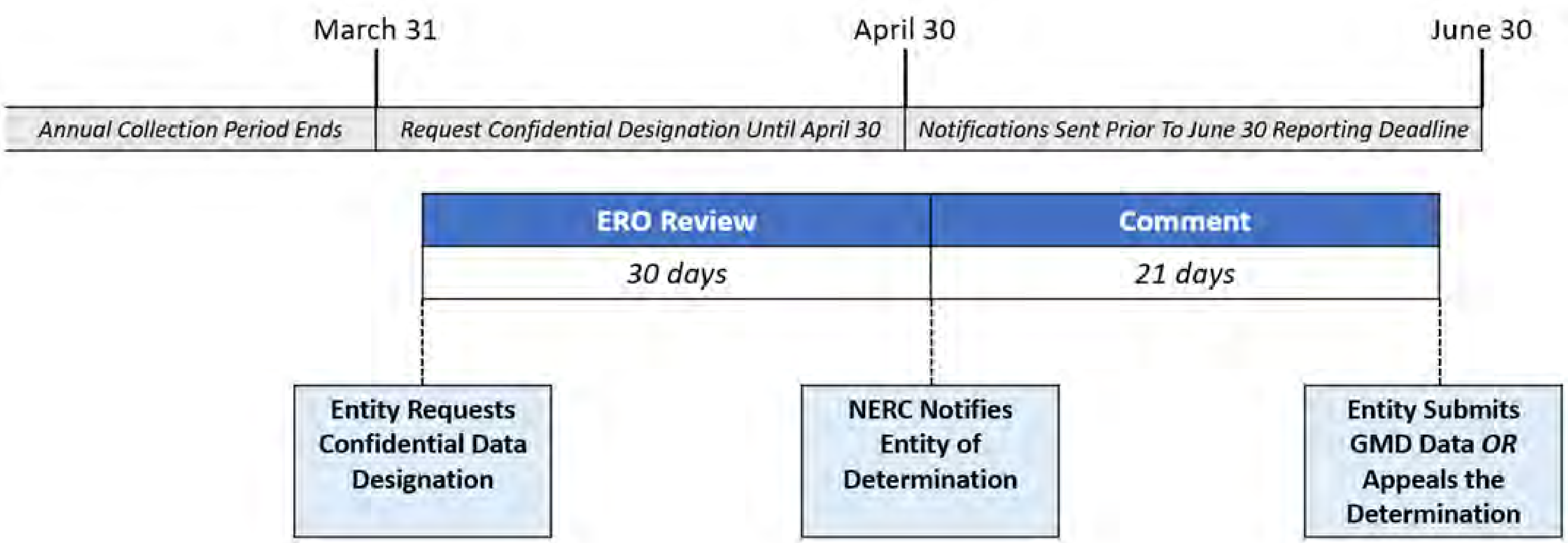
…Notwithstanding [the Commission's] findings here, to the extent any entity seeks confidential treatment of the data it provides to NERC, the burden rests on that entity to justify the confidential treatment. (P 95)

Restrictions on Disseminating Data

- If a Reporting Entity reasonably believes that any information required to be submitted under the GMD Data Request is Confidential Information, the Reporting Entity shall submit a request for Confidential Information treatment in accordance with FERC's guidance in Order No. 830
  - An entity will request confidential treatment before entering any data
- Data Reporting Instruction Appendix E Contains Guidance
- When data is determined by NERC to be confidential it will be marked accordingly in the data portal by NERC

Process for Confidential Designation

- Entities submit requests for confidential designation by April 30



Process for Confidential Designation

- Reporting entities submit Confidential Information designation request by form emailed to NERC (gmdconfidentialrequest@nerc.net)
- Request form will include the following info:
  - Entity Name, NERC I.D., and Contact
  - Date of Request
  - Type of GMD Monitoring Equipment (GIC monitor, magnetometer, both)
  - Device I.D. (if assigned in NERC GMD data system)
  - Narrative Justification providing explanation for why the information should not be released to a GMD data requestor, including:
    - Data fields in the GMD data system that meet Confidential Information definitions in NERC Rules of Procedure Section 1501
    - Category of Confidential Information (e.g., CEII)
    - Specific justification for why the reporting entity believes the information is Confidential Information
  - Date after which the data is no longer considered confidential

Confidential Information Definitions

- NERC Rules of Procedure Section 1500 Includes the following:

Critical Energy Infrastructure Information (CEII)

CEII means specific engineering, vulnerability, or detailed design information about proposed or existing Critical Infrastructure that (i) relates details about the production, generation, transportation, transmission, or distribution of energy; (ii) could be useful to a person in planning an attack on Critical Infrastructure; and (iii) <u>does not simply give the location of the Critical Infrastructure</u>. See NERC Rules of Procedure Section 1501

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NERC Staff Process

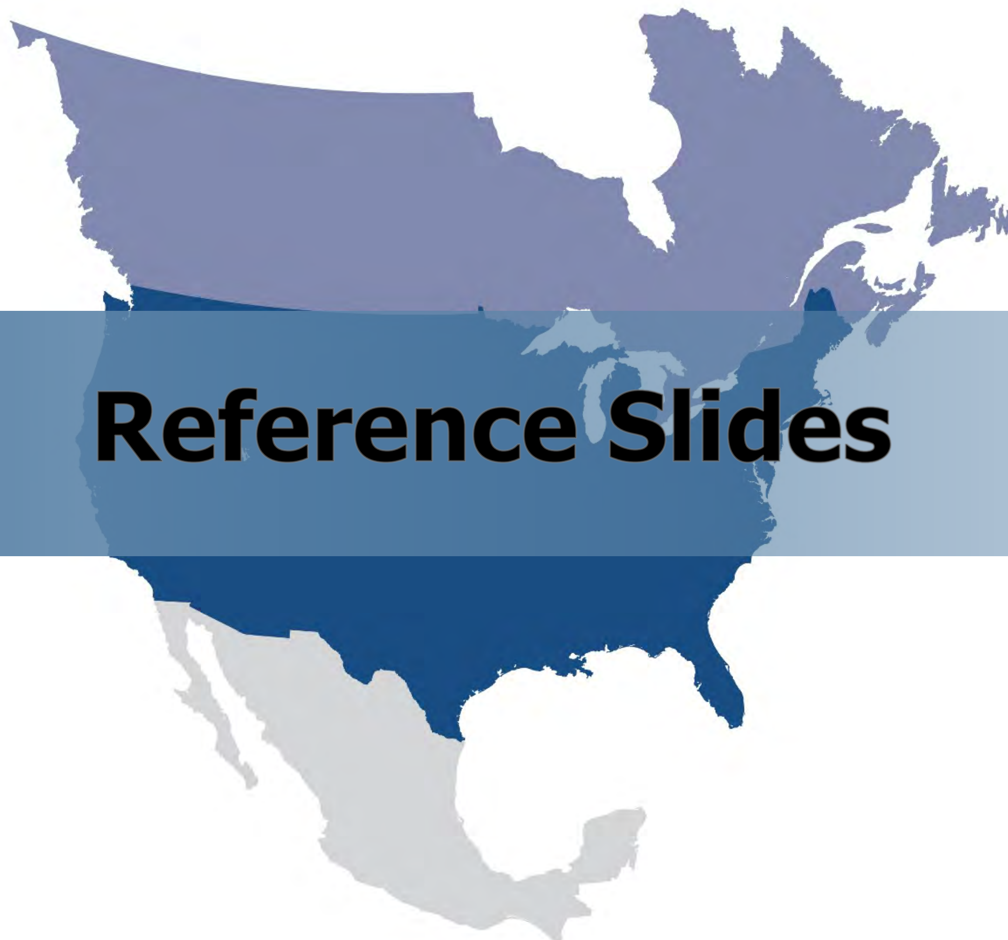
1. NERC Performance Analysis (PA) receives a request for Confidential Information designation via email
   - Verifies that all required information has been provided
   - Acknowledges receipt to the submitter
2. PA forwards the request for internal review
   - Includes NERC Security, E-ISAC, Engineering and Legal staff
3. PA sends response letter to submitting entity
4. Response letters include instructions for appeal

Appeals

- A Reporting Entity that receives a rejection of their request for confidential designation may appeal the determination to FERC or other applicable Governmental Authority. The Reporting Entity shall submit the appeal in writing within 21 days of NERC’s notification and provide a copy of the appeal to NERC.
- NERC's determination regarding confidentiality shall be final within 21 days of the decision, unless the Reporting Entity appeals to the appropriate Governmental Authority.

Marking as Confidential Information

- Data that is designated as Confidential Information will be appropriately marked and can only be viewed by the submitting entity and ERO GMD Data System administrators.
- Other system users, including public data requestors, cannot view, download, or select data that NERC designates as Confidential Information.



Reference Slides

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Historical Storms

- NERC will also collect historical GIC data for K-7 events dating back to May 2013 (one-time collection)

Table B.1: Historical GMD Events From May 2013 to Present for One-time Reporting

Event ID Number	K_p	Start Date	Time (UTC)	End Date	Time (UTC)
2013E01	7	2013-05-31	15:00:00	2013-06-01	15:00:00
2013E02	8	2013-10-02	00:00:00	2013-10-03	03:00:00
2015E01	8	2015-03-17	03:00:00	2015-03-18	06:00:00
2015E02	8	2015-06-22	03:00:00	2015-06-23	15:00:00
2015E03	7	2015-09-11	03:00:00	2015-09-11	18:00:00
2015E04	7	2015-09-19	18:00:00	2015-09-20	18:00:00
2015E05	7	2015-10-06	18:00:00	2015-10-09	09:00:00
2015E06	7	2015-12-20	03:00:00	2015-12-21	09:00:00
2017E01	7	2017-05-27	15:00:00	2017-05-28	15:00:00
2017E02	8	2017-09-07	21:00:00	2017-09-09	03:00:00
2017E03	7	2017-09-27	15:00:00	2017-09-29	00:00:00
2018E01	7	2018-08-25	18:00:00	2018-08-27	00:00:00

Data Collection Events

GMD Event Timeline

A GMD Event is predicted

- Space Weather monitors issue prediction (e.g., NOAA SWPC)
- Predictions issued 1-3 days prior to GMD event
- Warnings issued ~30 minutes prior to onset

A GMD Alert is Issued

- Space Weather monitors issue Alert (e.g., NOAA SWPC Alert message)
- Will indicate onset of GMD above threshold (e.g., K_P-7)

NERC GMD Data Collection Period

Return to normal (quiet)

- Dashboards (e.g., NOAA SWPC website) provide continuous information that will indicate when normal conditions have returned

NERC GMD Data Collection Event is Announced

- NERC Announces Start and End Date/Times for GMD Data Collection Period