Agenda
Reliability and Security Technical Committee

June 21, 2023 | 8:30 a.m.–4:30 p.m. Central
Hybrid Meeting

In-Person ***(Committee Members, NERC Staff, Presenters ONLY)***

MRO
380 St. Peter Street, Suite 800
St. Paul, MN 55102
Phone: 651-855-1760

Virtual Attendees WebEx Link: Join Meeting
Attendee password: RSTCJUNE23 (77825863 from phones and video systems)
Webinar number: 2309 271 4886

Join by Phone
+1-415-655-0002 US Toll | Access code: 230 927 14886
+1-416-915-8942 Canada Toll

Call to Order

NERC Antitrust Compliance Guidelines and Public Announcement*

Introduction and Chair's Remarks

Agenda

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

Consent Agenda

2. **Consent Items* - Approve**
   a. March 20-22, 2023 RSTC Meeting Minutes
   b. Reliability Assessments Subcommittee Scope

Regular Agenda

3. **Remarks and Reports**

  a. Subcommittee Reports*
  b. RSTC Work Plan
  c. Report of May 10, 2023 Member Representatives Committee (MRC) Meeting and May 11, 2023 Board of Trustees Meeting – *Chair Ford*
  d. LMWG Work Plan Item Adjustment
  e. Report on the 2nd Quarter RSTC Executive Committee Meetings

4. **Reliability Guideline: Generating Unit Winter Weather Readiness—Current Industry Practices* – Approve** – *David Lemmons, EAS | Srinivas Kappagantula, Sponsor*

5. **RSTC SAR Development Process*** – **Request for Comments**

6. **White Paper: Grid Forming Functional Specifications for BPS-Connected Battery*** – **Approve** – *Julia Matevosyan , IRPS Chair | Jody Green, Sponsor*

7. **Reliability Guideline: Performance, Modeling, and Simulations of BPS-Connected Battery Energy Storage Systems and Hybrid Power Plants*** – **Approve** – *Julia Matevosyan , IRPS Chair | Jody Green, Sponsor*

8. **Reliability Guidelines* – Retire** – *Julia Matevosyan , IRPS Chair | Jody Green, Sponsor*
  a. BPS-Connected Inverter-Based Resource Performance
  b. Improvements to Interconnection Requirements for BPS-Connected Inverter-Based Resources

9. **EMT Task Force Work Plan* – Information** – *Miguel Angel Cova Acosta, EMTTF Chair | Jody Green, Sponsor*

Break 10:25-10:45 a.m.

10. **Implementation Guidance: Usage of Cloud Solutions for BES Cyber System Information (BCSI)* – Endorse –** *Brent Sessions, SWG Co-Chair | Monica Jain, Sponsor*

11. **National Institute of Standards and Technology Cyber Security Framework to NERC CIP On-Line Information Resource Mapping* – Information –** *Brent Sessions, SWG Co-Chair | Monica Jain, Sponsor*

12. **Whitepaper: Zero Trust* – Approve –** *Brian Burnett, SITES | Marc Child, Sponsor*

13. **Probabilistic Assessment Working Group 2022 ProbA Regional Risk Scenarios Report* – Approve –** *Bryon Domgaard, PAWG Chair | Kayla Messamore, Sponsor*

14. **6GHz Task Force White Paper* – Information –** *Jennifer Flandermeyer, 6GHzTF | David Grubbs, Sponsor*

Lunch 12:00-1:00 p.m.

15. **White Paper – Overview of Energy Reliability Assessments – Volume 1 – Approve –** *Peter Brandien, ERATF Chair*

16. **Energy Reliability Assessments Working Group* – Approve –** *Peter Brandien, ERATF Chair*

17. **Resources Subcommittee Reliability Guidelines* – Approve –** *Greg Park, RS Chair | Rich Hydzik, Sponsor*

a. Reliability Guideline: Integrating Reporting ACE with the NERC Reliability Standards

b. Reliability Guideline: Operating Reserve Management

18. **SAR for Revisions to MOD-031 Standard* – Endorse –** *Shayan Rizvi, SPIDERWG Chair | Wayne Guttormson, Sponsor*

19. **Reliability Guideline: DER Data Collection and Model Verification of Aggregate DER* – Approve –** *Shayan Rizvi, SPIDERWG Chair | Wayne Guttormson, Sponsor*

    a. The following two Reliability Guidelines were merged to create this guideline and will be retired upon approval.

        i. Reliability Guideline: DER Data Collection for Modeling in Transmission Planning Studies

        ii. Reliability Guideline: Model Verification of Aggregate DER Models used in Planning Studies

20. **White Paper: Security Risks Posed by DER and DER Aggregators* – Request RSTC Comments –** *Shayan Rizvi, SPIDERWG Chair | Wayne Guttormson, Sponsor*

21. **SARs for Revisions to EOP-004 Standard and EOP-005 Standard* – Request RSTC Comments –** *Shayan Rizvi, SPIDERWG Chair | Wayne Guttormson, Sponsor*

Break 2:40-3:00 p.m.

22. **Time Monitoring Reference Document* – Approve –** *Jimmy Hartmann, RTOS Chair | Todd Lucas, Sponsor*

23. **BES–Initiated Load Loss Data Collection Whitepaper* – Information –** *Donna Pratt, NERC Staff*

24. **System Protection and Control Working Group Order 881-A Position Paper* – Endorse – *Lynn Schroder, SPCWG Chair | Todd Lucas, Sponsor***

25. **2023 ERO Reliability Risk Priorities Report RSTC Strategic Plan and RSTC Work Plan Priorities* – Call for Volunteers –** *Rich Hydzik, RSTC Vice Chair*

26. **Election of RSTC Chair and Vice Chair*** – **Approval** – *Wayne Guttormson, RSTC Nominating Subcommittee*

27. **Chair's Closing Remarks and Adjournment *(passing of the "gavel")***

*Background materials included.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

NERC Antitrust Compliance Guidelines

I. General

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

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

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

II. Prohibited Activities

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

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

III. Activities That Are Permitted

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

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

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

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

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

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

Minutes
Reliability and Security Technical Committee

March 22-23, 2023
In-Person Meeting

A regular meeting of the NERC Reliability and Security Technical Committee (RSTC) was held on March 22-23, 2023, in-person in Clearwater, FL. The agenda packages and presentations are available on the RSTC webpage.

Chair Ford called the meeting to order at 8:30 a.m. Eastern on Wednesday, March 22, 2023 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.

Introductions and Chair's Remarks
Chair Ford welcomed everyone to the meeting and called on Ms. Candice Castaneda to review the meeting governance guidelines, and referenced the administrative items contained in the advance material package.

Consent Agenda
Upon motion duly made and seconded, the Committee approved the Consent Agenda which consisted of the December 6-7, 2022 minutes and the SPIDERWG scope document as presented to the Committee.

Regular Agenda
Chairs Remarks
Chair Ford acknowledged the attendance of NERC Trustee Rob Manning as the new Board of Trustees RSTC liaison. Mr. Manning provided remarks highlighting both the informational session the day prior and the knowledge he received from the presentations, as well as the depth of work before the Committee in the agenda package and he looked forward to hearing the discussions.

Chair Ford then acknowledged David Ortiz, FERC and called on David to make some opening comments. Mr. Ortiz noted that he was attending as a Commission staff member and his remarks represented his own opinions and not those of the Commission or any individual Commissioner. Mr. Ortiz provided comments on the day's agenda topics highlighting that it is clear priorities are aligned and that it's through the RSTC that the work gets done. Additionally, he stated that the RSTC agendas cover every aspect of the reliability challenges industry is facing: energy adequacy, inverter-based resources, distributed energy resources, supply chain security, low impact cyber systems, and more. He noted that the challenges that industry faces are multifaceted. Thus, collaboration across FERC and NERC and Federal and State entities is needed to resolve them. He concluded with looking forward to the discussions of the day.

Chair Ford referenced the subgroup reports contained in the Agenda package and thanked the Sponsors for reports being submitted in the requested format.

Lastly, Chair Ford provided highlights from the February 2023 Member Representatives Committee and Board of Trustees meetings.

Nominating Subcommittee Member Election
Chair Ford reviewed the Nominating Subcommittee nomination process for the six (6) open seats noting that 6 nominations were received: John Stephens – Sector 5, Truong Lee – Sector 6, William Allen – At-Large, Wayne Guttormson – At-Large Canadian, Ian Grant – At-Large, Srinivas Kapagantula – At-Large. Per the charter, as Chair of the RSTC, Chair Ford requested approval of the proposed Nominating Subcommittee slate. Upon motion duly made and seconded, the Committee approved the slate as presented to the Committee.

RSTC Sponsor Assignments
Mr. Stephen Crutchfield presented on the role and expectations of an RSTC sponsor, as well as the new sponsor assignments for each program area.

EMT Modeling Guideline
Mr. Jody Green, Sponsor provided opening comments and Mr. John Moura presented on the EMG Modeling Guideline noting the IRPS has been developing the Reliability Guideline: Electromagnetic Transient Modeling for BPS-Connected Inverter-Based Resources – Recommended Model Requirements and Verification Practices. This guideline is intended to serve as a useful reference for TPs and PCs as they begin performing or coordinating EMT studies during the interconnection study process or during planning assessments. He presented that the primary goal of this guideline is to enable TPs and PCs to obtain high-quality EMT models for BPS-connected inverter-based resources (IBR) so that they can perform applicable simulations when necessary. Utilization of the recommendations and best practices within this guideline should allow TPs and PCs to proactively identify and better mitigate emerging reliability risks. The guideline will also support EMT SAR Project 2022-04 EMT Modeling and will also serve as a foundation for future EMT modeling related activities of IRPS. Finally, he noted that the guideline was posted for a 45-day public comment period and was updated in response to the comments received during the public comment period and is presented for approval. Upon motion duly made and seconded the Committee approved the Guideline as presented.

EMT Task Force Scope
Mr. Green, Sponsor provided opening comments and Mr. Moura presented highlighting the growing penetration of inverter based resources (IBR), Electromagnetic Transient (EMT) modeling and studies are becoming increasingly important and highlighting experience from Regional Entities that routinely run EMT studies shows that EMT studies are very complex and often require dedicated staff, time, and specialized expertise. He noted that the EMT models are complex and require thorough quality testing and validation and that EMT studies also require specialized tools, and the industry needs guidance on best practice when using EMT models and performing EMT studies. Mr. Moura concluded that for the reasons noted, the RSTC is asked to consider and approve dedicated task force leadership and the task force scope document. Upon motion duly made and seconded, the RSTC approved Miguel Angel Cova Acosta (Vestas) and Adam Sparacino (MEPPI) as the task force co-leads and the scope document as presented to the Committee.

SPIDERWG Standards Authorization Requests - FAC-001 and FAC-002
Mr. Wayne Guttormson, Sponsor provided opening comments and Mr. Shayan Rizvi, SPIDERWG Chair presented the FAC-001 and FAC-002 Standards Authorization Requests (SARs) for consideration and endorsement. Mr. Rizvi noted the SARs were developed per the approved NERC Reliability Standards Review and developed per a milestone plan presented to the RSTC Executive Committee and the SPIDERWG received RSTC comments and made conforming revisions to the SARs. The Committee engaged in a lengthy discussion on what constitutes DER, timing implementation and ensuring the alignment with existing standards and SARs. Upon motion duly made and seconded the Committee endorsed the FAC-001 and FAC-002 SARs.

Reliability Guideline: BPS Perspectives on the Adoption of 1547-20
Mr. Rizvi presented on the Reliability Guideline noting the guideline is provided for Authority Governing Interconnection Requirements (AGIRs) and for other NERC registered entities (e.g., PC, RC, and BA) to understand the benefits of IEEE 1547-2018 and the steps to adoption of the IEEE standard. He noted the guideline is not intended to suffice as engagement or coordination among RCs and other stakeholders nor intended to address regionally-specific consideration; rather, it is intended to serve as a useful reference in these coordination activities. Upon motion duly made and seconded, the Committee approved the Reliability Guideline: BPS Perspectives on the Adoption of 1547-20.

SAR for Revisions to MOD-031 Standard – Request RSTC Reviewers
Mr. Rizvi presented on the SAR noting the purpose of this SAR is to revise and modify MOD-031-3 in the “Requirements and Measurements” section so that PC are allowed to obtain existing and forecasted DER information from DPs or TPs. This project’s goal is to ensure that various forms of historical and forecast demand and energy data and information is available to the parties that perform reliability studies and assessments, and provide the authority needed to collect the applicable data. He stated the RAS already had already reviewed the draft SAR with comments incorporated and that the SPIDERWG was now seeking RSTC reviewers. Chair Ford requested that Mr. Crutchfield email the draft SAR to the entire RSTC and requested comments be provided to Mr. Crutchfield by April 21 and Mr. Crutchfield will submit all comments received to the SPIDERWG.

Winter Storm Elliott Overview
Mr. Bill Graham, NERC Staff presented an overview of Winter Storm Elliott highlighting the weather conditions, impact summary, entity preparations and operating condition, energy emergency alerts, and reported load shedding. He noted areas that experienced blizzard conditions included parts of Minnesota, Iowa, Wisconsin, Michigan, Ohio, New York, and Ontario, with the Buffalo area of New York and the Fort Erie and Kingston areas of Ontario experiencing almost two full days of blizzard and zero-visibility conditions as well as the cold wave affected all U.S. states from Colorado to the eastern seaboard and as far south as Miami, Florida.

Supply Chain Working Group Security Guidelines
Ms. Christine Ericson, Sponsor provided opening comments and Mr. Wally Magda, SCWG chair presented on the Provenance and Vendor Risk Management guidelines. Mr. Magda stated in supply chain security, “provenance” refers to knowing about a computer system’s “heritage” or that of its components (i.e., information that indicates whether its source is authentic (i.e., genuine or counterfeit)). By knowing a system or component’s origin, development, ownership, location, changes to its components, and accompanying data, users are better able to identify and defend against threats to cyber security that

could have an adverse impact on the BPS. With respect to the Vendor Risk Management guideline Mr. Magda noted most supply chain cyber security risks originate with vendors, so they are the most important component of an entity's Bulk Electric System (BES) supply chain cyber security risk management plan and the security guideline describes how an entity can identify, assess, and mitigate vendor cyber security risks as well as document their vendor risk management program. Upon motion duly made and seconded, the committee approved the Supply Chain Working Group Security Guidelines.

Real Time Operating Subcommittee Reliability Guidelines

Mr. Todd Lucas, Sponsor provided opening comments and Mr. Jimmy Hartmann, RTOS chair presented on the Real Time Operating Subcommittee Reliability Guidelines first addressing the Cyber Intrusion Guide for System Operators highlighting that due to their unique role in operating the BES, System Operators may be the first to observe and report unusual behavior. To ensure that entities are able to respond effectively, it is important that System Operators maintain a questioning attitude and readiness to collaborate with other groups to assist in identifying something that requires further investigation. Further, System Operators should understand their important role in recognizing strange and unusual cyber security behavior and notifying the right people consistent with their incident response plans.

Next, Mar. Hartmann addressed the Gas and Electrical Operational Coordination Considerations Guideline highlighting the transformation in the mix of fuel sources used to power electric generation throughout North America and the increased penetration of renewable resources in particular as well as the continued increase in the use of natural gas highlights the continued need for the coordination processes discussed in this guideline. This guideline should serve as a reference document that NERC functional entities may use as needed to improve and ensure BES reliability.

Upon motion duly made and seconded the Committee approved each of the Real Time Operating Subcommittee Reliability Guidelines.

Joint FERC NERC Cold Weather Inquiry Recommendation 21

Mr. Lucas provided opening comments and Mr. Hartmann presented on Recommendation 21 noting the Real Time Operating Subcommittee (RTOS) was asked to consider and possibly recommend appropriate action in consideration of Recommendation 21 from the February 2021 Joint FERC/NERC/ERO cold weather report and that a NERC Alert was issued on September 12, 2022 that the RTOS used to develop the response for the recommendation. After discussion by the Committee, the action for this item was amended from approve to accept and upon motion duly made and seconded, the Committee accepted the Joint FERC NERC Cold Weather Inquiry Recommendation 21. Additionally, RSTC members were requested to send any follow up requests/feedback to Mr. Crutchfield who then would provide all submissions to the RTOS.

ERATF Whitepaper: Considerations for Performing an Energy Reliability Assessment

Mr. Pete Brandien presented on the ERATF Whitepaper highlighting energy reliability assessments are critical for assuring the reliable operation of the Bulk Power System (BPS) as the penetrations of variable generation resources and/or just-in-time energy supplies increase. He noted the whitepaper is posted for a public comment period through April 21 and the ERATF is seeking RTSC comments by the due date.

ERO Event Analysis Process

Mr. Brad Gordon, NERC Staff presented on the ERO Event Analysis Process and requested RSTC approval to post for a 45-day comment period. Upon motion duly made and seconded the Committee approved the public posting comment period.

ERO Event Analysis Program Quarterly Update

Mr. Matt Lewis provided the quarterly update for the ERO Event Analysis Program.

ERO Performance Analysis Update

Mr. Jack Norris provided an update on the ERO Performance Analysis. Through discussion by the Committee it was requested to add other types of resources (wind/solar) and Mr. Norris noted that an update to GADs will include wind/solar in the future.

2023 State of Reliability Report

Ms. Donna Pratt presented on the 2023 State of Reliability (SOR) report highlighting is prepared annually to provide objective, credible, and concise information to policy makers, industry leaders, and the NERC Board of Trustees (Board) on issues affecting the reliability and resilience of the North America BPS. Specifically, the report identifies system performance trends and emerging reliability risks, determines the relative health of the interconnected system, and measures the success of mitigation activities deployed. Ms. Pratt reviewed the timeline for the report including the presentation via Webinar to the RSTC and the request for endorsement by the RSTC by no later than June 6, 2023.

Chair's Closing Remarks and Adjournment

Chair Ford called on Trustee Manning, Mr. Ortiz, and Mr. Lauby to provide any closing comments. Chair Ford concluded the meeting by thanking the participants, the committee members and looked forward to the meeting the next day.

March 23, 2023
Chair Ford called the meeting to order at approximately 8:30 a.m. Eastern, and thanked everyone for attending. Ms. Tina Buzzard reviewed the procedures for the meeting, reviewed the Antitrust Compliance Guidelines, and confirmed quorum, as well as provided an overview of the polling actions to be used for Committee actions during the meeting. Ms. Candice Castaneda reviewed the governance policies for the meeting.

Introductions and Chair's Remarks
Chair Ford thanked everyone for attending and highlighted the agenda for the day.

Regular Agenda
BCSI in the Cloud Tabletop Exercise (Technical Reference)
Ms. Monica Jain, Sponsor provided opening comments and Mr. Brent Sessions, SWG Co-Chair highlighted the BCSI in the Cloud TTX Technical Reference is a document package and the files are meant to go together to capture the experiences of the tabletop exercise and to show examples of the types of information exchanged. He also noted that the package is not considered compliance guidance or guidelines, but instead a technical reference that industry and the ERO might find useful to prepare their own tabletop exercises to test their particular cloud environments. Upon motion duly made and seconded the Committee approved the technical reference document.

FERC Lessons Learned paper
Ms. Jain provided opening comments and Mr. Sessions summarized the FERC Lessons Learned Paper highlighting that the purpose of the document is to provide considerations related to categorization practices and the document expands on CIP-002 lessons learned from FERC Staff Report Lessons Learned from Commission-Led CIP Reliability Audits (FERC Report) and was not intended to establish new requirements under NERC's Reliability Standards, modify the requirements in any existing reliability standards, or provide an interpretation under Section 7 of the Standard Processes Manual. He noted that compliance will continue to be determined based on language in the NERC Reliability Standards as they may be amended from time to time, as well as implementation of this lesson learned is not a substitute for compliance with requirements in NERC's Reliability Standards. Upon motion duly made and seconded the Committee approved the FERC Lessons Learned Paper.

PAWG 2022 ProbA Regional Risk Scenarios Report
Mr. Bryan Domgaard presented a summary of the PAWG 2022 ProbA Regional Risk Scenarios Report and requested a review by RSTC members. Chair Ford requested that RSTC members should email their interest to Mr. Crutchfield.

Towards Integrating Cyber and Physical Security for a More Reliable, Resilient, and Secure Energy Sector
Mr. Dan Goodlett, NERC Staff noted the report was created under the direction and guidance of a joint task force of IEEE members and the North American Electric Reliability Corporation (NERC) and that the report provides a foundation for establishing the concept of "security integration," which attempts to begin addressing security issues through a more integrated approach for cyber and physical security into the planning, design, and operational phases of the bulk power system.

Nominating Subcommittee
Ms. Castaneda presented on the process and timeline for the request for RSTC Chair and Vice Chair nominations stating that the final slate will be brought to the RSTC for consideration and approval at the March 2023 meetings.

Standing Committee Coordination Group (SCCG) Update* - Information – Rich Hydzik, RSTC Vice Chair
Mr. Rich Hydzik provided the quarterly report on the SCCG activities.

Forum and Group Reports
Ms. Venona Greaff, NAGF and Mr. Roman Carter, NATF provided highlights of their written reports that were provided in the advance agenda package.

RSTC 2023 Calendar Review
Mr. Crutchfield reviewed the 2023 meeting dates and requested members to please advise him if there are any concerns or industry conflicts to the proposed 2023 dates.

Chair's Closing Remarks and Adjournment
Chair Ford thanked attendees and Committee members for their attendance and participation. There being no further business before the RSTC, Chair Ford adjourned the meeting.

Stephen Crutchfield
Stephen Crutchfield
Secretary

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

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 system~~s~~, both existing and as planned. ~~Those~~ The 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~~assessments is provided in the *NERC Rules of Procedure: Section 800*.[2]

In addition to ~~supporting the~~conducting a 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 defined assessment period.
2. Support the annual review of each Assessment Area's long-term and short-term resource adequacy plans. This includes:
   a. Identify~~ing~~ and monitor the key issues, risks, and uncertainties that may impact or have the potential to impact bulk power system reliability;
   b. ~~Coordinating~~Coordinate~~ing~~ timely submittals of Assessment Area narratives and responses to questions developed by NERC with input and support from the RAS.
3. Address and resolve ~~any~~ potential reliability issues or differences between the subcommittee's assessment and the ~~assessment~~ Assessment ~~area's~~ 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 Reliability and Security Committee (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.
5. Facilitate data collection efforts of the Regional Entities and stakeholders for NERC's reliability assessments~~ and .identify~~ Identify and propose recommendations for improved RAS data collection efforts.

[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

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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~~ analysis 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-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 and approved by the RSTC, to support analysis and work products.
11. Review emerging or best practices of reliability assessment for potential consideration into RAS practices and work products.

Commented [A2]: Confirm RSTC needs to approve. Could we revise to sub-teams from Working Groups?

Working Groups

Working groups are able to report to the RAS~~.~~, as approved by the RSTC. Working group's scope, objectives, duration, work plans/deliverables, and other related documents will be endorsed by the RAS for RSTC consideration of approval, in accordance with the RSTC charter. The RAS may recommend to the RSTC the creation of a Working Group to address a reliability need within the RAS' purview.

Commented [A3]: Allow the PAWG chair to present directly to RSTC after RAS approval

Beginning in 2017, the Probabilistic Assessment Working Group (PAWG) reports to the RAS.

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Representation

The RAS chair and ~~vice~~ Vice ~~chair~~ Chair will be appointed by the NERC RSTC leadership for a two-year term. The ~~vice~~ Vice ~~chair~~ Chair should be available to ~~succeed~~ ascend to the ~~chair~~Chair.

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Subcommittee members are appointed by their Region or ~~electric industry sector~~a NERC entity within the ~~assessment area~~aAssessment aArea ~~for two-year terms, without limit to the number of terms~~. Any Region or ~~electric industry sector~~NERC entity within the ~~assessment area~~aAssessment aArea may ~~name~~ designate 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

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Trustees. ~~The~~Unless otherwise specified by the RAS Chair, ~~T~~the RAS ~~chair~~ Chair will periodically ~~apprise~~ report to the RSTC on the subcommittee's, and reporting Working Group'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~~ may also be the RAS C~~c~~hair or ~~vice-chair~~Vice-~~c~~ 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)
  - 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~~outcomes or consensus cannot be achieved, the RAS will defer to the RSTC to ~~settle~~ resolve the issue. If strong minority opinions develop, those opinions ~~may~~ should be documented as desired by the minority and forwarded to the RAS Chair, RAS RSTC Sponsor, and RSTC Chair for consideration of future ~~meeting consideration.~~discussion(s).

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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.

Scope Review

The RAS Scope shall be reviewed on a biennial basis.

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RSTC Status Report 6 GHZ Task Force (6GHZTF)

Chair: Jennifer Flandermeyer
Vice Chair: Larry Butts
June 20 – 22, 2023

● On Track
● Schedule at risk
● Milestone delayed

Purpose: Provide to the RSTC: determine scope of issue, gather information related to risk of harmful interference in the 6 GHz spectrum, evaluate options for industry outreach, and recommendations related to the issue

Items for RSTC Approval/Discussion:

- **Information Only**

Recent Activity

- Posted RSTC approved whitepaper for extent of condition of the 6 GHz network.

Upcoming Activities

- Develop recommendation on how to establish a 6 GHz spectrum baseline, and how to conduct interference testing in three key areas (urban, suburban, rural)
- Conduct a webinar to raise awareness for the industry
- Support development of a Level 2 Alert that encompasses the above recommendations as well as recommendations from the extent of condition whitepaper;
- Develop transition plan for the 6GHZTF (potential Telecom WG or disband)

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

Milestone	Status	Comments
Publish Extent of Condition Whitepaper	● (green)	Completed
Publish 6GHZ Interference Preparedness Whitepaper	● (green)	Review phase Q4/2023
Develop materials for Webinar	● (green)	Planning phase Q4/2023
Support the NERC Level 2 Alert	● (green)	Planning phase Q4/2023
Develop Transition Plan to Potential TWG or Disband	● (green)	Q4/2023

RSTC Status Report – Event Analysis Subcommittee (EAS)

Chair: Chris Moran
Vice-Chair: James Hanson
June 20-22, 2023

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

Purpose: The EAS will support and maintain a cohesive and coordinated event analysis (EA) process across North America with industry stakeholders. EAS will develop lessons learned, promote industry-wide sharing of event causal factors and assist NERC in implementation of related initiatives to reduce reliability risks to the Bulk Electric System.

Items for RSTC Action:

- Approve Reliability Guideline: Generating Unit Winter Weather Readiness v4

Recent 2023 Activity

- RSTC Work Plan Summit
- Ongoing Development of Lessons Learned
- Sub-team performing ERO EAP periodic review
- Sub-team performing Reliability Guideline review
- Initial Draft EAS Scope

Ongoing & Upcoming Activities

- ERO EAP Periodic Review
- Reliability Guideline Review: Generating Unit Winter Weather Readiness
- Development of Lessons Learned
- FMMTF Development of Failure Mode & Mechanism Diagrams
- EAS Scope document periodic review

Workplan Status *(6 month look-ahead)*

Milestone	Status	Comments
ERO EAP Periodic Review	Green	On-Going
Event Analysis Data & Trends for 2023 SOR	Green	Pending in coordination with the PAS
Winter Weather Webinar	Green	Upcoming Sept 2023
Lessons Learned for 2023	Green	On-Going
11th Annual SA Conference	Green	Upcoming Fall 2023
FMM Diagrams for 2023	Green	On-Going

EGWG Status Report

Chair: Mike Knowland
Vice-Chair: Daniel Farmer
June 21, 2023

On Track
Schedule at risk
Milestone delayed
Not started
Complete

Purpose: The EGWG was formed to address fuel assurance issues as a result of the RISC identified Grid Transformation.

Items for RSTC Approval/Discussion:
N/A

Recent Activity

- The EGWG completed the three year reliability guideline review - "Fuel Assurance and Fuel-Related Reliability Risk Analysis for the Bulk Power System".

Upcoming Activity

- The Fuel Assurance guideline is ready for the 45-day posting for comments from Jun 23 – Aug 7.
- Develop Coordination Plan with NAESB for potential electric related risks/objectives in natural gas related standards as well as follow up to complete and assess results of survey for Fuel Assurance Guideline.

Workplan Status *(6 month look-ahead)*

Milestone	Status	Comments
Gauge efficacy of Fuel Assurance guideline	On Track	In progress
NAESB joint inquiry coordination	On Track	In progress
Conduct triennial review of 3/20 Fuel Assurance Guideline	On Track	In progress
Design Basis Criteria RSTC approval	Complete	RSTC endorsed 9/22

RSTC Status Report – Electromagnetic Pulse Working Group (EMPWG)

Chair: Vacant
Vice-Chair: Vacant
June 2023

On Track
Schedule at risk
Milestone delayed

Purpose: The purpose of the EMPWG is to address key points of interest related to system planning, risks and assessments, modeling, and reliability impacts to the bulk power system (BPS).

Items for RSTC Approval/Discussion:
None

Workplan Status *(6 month look-ahead)*

Milestone	Status	Comments
Policy - Report of Findings	Milestone delayed	Completion of policy draft by Q2 2022.
R&D - Report of Findings	Milestone delayed	Completion of draft documents by Q2 2022.
Vulnerability Assessment - Report of Findings	Milestone delayed	Completion of draft documents by Q2 2022.
Mitigation - Technical Report	Milestone delayed	Completion of hardening draft by Q2 2022.
Response & Recovery - Report of Findings	Milestone delayed	Initial drafts expected by Q4 2022.

Recent Activity

- Since the chair and vice-chair roles remain unfilled, the Coordinator is working with sub-team leads to finalize work products
- Higher priorities and decreased availability of SMEs has led to missed deadlines in the work plan
- No new activities are being pursued, but documentation that has been developed is being consolidated into a reference document for industry..

Upcoming Activity

- Reference documents and/or white papers will be submitted to for review and approval no later than the RSTC's September meeting. Once approved, the information will be made available for industry reference
- When existing activities are completed, the EMPWG will revert to inactive status.

RSTC Status Report – Energy Reliability Assessment Task Force (ERATF)

Chair: Peter Brandien
March 21 - 23, 2023

On Track
Schedule at risk
Milestone delayed

Purpose: The ERATF is tasked with assessing risks associated with unassured energy supplies stemming from the variability and uncertainty from renewable energy resources, limitations of the natural gas system and transportation procurement agreements, and other energy-limitations that inherently exist in the future resource mix.

Recent Activity:

- The 2023 ERATF work plan was submitted to the RSTC during the Jan 31 – Feb 2 summit.
- The task force accepted the white paper on "Considerations for Performing an Energy Reliability Assessment".

Items for RSTC Approval/Discussion:

- *Approve the white paper entitled "Considerations for Performing an Energy Reliability Assessment" for a 45-day comment period.*

Upcoming Activity:

- Complete the documentation on convert the task force into a working group.
- Reoccurring meetings with the Tiger team:
  - The goal of Volume 2 of the technical paper is to document detailed scenarios on conducting energy reliability assessments in the operations time horizon and the planning time horizon.
- Provide technical assistance for the Standard drafting team, as needed.
- The next ERATF team call is scheduled for March 21, 2023.

Workplan Status *(6 month look-ahead)*

Milestone	Status	Comments
Assemble the subject matter experts for the Tiger team.	On Track	On track.
The Tiger team complete draft #1 document on the scenarios on conducting an energy reliability assessment.	On Track	On track.
Engage industry research and development organizations to review the document.	On Track	On track.

RSTC Status Report: Facility Ratings Task Force (FRTF)

Chair: Tim Ponseti
Vice-Chair: Jennifer Flandermeyer

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

Purpose: The NERC RSTC Facility Ratings Task Force (FRTF) will address risks and technical analyses associated with Facility Ratings.

Items for RSTC Approval/Discussion:

- None

Workplan Status *(6 month look-ahead)*

Milestone	Status	Comments
Item 1 – Implementation Guidance on sustaining accurate facility Ratings	Green	In Progress
Item 2 – Support Project 2021-08 Modifications to FAC-008 SDT	Green	In Progress
Item 3 – Whitepaper on Sampling for Facility Rating programs	Green	In Progress

Recent Activity

- Hold regular leadership meetings to discuss progress and strategy on deliverables.
- All three sub-teams holding regular meetings and working on deliverables.
- Tim Ponseti and Howard Gugel presented and discussed Facility Ratings issues with the Operations Leadership Team.
- Held meeting with full task force April 28th to provide updates on the individual work plan items.

Upcoming Activity

- Sub-teams working on deliverables.
- Bi-monthly FRTF meetings to discuss progress on work plan initiatives and other relevant topics.

RSTC Status Report: Inverter-Based Resource Performance Subcommittee (IRPS)

Chair: Julia Matevosyan
Vice-Chair:Rajat Majumder

On Track
Schedule at risk
Milestone delayed

Purpose: *To explore the performance characteristics of utility-scale inverter-based resources (e.g., solar photovoltaic (PV) and wind power resources) directly connected to the bulk power system (BPS).*

Items for RSTC Approval/Discussion:

- Refresh/Revision of a previous work item: Reliability Guideline: Performance Modeling of BPS-Connected BESS and Hybrid Power Plants that was approved in March 2021
- Item 22: Grid Forming White Paper

Recent Activity

- Technical Presentation on Leveraging Real-Time Simulation Technology to Accelerate EMT Simulations with Scalable Real-Code Controller Integration for Advanced IBR Integration Studies
- Technical Presentation on Large System Stability Analysis and Planning Using Impedance-Based Analysis

Upcoming Activity

- Work Plan Item #8: Reliability Guideline: Recommended Approach to Interconnection Studies for BPS-Connected Inverter-Based Resources
- Work Plan Item #20: Assessment: Gap Analysis of Any IBR-Related Issues Not Addressed by NERC Standards.
- Work Plan Item #24: Commissioning Best Practices for IBRs

Workplan Status *(6 month look-ahead)*

Milestone	Status	Comments
Item 8 - Reliability Guideline: Recommended Approach to Interconnection Studies for BPS-Connected Inverter-Based Resources	On Track	In progress
Item 20 - Assessment: Gap Analysis of Any IBR-Related Issues Not Addressed by NERC Standards	On Track	In progress
Item 22 - Grid Forming White Paper	On Track	In Progress
Item 24 - White Paper: BPS-Connected IBR Commissioning Best Practices	On Track	In Progress

RSTC Status Report – Load Modeling Working Group (LMWG)

Chair: Kannan Sreenivasachar,
Vice-Chair: Robert J O'Keefe

On Track
Schedule at risk
Milestone delayed

Purpose:
The LMWG is transitioning utilities from the CLOD model to the CMLD Composite Load Model. The CLOD model lacks the capability to model events like FIDVR, which can have significant consequences on planning decisions.

Items for RSTC Approval/Discussion:

- **Approve**: Work Plan Item Change: Change White Paper on End-Use Load Electrification into three separate Technical Reference *Documents*

Recent Activity

- April 25, 2023 LMWG Spring Meeting. Posted Presentations, Agenda to NERC.com
- Distributed Draft April 25, 2023 minutes for comment and changes.
- Began planning and preparation for July 25, 2023 Summer Meeting.
- Developed a one-pager on converting the Work Plan Item: White Paper on End-Use Load Electrification into three separate TRDs,

Upcoming Activity

- *Develop Electric Vehicle Charger Models (TRD)*
- *Develop Data Center TRD*
- *Develop Electric Heat Pump TRD*
- *Continue Implementation of Modular CMLD*
- *Continue coordination with SPIDERWG on DER Models*
- *Update LMDT tool*

Workplan Status *(6 month look-ahead)*

Milestone	Status	Comments
Implementation of Modular CMLD Model	On Track	In progress
Develop Electric Vehicle Charger TRD	On Track	In progress
Develop Data Center Models Questionnaire to support TRD	On Track	In progress
Develop Heat Pump TRD	On Track	In progress
Implementation of Single-Phase Motor Models	On Track	In progress
Coordination with SPIDERWG	On Track	In progress

RSTC Status Report – Performance Analysis Subcommittee (PAS)

Chair: David Penney
Vice-Chair: Heide Caswell
September 1, 2022

On Track
Schedule at risk
Milestone delayed
Not started
Complete

Purpose: The PAS reviews, assesses, and reports on reliability of the North American Bulk Power System (BPS) based on historic performance, risk and measures of resilience.

Items for RSTC Approval/Discussion:

- Section 1600 Load Loss data collection

Recent Activity

- Development of the 2023 State of Reliability Report
- RSTC presentation May 15 with review and e-ballot complete by June 6

Upcoming Activity

- State of Reliability Report expected to be released in late June
- Accept for posting - load loss data collection white paper
- Develop security metric
- Review weighting of the Severity Risk Index (SRI) components

Workplan Status *(6 month look-ahead)*

Milestone	Status	Comments
Load loss data Section 1600 Data Request	Not started	Begin DRI and Section 1600 data request materials for load loss data
Review proposed new metrics	On Track	Cyber and physical security metrics under development
2023 State of Reliability Report	On Track	E-ballot endorsement due June 6 Release expected in late June

RSTC Status Report – Reliability Assessments Subcommittee (RAS)

Chair: Andreas Klaube (12/2022)
Vice-Chair: Amanda Sargent (12/2022)
June 20-22, 2023

On Track
Schedule at risk
Milestone delayed

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

Items for RSTC Approval/Discussion:
- RAS Scope (Approval)
- Reliability Assessments Review Process (Discussion)

Recent Activity:
- 2023 SRA published on May 17, 2023
- April 11-12, 2023 RAS meeting: Topics - RAS Work plan review, 2023 LTRA planning, 2023 SRA, RAS Scope, PAWG Work plan review
- Coordination with RTOS and EAS on work plan items

Upcoming (RSTC) Activity:
- Coordination with RTOS on development of the WRA Request Materials that address Cold Weather Inquiry Report Recommendations

Workplan Status *(6-month look ahead)*

Milestone	Status	Comments
2023 Long-Term Reliability Assessment (LTRA)	On Track	Preliminary Assessment Area submissions are due June 16, 2023
2023-2024 Winter Reliability Assessment (WRA)	On Track	Assessment Area informational request material planned for July/August 2023
Reliability Assessment Inputs and Grid Transformation	On Track	Coordinating with other RSTC groups/SMEs
Special Reliability Assessments Scope and Prioritization	On Track	Draft scope in development; for RSTC review and assignment to a task force

RSTC Status Report – Resources Subcommittee (RS)

Chair: Greg Park
Vice-Chair: William Henson
March 2023

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

Purpose: The RS assists the NERC RSTC in enhancing Bulk Electric System reliability by implementing the goals and objectives of the RSTC Strategic Plan with respect to issues in the areas of balancing resources and demand, interconnection frequency, and control performance.

Items for RSTC Approval/Discussion:

- **Operating Reserve Management Guideline**
- **Integrating Reporting ACE with NERC Reliability Standards Guideline**

Recent Activity

- Quarterly review of interconnection performance
- Reviewed and Provided Feedback to NERC staff for Bias settings to be implemented by BAs on June 7th, 2023

Upcoming Activity

- In Person/Hybrid Meetings Scheduled
  - July 25th – 26th Montreal Canada, Hosted by Hydro Quebec

Workplan Status *(6 month look-ahead)*

Milestone	Status	Comments
Support ERSWG Measures 1,2,4, and 6	Green (On Track)	Periodic review and consultation with NERC staff ongoing
Reliability Guideline: Integrating Reporting ACE with the NERC Reliability Standards	Red (Milestone delayed)	Approval Item
Reliability Guideline: Primary Frequency Control	Red (Milestone delayed)	Reviewing Public Comment
Reliability Guideline: Operating Reserve Management	Yellow (Schedule at risk)	Approval Item

RSTC Status Report – Real Time Operating Subcommittee (RTOS)

Chair: Jimmy Hartmann
Vice-Chair: Tim Beach
June 2023

On Track
Schedule at risk
Milestone delayed

Purpose: The RTOS assists in enhancing BES reliability by providing operational guidance to industry; oversight to the management of NERC-sponsored IT tools and services which support operational coordination, and providing technical support and advice as requested.

Recent Activity

- RTOS endorsed minor updates for the following Reliability Plans:
    - BC HYDRO
    - FRCC
    - MISO
    - RC WEST
    - VACAR-S

Items for RSTC Approval/Discussion:

RTOS approved the triennial review for Time Monitor Reference Document changes and recommends RSTC approval. The document was updated to the new Committee and Subcommittee names along with some minor edits such as additional information on the western interconnection time error correction process and additional references for specific time zone references.

Upcoming Activity

Continued work related to the Cold Weather Report

Workplan Status *(6 month look-ahead)*

Milestone	Status	Comments
Monitor development of common tools and act as point of contact for EIDSN.	Green (On Track)	On-going
Frequency Monitor Reporting (Standing RTOS agenda item to discuss).	Green (On Track)	On-going
Time Monitor Reference Document	Green (On Track)	Complete
Reliability Guideline: Methods for Establishing IROLs	Yellow (Schedule at risk)	On hold
Continued work related tasks from the Cold Weather Report	Green (On Track)	On-going

RSTC Status Report – Supply Chain Working Group (SCWG)

Chair: Christopher Strain
Vice-Chair: Dr. Tom Duffey
June 2023

On Track
Schedule at risk
Milestone delayed

Purpose: To Identify known supply chain risks and address through guidance documentation or other appropriate vehicles. Partner with National Laboratories to address supply chain risk.

Items for RSTC Approval/Discussion:

- **None**

Recent Activity

- New chair and vice chair have assumed those roles
- Sub-teams are revising two guidelines (Vendor Incident Response and Procurement Language) and preparing new content for two others (Cloud Service Providers and Procurement Sourcing) ;
- The "security summit" after March's RSTC meeting was a success. It included updates from the security-focused RSTC groups and presentations from NERC and two National Labs.

Upcoming Activity

- Three supply chain security guidelines that are being developed are expected to be ready for RSTC's September meeting.
- Efforts have begun to address the RSTC strategic plan item "Supply Chain Security." Once a team is established, they will begin work on a gap assessment of the CIP Reliability Standards.

Workplan Status *(6 month look-ahead)*

Milestone	Status	Comments
Periodic Review of Supply Chain Security Guidelines	On Track	In Progress
Guidance documentation on supply chain risk management issues and topics	On Track	In Progress
Whitepaper: NERC Standards Gap Assessment	On Track	In Progress

RSTC Status Report
Security Integration and Technology Enablement Subcommittee (SITES)

Chair: Brian Burnett
Vice Chair: Thomas Peterson
June 2023

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

Purpose: To identify, assess, recommend, and support the integration of technologies on the bulk power system (BPS) in a secure, reliable, and effective manner.

Items for RSTC Approval/Discussion:

- **Accept**: *None*
- **Approve**: *Whitepaper: Zero Trust for OT*
- **Comment:** Joint Whitepaper: Privacy & Security for DER and DER Aggregators

Recent Activity

- Zero Trust White Paper finished and submitted for RSTC approval
- Joint DER Whitepaper initial draft out for comment (submitted by SPIDERWG)
- BES Ops in Cloud whitepaper delayed 3 months. Internal NERC review & NERC collab with SITES on final recommendations drafting

Recent Activity – Cont.

- . New Tech Enablement & Field Testing paper outline developed including recommendations. Out for comment / feedback

Upcoming Activity

- Submission of BES Ops Cloud whitepaper to RSTC for comment or approval
- Begin work on new work item(s)

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

Milestone	Status	Comments
BES Operations in the Cloud	Red	ETA Sept 2023
Zero-Trust for OT	Green	June RSTC Agenda for Approval
New Tech Enablement	Green	Seeking comments on Outline
Privacy & Security for DER and DER Aggregators	Green	June RSTC Agenda for Comment
2023 State of Technology Report	Green	Planning Phase

RSTC Status Report – Synchronized Measurement Working Group (SMWG)

Chair: Qiang "Frankie" Zhang
Vice-Chair: Clifton Black
June 2023

● On Track
● Schedule at risk
● Milestone delayed

Purpose: The purpose of the SMWG is to provide technical guidance and support for the use of synchronized and high-resolution measurements to enhance the reliability and resilience of the bulk power system (BPS) across North America.

Items for RSTC Approval/Discussion:

Recent Activity

- Developed and published the reporting criteria for oscillation event reporting template.
- Consolidated the two oscillation papers.
- Finalized the 3/21 oscillation event report.
- Held spring SMWG meeting (4/6).

Upcoming Activity

- Add oscillation as a category in RCIS.
- Hold July SMWG Virtual Meeting
- Draft a Synchrophasor Data Accuracy Maintenance Manual.
- Hold a discussion with the RCs about challenges with Real-time Operational Use of PMU Data.

Workplan Status *(6 month look-ahead)*

Milestone	Status	Comments
Add Oscillation as a Category in RCIS	● (green)	Initiated
July SMWG Virtual Meeting	● (green)	Planned
Synchrophasor Data Accuracy Maintenance Manual	● (light green)	Scheduled
Discussions with RCs regarding Challenges with Real-time Operational Use of PMU data	● (light green)	Planning
Deploy ESAMS	● (light green)	Pursuing

RSTC Status Report – System Protection and Control Working Group (SPCWG)

Chair: Lynn Schroeder
Vice-Chair: Manish Patel
As of May 17, 2023

On Track
Schedule at risk
Milestone delayed

Purpose: The SPCWG will promote the reliable and efficient operation of the North American power system through technical excellence in protection and control system design, coordination, and practices.

Items for RSTC Approval/Discussion:

- **Endorse 881/881A position paper**

Recent Activity

- Bill Crossland retired as chair. Lynn Schroeder took over as chair and Manish Patel was approved as Vice-Chair by RSTC leadership
- FERC 881 impact on PRC-023 position paper submitted to RSTC at June meeting
- Review and update documents: Determination of Practical Transmission Relaying Loadability Settings
- Review TRD: Transmission System Phase Backup Protections
- Develop Technical Reference document for Ethernet based P&C.

Upcoming Activity

- Work on projects

Workplan Status *(6 month look-ahead)*

Milestone	Status	Comments
FERC 881	On Track	Report submitted
Practical Relay Loadability	On Track	Work continues
Ethernet P&C TRD	On Track	Work continues
Review and update Transmission System Phase Backup Protections	On Track	Work Continues

RSTC Status Report – System Planning Impacts from DER Working Group (SPIDERWG)

On Track
Schedule at risk
Milestone delayed

Chair: Shayan Rizvi
Vice-Chair: John Schmall
June XX, 2023

Purpose: *Historically, the NERC Planning Committee (PC) identified key points of interest that should be addressed related to a growing penetration of distributed energy resources (DER). The purpose of the System Planning Impacts from Distributed Energy Resources)SPIDERWG) is to address aspects of these key points of interest related to system planning, modeling, and reliability impacts to the Bulk Power System (BPS). This effort builds off of the work accomplished by the NERC Distributed Energy Resources Task Force (DERTF) and the NERC Essential Reliability Services Task Force/Working Group (ERSTF/ERSWG), and addresses some of the key goals in the ERO Enterprise Operating Plan.*

Items for RSTC Approval/Discussion:
- **Approval**: *Reliability Guideline: Data Collection and Model Verification for Aggregate DER*
- **Endorse:** *SAR MOD-031*
- **RSTC Review:** *SAR EOP-004*
- **RSTC Review:** *SAR EOP-005*
- **RSTC Review**: *White Paper:*

Workplan Status *(6 month look-ahead)*

See next slide for details

Workplan posted: *https://www.nerc.com/comm/RSTC/Pages/SPIDERWG.aspx*

Recent Activity
- Met in early May 2023 to update work products and focus on high priority items.
- Engaged EAS and PAS for EOP-004 SAR
- Successful engagement and collaboration plan established for EAS and RTOS for EOP-005 SAR

Upcoming Activity
- *SPIDERWG meeting in August to:*
  - *Return responses to this meeting's review*
  - *Revising and Collaborating with other RSTC groups on SAR developments*
  - *Continue drafting of SARs*
  - *Focus on Studies RG, security white paper, DER Aggregator/DERMS impacts*

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Work Look Ahead – non-SAR

- On Track
- Schedule at risk
- Milestone delayed

Workplan Status (6 month look-ahead)

Milestone	Status	Comments
S1 – Reliability Guideline: Bulk Power system Planning under Increasing Penetration of Distributed Energy Resources	On Track	On track for RSTC engagement in Q3 2023
Reliability Guideline Review: Tranche 3 – Analysis	Milestone delayed	Coming for RSTC approval in Q2 2023. Original milestone Q1 2023.
Reliability Guideline Review: Tranche 3 – Coordination	On Track	Seeking approval in Q1 2023. This is the 1547-2018 RG.
C10 – White Paper: Security Risks Posed by DER and DER Aggregator	On Track	In draft. Seeking RSTC review Q2 2023.
C11 – White Paper: Variability, Uncertainty, and Data Collection for the BPS with DER Aggregators	On Track	In progress for Q3 2023 RSTC review request.
A3 – White Paper: Modeling of DER Aggregator and DERMS Functional Impacts	On Track	In draft. Seeking RSTC review in Q3.
C2 – White Paper: Communication and Coordination strategies for Transmission Entities and Distribution Entities regarding Distributed Energy Resources	On Track	In draft. Major involvement with external stakeholders underway.

Work Look Ahead - SAR

On Track
Schedule at risk
Milestone delayed

Workplan Status (6 month look-ahead)

Milestone	Status	Comments
C14 – SAR MOD-031	On Track	Seeking RSTC endorsement in Q2 2023
C15 – SAR EOP-004	On Track	In draft. Coming for RSTC review in Q2 2023
C16 – SAR EOP-005	On Track	In draft. Coming for RSTC review in Q2 2023
C17 – SAR BAL-003	On Track	In draft and coordination. Coming for RSTC review in Q3 2023
C18 – SAR PRC-006	On Track	In draft and coordination. Coming for RSTC review in Q4 2023
C19 – SAR on OPAs and RTAs	On Track	In draft and coordination. Coming for RSTC review in Q4 2023

RSTC Status Report – Security Working Group (SWG)

Co-Chair: Brent Sessions
Co-Chair: Katherine Street
June 2023

On Track
Schedule at risk
Milestone delayed

Purpose: Provides a formal input process to enhance collaboration between the ERO and industry with an ongoing working group. Provides technical expertise and feedback to the ERO with security compliance-related products.

Items for RSTC Approval/Discussion:
- Usage of cloud solutions for BCSI Guidelines

Recent Activity
- BCSI in the Cloud TTX package approved by RSTC
- ERT Sub-Team ongoing meetings
- FERC LL paper approved by RSTC
- New projects prioritized using new process
- OLIR team submitted mappings to NIST, in NIST approval process
- Reviewed cyber principles in planning ERO paper

Upcoming Activity
- New Calls for Volunteers for top 5 new projects

1. Mapping CIP Standards to NIST SP800-53r5 Security and Privacy Controls to OLIR*
2. Communication Protection Systems Guideline
3. SWG Guideline Review
4. Comprehensive physical security assessment
5. EISAC Physical Issue Reporting – Lows Guideline

*Call for Volunteers has been distributed and sub-team is formed

Workplan Status *(6 month look-ahead)*

Milestone	Status	Comments
Guideline Review	On Track	Survey to industry
Ongoing ERT comments	On Track	Ongoing
CIP -> CSF OLIR Mapping	On Track	NIST approval process
Sub-team formation for work initiatives	On Track	In Process
Cloud Encryption Guidance Document	On Track	Submitted for endorsement

Changes to the Work Plan (One Pager)

The work plan for the year 2023 included a Work Plan Item "White Paper on End-Use Load Electrification." This White Paper would provide NERC recommendations on modeling three different end-use loads, namely, Electric Vehicles (EVs), Data Centers, and Heat-Pumps. The LMWG has identified two important requirements for developing this White Paper.

- A reasonably accurate forecast of the each of these loads (EVs, Data Centers, and Heat-Pumps)
- An accurate dynamic simulation model

Unfortunately, the relevant forecasts and models are unavailable, and secondly, the NERC Load Modeling Working Group (LMWG) does not have the expertise to forecast these types of end-use loads. It is assumed that each control area would have expertise to forecast each of the above end-use loads. Also, developing the necessary forecasts and models is outside the scope of the LMWG. The main function of LMWG is to look at available load forecast, proposed load models, their specifications, and implementation in various software. With this information the LMWG evaluates the impact on system performance. In view of this, the White Paper that was originally planned on the above end-use loads cannot be developed this year. In lieu of the White Paper, the proposal is to develop a technical update documentation for each of these three end-use loads. First a quick review of the definitions.

- **White Papers :** Documents and explores technical facets of topics. May make recommendations.
- **Technical Reference Documents (TRD)**: Serve as a reference for electric utility industry and/or NERC stakeholders regarding a specific topic of interest. Deliverables document industry practices and technical concepts.

Technical Document on Electric Vehicles

The objective of the EV TRD is to assess characteristics that would make EVs grid-friendly and not adversely impact system performance. In order to study the impact on system performance, a model with associated data is necessary. Presently, the LMWG has access to a beta version of a dynamic model for an EV in PSLF software; however the LMWG does not any approved PSS/E software to model EVs. At the last NERC LMWG meeting, NERC representatives presented results based on the beta version of a dynamic EV model showing the impact of EVs on the WECC system using the PSLF EV model. We are now soliciting WECC members to try out the beta version of the EV model and look at its impact on system performance. Once a model is available in PSS/E, the Eastern Interconnection can start looking at the impact on system performance provided each area has a forecast for EVs.

Technical Document on Data Centers

Data Centers are spot loads rated in several hundreds of MWs. NERC LMWG is trying to understand the characteristics of these types of loads. In light of this, the NERC LMWG is in the process of finalizing a list of questions to send to Data Center owners, requesting their responses. Based on the responses and analysis of them among other considerations, we will develop dynamic simulation models. We will also provide a basis for recommendations for on-going monitoring and data collection (installation of DMEs at data center POIs), to further study the impacts on system performance.

Technical Document on Heat-Pumps

With respect to Heat-Pumps, not enough is known about their characteristics. Prof. Bernie from the University of Wisconsin along with members from BPA have presented some preliminary results. Once we understand more about their characteristics, both in heating and cooling modes, we will be in a better position to develop a dynamic simulation model and corresponding data to study their impact in system performance subject to each area having a forecast for Heat-Pumps.

The information that we have for each of the above end-use loads in terms of dynamic models and associated data are at different stages of maturity and hence the technical update documentation completion date for each would have to be staggered. The NERC LMWG is proposing a December 2023 completion date for the technical update documentation for EVs, July 2024 for Data Centers, and December 2024 for Heat-Pumps.

Reliability Guideline: Generating Unit Winter Weather Readiness

Action

Approve

Background

The Event Analysis Subcommittee (EAS) is currently seeking approval for the Generating Unit Winter Weather Readiness Reliability Guideline. This guideline has recently undergone updates after being posted for a 45-day comment period as part of the RSTC's triennial review process. The EAS has addressed all comments received during this review process, ensuring the document is comprehensive and highly effective.

Summary

This reliability guideline is applicable to electric sector organizations responsible for the operation of the BPS. This guideline will provide 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 mitigating future cold weather-related events. This document will provide a collection of recommended 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.

<Public>

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Reliability Guideline

Generating Unit Winter Weather Readiness – Current Industry Practices – Version 4

~~October~~ ~~May~~June 202~~2~~3

RELIABILITY | RESILIENCE | SECURITY

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

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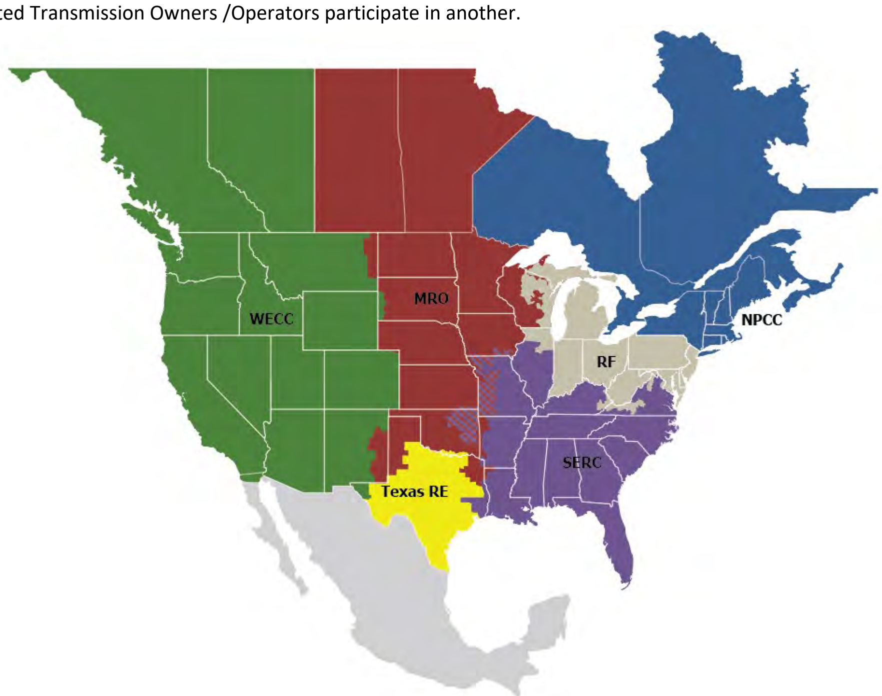
Preface

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, 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 made up of six Regional Entity boundaries as shown in the map and corresponding table below. The multicolored area denotes overlap as some load-serving entities participate in one Regional Entity 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 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 nor are they Reliability Standards; 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.

Introduction

Purpose

This reliability guideline is applicable to electric~~ity~~ sector organizations responsible for the operation of the BPS. This guideline ~~provides~~ will provide 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 mitigating future cold weather-related events. This document ~~is a~~will provide a collection of recommended 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.

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Expectations

- ~~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~~ winterization and ~~Summerization summerization~~summarization procedures with NRC regulation and INPO guidance than ~~are expected by~~indicated in this document.

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- ~~2.~~ 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.

- ~~3.~~ After identifying ~~an issue channels about any~~issues related to derates, outages, or other operational issues, ~~Generator Operator~~Generator Owners~~s~~ should communicate with their Balancing Authorities, Transmission Operators, and Reliability Coordinators (Reliability Entities)~~), all via the appropriate channels, any derates, outages or other operational issues~~ as soon as ~~as reasonably~~ possible~~ after identification of an issue~~. ~~Generator Operators~~Generator Operators should also use past experiences at the plant to identify the potential for freezing issues (including potential fuel concerns) and warn the Reliability Entities of that potential if measures to address the issue are not available. This level of communication allows the Balancing Authorities, Transmission Operators, and Reliability Coordinators to better assess the level of risk on the system.

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Chapter 1: Guideline Details

An effective winter weather readiness program~~, which~~ that 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 j~~J~~ob s~~S~~afety a~~A~~nalysis (JSA) should be completed to address the exposure risks, travel conditions, and slips/falls related to icing conditions. Winter weather a~~A~~lerts should be communicated to all impacted entities. A b~~B~~usiness c~~C~~ontinuity and e~~E~~mergency r~~R~~esponse p~~P~~lan 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
  - ~~1.~~ Set expectations for safety, reliability, and operational performance~~.~~
  - ~~2.~~ Ensure that a winter weather preparation procedure exists for each operating location~~.~~
  - ~~3.~~ Consider a fleet-wide annual winter preparation meeting, training exercise, or both to share best practices and lessons learned~~.~~
  - ~~4.~~ Share lessons learned across the fleet and through industry associations (formal groups or other informal networking forums)~~.~~
- ~~2.~~ Plant Management
  - ~~1.~~ 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~~.~~
  - ~~2.~~ 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~~.~~
  - ~~3.~~ Ensure proper execution of the winter weather preparation procedures~~.~~
  - ~~4.~~ Conduct a plant readiness review prior to an anticipated severe winter weather event~~.~~
  - ~~5.~~ Encourage plant staff to look for areas at risk due to winter conditions and bring up opportunities to improve readiness and response~~.~~
  - ~~6.~~ Following each winter, conduct an evaluation of the effectiveness of the winter weather preparation procedure and incorporate lessons learned~~.~~

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~~III.~~ Processes and Procedures

Winter weather preparation procedures should be developed for seasonal winter preparedness. Components of effective winter weather preparation procedures are included in **Appendix C**~~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~~which need 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 l~~L~~essons l~~L~~earned documents provide~~s~~ a process in which that sharing may be performed anonymously.

Evaluation of Potential Problem Areas with Critical Components

Identify and prioritize critical components, systems, and other areas of vulnerability ~~which~~ that 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. Depending on the plant, ~~-~~further checks and winterization activities might be needed prior to forecasted extreme winter events in addition to seasonally. Links to the ~~NOAA First Frost Date~~National Oceanic and Atmospheric Administration first frost date[1] and ~~NOAA Last Frost Date~~last frost date[2] maps are included for reference.

Winterization efforts should include addressing ~~-~~critical instrumentation or equipment that ~~when frozen~~ has the potential to perform the following when frozen:

- ~~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 is provided below. This is not meant to be an all-inclusive list. The list has been split into two sections to assist with the identification of issues seen at conventional generators and inverter-based resources. Individual entities should review their plant design and configuration, identify areas where critical components' potential exposure to the elements, ambient temperatures, or both might cause issues and tailor their plans to address them accordingly.

Conventional Generation

- ~~1.~~ Critical level transmitters
  - ~~1.~~ Drum level transmitters and sensing lines
  - ~~2.~~ Condensate tank level transmitters and sensing lines

[1] https://www.ncdc.noaa.gov/monitoring-content/sotc/national/2014/sep/earliest-first.png
[2] https://www.ncdc.noaa.gov/file/day-last-spring-freeze-mapjpg

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    - De-aerator tank level transmitters and sensing lin
    - es
    - Hotwell level transmitters and sensing lines
    - Fuel oil tank level transmitters/indicators
- Critical pressure transmitters
    - Gas turbine combustor pressure transmitters and sensing lines
    - Feed water pump pressure transmitters and sensing lines
    - Condensate pump pressure transmitters and sensing lines
    - Steam pressure transmitters and sensing lines
- Critical flow transmitters
    - Steam flow transmitters and sensing lines
    - Feed water pump flow transmitters and sensing lines
    - Natural gas or liquid fuel flow transmitters and sensing lines
- Instrument air system
    - Verify that automatic blow downs, traps, dew point monitoring, and instrument air dryers are functioning correctly within acceptable parameters~~.~~
    - Ensure that ~~L~~low point drain lines are periodically drained by operators to remove moisture during extreme cold weather~~.~~
- Motor-operated valves, valve positioners, and solenoid valves
- Drain lines, steam vents, and intake screens
- Water pipes, water treatment, and fire suppression systems[3]
    - Low/no water flow piping systems
- Fuel supply, materials, and ash handling
    - Coal piles, other solid fuel storage, and handling equipment
    - Transfer systems for backup fuel supply
    - Gas supply regulators, other valves, and instrumentation (may require coordination with gas pipeline operator)
    - Fuel oil heaters and flow control devices
    - Ash disposal systems and associated equipment
    - Lime storage and transfer equipment
- Tank Heaters
    - Conduct initial tests

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[3] 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 procedures.

- ~~2.~~ Check availability of spare heaters
- ~~3.~~ Record current tank 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 batteries and ~~UPS~~ uninterruptible power supply systems critical to the functioning of the facility are housed in temperature-controlled locations and protected from weather~~.~~
- ~~12.~~ Functional heat tracing, insulation, and temperature responsive ventilation (heaters, fans, dampers, and~~&~~ louvers) based on expected weather conditions~~.~~
- ~~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~~ soot-~~-~~blowing ~~Systems~~ systems (~~Transmitters~~transmitters, regulators, drain valves, and traps)

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Inverter-Based Resources

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- ~~1.~~ Functional wind turbine lube oil equipment within the nacelle, such as radiators, fans, heaters, and bypass valv~~esing within the nacelle~~
- ~~2.~~ Adequacy of tracking systems' lube oil for expected temperature during cold weather~~.~~
- ~~3.~~ Accessibility of roads throughout the facility~~.~~
- ~~4.~~ Anemometer functionality~~.~~
- ~~5.~~ Ensure liquid-cooled inverters have freeze protection measures, such as anti-freeze or~~,~~ heaters, ~~, etc.~~ to address expected temperatures for that location~~.~~
- ~~6.~~ Ensure winterization measures for battery systems are sufficient for expected cold weather conditions~~.~~
- ~~7.~~ Ensure blade de-icing capabilities are known~~.~~
- ~~8.~~ Consider snow removal and de-icing plans for facilities~~.~~

Potential vulnerabilities associated with emergency generators, including Blackstart Resources, should be evaluated when developing the site-specific winter weather preparation procedure(s)~~,~~ as they may provide critical system(s) backup.

~~V.~~ Testing of Emergency and Backup Systems[4]

In addition to the typical problem areas identified above, emphasis should be placed on cold weather preparation and testing of infrequently used equipment and systems where applicable, such as startup of emergency generators, operation on secondary fuels, fire pumps, and auxiliary boilers~~, where applicable~~.

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~~VI.~~ Training

Coordinate annual winter training with plant specific awareness and maintenance training. This may include, but is not limited to, the following: 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, installation of winter-season wind breaks, preparation and staging of portable heaters, and lessons learned from previous experiences or the NERC Lessons Learned program. In addition, training should ~~cover~~ also include the following:

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- ~~1.~~ Entities should ~~c~~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.~~ Entities should maintain the correct coding for~~Ensure appropriate~~ NERC Generation Availability Data Systems ~~(GADS) coding for~~on 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."

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~~VII.~~ Winter Event Communications

Clear and timely communication is essential to an effective program. Key communication points should include the following actions:

- ~~1.~~ Before a severe winter weather event, plant management should communicate with their appropriate senior management and Reliability Entities that the site-specific winter weather preparation procedure, checklists, and readiness reviews have been completed.
- ~~2.~~ Before and during a severe winter weather event, entities should 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~~ should 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~~ plant m~~M~~anagement~~, as appropriate,~~ should conduct an analysis, develop lessons learned and appropriate corrective actions, and incorporate good industry practices as appropriate:~~.~~
  - ~~1.~~ This process should include a feedback loop to enhance current winter weather readiness programs, processes, procedures, checklists and training (continuous improvement).
  - ~~2.~~ Sharing of technical information and lessons learned through the NERC Event Analysis Program or some other method is encouraged.

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[4] See Appendix C~~Attachment 1~~, Section 8, "Special Operations Instruction" for more information

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Appendix A: ~~Appendix A:~~ Cold Weather Event Reports

The list below provide previous cold weather event reports:~~.~~

- ~~FERC - NERC - Regional Entity Staff Report: The February 2021 Cold Weather Outages in Texas and the South Central United States~~FERC-NERC-Regional Entity Staff Report: The February 2021 Cold Weather Outages in Texas and the South Central United States *November 2021, Federal* Energy Regulatory Commission, North American Electric Reliability Corporation and Regional Entity Staff Report[5]
- ~~Report on Outages and Curtailments during the Southwest Cold Weather Event of February 1-5, 2011~~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[6]
- 2019 FERC and NERC Staff Report: "~~The South Central United States Cold Weather Bulk Electric System Event of January 17, 2018~~The South Central United States Cold Weather Bulk Electric System Event of January 17, 2018"[7]
- ~~Electric Reliability Organization Event Analysis Process~~Electric Reliability Organization Event Analysis Process,[8] dated January 2017, ERO Event Analysis Process and associated ~~Lessons Learned~~Lessons Learned[9]
- ~~Previous Cold Weather Reports and Training Materials~~Previous Cold Weather Reports and Training Materials[10]
- There are a number of ~~"~~"sound practices~~"~~" from the industry that are detailed in the *Southcentral Cold Weather* ~~*report*~~*Report*, starting on page 100.[11] ~~Link to the report: https://www.ferc.gov/legal/staff-reports/2019/07-18-19-ferc-nerc-report.pdf~~
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[5] *https://www.ferc.gov/media/february-2021-cold-weather-outages-texas-and-south-central-united-states-ferc-nerc-and*
[6] *https://www.nerc.com/pa/rrm/ea/Pages/February-2011-Southwest-Cold-Weather-Event.aspx*
[7] ~~https://www.nerc.com/pa/rrm/ea/Documents/South_Central_Cold_Weather_Event_FERC-NERC-Report_20190718.pdf#search=South%20Central%20United%20States%20Cold%20Weather~~https://www.nerc.com/pa/rrm/ea/Documents/South_Central_Cold_Weather_Event_FERC_NERC_Report_20190718.pdf#search=South%20Central%20United%20States%20Cold%20Weather
[8] http://www.nerc.com/pa/rrm/ea/ERO_EAP_Documents%20DL/ERO_EAP_v3.1.pdf
[9] http://www.nerc.com/pa/rrm/ea/Pages/Lessons-Learned.aspx
[10] http://www.nerc.com/pa/rrm/ea/Pages/February-2011-Southwest-Cold-Weather-Event.aspx
[11] https://www.ferc.gov/legal/staff-reports/2019/07-18-19-ferc-nerc-report.pdf

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Appendix B: ~~Appendix B:~~ Cold Weather Related Lessons Learned

The list of lessons learned shown below provide details related to previous cold weather events impacting generators:

- LL20230401 – "Combustion Turbine Anti-Icing Control Strategy"[12]
- LL20221201 – "Air Breaker Cold Weather Operations"[13]
- LL20110902 – "Adequate Maintenance and Inspection of Generator Freeze Protection"[14]
- LL20110903 - "Generating Unit Temperature Design Parameters and Extreme Winter Conditions"[15]
- LL20111001 - "Plant Instrument and Sensing Equipment Freezing Due to Heat Trace and Insulation Failures"[16]
- LL20120101 – "Plant Onsite Material and Personnel Needed for a Winter Weather Event"[17]
- LL20120102 – "Plant Operator Training to Prepare for a Winter Weather Event"[18]
- LL20120103 – "Transmission Facilities and Winter Weather Operations"[19]
- LL20120901 – "Wind Farm Winter Storm Issues"[20]
- LL20120902 – "Transformer Oil Level Issues During Cold Weather"[21]
- LL20120903 – "Winter Storm Inlet Air Duct Icing"[22]
- LL20120904 – "Capacity Awareness During an Energy Emergency Event"[23]
- LL20120905 – "Gas and Electricity Interdependency"[24]

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[12] https://www.nerc.com/pa/rrm/ea/Lessons%20Learned%20Document%20Library/LL20230401_CT_Anti-Icing_Control_Strategy.pdf
[13] https://www.nerc.com/pa/rrm/ea/Lessons%20Learned%20Document%20Library/LL20221201_Air_Breaker_Cold_Weather_Operation.pdf
[14] https://www.nerc.com/pa/rrm/ea/Lessons%20Learned%20Document%20Library/LL20110902_Adequate_Maintenance_and_Inspection_of_Generator_Freeze_Protection.pdf
[15] https://www.nerc.com/pa/rrm/ea/Lessons%20Learned%20Document%20Library/LL20110903_Generating_Unit_Temperature_Design_Parameters_and_Extreme_Winter_Conditions.pdf
[16] https://www.nerc.com/pa/rrm/ea/Lessons%20Learned%20Document%20Library/LL20111001_Plant_Instrument_and_Sending_Equipment_Freezing_Due_to_Heat_Trace_and_Insulation_Failures.pdf
[17] https://www.nerc.com/pa/rrm/ea/Lessons%20Learned%20Document%20Library/LL20120101_Plant_Onsite_Material_and_Personnel_Needed_for_a_Winter_Weather_Event.pdf
[18] https://www.nerc.com/pa/rrm/ea/Lessons%20Learned%20Document%20Library/LL20120102_Plant_Operator_Training_to_Prepare_for_a_Winter_Weather_Event.pdf
[19] https://www.nerc.com/pa/rrm/ea/Lessons%20Learned%20Document%20Library/LL20120103_Transmission_Facilities_and_Winter_Weather_Operations.pdf
[20] https://www.nerc.com/pa/rrm/ea/Lessons%20Learned%20Document%20Library/LL20120901_Wind_Farm_Winter_Storm_Issues.pdf
[21] https://www.nerc.com/pa/rrm/ea/Lessons%20Learned%20Document%20Library/LL20120902_Transformer_Oil_Level_Issues_During_Cold_Weather.pdf
[22] https://www.nerc.com/pa/rrm/ea/Lessons%20Learned%20Document%20Library/LL20120903_Winter_Storm_Inlet_Air_Duct_Icing.pdf
[23] https://www.nerc.com/pa/rrm/ea/Lessons%20Learned%20Document%20Library/LL20120904_Capacity_Awareness_during_an_Energy_Emergency_Event.pdf
[24] https://www.nerc.com/pa/rrm/ea/Lessons%20Learned%20Document%20Library/LL20120905_Gas_and_Electricity_Interdependency.pdf

Field Code Changed

Field Code Changed

- LL20180702 – "Preparing Circuit Breakers for Operation in Cold Weather"[25]
- LL20200601 – "Unanticipated Wind Generation Cutoffs during a Cold Weather Event"[26]
- LL20201101 – "Cold Weather Operation of SF6 Circuit Breakers"[27]

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

[26] https://www.nerc.com/pa/rrm/ea/Lessons%20Learned%20Document%20Library/LL20200601_Unanticipated_Wind_Generation_Cutoffs_during_a_Cold_Weather_Event.pdf

[27] https://www.nerc.com/pa/rrm/ea/Lessons%20Learned%20Document%20Library/LL20201101_SF6_CB_Operation_during_Cold_Weather.pdf

Appendix C~~Appendix C~~: Elements of Cold~~/ Winter~~ Weather Preparation Procedures

This ~~Attachment~~ 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**

- ~~1.~~ Review the work management system to ensure adequate annual preventative work orders exist for freeze protection and winter weather preparedness~~.~~
- ~~2.~~ Ensure all freeze protection and winter weather preparedness preventative work orders are completed prior to the onset of the winter season~~.~~
- ~~3.~~ 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~~.~~
- ~~4.~~ As appropriate to ~~your~~ the 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~~.~~
- ~~5.~~ 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**

- ~~1.~~ Ensure all critical site specific problem areas (as noted ~~above in section~~ in the~~IV.~~ **Evaluation of Potential Problem Areas with Critical Components**~~**Evaluation of Potential Problem Areas with Critical Components**~~ section) have adequate protection to ensure operability during a severe winter weather event and~~. E~~ emphasize the points in the plant where equipment freezing would cause a generating plant trip, derate, or failure to start~~.~~
- ~~2.~~ Develop a list of critical instruments and transmitters that require maintenance prior to winter and increase surveillance during severe winter weather events~~.~~

• **Insulation, heat trace, and other protection options**~~—~~

~~3.~~ Entities should e~~E~~nsure processes and procedures verify adequate protection and necessary functionality (by primary or alternate means) before and during winter weather and~~. C~~consider the effect of wind chill and precipitation when applying freeze protection.~~—~~ Considerations include, but are not limited to,~~:~~

- ~~1.~~ ~~I~~insulation thickness, quality, and proper installation.
- ~~i.~~ Entities should ~~V~~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.

~~2.~~ • **Heat trace capability and electrical continuity/ground faults**

- ~~i.~~ Entities should ~~P~~perform a complete evaluation of all heat trace lines and~~,~~ 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

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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, actuators, and pipe supports~~.~~

- ~~3.~~ **Wind breaks**
  - ~~i.~~ Install permanent or temporary wind barriers as deemed appropriate to protect critical instrument cabinets, crucial equipment, heat tracing and sensing lines~~.~~
    - ~~4.~~ 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~~.~~
  - ~~iv.~~ Ensure adequate fuel supply for heaters~~.~~

- ~~5.~~ **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~~.~~

- **Supplemental equipment**
  - ~~4.~~ ~~—~~ Prior to the onset of the winter season, entities should 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 the following:
    - ~~1.~~ Tarps
    - ~~2.~~ Portable heaters, heat lamps, or both

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- ~~3.~~ Scaffolding
- ~~4.~~ Blankets
- ~~5.~~ Extension cords
- ~~6.~~ Kerosene/propane
- ~~7.~~ Temporary enclosures
- ~~8.~~ Temporary insulation
- ~~9.~~ Plastic rolls
- ~~10.~~ Portable generators
- ~~11.~~ Portable lighting
- ~~12.~~ Instrumentation tubing
- ~~13.~~ Heat guns or handheld welding torches
- ~~14.~~ Ice removal chemicals and equipment
- ~~15.~~ Snow removal equipment
- ~~16.~~ Cold weather personal protective equipment ~~(PPE)~~ available to personnel as appropriate.
- ~~17.~~ Properly winterize service vehicles
- ~~18.~~ Supplies for slip hazard reduction, such as sand, rock salt, or calcium chloride

- **Operational supplies**

~~5.~~ ~~—~~Prior to the onset of a severe winter weather event, entities should 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 the following items:

- ~~1.~~ Aluminum sulfate
- ~~2.~~ Anhydrous ammonia
- ~~3.~~ Aqueous ammonia
- ~~4.~~ Carbon dioxide
- ~~5.~~ Caustic soda
- ~~6.~~ Chlorine
- ~~7.~~ Diesel fuel
- ~~8.~~ Ferric chloride
- ~~9.~~ Gasoline (unleaded)
- ~~10.~~ Hydrazine
- ~~11.~~ Hydrogen
- ~~12.~~ Sulfuric acid
- ~~13.~~ Calibration gases
- ~~14.~~ Lubricating oils (lighter grades or synthetic)

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- ~~15.~~ Welding supplies
- ~~16.~~ Limestone

~~6.~~ **Staffing (as necessary)**

- ~~1.~~ Enhanced staffing during severe winter weather events~~.~~
- ~~2.~~ Arrangements for lodging and meals~~.~~
- ~~3.~~ Arrangements for transportation~~.~~
- ~~4.~~ Arrangements for support and appropriate staffing from responsible entity for plant switchyard to ensure minimal line outages~~.~~
- ~~5.~~ Arrangements for storage of in-house food inventories for extended work shifts~~.~~
- ~~6.~~ Arrangements for on-site lodging during severe winter weather events~~.~~

~~7.~~ **Communications**

- ~~1.~~ Identify appropriate communication protocols to follow during a severe winter weather event~~.~~
- ~~2.~~ Identify and verify operations of a back-up communication option in case ~~the~~ interpersonal communications capability is not available (e.g., satellite phone)~~.~~
- ~~3.~~ Include availability of interpersonal communication capability and available back-up communication options in job safety briefing for severe winter weather events~~.~~

Special operations instruction

- ~~8.~~ Should be~~(~~ just prior to or during a severe winter weather event~~)~~ as appropriate~~.~~
- ~~1.~~ Utilize the "buddy system" during severe winter weather events to promote personnel safety~~.~~
- ~~2.~~ Utilize cold weather checklists to verify critical equipment is protected (~~—~~e.g., 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) do not freeze.
- ~~ii.~~ Evaluate freeze protection needs for standby systems idled during current operations (out of service filters, heat exchangers, stagnant piping, etc.)
- Prior to cold weather, test dual fuel capability where applicable. Identify alternate suppliers of fuel as necessary
- ~~3.~~ Ensure that alternate fuel suppliers are capable of delivering required quantities of fuel during adverse winter conditions
- ~~4.~~ Discuss with the Balancing Authority the possibility for the unit to be called upon~~.~~ (If likely, initiate pre-warming and/or early start-up, of scheduled units prior to a forecasted severe winter weather event.)
- Run emergency generators immediately prior to severe winter weather events to help ensure availability
- ~~5.~~ Review fuel quality and quantity~~.~~
- ~~6.~~ Place ~~in service~~ critical equipment in service, 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~~.~~

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Contributors

NERC gratefully acknowledges the contributions and assistance of the following industry experts in the preparation of this guideline.

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Guideline Information and Revision History

Guideline Information	
Category/Topic: [NERC use only]	**Reliability Guideline/Security Guideline/Hybrid:** Reliability Guideline
Identification Number: [NERC use only]	**Subgroup:** [NERC use only]

Revision History

Version	Comments	Approval Date
1.0	Initial Version – *Winter Weather Readiness*	March 5, 2013
2.0	Three year document review per the OC Charter	August 23, 2017
3.0	Three year document review	December 15, 2020
4.0	Expand for generator types, add metrics structure	~~December XX~~June 22, ~~2022~~2023

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Metrics

Pursuant to the Commission's Order on January 19, 2021, *North American Electric Reliability Corporation*, 174 FERC ¶ 61,030 (2021), reliability guidelines shall now include metrics to support evaluation during triennial review consistent with the RSTC Charter.

Baseline Metrics

All NERC reliability guidelines include the following baseline metrics:

- BPS performance prior to and after a reliability guideline as reflected in NERC's State of Reliability Report and Long Term Reliability Assessments (e.g., Long Term Reliability Assessment and seasonal assessments)
- Use and effectiveness of a reliability guideline as reported by industry via survey
- Industry assessment of the extent ~~to which a~~ that a reliability guideline is addressing risk as reported via survey

Effectiveness Survey

On January 19, 2021, FERC accepted the NERC proposed approach for evaluating Reliability Guidelines. This evaluation process takes place under the leadership of the RSTC and includes:

- industry survey on effectiveness of Reliability Guidelines;
- triennial review with a recommendation to NERC on the effectiveness of a Reliability Guideline and/or whether risks warrant additional measures; and
- NERC's determination whether additional action might be appropriate to address potential risks to reliability in light of the RSTC's recommendation and all other data within NERC's possession pertaining to the relevant issue.

NERC is asking entities who are users of Reliability and Security Guidelines to respond to the short survey provided in the link below.

Effectiveness Survey: Generating Unit Winter Weather Readiness

RSTC SAR Development Process

Action
Request for RSTC Comments

Summary
As part of the Framework to Address Known and Emerging Reliability and Security Risks[1], the RSTC reviews and provides guidance in developing deliverables[2] critical to ERO functions, such as Reliability Standards. In performing this function, the RSTC or its groups may develop Standard Authorization Request(s) ("SAR")[3].

Additionally, the RSTC may endorse a SAR proposed by one of its subcommittees, work groups or task forces ("RSTC Group") prior to any submission to the NERC Reliability Standards Staff or the NERC Standards Committee. RSTC endorsement of a SAR supports initial vetting of the technical material and the development of a sound technical justification to mitigate the identified risk.

NERC Staff will review the proposed RSTC SAR Development Process and seek comments by the RSTC.

[1] See https://www.nerc.com/comm/RISC/Related%20Files%20DL/Framework-Address%20Known-Emerging%20Reliabilit-Securit%20%20Risks_ERRATTA_V1.pdf
[2] NERC provides White Papers, Technical Reference Documents, Reliability Guidance, and other resource documents that can assist registered entities with the identification and addressing of risks within their systems.
[3] See https://www.nerc.com/comm/SC/Documents/Appendix_3A_StandardsProcessesManual.pdf

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DRAFT

Reliability and Security Technical Committee Standard Authorization Request (SAR) Process

The Reliability and Security Technical Committee ("RSTC") is a standing committee of the North American Electric Reliability Corporation ("NERC"). As stated in the RSTC Charter, the committee strives to advance the reliability and security of the interconnected Bulk Power System ("BPS") of North America by:

- Creating a forum for aggregating ideas and interests, drawing from diverse industry stakeholder expertise, to support the ERO Enterprise's mission;
- Leveraging such expertise to identify solutions to study, mitigate, and/or eliminate emerging risks to the BPS for the benefit of industry stakeholders, the NERC Board of Trustees ("Board") and ERO Enterprise staff and leadership; and,
- Overseeing the implementation of group work plans that drive risk-mitigating technical solutions.

SAR Development Process

As part of the Framework to Address Known and Emerging Reliability and Security Risks[1], the RSTC reviews and provides guidance in developing deliverables[2] critical to ERO functions, such as Reliability Standards. In performing this function, the RSTC or its groups may develop Standard Authorization Request(s) ("SAR")[3].

Additionally, the RSTC may endorse a SAR proposed by one of its subcommittees, work groups or task forces ("RSTC Group") prior to any submission to the NERC Reliability Standards Staff or the NERC Standards Committee. RSTC endorsement of a SAR supports initial vetting of the technical material and the development of a sound technical justification to mitigate the identified risk.

RSTC Group SAR Development Steps: (See Figure 1)

1 Identify Risk Reliability Gap (problem statement) and clearly articulate risk to Reliability, Resilience or Security through any of the following:

   a. White Paper

   b. Event Analysis or Disturbance Report

   c. RISC Report

   d. Assessment

   e. Other documents or reports

[1] See https://www.nerc.com/comm/RISC/Related%20Files%20DL/Framework-Address%20Known-Emerging%20Reliabilit-Securit%20%20Risks_ERRATTA_V1.pdf

[2] NERC provides White Papers, Technical Reference Documents, Reliability Guidance, and other resource documents that can assist registered entities with the identification and addressing of risks within their systems.

[3] See https://www.nerc.com/comm/SC/Documents/Appendix_3A_StandardsProcessesManual.pdf

2 Develop technical justification for SAR development

a. Include assessment of other mitigation measures (reliability guideline, reference document, etc.) vs SAR. Why was a SAR chosen as the risk mitigation measure?

b. Clearly articulate the reliability gap with the associated risks.

c. Develop proposed SAR Prioritization (High/Medium/Low)

d. Assess level of residual (or acceptable) risk once the project is complete.

e. Ensure the SAR doesn't duplicate the efforts that would be part of the Standards Drafting Team responsibility (solutions to the problem and drafting requirement language).

3 Obtain RSTC or RSTC EC approval to develop SAR (per Notional Work Product Flow Process[4]).

4 Develop SAR and present to RSTC for RSTC comment

a. RSTC members to share the draft SAR with industry stakeholders within their sector, organization or trade group for their review and comments

b. Post draft SAR for a 30-day public comment period. This comment period may overlap or coincide with the RSTC member comment period.

5 RSTC Group to respond to comments and update SAR

6 Present SAR for RSTC Endorsement

7 Based on prioritization, submit SAR to Standards Committee, to ensure higher risk items can be addressed first

8 Upon Standards Committee approval, the RSTC Sponsor will coordinate with the RSTC Group leadership to liaise with the Standard Drafting Team for technical input and assistance.

[4] https://www.nerc.com/comm/RSTC/Documents/RSTC%20Work%20Plan%20Notional%20Process_Approved_Sept_2020.pdf

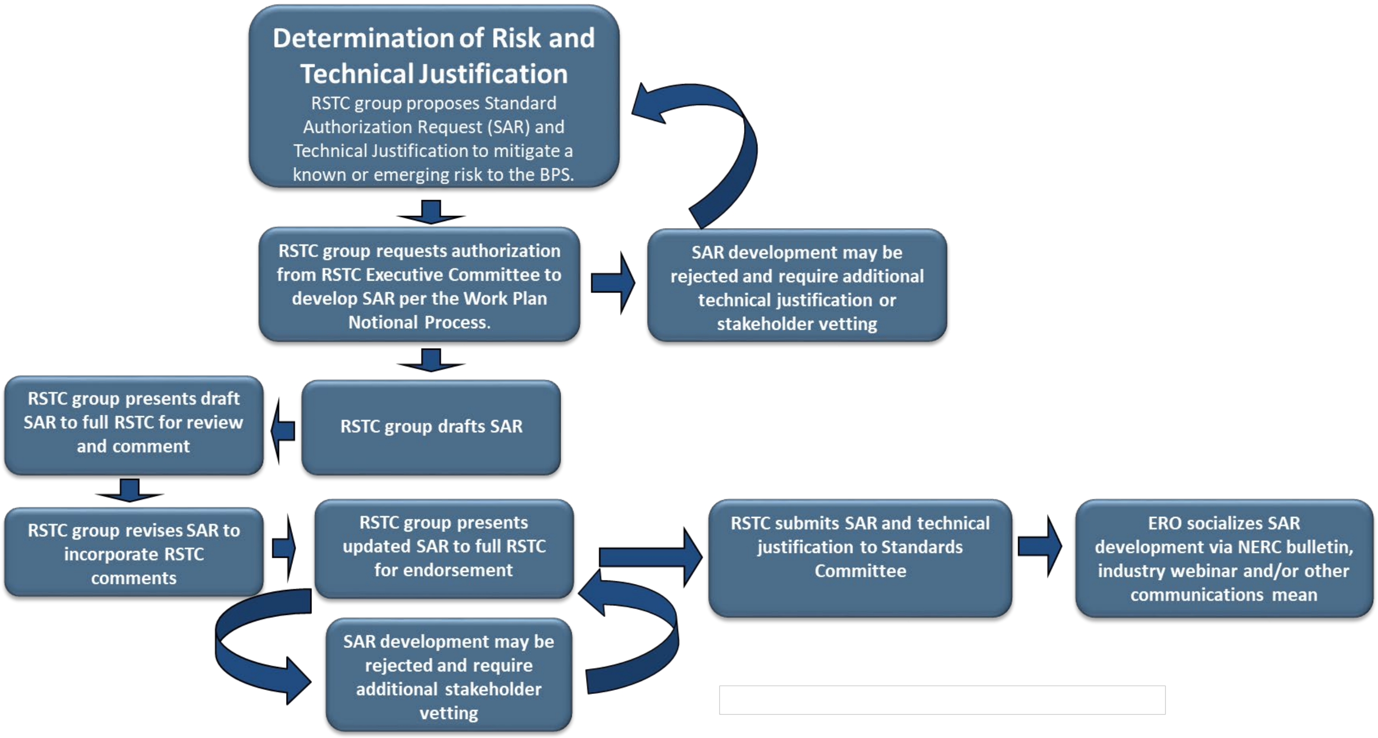

Figure 2: SAR Development Process Flow Diagram

SAR Development Process - Checklist

☐ Do you have a technical basis document from NERC, industry, or an approved RSTC document that justifies the creation of a SAR?

☐ Has the RSTC or RSTC EC authorized the RSTC Group to create the SAR?

☐ Has the SAR been added to the RSTC Group work plan?

☐ Have you created and vetted the SAR with industry stakeholders (internal to the RSTC Group or with external outreach)?

	Author	Outreach
RSTC Group Membership	X	
RSTC Group RSTC Sponsor		X
Other/Related RSTC group		X
Webinar/Other Engagement		X
Trade Associations		X
Government/Regulatory		X
RSTC Strategic Planning Process		X
SCCG		X

☐ Has the SAR been presented to the RSTC as a first draft within its review/comment period?

☐ Have RSTC comments been reviewed and conforming revisions made to the SAR to address those comments?

☐ Has the SAR been presented as a final draft to industry for information? (Optional as circumstances warrant)

☐ Has a final draft of the SAR been presented to the RSTC, with a response to comments received?

☐ Has the RSTC endorsed the SAR, including priority?

☐ Has the endorsed SAR been submitted to the Standards Committee through NERC Staff?

White Paper: Grid Forming Functional Specifications for BPS-Connected Battery Energy Storage Systems

Action

Approve

Background

The Inverter-Based Resource Performance Subcommittee (IRPS) has developed the White Paper: Grid Forming Functional Specifications for BPS-Connected Battery Energy Storage Systems. This white paper is intended to provide functional specifications to be used by Transmission Planners (TPs) and Planning Coordinators (PCs) to determine whether or not interconnecting battery energy storage systems (BESS) can be considered a Grid Forming (GFM) resource based on its performance. This white paper also provides significant information regarding the implementation of GFM resources internationally and the benefits of GFM resources for BPS reliability. Additionally, a number of recommendations are made to industry regarding best practices for the implementation and study of GFM resources.

Summary

This guideline has been posted for comment from IRPS members and numerous technical revisions were made in response to the comments received during this comment period. IRPS is seeking RSTC approval for this white paper.

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Grid Forming Functional Specifications for BPS-Connected Battery Energy Storage Systems

~~Functional Specifications, Verification, and Modeling~~

June 2023

RELIABILITY | RESILIENCE | SECURITY




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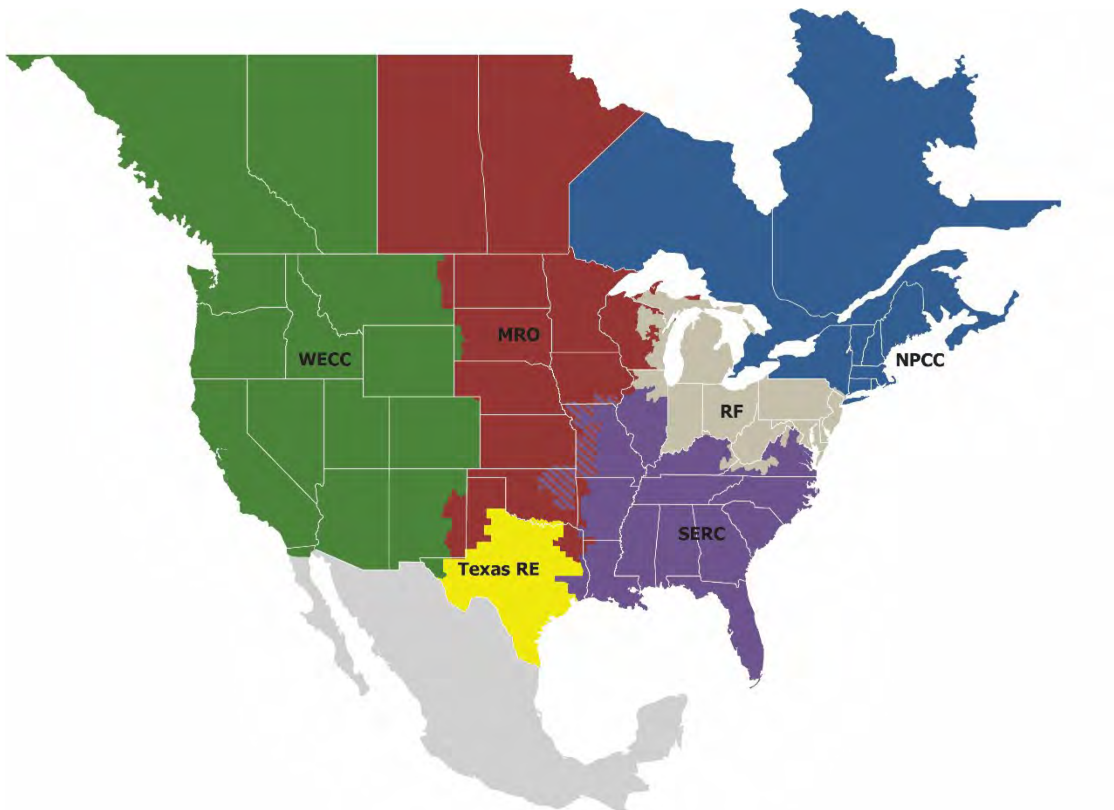
Table of Contents

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, 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 on 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	Western Electricity Coordinating Council

Executive Summary

Studies have shown that grids dominated by inverter-based resources (IBR), in the absence of supplemental synchronous machine-based solutions, need grid forming (GFM) IBRs to maintain stable operation. While some smaller islanded systems are already facing these challenges today, it is expected that the need for GFM technology will accelerate ~~very quickly~~ with the rapid growth of IBRs across North America and the world. Industry needs to proactively plan to ensure sufficient GFM IBRs are installed on the system under these future operating conditions. One of the most significant obstacles of deploying GFM on the bulk power system (BPS) is establishing clear interconnection requirements regarding the expected performance, testing, and validation of the technology. This paper addresses how Transmission Owners (TOs), Transmission Planners (TPs), and Planning Coordinators (PCs) can establish these requirements and test interconnecting resources to ensure they meet the GFM specifications. Generator Owners (GOs) will also have clear performance expectations for GFM resource interconnections and can work with their respective equipment manufacturers prior to interconnection studies being conducted to help streamline the interconnection queue process, where possible. TPs and PCs will need to test new project models to ensure they meet the GFM specifications. The recommended set of GFM tests are provided in this paper, ~~thoughtfully~~ designed to verify the unique characteristics of GFM. The paper also addresses ~~ensuring~~ GFM model quality and accuracy as a prerequisite to any studies being conducted.

A common question posed by industry stakeholders is “how many future IBRs should be deployed with GFM functionality enabled?” The answer is system-specific and requires detailed reliability studies to determine, and studies conducted thus far indicate these numbers may be upwards of 30%.[1,2] Since the current percentage of GFM resources is near zero in nearly all large interconnected power systems, it is recommended to start requiring and enabling GFM in all future Battery Energy Storage System (BESS) projects for multiple reasons. GFM technology is commercially available and can help improve stability and reliability in areas with high IBR penetration. Furthermore, existing BESS can potentially be retrofitted with GFM technology and new BESS can be equipped with GFM technology at a ~~small~~ relatively low incremental project cost.[3] Enabling GFM in all future BESS projects is a relatively low-cost solution that helps ensure system-wide stability that is difficult to quantify today due to study limitations. Industry should begin specifying, requiring, and implementing GFM for all new BPS-connected BESS quickly to mitigate any potential BPS reliability risks that could be posed under high IBR penetration levels expected in the near future.

Key Takeaways and Recommendations

The following key takeaways and recommendations should be considered and implemented by the associated entities for adoption of GFM to improve overall BPS reliability under conditions of increasing penetrations of IBRs:

- GFM technology is commercially available and field-proven for BPS-connected applications, particularly for BESS (including standalone BESS[4] in ac-coupled hybrid plants) as well as dc-coupled solar photovoltaic (PV)+BESS[5] applications. GFM requirements, policies, and/or market incentives should be developed for BESS or hybrid plants including BESS, as mentioned above. (*OEMs, developers, GOs, GOPs, TPs, PCs, Transmission Operators (TOPs), Reliability Coordinators (RCs), regulatory entities, policymakers)*
- All newly interconnecting BPS-connected BESS should be designed, planned, and commissioned with GFM controls[6] enabled to improve overall system stability across the BPS, particularly with increasing levels of IBRs. Developers and GOs can ensure requirements[7] are in contractual language with OEMs. Existing BESS may be

[1] https://ieeexplore.ieee.org/document/9875186

[2] Using the full capabilities of modern inverters may enable lowering this threshold somewhat.

[3] New interconnection studies is recommended for the existing GFL project updated to GFM

[4] World’s largest ‘grid-forming’ battery to begin construction in Australia – pv magazine International (pv-magazine.com)

[5] Hybrid Solar and Storage in Hawaii | T&D World (tdworld.com)

[6] As functionally specified in this paper

[7] See, for example: Appendix J-1 Oahu RDG PSA (hawaiianelectric.com)

able to be retrofitted at relatively low incremental costs; however, they will need to be restudied by the TP and PC and potentially retuned, as determined by the study results. *(GOs, TPs, PCs, developers, OEMs)*

- TOs in consultation with their TPs and PCs, should establish clear GFM functional specifications for BESS in their interconnection requirements (or provisions in power purchase agreements) using the materials contained in this guideline. *(TOs, TPs, PCs)*
- TPs and PCs should integrate GFM functional testing requirements in their interconnection study processes that ensure newly connecting GFM is able to meet the performance requirements for GFM. *(TPs, PCs)*
- GFM technology can operate reliably and provide stabilizing characteristics in areas of high IBR penetrations and areas of low system strength. GFM BESS presents a unique opportunity to support system stability (e.g., transient, oscillatory, voltage) with a relatively ~~minor~~ low incremental cost to all resources and end-use consumers. *(Developers, OEMs, GOs, GOPs, TPs, PCs, TOPs, RCs)*
- GFM technology will continue to develop and improve beyond where it is today. Future research efforts can help aid in accelerated development and adoption, particularly focusing on GFL-to-GFM conversion possibilities, equipment standardization, GFM in blackstart applications, technical specifications for GFM blackstart, and GFM controls in other IBR technologies such as wind and solar PV. *(US Department of Energy, national laboratories, research institutes, academic institutions)*

Introduction

Background

NERC *White Paper: Grid Forming Technology*[8] defined GFM controls for IBRs as:

> **Grid Forming Control for BPS-Connected Inverter-Based Resources** are controls with the primary objective of maintaining an internal voltage phasor that is constant or nearly constant in the sub-transient to transient time frame. This allows the IBR to immediately respond to changes in the external system and maintain IBR control stability during challenging network conditions. The voltage phasor must be controlled to maintain synchronism with other devices in the grid and must also regulate active and reactive power appropriately to support the grid.

This uniquely differs from conventional grid following (GFL) IBR controls in that the primary GFL control objective in the sub-transient time frame is to maintain a constant output *current* phasor magnitude and angle.~~;~~ ~~t~~The current phasor begins changing within the sub-transient time frame to control the active and reactive power being injected into the network. In the shortest [sub-transient] time frames (e.g., 0-5 cycles after a disturbance), a conventional GFL inverter's control objective is to maintain a desired active power and reactive power, so it does not maintain fixed voltage magnitude or phase angle on those timescales. On longer timescales (seconds), it can also pursue other control objectives such as maximum power point tracking, frequency response, and voltage regulation.

A GFM inverter's control objective, on the other hand, in the shortest [sub-transient] time frames (e.g., 0-5 cycles after a disturbance), is to maintain *voltage* phasor magnitude and angle internally, and prioritize the support of terminal voltage. Therefore, it does not maintain fixed active or reactive power on those time frames. On longer time frames, a GFM inverter must~~may~~ also ~~pursue other objectives including synchronization~~ synchronize with other sources and may also pursue other objectives including tracking of active power and reactive power set point. In all cases, the inverter controls could be restricted by the inverter and primary energy source capability limits (e.g., available energy, current limits, voltages).

Benefits of Enabling GFM Controls in BPS-Connected BESS

It is estimated that there was 427 GW of BESS capacity in the interconnection queues around the US as of the end of 2021.[9] In the absence of any requirements or incentives for GFM capability, all of these resources are being planned with GFL controls~~ enabled~~. Many of these BESS will be deployed in IBR-dominated areas of the BPS with existing stability constraints. Installing these resources as GFL will likely further reduce stability margins and may result in new stability constraints. This will lead to further reduction of low-cost generation from existing IBRs in these areas (i.e., curtailment of IBRs during real-time operation) due to stability constraints that could be addressed by GFM, thus increasing overall energy costs. To relieve these constraints without considering GFM in BESS, additional transmission assets such as synchronous condensers[10] , GFM STATCOM[11] with energy storage, or new transmission lines[12] will be needed which will drive transmission costs higher.

GFM controls can provide grid stabilizing characteristics that support reliable operation of the BPS under increasing penetration of IBRs. Enabling GFM in BPS-connected BESS allows for ~~an organic~~ system-wide enhancement of stability margins as these resources are interconnected. Therefore, system stability enhancements can be achieved at much lower cost than through the addition of transmission assets.[13] As discussed above, GFM controls can be implemented

[8] https://www.nerc.com/comm/RSTC_Reliability_Guidelines/White_Paper_Grid_Forming_Technology.pdf
[9] https://emp.lbl.gov/sites/default/files/queued_up_2021_04-13-2022.pdf
[10] https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/congestion-information/sa-transition-to-fewer-synch-gen-grid-reference.pdf?la=en
[11] STATCOM Technology Evolution for Tomorrow's Grid (nxtbook.com)
[12] Adding new transmission lines will decrease the transfer impedance (make it a stiffer/stronger system)
[13] Transmission assets still serve critical roles for overall BPS reliability in addition to the considerations for GFM BESS presented in this paper.

on any type of IBR including new solar photovoltaic and wind plants with some limitations; however, GFM controls in BESS are particularly low hanging fruit for assuring BPS reliability since they already have the needed energy buffer on the dc side which makes the enhancement purely software-based (minimizing much more costly hardware-based improvements and/or the moderate level of curtailment that may be needed for other IBR technologies).
While some areas like the Hawaii islands already need to enable GFM BESS to maintain grid stability and prevent large-scale outages, many areas of the US are reaching relatively high penetrations of IBRs now or in the future and will face similar challenges. Industry is faced with a unique window of opportunity to procure, test, and gain experience with GFM technology now before significant adverse reliability issues are faced with insufficient GFM controls installed in the future.

Testing and Demonstration of Services Ahead of Requirements

Existing GFL technology can provide a number of essential reliability services to the BPS. Demonstration projects[14] have illustrated these capabilities for many years, and modern IBR facilities can provide regulation services, primary and fast frequency response, dynamic voltage support, etc. GFM control do not preclude a resource from providing any of these critical features to the BPS. Rather, GFM controls enable additional features from BESS beyond what can be provided from GFL today. Examples include operating in low system strength conditions, improving overall system stability, helping stabilize the system following large generator loss events (supporting arresting frequency changes), and potentially enabling blackstart capability from IBRs.

Multiple GFM projects around the world have been deployed, with more GFM projects under procurement See **Table I.1** and more details in **Appendix A**. However, widespread adoption has been relatively slow due to limited pilot projects (particularly of large numbers of GFM resources in one area) and difficulties establishing GFM performance specifications and testing procedures. Furthermore, detailed studies of GFM technology require electromagnetic transient (EMT) modeling and industry is challenged conducting large EMT studies due to lack of expertise and computational limitations today.

Table I.1: GFM BESS Projects Deployed or under Construction

Project Name	Location	Size (MW)	Time
Project #1	Kauai,USA	13	2018
Kauai PMRF	Kauai,USA	14	2022
Kapolei Energy Storage	Hawaii, USA	185	2023
Hornsdale Power Reserve	Australia	150	2022
Wallgrove	Australia	50	2022
Broken Hill BESS	Australia	50	2023
Riverina and Darlington Point	Australia	150	2023
New England BESS	Australia	50	2023
Dalrymple	Australia	30	2018
Blackhillock[15]	Great Britain	300	2024
Bordesholm[16]	Germany	15	2019

While GFM capability in batteries can be delivered at relatively low ~~(or even zero)~~ incremental cost, there may still be some costs associated with project and product development simply due to the newness of the technology.

[14] Demonstration of Essential Reliability Services by a 300-MW Solar Photovoltaic Power Plant (nrel.gov)

[15] Zenobē breaks ground on pioneering 300MW battery in Blackhillock - Zenobē (zenobe.com)

[16] The Bordesholm stand-alone grid ensures power supply even in the event of a grid failure - Sunny. SMA Corporate Blog (sma-sunny.com)

Widespread adoption of GFM IBRs will ensure an adequate level of BPS reliability moving forward. In addition, market operators may establish market-based mechanisms that can drive GFM adoption at a rapid pace, where appropriate.

The Cost of Inaction

This is a unique moment in the industry when a need is becoming fully understood and an effective, relatively low-cost GFM solution has emerged. GFM capability in BESS is a viable and effective solution to address declining stability margins system-wide and to manage decreasing system strength and the issues that arise under these conditions (e.g., wind and solar PV curtailments). The industry is at the cusp of a rapid growth of BESS capacity on the system in the next few years. Without GFM functional specifications and test procedures established by TOs, TPs, and PCs, and the appropriate incentives or requirements in place, much or all of the newly installed BESS capacity will likely not have GFM capability enabled (either precluding the possibility of GFM or requiring significantly more costly retrofits or network upgrades). If GFM capability is not adopted very soon, the outcome will be ~~continued decrease~~reduced ~~in the~~ transfer limits ~~transfer limits of~~ for existing IBRs~~,~~ and consequently growing levels of solar PV and wind curtailment, and additional costs of supplemental stabilizing equipment (e.g., synchronous condensers) in the future.

ISOs/RTOs/utilities should work with stakeholders to carry out studies of the implementation of GFM technology in low grid strength ~~grid~~ areas[17] and act quickly to implement pilot projects (similar to how the provision of ancillary services from GFL IBRs has been tested in the past). Experience from GFM BESS project installations around the world, particularly Great Britain and Australia (see **Appendix A**), can be used as a guide.

Presently, the recommendation is that all new BESS connecting to the BPS should have the capability for GFM operation or future capability to be upgraded with GFM controls (if necessary). TOs should establish this requirement in their interconnection requirements or power purchase agreements (PPAs). Developers and GOs can also ensure that these requirements are in contractual language with the equipment manufacturers. It is strongly recommended that newly interconnecting resources enable the GFM controls to support enhanced BPS reliability.

Functionally Defining GFM Performance

Although the concept of GFM technology has been around for many years, mainly in small islanded systems or microgrids, the term has presented confusion in recent years when the concept is applied to the BPS. Various documents have proposed definitions to try and reduce confusion (see Appendix A for reference). Most definitions agree that at a minimum GFM controls tend to hold their voltage magnitude and angle at the device terminals constant in the period immediately following a system event. This tends to provide a resistance to change in the external system and thereby grants certain stabilizing properties. Although there is general consensus on what GFM is as a concept, opinions differ on the degree and extent the concept should be used when qualifying an interconnecting device as GFM, as well as how to test the capability. Specifying GFM may be done in a number of ways, including the following:

1. Control topology: The theoretical behavior of a device may be defined based on specific types of control topologies such as virtual synchronous machine or droop-based topologies. It is not recommended to define GFM behavior based on control topology, to leave the room for innovation.
2. *Quantitative response metrics:* The precise behavior of a device in response to external system events can be defined, with no regard to the internal control topology. Quantities like active and reactive power rise time in response to a network event can be used to test whether the controls provide the stabilizing influence expected from GFM.
3. *Frequency domain characterization:* GFM controls tend to have signature responses to stimuli with varying frequencies. It is likely possible to provide an accurate determination of the GFM capabilities of a device by

[17] Due to loss of last synchronous machine, an extremely low system strength scenario manifests in the tests described in this document

measuring its response to external perturbations across a range of frequencies[18]. Significant promising research work is underway in this field.[19] [20]

4. *General testing definition (***Recommended***):* It is possible to determine whether a device functionally meets the definition for GFM control by observing whether the device is capable of performing well during certain well-defined simulation tests. For example, GFM IBRs can be subjected to severe external events that are generally difficult or impossible for conventional GFL devices to stably operate through. For example, a GFM device, like a synchronous generator, is able to operate and serve load with no other synchronous machines in service. It is generally able to operate in synchronism with other synchronous machines, continue stable operation when those machines are disconnected, and continue stable operation when those machines are re-connected. GFL IBRs are generally not able to do all of these things. Even if a GFM plant will not be subjected to these events in real-time operation, the tests indicate that the controls can provide the stability benefits needed.

To avoid confusion and conflicts in understanding, the fourth approach is proposed and further described in Chapter 2, ~~proposed~~ until sufficient research and field experience is available to fairly and effectively use other methods. This method provides confidence that GFM controls will provide the necessary stabilizing characteristics even if the specific test scenarios never occur during real-time operations. The method is simple to implement and agnostic to GFM control topologies, and similar approaches have been successfully implemented in BESS procurements around the world[21] [22].

Minimum Necessary Capacity of GFM Inverters for Future High IBR Grids

It is well understood that as the penetration of IBRs continues to rise, the grid will need some amount of GFM-enabled resources to ensure system stability[23]. This logically raises the question of a necessary or recommended capacity (presumably a % value) of GFM-enabled IBRs relative to the total capacity of IBRs and/or machines on the BPS. While industry does not currently have a rule-of-thumb to prescribe the minimum necessary capacity of GFM IBRs needed to stabilize a given system, recent research provides a few points of reference. This section outlines current industry recommendations on this topic.

Relatively few studies have been performed, particularly for large interconnected power systems. However, smaller islanded systems have explored this issue in much more detail. For example, power hardware in the loop (PHIL) tests of the HECO Maui system illustrated the percentage of GFM inverters needed for stability at various system inertia levels.[24] This work found that as system inertia dropped towards zero (an entirely inverter-based system), the amount of GFM inverters necessary to maintain system stability increased relatively linearly. When the system has zero mechanical rotating inertia system inertia, the percentage of GFM inverters relative to total system capacity (consisting of only GFM and GFL inverters) was around 30% (see **Figure I.1**). The GFL IBRs in this system consisted primarily of IBRs with no voltage or frequency support capability, with only a few grid-supportive GFL IBRs providing voltage support or fast frequency response. HECO also highlighted needing some reliability margin, therefore recommending that this ratio be increased to account for unexpected issues like legacy distributed energy resource momentary cessation issues or unexpected inverter tripping issues. This study also highlighted that the necessary

[18] Small-signal frequency-domain methods can be used as screening methods which are typically followed up by time-domain verification that consider both large and small-signal stability.

[19] Sequence Impedance Measurement of Utility-Scale Wind Turbines and Inverters - Reference Frame, Frequency Coupling, and MIMO/SISO Forms (nrel.gov)

[20] A Testing Framework for Grid-Forming Resources, IEEE Power and Energy Society General Meeting, 2023 (accepted for publication)

[21] https://www.nationalgrideso.com/document/250216/download

[22] https://www.youtube.com/watch?v=2e5ET0L1j5g

[23] Note that, alternatively, adequately sized and placed synchronous condensers can also be used to ensure system stability with high IBR. However, with GFM capability provided by IBRs themselves, installation of these additional grid assets can be avoided.

[24] https://ieeexplore.ieee.org/abstract/document/9875186

capacity of GFM IBRs does not necessarily depend on the total percentage of generation from IBRs (which was above 95% in all cases studied). Instead, low total online synchronous machine capacity (as quantified via system inertia constant, for example) was a much better predictor of the need for GFM.

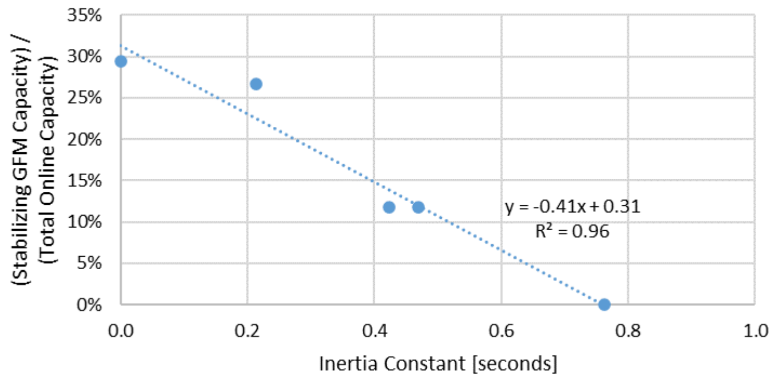


Figure I.1: HECO Study of GFM Needed for Stability at Various Inertia Levels

Similarly, a recent paper[25] from the European Union-funded project, MIGRATE, studied the composition of GFM and GFL inverters in various systems and identified a need for at least a 37% ratio of GFM IBRs to total IBRs in the system. There were sensitivities based on numerous factors that modified that number slightly.

It is important to note that the actual GFM capacity needed for system stability will vary from system to system and can also depend on the type of contingency being studied. Issues could be system-wide (e.g., need for stable fast frequency response) or could be more localized (e.g., need for operation in low short circuit strength networks). This could drive the need for stabilizing services from additional resources, or from existing installed resources. The needed capacity of GFM is also impacted by the dynamic characteristics of other sources in the network such as GFL inverters and load. With the approval of FERC Orders 842 and 827 and IEEE 2800-2022, the response of GFL resources may be more advanced than that of legacy IBRs, which could impact the necessary capacity of GFM to maintain grid stability.

As an example, a study on an island power network[26] identified that the minimum percentage of GFM required to maintain frequency and voltage stability was 11% if frequency and voltage support were provided by other IBR resources per IEEE 2800-2022. However, if GFL IBRs had no frequency and voltage response capability, the study identified that a minimum of 23.5% GFM IBR was necessary to maintain stability. Therefore, it is important that TOs, TPs, and PCs ensure adequate levels of GFM resources moving forward to maintain system stability, while considering system characteristics, capabilities of existing and future GFL IBRs, and with suitable margin to avoid any adverse reliability impacts from unexpected performance issues.

[25] https://www.h2020-migrate.eu/_Resources/Persistent/5d0f8339650bcf53cd24a3006556daa1da66cb42/D3.4%20-%20New%20Options%20in%20System%20Operations.pdf
[26] "Services from IBR for future systems", 2022 ESIG Reliability Working Group Meeting, October 2022.

Chapter 1: Functional Specifications for GFM BESS

This chapter defines the recommended functional specifications for GFM BESS. For effective and efficient adoption of GFM technology, TOs will need to establish functional specifications that define GFM functionality. The GFM specification can then be provided to OEMs by developers and GOs to ensure procurement of GFM resources.

Functional Specifications for GFM and GFL Battery Energy Storage

All BPS-connected generating resources are required to meet applicable interconnection requirements and performance-based standards. Requirements often establish specifications related to, but not limited to, the following:

- **Dispatchability:** Capability of the facility to be dispatched (or curtailed) to a specific active power set point
- **Steady-State Voltage Control:** Capability of the facility to control steady-state voltage at the point of interconnection to a specific voltage schedule (set point and operating band)
- **Dynamic Reactive Power Support:** Capability of the facility to provide dynamic reactive support in response to normal and emergency grid conditions within the expected ride-through performance range
- **Active-Power Frequency Control:** Capability of the facility to respond to changes in system frequency by changing active power output when the resource has available headroom/tailroom
- **Disturbance Ride-Through Performance[27]:** Capability of the facility to ride through normal grid disturbances within a defined set of parameters or expectations including but not limited to faults, and phase jumps
- **Fault Current and Negative Sequence Current Contribution:** Capability of the facility to provide fault current, including negative sequence current to mitigate unbalanced voltage conditions and facilitate relay operation[28]
- **Security:** Capability of the facility to ensure cyber and physical controls are in place to ensure resilience to potential threats.

Functional Specifications Defining Grid Forming BESS

Additionally, the functional specifications need to be clearly defined for the GFM-specific functions. The following are performance characteristics specific to GFM BESS: These characteristics shall be provided within GFM BESS equipment rating limits:

- **GFM-Specific Voltage and Frequency Support:** GFM shall provide autonomous, near-instantaneous frequency and voltage support by maintaining a nearly-constant internal voltage phasor in the sub-transient time frame, including:
  - **Phase Jump Performance:** GFM shall resist near-instantaneous voltage magnitude and phase angle changes by providing appropriate[29] levels of active and reactive power output in the sub-transient time frame.
  - **System Strength Support:** GFM shall help reduce the sensitivity of voltage change for a given change in current in the sub-transient time scale.

[27] GFM BESS FRT capability and performance during and after the fault is critical to grid stability and should be tested just as it would be for a GFL facility

[28] This can be achieved, for example, by maintaining balanced GFM resource internal voltage during asymmetrical faults.

[29] As an example, if the phase difference between the inverter terminal and the grid increases, the resource should increase (or make less negative) its active power injection in the sub-transient time scale. If the phase difference reduces, it should result in a reduction of its active power injection in the sub-transient time scale.

- **Ability to Stably Operate with Loss of Last Synchronous Machine:** GFM shall be able to stably operate through and following the disconnection of the last synchronous machine in its portion of the power grid[30].

There are additional desirable characteristics for GFM performance; however, present technology may not be able to widely meet this performance specification today. Therefore, they are listed here for consideration in specification for future GFM technology. They include the following:

- **Passivity:** GFM should present a non-negative resistance and present a passive characteristic to the grid within a wide frequency range (0–300 Hz) to prevent adverse interactions.
- **Negative Sequence Current during Continuous Operating Region:** GFM Plant should provide negative sequence current.
- **Balanced GFM Internal Voltage:** The GFM resource should also ensure its internally generated voltage remains balanced during all near-nominal operating conditions (e.g., 0.9–1.1. pu voltage range).

Blackstart Considerations

GFM and blackstart-capable are not synonymous terms; however, GFM functionality is a prerequisite for an inverter-based resource (IBR) to be eligible for blackstart capability. The TO, TOP, or RC may establish additional requirements for blackstart capability[31] beyond the general specifications for GFM, which may necessitate extended capability for the short-term overcurrent, more stringent ride-through capability, longer energy duration needs or additional hardware to supply sufficient and reliable start-up power to restore the electricity system from a blackout. These unique local requirements may preclude certain GFM resources from participating in blackstart services. It should be noted that a GFM IBR does not necessarily have to provide blackstart services, and blackstart capability requirement should be specified separately.

Additional Considerations

The following are additional considerations for the functional specification of GFM in BESS:

- All the functional specifications listed above are applicable when the BESS is within its limits of the energy source behind the inverter and the equipment ratings of the inverter[32]. These functional specifications do not impose any requirements for ~~magnitude of~~ fault current capability beyond equipment ratings.
- GFM BESS shall continue providing GFM operational characteristics even at its highest and lowest allowable state of charge. If the BESS remains connected to the network, it shall remain in GFM mode as defined in the Introduction of this document. There should be no state of charge condition where the BESS should need to operate in GFL mode.
- Performance requirements for BPS-connected inverter-based resources such as, for example, IEEE 2800 ~~will~~ may also apply to GFM resources unless explicitly stated by the local interconnection requirements. To the extent that existing requirements ~~in IEEE 2800 or 1547~~ may create any barriers to GFM applications, exceptions may need to be considered and specified by the TO. Simultaneously, industry can contribute towards improvements of the relevant standards to accommodate the requirements for GFM.

[30] While generation capacity in the system can still meet the load.

[31] https://www.hawaiianelectric.com/documents/clean_energy_hawaii/selling_power_to_the_utility/competitive_bidding/20220531_exh_5.pdf

[32] Transient conditions can cause GFM BESS to reach current limits, resulting in transient behavior that differs from the GFM performance characteristics described above.

Chapter 2: Verifying GFM Functionality

This chapter describes the functional performance verification tests that determine whether an interconnecting BESS can be classified as GFM. TPs and PCs should integrate these tests as part of the interconnection study process in coordination with TOs establishing GFM requirements for newly interconnecting BESS. GOs, developers, OEMs can ensure that planned facilities meet these functional specifications prior to interconnection studies, which will help expedite the process. Verifying GFM functionality with test simulations[33] (referred to herein as "GFM functional tests") using accurate and detailed electromagnetic transient (EMT) models provided and certified directly from the OEM is necessary, in addition to attestations and detailed descriptions of the control modes from the OEMs.

Model Quality Fundamentals

The most important prerequisite to model-based performance verification is establishing confidence in the model quality. Ensuring an accurate and verified model is a fundamental pre-requisite to conducting any reliability studies using the models, and clear model quality requirements and checks should be established by TPs and PCs in all instances. As with all model representations of actual facilities, the following fundamental aspects of modeling and verification are needed before GFM-specific testing is conducted:

- OEM-provided validated models and validation test reports against lab or field test, or hardware-in-the-loop test of the product to be used in this project. This model validation test may include a generic representation of the overall facility but must include the actual control and converter level protection of the product that will be installed in the project. The following validation tests are recommended at a minimum:[34]
  - Balanced and unbalanced faults
  - Grid voltage disturbance – step change in magnitude and phase
  - Grid frequency disturbance – step change in frequency and frequency ramp at slow and fast ROCOF
  - Active and reactive power dispatch command step change
  - Loss of the last synchronous generator[35]
  - Load rejection
- Attestation from the inverter OEM(s) that the model provided matches the expected as-built configuration and settings to the degree known at the time of model submission.[36]
- Attestation from the plant-level controller(s) OEM(s) that the model provided matches the expected as-built configuration and settings to the degree known at the time of model submission.
- Model quality checks conducted by the TP/PC to ensure appropriate representation and parameterization of the model provided by the GO/developer.
- Model documentation is provided that describes the functionality and operation of the resource being deployed and model used.
- The model meets the quality criteria outlined in the NERC EMT Reliability Guideline[37]

[33] One of the best mechanisms to gain confidence in simulation models is to compare them against real event data. Currently availability of this type of data is limited for GFM installations, but as more are obtained in the coming years it will be beneficial to review this performance and integrate the learning into future GFM guides.

[34] Refer to IEEE 2800.2 once published for additional benchmarking test that could supplement or augment those listed.

[35] For model validation using hardware testing, OEMs may choose to leverage tests similar to those outlined in "Verification Test for GFM Functionality" section.

[36] The final tuning parameters/setting of the project should be accompanied with the provided model parameters/settings update to GO/TO.

[37] https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Reliability_Guideline-EMT_Modeling_and_Simulations.pdf

Description of GFM Functional Test System

The GFM functional test system (see **Figure 2.1**) consists of the following components connected to a single bus without any ~~or~~impedance:

- A synchronous generator with a simple excitation system model (e.g., SCRX) and turbine-governor model (e.g., TGOV1), with circuit breaker[38]
- A load[39] with both active and reactive power (inductive) components, with a maximum power factor of 0.9
- The GFM BESS plant model under test
- A duplicate of the GFM BESS plant model, rated at or near half (MVA and MW) of the model under test [40]

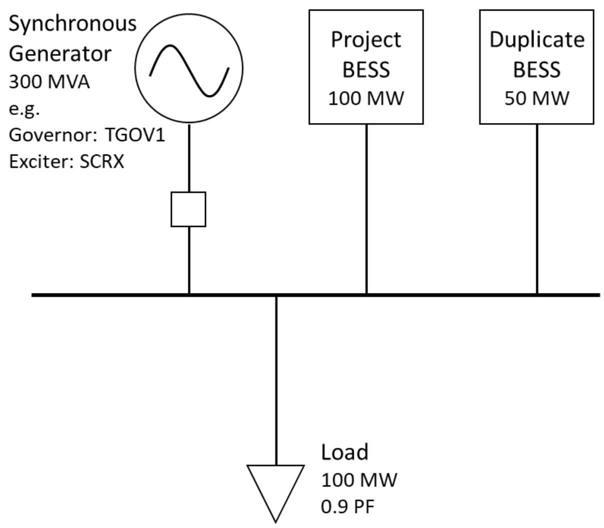


Figure 2.1: GFM Functional Test System[41]

The combined MVA rating of the BESS models must be sufficient to fully supply the load upon disconnection of the synchronous generator. The synchronous generator MVA rating must be sufficient to simultaneously serve the load and charge both BESS at their rated maximum charge power. Both BESS models should be in voltage control mode with the same voltage and frequency droop settings and set points. All protection settings in the BESS should reflect the equipment planned to be installed in the field; however, settings should be set as wide as possible within the equipment ratings and capabilities (as recommended in NERC reliability guidelines)[42] since the tests are intended to subject the GFM BESS to extreme frequency, voltage, and phase jump events.

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[38] For simulating the loss of the synchronous generator

[39] Constant impedance load model is used in the example tests described later in this chapter

[40] The purpose of adding the duplicate BESS is to consider control interaction between multiple GFM devices, including droop response and to provide flexibility in post event power balancing.

[41] BESS ratings and synchronous generator ratings are for example only.

[42] https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Reliability_Guideline-EMT_Modeling_and_Simulations.pdf

Description of GFM Functional Tests and Success Criteria

Using simulated disturbances that only a GFM BESS meeting the functional specifications could survive, the following suite of GFM functional tests are designed to ensure that each proposed project meets the GFM BESS functional specifications as described in this document.[43,44]

- **Test 1 – BESSs Initially Discharging and Ends at Higher Level of Discharging:** This test assesses the GFM BESS performance following the generator trip when operating within its limits and in discharging state.
- **Test 2 – BESS Initially Charging and Ends Discharging:** This test assesses the GFM BESS performance when operating within its limits and transitioning from charging state to discharging state after the generator trips.
- **Test 3 – BESS GFM Performance at Maximum Active Power:** This test assesses the GFM BESS performance following the generator trip when operating at or near its limits.

Each test is conducted using different initial operating conditions, as outlined in **Table 2.1**–**Table 2.3**. Once the system is stable at the given power flow conditions (without oscillations), the synchronous generator is disconnected. Each test then includes a set of pass/fail success criteria that *all* must be met. TPs/PCs should add additional qualitative or quantitative criteria specific to their own systems, as applicable. GFM BESS under test must pass all three tests to qualify as GFM.[45]

Although the tests require the BESS to be operated in the absence of any synchronous generation, many GFM BESS will never be operated that way. Regardless, the ability to survive such tests indicates that the controls have the necessary properties from GFM in grid-connected conditions. Conversely, if the resource is unable to meet the performance requirements in these tests, the controls will not have the desired characteristics for future BPS operating conditions.

These tests do not guarantee that the facility will be stable for a specific location on the grid. Interconnection studies are critical for ensuring reliable operation of the BPS for each specific interconnecting resource.[46] If settings change during interconnection studies, the model with the new settings should still pass these tests.

Test 1: BESSs Initially Discharging and Ends at Higher Level of Discharging

Table 2.1: Test 1 – Setup and Success Criteria	
Initial Dispatch	
• The ~~big BESS~~ project BESS ~~1~~ is dispatched at 20% of its maximum discharge power limit. • The ~~small BESS 2~~duplicate BESS is dispatched at 20% of its maximum discharge power limit	
Test Sequence:	
1. Run until the system is stable at the given power flow conditions, without oscillations. 2. Trip the synchronous generator.	
Success Criteria	
Pre-Trip:	**Pass/Fail**

[43] TP/PC may require additional tests such as load rejection, faults, etc.

44 For example: Hawaiian Electric Facility Technical Model Requirements and Review Process, August 2022: https://www.hawaiianelectric.com/documents/clean_energy_hawaii/selling_power_to_the_utility/competitive_bidding/20210901_cbre_rfp/20210825_redline_lanai_appxb_att3.pdf

[45] GFL BESS can potentially form an island with load under very specific power flow and resonance conditions. Hence, it's important to subject the project model to all three tests.

[46] Other tests such as ride-through capability, voltage control, etc. are necessary to be conducted for all resources, including GFM and GFL.

Table 2.1: Test 1 – Setup and Success Criteria	
a. BESSs active power outputs match dispatched levels.	
b. Synchronous generator active power output matches the rest of the load.	
c. Frequency should be 1 pu.	
d. Voltage at Bus 1 should be within 5% of nominal.	
e. Phase voltage and current waveform should not be distorted.	
f. There should not be oscillations in the RMS quantities.	
g. Reactive power output from all devices should be within limits.	
Post-Trip:	**Pass/Fail**
a. Immediately following the trip, BESS output should be well controlled. System frequency and voltage should not oscillate excessively or deviate from steady state levels for any significant amount of time.	
b. Voltage settles to a stable~~, acceptable~~ operating point.	
c. The final voltage is as expected based on the droop and deadband settings.	
d. Frequency settles to a stable~~, acceptable~~ operating point.	
e. The final frequency is as expected based on the droop and deadband settings.	
f. Any oscillation shall be settled.	
g. Any distortion observed in phase quantities should dissipate over time.	
h. Active power from each BESS should move immediately to meet the load requirement and settle according to its frequency droop setting.	
i. Reactive power from each BESS should move immediately and settle according to its voltage droop setting.	

Test 2: BESS initially charging and ends up discharging

Table 2.2: Test 2 – Setup and Success Criteria	
Initial Dispatch	
• The ~~BESS_1~~project BESS ~~under test~~ is dispatched at half of its maximum charge power limit. • The ~~smaller duplicate BESS_2~~duplicate BESS is dispatched at half of its maximum charge power limit.	
Test Sequence:	
1. Run until the system is stable at the given power flow conditions, without oscillations. 2. Trip the synchronous generator.	
Success Criteria	
Pre-Trip:	**Pass/Fail**
a. BESSs active power outputs match dispatched levels.	
b. Synchronous generator active power output matches ~~the rest of~~ the load and both BESS charging.	
c. Frequency should be 1 pu.	
d. Voltage at Bus 1 should be within 5% of nominal.	
e. Phase voltage and current waveform should not be distorted.	
f. There should not be oscillations in the RMS quantities.	
g. Reactive power output from all devices should be within limits.	
Post-Trip:	**Pass/Fail**
a. Immediately following the trip, BESS output should be well controlled. System frequency and voltage should not oscillate excessively or deviate from steady state levels for any significant amount of time.	
b. Voltage settles to a stable~~, acceptable~~ operating point	
c. The final voltage is as expected based on the droop and deadband settings.	
d. Frequency settles to a stable~~, acceptable~~ operating point	
e. The final frequency is as expected based on the droop and deadband settings.	
f. Any oscillation shall be settled.	
g. Any distortion observed in phase quantities should dissipate over time.	
h. Active power from each BESS should move immediately to meet the load requirement and settle according to its frequency droop setting.	
i. Reactive power from each BESS should move immediately and settle according to its voltage droop setting.	

Test 3: BESS GFM Performance at Maximum Active Power

Table 2.3: Test ~~2~~ 3 – Setup and Success Criteria	
Initial Dispatch	
• The ~~BESS 1~~project BESS ~~under test~~ is dispatched at 0 MW. • The ~~smaller duplicate BESS 2~~duplicate BESS is dispatched at its maximum discharge power limit.	
Test Sequence:	
1. Run until the system is stable at the given power flow conditions, without oscillations. 2. Trip the synchronous generator (no fault).	
Success Criteria	
Pre-Trip:	**Pass/Fail**
a. BESSs active power outputs match dispatched levels.	
b. Synchronous generator active power output matches the rest of the load.	
c. Frequency should be 1 pu.	
d. Voltage at Bus 1 should be within 5% of nominal.	
e. Phase voltage and current waveform should not be distorted.	
f. There should not be oscillations in the RMS quantities.	
g. Reactive power output from all devices should be within limits.	
Post-Trip:	**Pass/Fail**
a. Immediately following the trip, BESS output should be well controlled. System frequency and voltage should not oscillate excessively or deviate from steady state levels for any significant amount of time.	
b. Voltage settles to a stable~~, acceptable~~ operating point	
c. The final voltage is as expected based on the droop and deadband settings.	
d. Frequency settles to a stable~~, acceptable~~ operating point	
e. The final frequency is as expected based on the droop and deadband settings.	
f. Any oscillation shall be settled.	
g. Any distortion observed in phase quantities should dissipate over time.	
h. Active power from BESS 1 should move immediately to meet the load requirement and settle according to its frequency droop setting. Active power from BESS 2 should not exceed its max discharge power limit at steady state.[47]	
i. Reactive power from each BESS should move immediately and settle according to its voltage droop setting.	

Example Conducting GFM Functional Tests

To illustrate conducting the GFM functional tests, an OEM-provided GFM model was subjected to each test outlined above. Appendix B provides additional examples of the GFM functional tests applied to a GFM model supplied by a different OEM. Table 2.4 shows the BESS voltage and frequency droop settings used for these tests.

Table 2.4: BESS Voltage and Frequency Droop Settings for Example Tests	
Parameter	Value
Voltage Droop	2% (on Qmax)

[47] BESS 2 output may exceed momentarily depending on the active power availability at the inverters.

Table 2.4: BESS Voltage and Frequency Droop Settings for Example Tests	
Frequency Droop	2% (on Pmax)
Frequency Deadband	0.03 Hz

Test 1: BESSs Initially Discharging and Ends at Higher Level of Discharging

The test system is initialized with power flow conditions shown in **Figure 2.2**.[48] BESSs are discharging at ~~a quarter~~20% of their maximum discharge site limit, with the synchronous generator servicing the rest of the load.

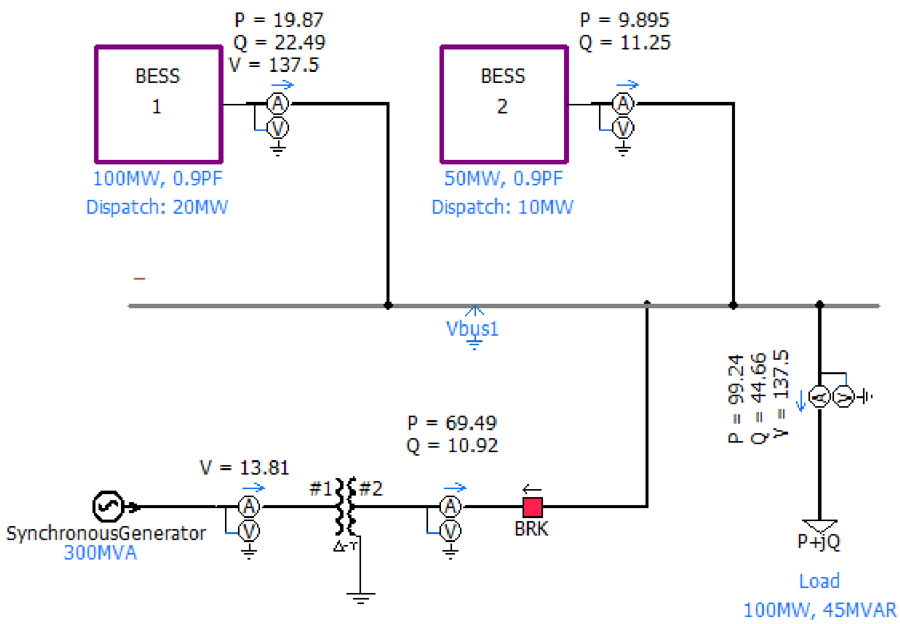

Figure 2.2: Example Test 1 – Initial Power Flow

Figure 2.3 shows the RMS quantities of the Test 1 simulation results including bus voltage (Vbus1_rms), frequency, active power (synchronous generator power (P_SyncGen), load power (P_Load), project BESS (BESS 1) power (P_BESS_1) and duplicate BESS (BESS 2) power (P_BESS_2)), reactive power, and current. The following observations are made:

- Near-instantaneous jump in active and reactive power from both BESS (see Point 1), followed by dynamics driven by specific GFM control topology and parameters.
- Minimal deviation in voltage thus resulting in small change in voltage-dependent load power (see Point 2)
- Final steady-state quantities (see Point 3 for values indicated by O-marker at *t = 40 sec* in **Figure 2.3**) can be verified against the droop parameters in **Table 2.4**.

[48] ~~Constant impedance load model is used in these tests.~~

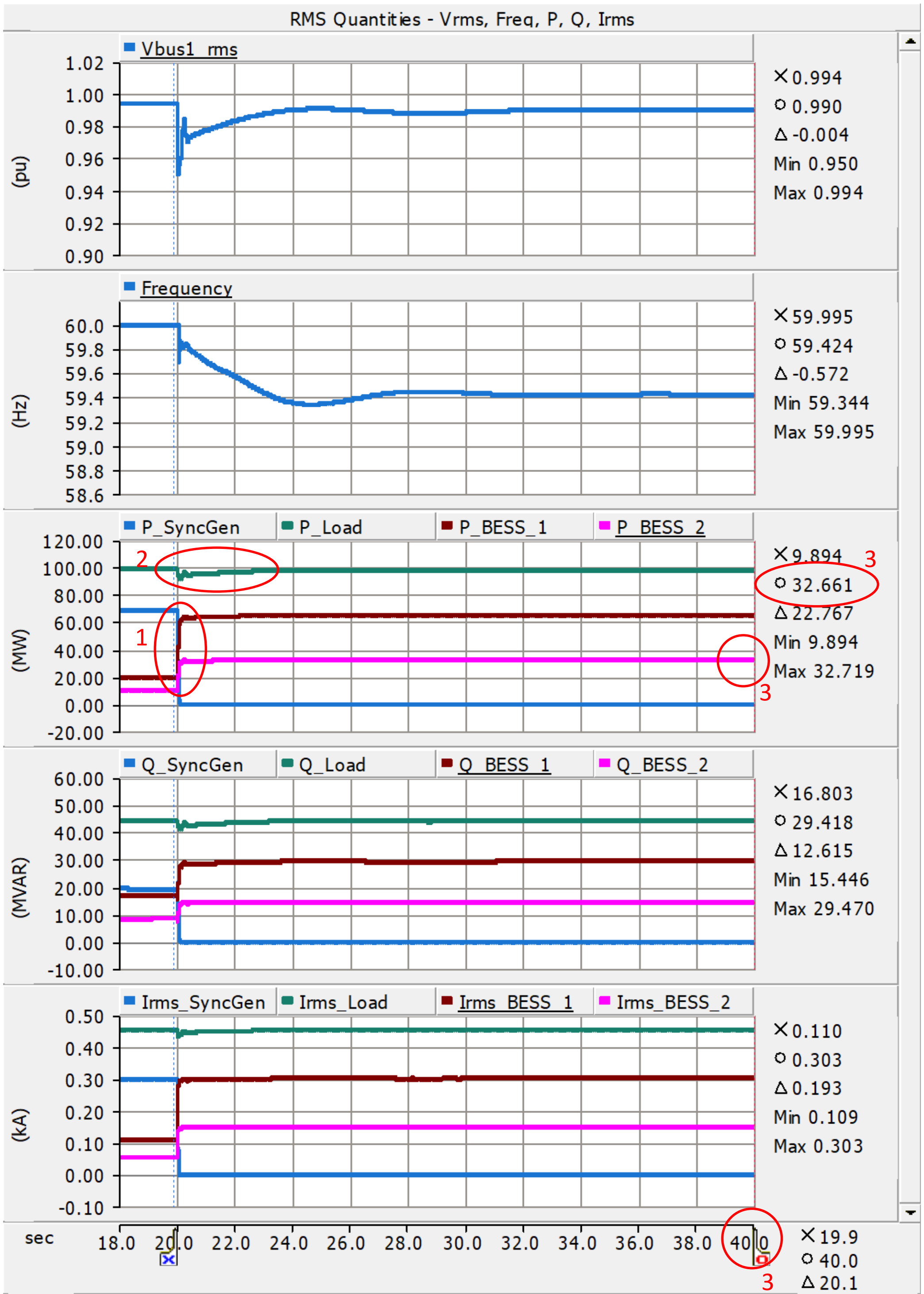

Figure 2.3: Test 1 Results – RMS Quantities

Figure 2.4 shows the instantaneous quantities of the Test 1 simulation results including bus voltage (Vbus1), synchronous generator current (I_SyncGen), load current (I_Load), ~~project~~ BESS 1 current (I_BESS_1) and ~~duplicate~~ BESS 2 current (I_BESS_2), with the following observations made:

- Phase angle shift in bus voltage (see Point 1)
- Sub-cycle increase in BESS currents (see Point 2)

- Sub-cycle change in BESS current phase angle; this is more observable in the Test 2 results

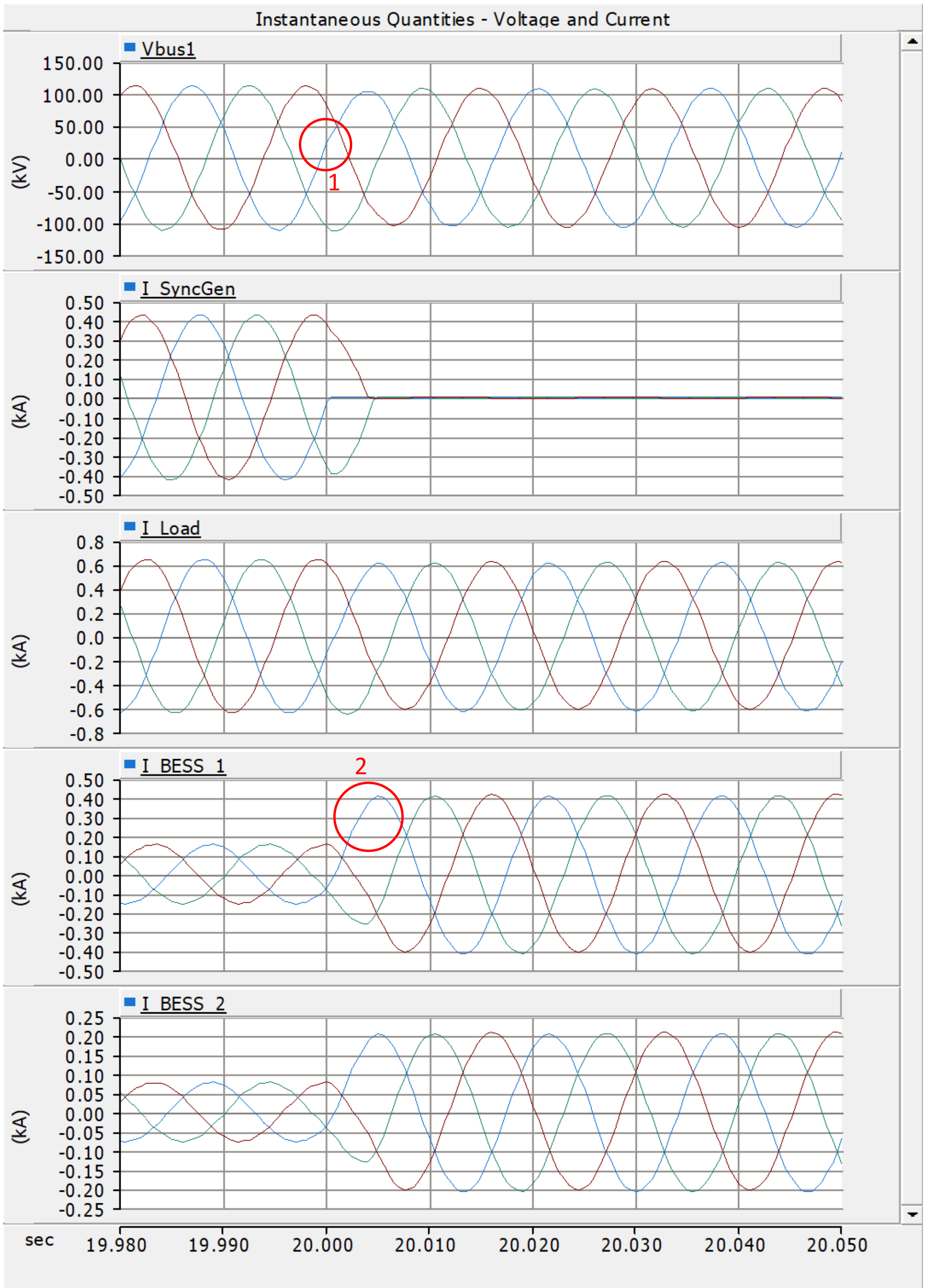

Figure 2.4: Test 1 Results – Instantaneous Quantities

As summarized in **Table 2.5**, the model passed Test 1.

Table 2.5: Evaluation of Test 1 Results	
Pre-Trip:	**Pass/Fail**
a. BESSs active power outputs match dispatched levels.	Pass
b. Synchronous generator active power output matches the rest of the load.	Pass
c. Frequency should be 1 pu.	Pass
d. Voltage at Bus 1 should be within 5% of nominal.	Pass
e. Phase voltage and current waveform should not be distorted.	Pass
f. There should not be oscillations in the RMS quantities.	Pass
g. Reactive power output from all devices should be within limits.	Pass
Post-Trip:	**Pass/Fail**
a. Immediately following the trip, BESS output should be well controlled. System frequency and voltage should not oscillate excessively or deviate from steady state levels for any significant amount of time.	Pass
b. Voltage settles to a stable~~, acceptable~~ operating point	Pass
c. The final voltage is as expected based on the droop and deadband settings.	Pass
d. Frequency settles to a stable~~, acceptable~~ operating point	Pass
c. The final frequency is as expected based on the droop and deadband settings.	Pass
f. Any oscillation shall be settled.	Pass
g. Any distortion observed in phase quantities should dissipate over time.	Pass
h. Active power from each BESS should immediately move to meet the load requirement and settle according to its frequency droop setting	Pass
i. Reactive power from each BESS should move according to its voltage droop setting.	Pass

Test 2: BESS Initially Charging and Ends Discharging

The test system is initialized with power flow conditions shown in **Figure 2.5**. BESS are initially charging at half of their maximum charge rating, with the synchronous generator supplying power to the load and both BESS.

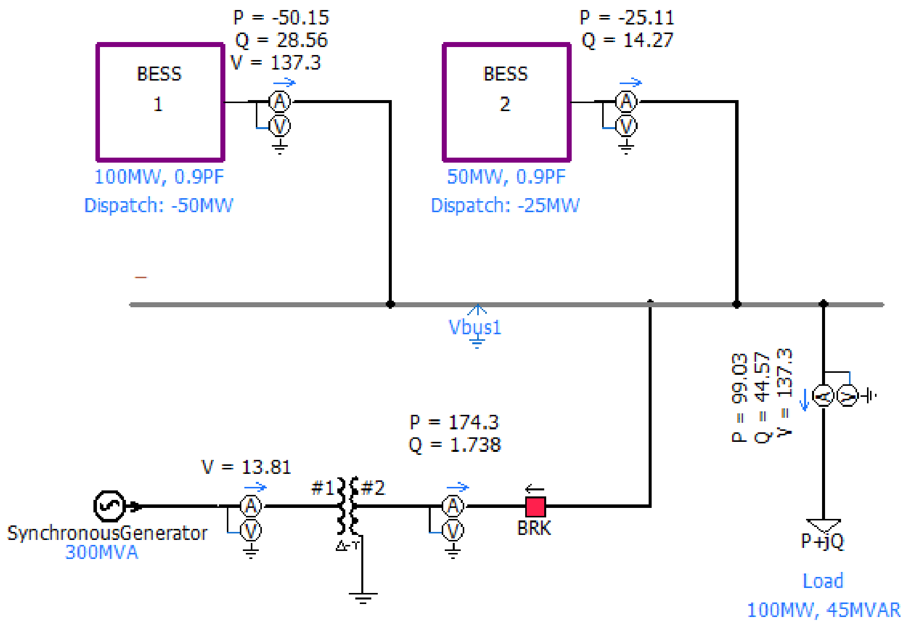

Figure 2.5: Example Test 2 – Initial Power Flow

In addition to similar observations as those from Test 1, the following can be noted in **Figure 2.6** which shows the RMS quantities of the Test 2 simulation results.

- Due to the larger differences between initial output power level and final settled output power level, driven by load, the frequency settled to a greater deviation according to the frequency droop setting.
- Frequency spike (see Point 1) is an artifact of frequency measurement algorithm in response to the shift in voltage phase angle (see Point 1 in **Figure 2.7**).

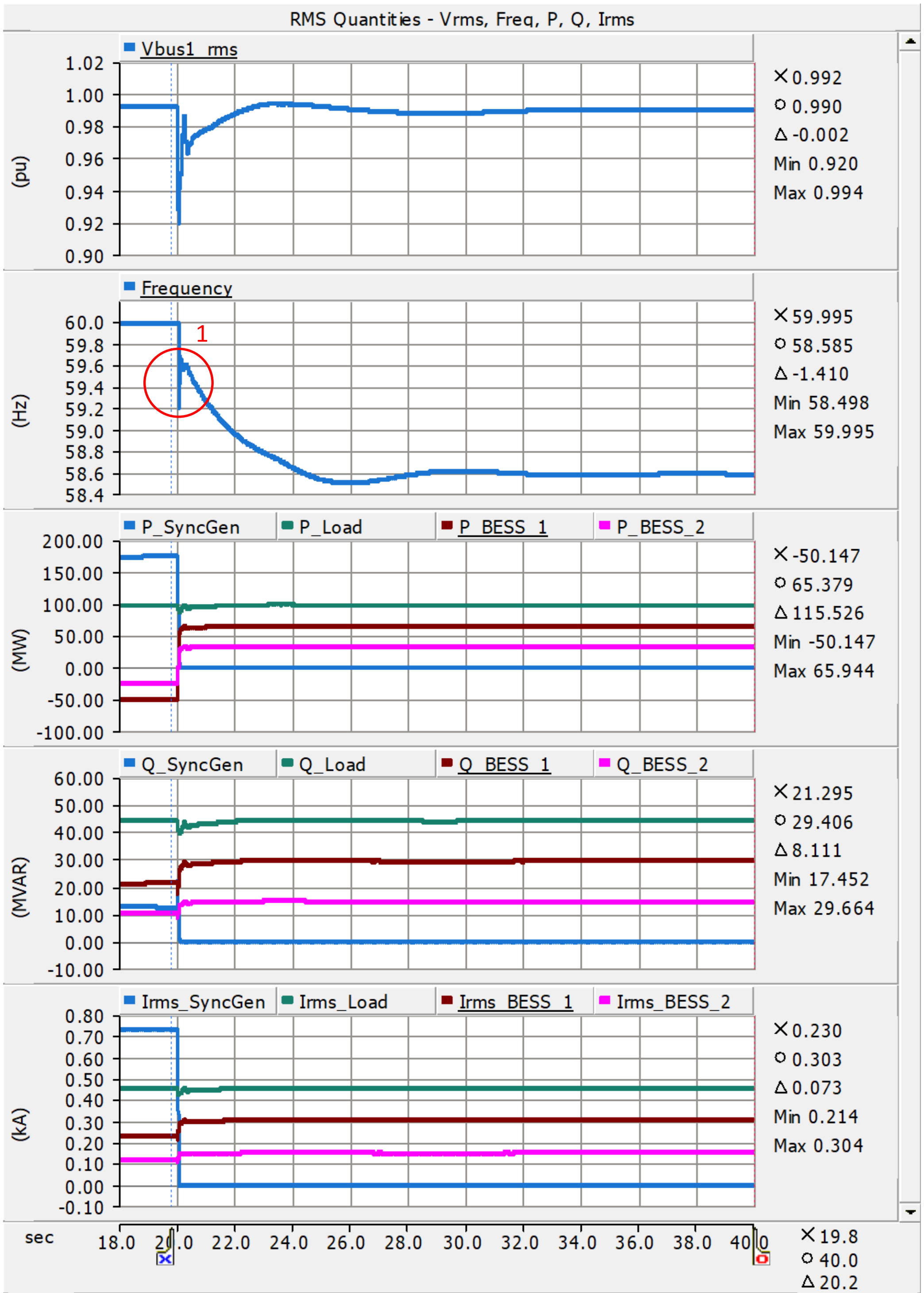

Figure 2.6: Test 2 Results – RMS Quantities

Figure 2.7 shows the instantaneous quantities of the Test 2 simulation results, with the following observations made:

- Phase angle shift in bus voltage (see Point 1)
- Current from both GFM BESS's increased within a quarter-cycle to make up for the loss of synchronous generator current (see Point 2)

- Change in BESS current phase angle as BESS's transition from charging to discharging within a quarter-cycle to serve the load (see Point 3)

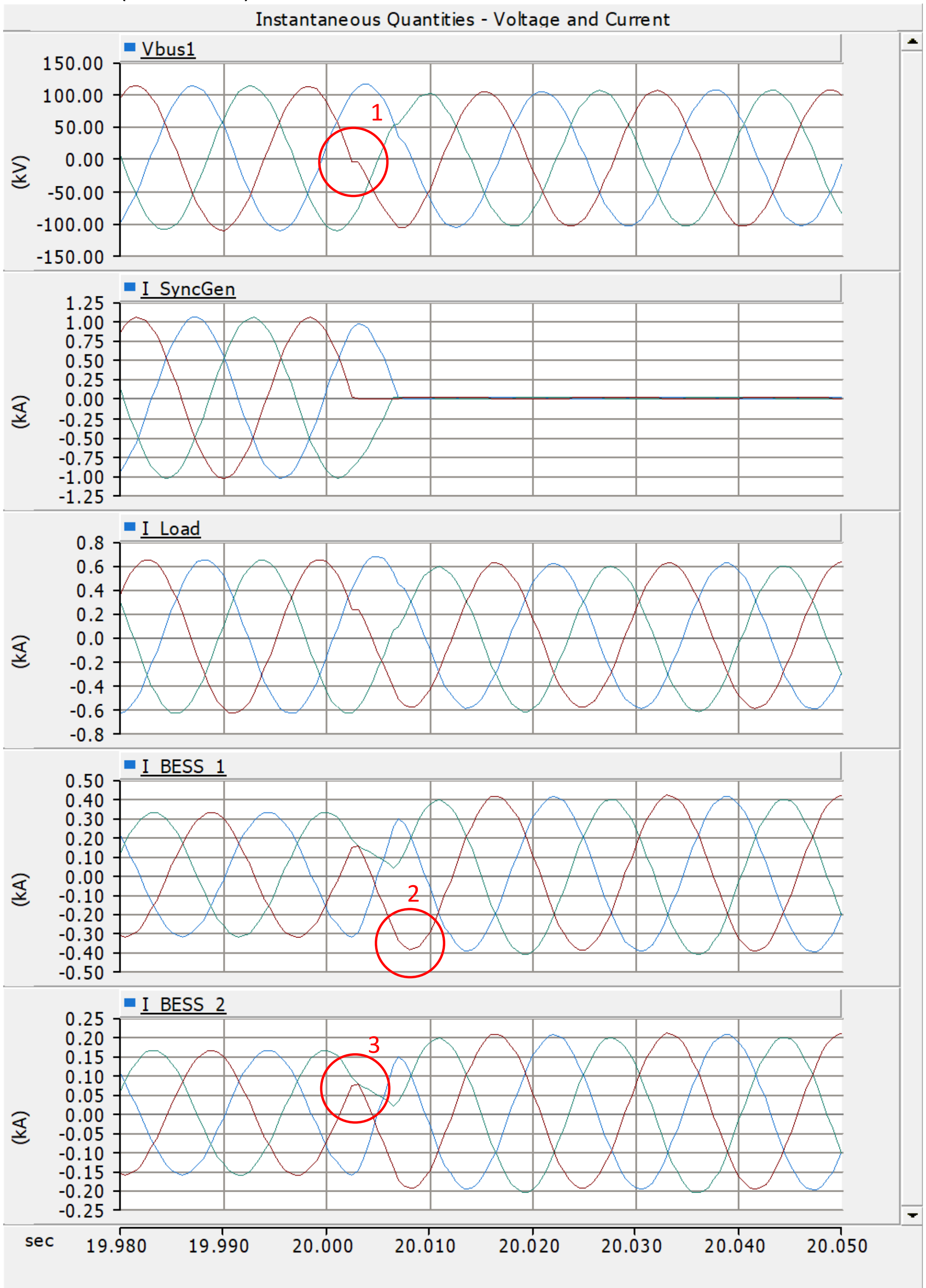

Figure 2.7: Test 2 Results – Instantaneous Quantities

As summarized below in **Table 2.6**, the model also passed Test 2.

Table 2.6: Evaluation of Test 2 Results	
Pre-Trip:	**Pass/Fail**
a. BESSs active power outputs match dispatched levels.	Pass
b. Synchronous generator active power output matches the ~~rest of the~~ load and both BESS charging.	Pass
c. Frequency should be 1 pu.	Pass
d. Voltage at Bus 1 should be within 5% of nominal.	Pass
e. Phase voltage and current waveform should not be distorted.	Pass
f. There should not be oscillations in the RMS quantities.	Pass
g. Reactive power output from all devices should be within limits.	Pass
Post-Trip:	**Pass/Fail**
a. Immediately following the trip, BESS output should be well controlled. System frequency and voltage should not oscillate excessively or deviate from steady state levels for any significant amount of time.	Pass
b. Voltage settles to a stable~~, acceptable~~ operating point.	Pass
c. The final voltage is as expected based on the droop and deadband settings.	Pass
d. Frequency settles to a stable~~, acceptable~~ operating point.	Pass
e. The final frequency is as expected based on the droop and deadband settings.	Pass
f. Any oscillation shall be settled.	Pass
g. Any distortion observed in phase quantities should dissipate over time.	Pass
h. Active power from each BESS should move immediately to meet the load requirement and settle according to its frequency droop setting.	Pass
i. Reactive power from each BESS should move immediately and settle according to its voltage droop setting.	Pass

Test 3: BESS GFM Performance at Maximum Active Power

The test system is initialized with power flow conditions shown in **Figure 2.8**. BESS ~~-~~1 is dispatched to zero active power and BESS ~~-~~2 is dispatched to its maximum discharge ~~site~~ limit of the site. The synchronous generator serves the remainder of the load.

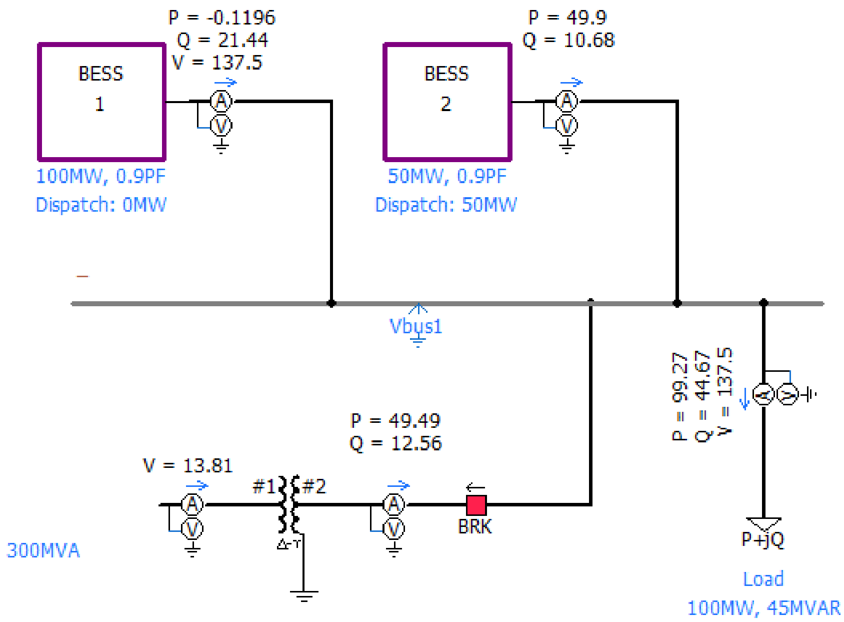

Figure 2.8: Example Test 3 - Initial Power Flow

Figure 2.9 shows the Test 3 simulation results with the following observations made that are unique to this test:

- BESS 2 will not follow the droop curve past its maximum discharge power limit (see Point 1). BESS 1 makes up the difference to meet load demand, reaching the final frequency based on droop and deadband settings.[49]

[49] BESS 2 has extra power capability at the inverter level, allowing it to momentarily exceed site power limit.

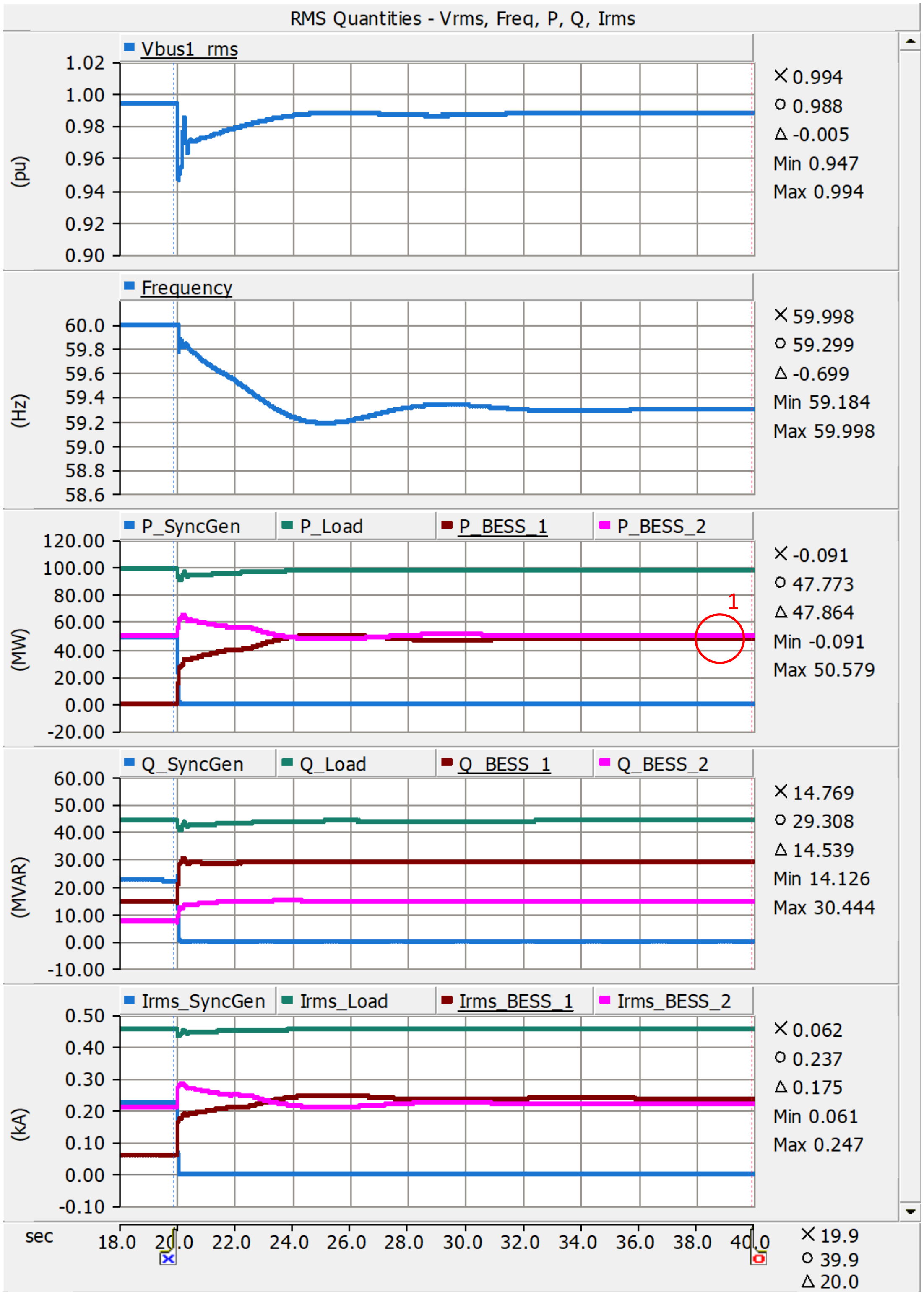

Figure 2.9: Test 3 Results – RMS Quantities

Figure 2.10 shows the instantaneous quantities of the Test 3 simulation results. Similar to the previous tests, it shows GFM BESS~~s~~ currents changed within a quarter cycle to match the load current (see Point 1).

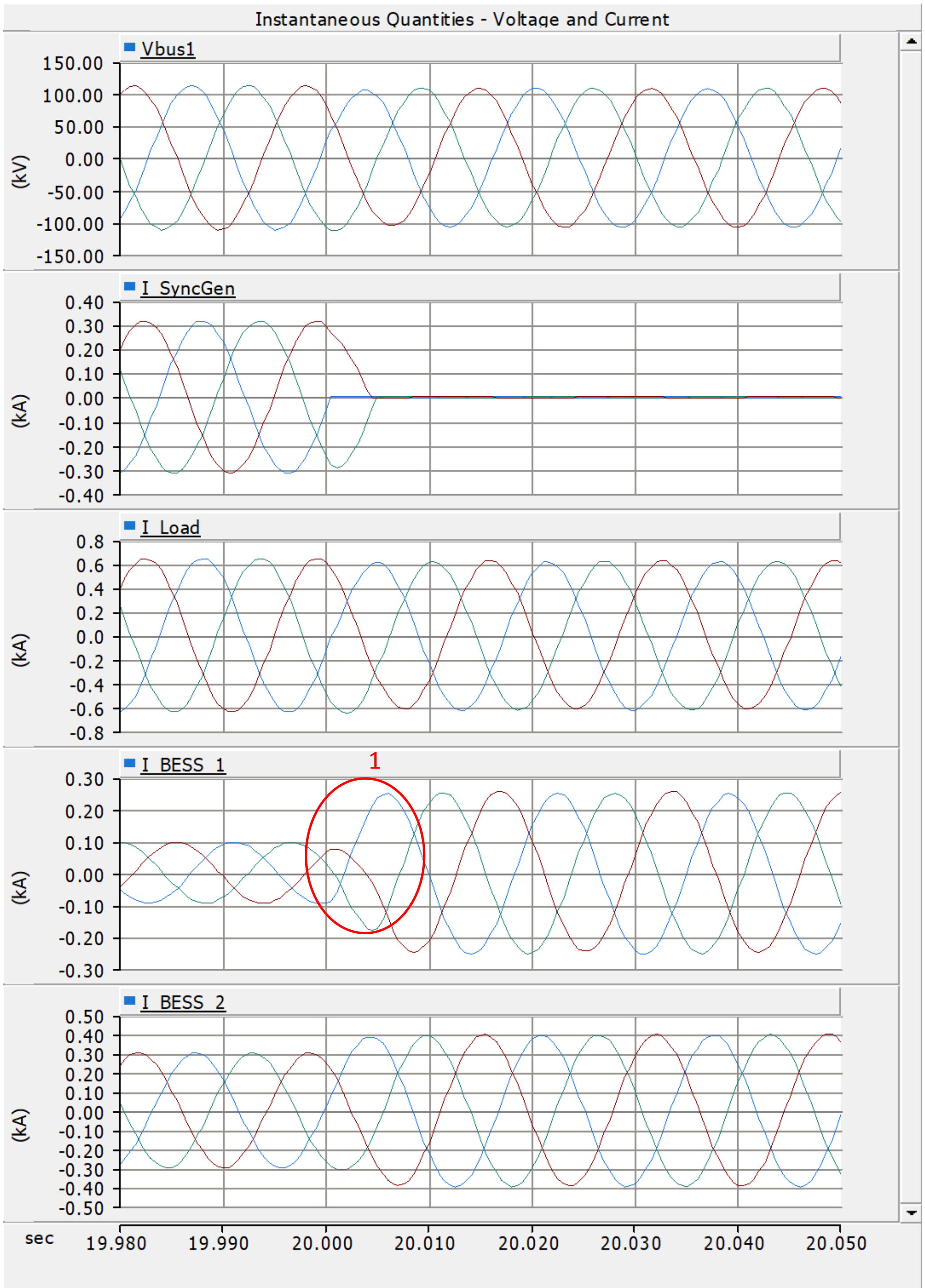

Figure 2.10: Test 3 Results – Instantaneous Quantities

As summarized below in **Table 2.7**, the model also passed Test 3.

Table 2.7: Evaluation of Test 3 Results	
Pre-Trip:	**Pass/Fail**
a. BESSs active power outputs match dispatched levels.	Pass
b. Synchronous generator active power output matches the rest of the load.	Pass
c. Frequency should be 1 pu.	Pass
d. Voltage at Bus 1 should be within 5% of nominal.	Pass
e. Phase voltage and current waveform should not be distorted.	Pass
f. There should not be oscillations in the RMS quantities.	Pass
g. Reactive power output from all devices should be within limits.	Pass
Post-Trip:	**Pass/Fail**
a. Immediately following the trip, BESS output should be well controlled. System frequency and voltage should not oscillate excessively or deviate from steady state levels for any significant amount of time.	Pass
b. Voltage settles to a stable~~, acceptable~~ operating point.	Pass
c. The final voltage is as expected based on the droop and deadband settings.~~Final voltage is within the tolerance of the droop and deadband settings.~~	Pass
d. Frequency settles to a stable~~, acceptable~~ operating point.	Pass
e. The final frequency is as expected based on the droop and deadband settings.~~Final frequency is within the tolerance of the droop and deadband settings.~~	Pass
f. Any oscillation shall be settled.	Pass
g. Any distortion observed in phase quantities should dissipate over time.	Pass
h. Active power from BESS 1 should move immediately to meet the load requirement and settle according to its frequency droop setting. Active power from BESS 2 should not exceed its max discharge power limit in steady state.	Pass
i. Reactive power from each BESS should move immediately and settle according to its voltage droop setting.	Pass

Illustration of GFM versus GFL Performance in Functional Tests

To illustrate the response of a grid following BESS for comparison with GFM, the same EMT model is put through Test 1 on the same test system *without* GFM functionality enabled. Note that frequency and voltage trip settings were widened to demonstrate the unstable behavior. **Figure 2.11** shows GFL failing Test 1 criteria and resulting in instability.

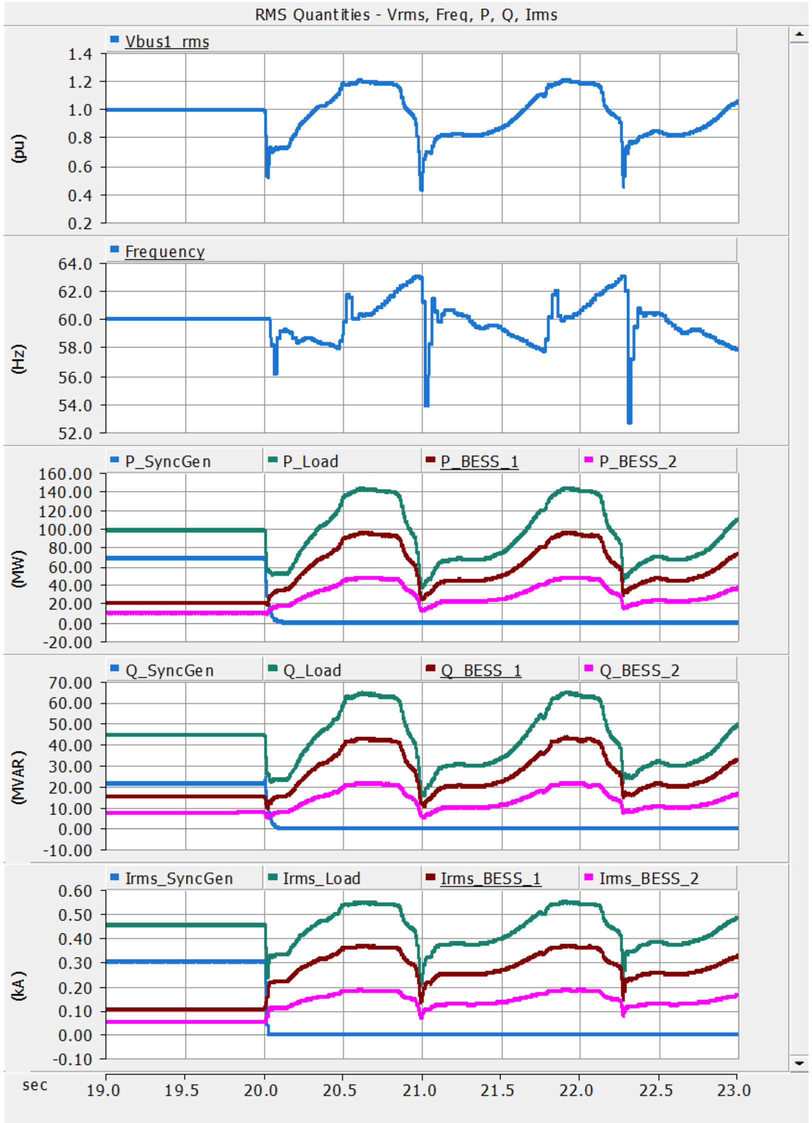

Figure 2.11: Test 1 Results with GFL

As summarized in **Table 2.8**, the BESS in GFL mode failed to settle to a steady state operating point, although the distortion in voltage and current waveforms are reasonable.

Table 2.8: Evaluation of GFL for Test 1	
Pre-Trip:	**Pass/Fail**
a. BESSs active power outputs match dispatched levels.	Pass
b. Synchronous generator active power output matches the rest of the load.	Pass
c. Frequency should be 1 pu.	Pass
d. Voltage at Bus 1 should be within 5% of nominal.	Pass
e. Phase voltage and current waveform should not be distorted.	Pass
f. There should not be oscillations in the RMS quantities.	Pass
g. Reactive power output from all devices should be within limits.	Pass
Post-Trip:	**Pass/Fail**

Table 2.8: Evaluation of GFL for Test 1	
a. Immediately following the trip, BESS output should be well controlled. System frequency and voltage should not oscillate excessively or deviate from steady state levels for any significant amount of time.	Fail
b. Voltage settles to a stable~~, acceptable~~ operating point	Fail
c. The final voltage is as expected based on the droop and deadband settings.	Fail
d. Frequency settles to a stable~~, acceptable~~ operating point	Fail
c. The final voltage is as expected based on the droop and deadband settings.	Fail
f. Any oscillation shall be settled.	Fail
g. Any distortion observed in phase quantities should dissipate over time.	Pass
h. Active power from each BESS should move immediately to meet the load requirement and settle according to its frequency droop setting.	Fail
i. Reactive power from each BESS should move immediately and settle according to its voltage droop setting.	Fail

Figure 2.12 and **Figure 2.13** are zoomed in versions of **Figure 2.11** to compare the GFL response (left) to GFM response (right). Notable differences include:

- Sub-cycle response in GFM current that GFL does not provide (see Point 1 in **Figure 2.12**)
- Fast active and reactive power response from GFM that GFL does not provide (see Point 2 in **Figure 2.13**)

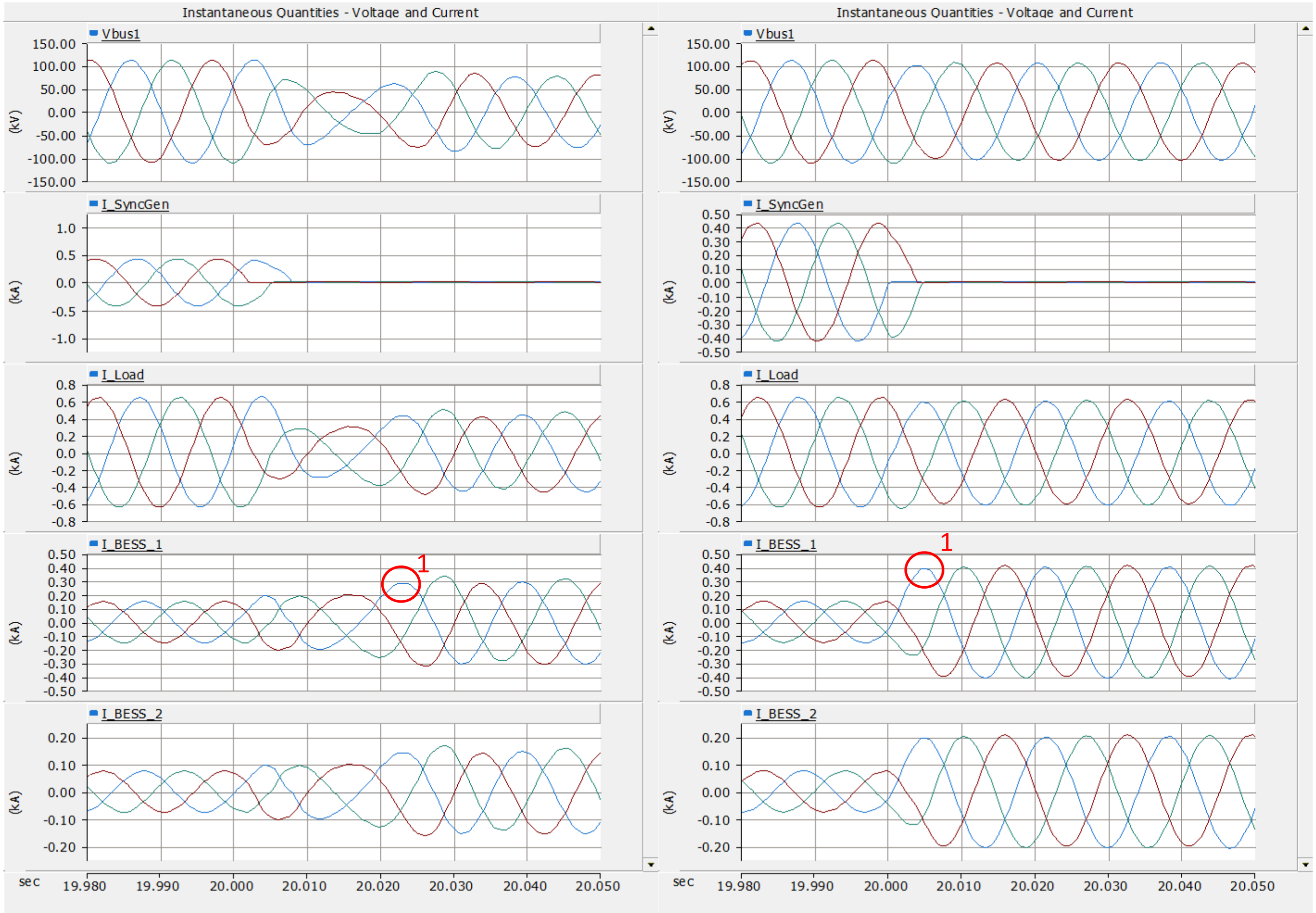

Figure 2.12: Comparison between GFL (Left) and GFM (Right) Responses – Instantaneous Quantities

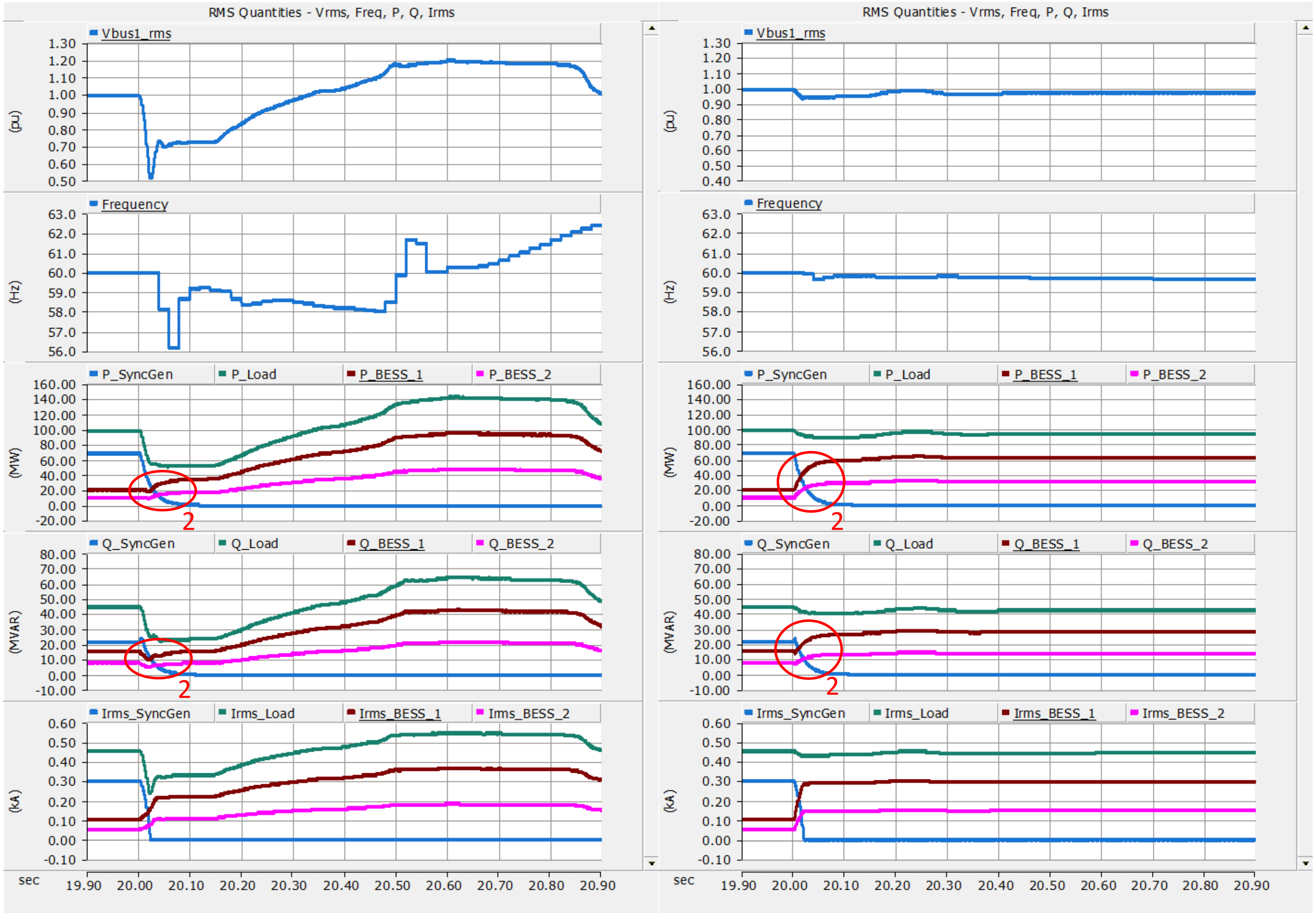

Figure 2.13: Comparison between GFL (Left) and GFM (Right) Responses – RMS Quantities

Appendix A: Industry Experience with GFM Integration

This appendix shares industry experience with integrating and operating GFM BESS technology on the BPS around the world.

Forum Network Technology/Network Operation (FNN) Guideline

The German FNN institute has published a guideline[50] on GFM behavior of HVDC systems and dc-connected power plant modules in 2020. The guideline is a supplement to VDE-AR-N-4131.[51,52] The FNN guideline describes the dynamic active power–frequency behavior and dynamic voltage control without reactive current specification. It consists of a conformity verification procedure for GFM resources, which includes methods for specifying the reference behavior, test description (networks and scenarios) as well as validation criteria. GFM resources are characterized with an immediate response and "network-stabilizing behavior" expected to counteract system events. This guideline includes tests that cover:

- Phase angle steps of 10 and 30 degrees
- Linear frequency change with 2 Hz/s ROCOF during 0.5 seconds
- Voltage magnitude step of 5% and 10% within normal operational ranges
- Grid distortion including the presence of negative sequence (2% unbalance in one phase), harmonics (including ranks 2, 5, 7, 19 and 31), and low frequency subharmonics (at 5, 10 and 15.9 Hz)
- Changes in the network impedance leading to short circuit ratio reductions from 20 to 5, from 5 to 2, and from 2 to 1
- Islanding in an active network, with only load or including another GFM converter

Conformity verification is based on time varying reference "envelopes" that can be applied to instantaneous value signals giving special attention to the initial behavior up to the first peak. These signals can be obtained from field measurements, electromagnetic transient (EMT) simulations, or hardware in the loop (HIL) simulations. Verification can include recalculated quantities to be determined over a certain time period such as active and reactive power. Conformity proof includes delivery of a technical verification report and a digital model with the installation manual and benchmark report.

Massive Integration of Power Electronic Devices (MIGRATE)

The European Union-funded MIGRATE project provides requirements for upcoming IBR-dominated power systems to maximize IBR penetration levels while maintaining stability and reliability.[53] In 2019, MIGRATE proposed high-level definition of GFM functions including:

- Behave as a voltage source
- Be synchronized with other grid forming sources
- Operate in standalone mode after seamless islanding
- Limit output current magnitude (preserving voltage source behavior and preferably avoiding control mode ~~switches~~ switching during voltage dips~~, for instance~~)

[50] VDE/FNN Guideline: Grid forming behavior of HVDC systems and DC-connected Power Plant Modules, August 2020: https://shop.vde.com/en/fnn-guideline-hvdc-systems-2

[51] VDE is the Europe's largest technical scientific associations Verband der Elektrotechnik

[52] Technical Connection Rule for the connection of HVDC systems and generation plants connected via HVDC systems

[53] PowerPoint-Präsentation (h2020-migrate.eu)

- Be compatible with all devices connected on the system, especially synchronous machines and GFL IBRs

Additionally, within this project a number of studies were carried out demonstrating compatibility of GFM IBRs with various control types operating in parallel in a ~~fully~~ 100% IBR system.

European Network of Transmission System Operators for Electricity (ENTSO-E) Report

ENTSO-E published *High Penetration of Power Electronic Interfaced Power Sources and the Potential Contribution of Grid Forming Converters*[54] defining seven properties of a GFM inverter:

- Creates system voltage (does not rely on being provided with firm clean voltage)
- Contributes to fault level (positive and negative sequence within first cycle)
- Contributes to total system inertia (limited by energy storage capacity)
- Supports system survival to allow effective operation of low frequency demand disconnection (LFDD) for rare system separations
- Controls act to prevent adverse control system interactions
- Acts as a sink to counter harmonics and inter-harmonics in system voltage
- Acts as a sink to counter unbalance in system voltage

While the MIGRATE definition focuses on capabilities regarding standalone operation and synchronization, the ENTSO-E paper adds a response deployment dimension.

Great Britain Grid Code GC0137

Grid Code change GC0137 *Minimum Specification Required for Great Britain GFM Capability*[55] was approved and published in February 2022. This grid code change was applied by National Grid Electricity System Operator (NGESO) to address grid stability issues arising from increasing penetration of IBRs. Although the requirements are non-mandatory, the provider of GFM IBRs will declare how much capability is available so that these GFM IBRs could be selected and remunerated for those capabilities through the market mechanism, which is still under development.[56] Successful implementation of this grid code would provide additional grid stability services by these GFM resources. To help relevant IBR stakeholders understand the GFM requirements, NGESO released the *GBGF Best Practice Guide*[57] in April 2023. GFM IBRs are expected to provide the same type of performance as synchronous generators to:

- Limit the rate of change of system frequency
- Inject instantaneous active power and instantaneous fast fault current into the grid
- Contribute to damping power
- Limit vector shift
- Contribute to synchronizing torque
- Contribute to voltage performance during a fault

GC0137 specifies the following minimum technical, design, and operational capability for GFM IBRs:

[54] https://euagenda.eu/upload/publications/untitled-292051-ea.pdf
[55] GC0137 Authority Decision (ofgem.gov.uk)
[56] https://www.nationalgrideso.com/industry-information/codes/grid-code/code-documents
[57] https://www.nationalgrideso.com/document/278491/download

- Withstand 2 Hz/sec ROCOF over a rolling 500 ms period
- Operate at a minimum short circuit level of zero MVA at the grid interconnection point
- Fast short circuit current injection ~~on both~~ with specified magnitude (typical 1 pu or 1.5 pu at zero voltage) and response speed (start in 5 ms and full in 30 ms)
- Active power responds to changes in the grid at bandwidths below 5 Hz to avoid ac system resonance problems
- Provide damping factor between 0.2 and 5.0

UK Stability Pathfinder

While a market for GFM capability is under development, NGESO needs some of the stability services such as improved system strength and inertia in certain locations today. Currently those are being procured through a series of tenders called Stability Pathfinder.[58] Phase 1 was only open to synchronous solutions and awarded to a number of synchronous condensers. Phase 2 was open to new technologies and five GFM BESS projects[59] were awarded in April 2022 with in-service dates between March 2024 and April 2026. These projects must comply with the requirements set forth in GC0137. Stability Pathfinder tenders are an exploratory temporary solution for broader procurement of stability services from a variety of capable technologies. NGESO is currently in the process of designing a market for new stability services, which will allow to them to procure additional stability services through a market mechanism.

Optimal System Mix of Flexibility Solutions for European Electricity (OSMOSE)

EU-funded project OSMOSE Deliverable 3.3 *Analysis of Synchronization Capabilities of BESS Power Converters*[60] was released in March 2022, defining GFM minimum technical ~~capabilities~~capability~~, technical~~ requirements ~~to formulate these capabilities,~~ and recommending to add these requirements into European-level and national grid codes. According to this specification, GFM resources~~units~~ shall within its rated power and current limits be capable of self-synchronization, standalone operation, and provide synchronization services. The GFM capabilities shall include:

- Standalone operation
- Synchronizing active power (in response to phase-jump)
- Inertial response (immediate active power output following a frequency change)
- System strength (immediate reactive power output in response to grid voltage variation)
- Fault current (immediate current output within installation capabilities following voltage dips, active/reactive current sharing during the first instances of the fault dependent on system impedance (not control action), during asymmetrical voltage dips prioritization between positive and negative sequence current can be defined by a system operator.)

The report proposed separating GFM resources into four types based on the capabilities shown in **Figure A.1**.

[58] https://www.nationalgrideso.com/future-energy/projects/pathfinders/stability
[59] Stability Phase 2 Master Results Final with Tech Type.xlsx (live.com)
[60] https://www.osmose-h2020.eu/wp-content/uploads/2022/04/D3.3-Analysis-of-the-synchronisation-capabilities-of-BESS-power-converters.pdf

- **Type 4:**
  - Services provided: Type 3 + **high fault current** (> 2 pu)
  - Criticality: if protection fail to detect faults
  - Cost: high for converters (oversizing), null for synchronous machines
- **Type 3:**
  - Services provided: Type 2 + **inertial response**
  - Criticality: when system inertia decreases system-wide
  - Cost: limited due to the need of an energy buffer from a few seconds to 1 minute
- **Type 2:**
  - Services provided: Type 1 + **synchronizing power**
  - Criticality: when system inertia decreases locally
  - Cost: very limited due to the need of an energy buffer < 1 s (other FFR resources can then take over)
- **Type 1**
  - Services provided: stand alone + system strength+ fault current (within ratings), wide range of SCR operation
  - Criticality: when system strength decreases locally
  - Cost: null, only software changes

Figure A.1: Type of Grid Forming Resources as proposed by OSMOSE project[61]

A delineation is made in the report between capabilities that can only be provided by GFM resources versus capabilities that can also be provided by GFL resources (e.g., power oscillation damping, provision of negative sequence current, phase jump withstand capability, harmonics mitigation). The paper defined synchronization services and concluded that due to criticality and geographic dependence, some of these services need to be required at the time of interconnection from all new large transmission-connected IBRs and some additional services should be required from new transmission-connected BESS. It was recognized that synchronous machines may be needed in the interim to provide additional short circuit current or, alternatively, higher overcurrent capability of IBRs can be incentivized.

UNIFI Consortium

The Universal Interoperability for Grid-Forming Inverters (UNIFI) Consortium is a US Department of Energy-funded effort to advance GFM technology. The consortium developed the first version of a set of specifications that outline plant- and unit-level performance requirements for GFM technologies.[62] These specifications are intended to facilitate the integration and seamless operation of GFM resources, particularly unifying their operation smoothly with synchronous generators. The purpose of the UNIFI specifications for GFM IBRs is to provide uniform technical requirements for the interconnection, integration, and interoperability of GFM IBRs of any size in electric power systems of any scale. These specifications establish functional requirements and performance criteria for integrating GFM IBRs in power systems at any scale which includes GFM devices used as the local load, in microgrid, distribution, and transmission system. These specifications cover all GFM technologies including, but not limited to: battery storage, solar PV, wind turbines, HVDC, STATCOM, UPS, supercapacitors, fuel cells, or other yet to be invented technologies. While each GFM resource have different ~~DC~~ dc-side and energy limitations, the specifications focus on the ac-side performance requirements.

This UNIFI specifications cover both normal and contingency operation conditions. Under normal operation conditions, performance requirements for GFM include (but are not limited to) autonomous voltage and frequency support of the grid, active and reactive power sharing, robust operation in low system strength grid, and mitigate

[61] Adapted from Carmen Cardozo's OSMOSE project presentation at 2022 ESIG GFM Workshop: https://www.esig.energy/event/2022-special-topic-workshop-grid-forming-ibrs/

[62] B. Kroposki, et. al, "UNIFI Specifications for Grid-forming Inverter-based Resources – Version 1," UNIFI Consortium, UNIFI-2022-2-1, December 2022 [Available at: https://sites.google.com/view/unifi-consortium/publications]

~~unbalancing~~ unbalanced ~~grid~~ voltage conditions~~operation support of~~. In contingency operation conditions, performance requirements for GFM include (but are not limited to) fault ride-through behavior, response to asymmetrical faults, response to phase jumps, and intentional islanding event. The requirements are considered to be the minimum capability from GFM resources; additional capabilities such as blackstart capability and short-term over current capability are also covered in the specifications.

ESIG Grid Forming White Paper and Workshop

The Energy Systems Integration Group (ESIG) published a technical report on GFM technology in March 2022.[63] The report covered the following topics

- GFM versus GFL inverter basic principles and an overview of types of GFM controls
- How BPS needs are changing with increasing penetrations of IBRs and the trade-offs between system needs and resource needs
- System services provided by GFM and technical requirements around the world, specifically around breaking the "chicken-and-egg" problem regarding deployment of GFM and requirements/incentives
- Advanced characterization and testing of GFM resources, including field tests
- Simulation tools needs (stability, analytics, economics, etc.) and the need for compatibility
- Recommendations for GFM technology moving forward

ESIG also held a technical workshop dedicated to GFM technology in June 2022, structured around steps needed to solve the "chicken-and-egg" issue around GFM technology deployment.[64] Topics addressed system operator experience with high shares of IBRs, OEMs with commercial GFM products, research and development in this space, and the low-hanging fruit of enabling GFM in BESS to provide core GFM capabilities (excluding high overcurrent and blackstart capability). Key points highlighted that commercial offerings for GFM BESS are already available today from multiple OEMs; however, the absence of clear GFM requirements is leading to customized site-specific applications that drive higher implementation costs. It was also recommended to distinguish between equipment specification/minimum capability requirements and system needs/services.

GFM BESS Projects around the World

BPS-connected GFM BESS are commercially available from different OEMs and projects are quickly growing around the whole world.[65] Some of the major GFM BESS projects are summarized here.

Kauai Experience

Kauai Island Utility Cooperative (KIUC) has had the BESS portion of a 13 MW ac-coupled solar PV+BESS plant operating in GFM mode since 2018, which is a significant portion of the 70 MW system peak load. Field experience has shown the plant to operate stably during grid disturbances while providing instantaneous response to frequency and voltage events, helping to avoid~~ing~~ load shedding and possible system outages.

Since April 2022, portions of a second solar PV+BESS plant on Kauai were converted to GFM mode. The second plant is a 14-MW dc-coupled solar PV+BESS plant that uses a different GFM control technique than the first plant. As of August 2022, the second plant now has all inverters in GFM mode. No adverse interactions between the two GFM plants have been observed in the field to-date.[66]

[63] https://www.esig.energy/grid-forming-technology-in-energy-systems-integration/
[64] https://www.esig.energy/event/2022-special-topic-workshop-grid-forming-ibrs/
[65] ESIG-GFM-batteries-brief-2023.pdf
[66] https://www.youtube.com/watch?v=2e5ET0L1j5g

Both GFM plants have been shown to operate stably at all hours of the day, including times when the system is dominated by synchronous generation and times when it is dominated by inverter-based generation (including one other 30 MW GFL solar PV+BESS plant, three other large (6–12 MW) solar PV plants and about 45 MW of aggregate behind-the-meter solar PV). System inertia constant ranges from about 0.5 MW-s/MVA to 2.7 MW-s/MVA (using total online capacity as the MVA base), and the percent of generation from IBRs ranges from about 6% to 95%. KIUC intends to continue operating both plants in GFM mode going forward and may add additional GFM generation in the future.

No EMT model of the KIUC system was available at the time of either of the two GFM plants' commissioning, so EMT studies were not conducted; instead, issues were addressed by monitoring the plants' performance in the field and working with the plant owners to make control parameter adjustments where necessary. Digital fault recorder data has been crucial for plant performance monitoring. The inverter model for the second plant described was tested extensively at NREL in partnership with the plant owner prior to commissioning and again prior to conversion to GFM.

HECO Experience

Hawaiian Electric (HECO) conducted extensive EMT studies of GFL and GFM solar PV+BESS and stand-alone BESS plants.[67] Studies showed that GFM controls are crucial to stability of the HECO system in the near future.[68] The first GFM plant in HECO is expected to come online in 2023 with several more to follow in subsequent years. As part of HECO's preparation, they also worked with NREL to test a 2.2 MVA BESS inverter's performance by using power hardware-in-the-loop (PHIL) simulation to connect it to a real-time EMT simulation of Maui's near-future transmission system.[69] The commercially available inverter tested at NREL can operate in GFM or GFL mode. It was used to represent a planned 30 MVA facility. The PHIL tests established that with the hardware inverter in conventional GFL mode, the Maui transmission system is unstable in certain very low inertia dispatch scenarios. They then demonstrated that with the inverter in GFM mode, the system is stable and resilient to a severe fault and an N-1 generation trip for several dispatch scenarios, including a zero inertia (zero synchronous machine) scenario.[70] This study also indicated that, for the Maui system, approximately 30% of online generation capacity needs to be GFM to maintain adequate damping.[71]

Australia Experience

The Australian Energy Market Operator (AEMO) published *Application of Advanced Grid-Scale Inverters in NEM* in August 2021,[72] describing GFM technology and application in the National Electricity Market (NEM). The Dalrymple BESS (30 MW/8 MWh) was the first transmission-connected GFM project in the NEM.[73] The South Australia Hornsdale Power Reserve (HPR) BESS plant has been upgraded from GFL to GFM control with the capabilities of providing grid inertia service[74] in July 2022. The HPR project is described below in more detail. Lastly, development of GFM BESS in Australia continues with BESS plants in New South Wales including:[75]

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67 https://dms.puc.hawaii.gov/dms/DocumentViewer?pid=A1001001A21F14B62327F00172

68 http://www.hawaiianelectric.com/documents/clean_energy_hawaii/selling_power_to_the_utility/competitive_bidding/20211015_exhibit_8_S3_hawaii_model_ESPA.pdf

69 Power HIL Validation of a MW-Scale Grid-Forming Inverter's Stabilization of Otherwise Unstable Cases of the Maui Transmission System (nrel.gov)

70 https://www.nrel.gov/docs/fy22osti/83545.pdf

71 On the HECO systems, additional GFM capacity may be needed to account for possible momentary cessation of GFL generation during transmission faults, which can cause voltage dropping very low in the whole system wide. This conclusion may not apply to the other larger systems where a fault does not reduce voltage system wide.

72 https://aemo.com.au/-/media/files/initiatives/engineering-framework/2021/application-of-advanced-grid-scale-inverters-in-the-nem.pdf

73 Dalrymple ESCRI-SA Battery Project – ElectraNet

74 https://www.pv-magazine-australia.com/2022/07/27/hornsdale-big-battery-begins-providing-inertia-grid-services-at-scale-in-world-first/?utm_source=dlvr.it&utm_medium=linkedin

75 Upgrade at Tesla Battery Project Demonstrates Feasibility of 'Once-In-A-Century Energy Transformation' for Australia - World-Energy

- Wallgrove GFM BESS by Tesla (50MW/75MWh): Transgrid began commercial operation in December 2022.
- Broken Hill BESS: AGL Energy is commissioning a 50MW/50MWh GFM BESS, construction started in fall 2022 with expected in-service date is mid-2023.
- Riverina and Darlington Point Energy Storage System: Edify Energy secured financing for three Tesla GFM BESS[76] projects (with total capacity of 150MW/300MWh)
- New England BESS: ACEN has started construction of 50MW/50 MWh GFM BESS in spring 2022 with expected completion date of 2023.[77]
- On December 17, 2022, the Australian Renewable Energy Agency (ARENA) announced co-funding of additional eight large scale GFM batteries across Australia with total project capacity of 2 GW/4.2 GWh, to be operational by 2025.[78]

Hornsdale Power Reserve (HPR) Experience

The HPR BESS project (150MW/193.5MWh) upgraded from GFL to GFM control to enhance grid stability. The process involved four phases, including:

- **Phase 1 – GFM control testing and benchmarking on PSCAD model and HIL:** ~~One~~ functional behavior of the upgraded GFM control is shown on a single machine infinite bus (SMIB) testing system. The GFM control performance~~s~~ of PSCAD model are well benchmarked with HIL using a variety of disturbance tests. The benchmark results of virtual inertial response test is shown in Figure A.2.

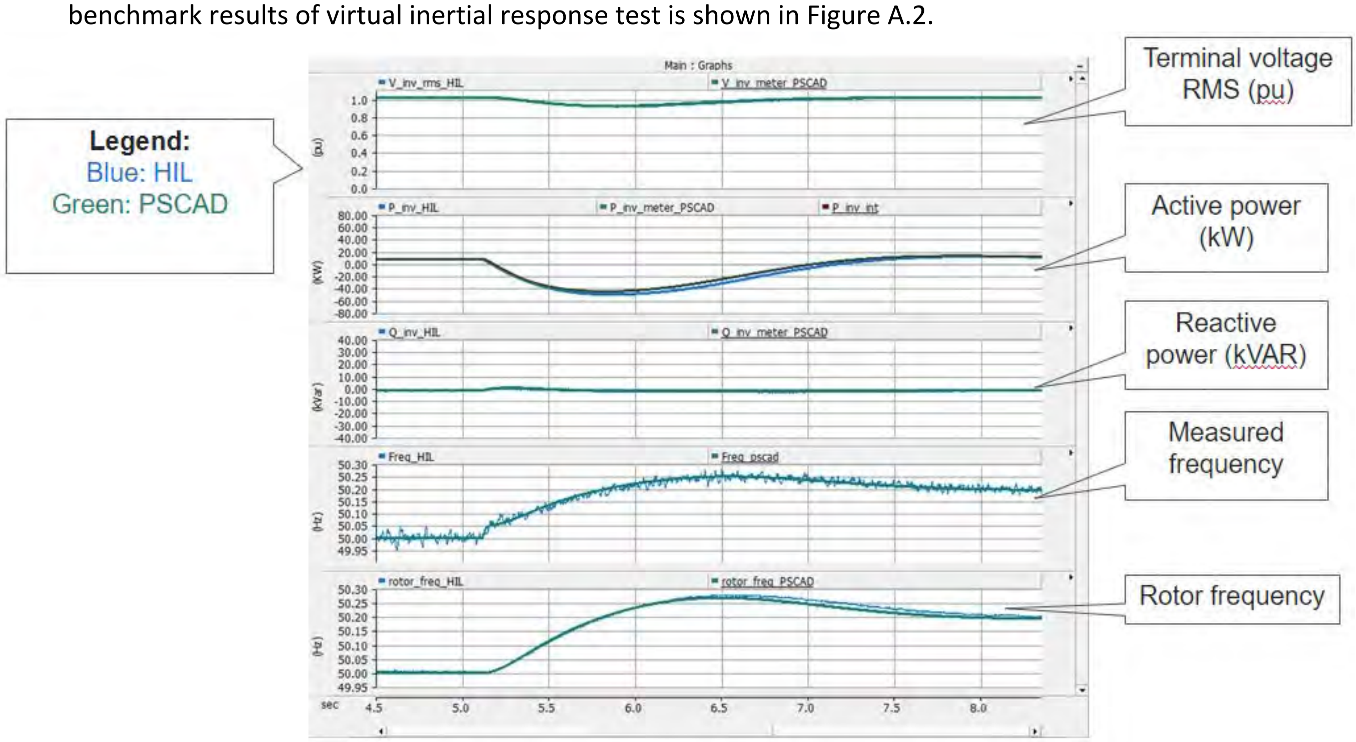

Figure A.2: PSCAD model and HIL (Hardware-in-loop) benchmarking

- **Phase 2 – Trialed GFM control mode at 2 out of 294 inverters at the HPR plant:** The two test inverters were upgraded with the actual GFM firmware while the rest of 292 inverters ~~ran on~~ operated with grid following controls. This verified the different GFM and GFL control responses for the same disturbance. **Figure A.3** and **Figure A.4** show the GFL and GFM active power response, respectively, to the change in frequency. The GFM

[76] https://edifyenergy.com/energy-storage-systems/financial-close-on-the-largest-approved-grid-forming-battery/
[77] https://www.pv-magazine-australia.com/2022/05/26/acen-commences-construction-of-new-england-big-battery/
[78] https://arena.gov.au/news/arena-backs-eight-grid-scale-batteries-worth-2-7-billion/

control contributes maximum power earlier than the GFL control, which is important to support the frequency nadir and avoid underfrequency load shedding. This test shows GFM controller has faster response for overfrequency as well.

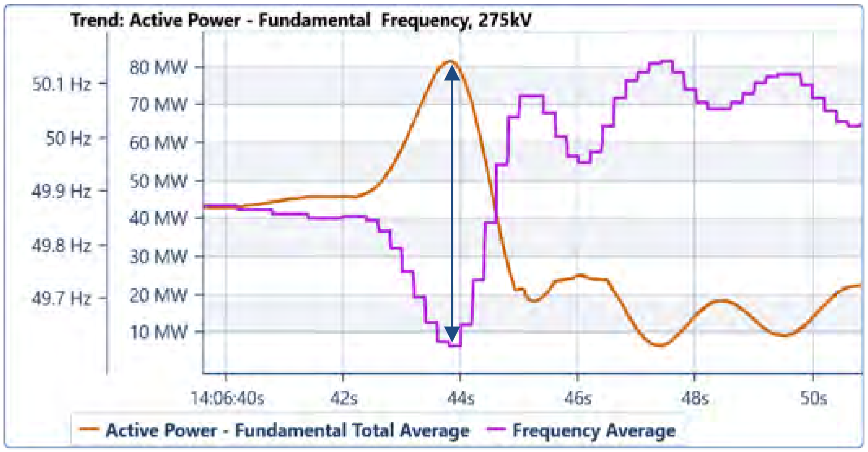

Figure A.3: GFL ~~IBR~~ Inverters'Response to Frequency Event

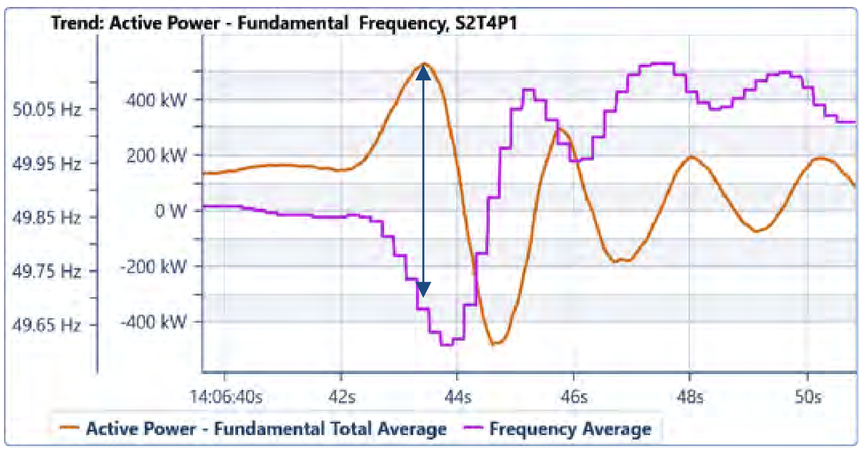

Figure A.4: GFM Inverters' ~~IBR~~ Response to Frequency Event

- **Phase 3 – A new system interconnection study was performed under national electricity rule NER 5.3.9:**[79] This required to prove that the grid performance of the new grid forming resource is similar or better than the previous grid following resource. The HPR plant virtual kinetic inertial support (2000 MW.s) for South Australia was validated[80] and it was noted grid forming BESS help improve system damping.
- **Phase 4 – After studies were approved, GFM controls were enabled for all inverters at the site:** The HPR GFM plant performance~~s~~ ~~are~~ is verified with the recorded site Elspec data which are also used to validate BESS PSCAD model. The site Elspec data performance and PSCAD model validation for a voltage dip are shown in **Figure A.5**. The HPR plant GFM controls provide damping to power oscillations and inertial energy to limit grid ROCOF and also provide voltage support ~~from~~ by sub-cycle current injection when the voltage waveform changes at the inverter terminals.

[79] NER Rule 5.3: Establishing or Modifying Connection - AEMC Energy Rules
[80] hornsdale-power-reserve-virtual-machine-mode-testing-summary-report.pdf (arena.gov.au)

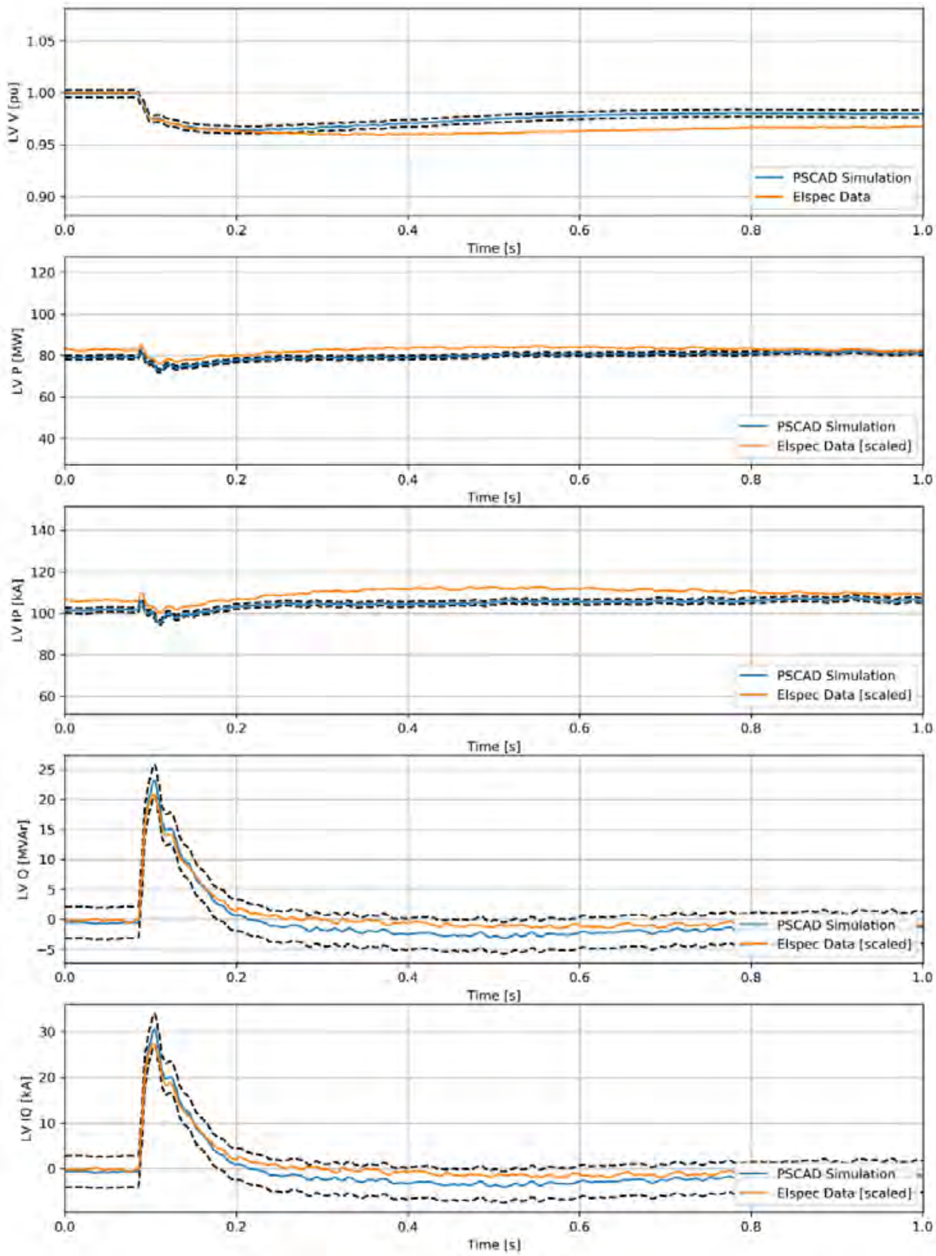

Figure A.5: Response from the HPR GFM plant inverter during voltage disturbance on the grid

Appendix B: Example of GFM Functional Test with Different OEM

To demonstrate diversity in commercially available GFM technologies, ~~and~~ potential differences in their controls and corresponding responses, the GFM functional tests described in Chapter 2 were repeated with a different GFM BESS model provided by another OEM, using the same initial condition and droop parameters. Despite the differences in their dynamic behavior, both OEMs' BESS EMT models passed all three verification tests and are verified to be GFM. Tests results are shown below in Figure B.1 – B.3.

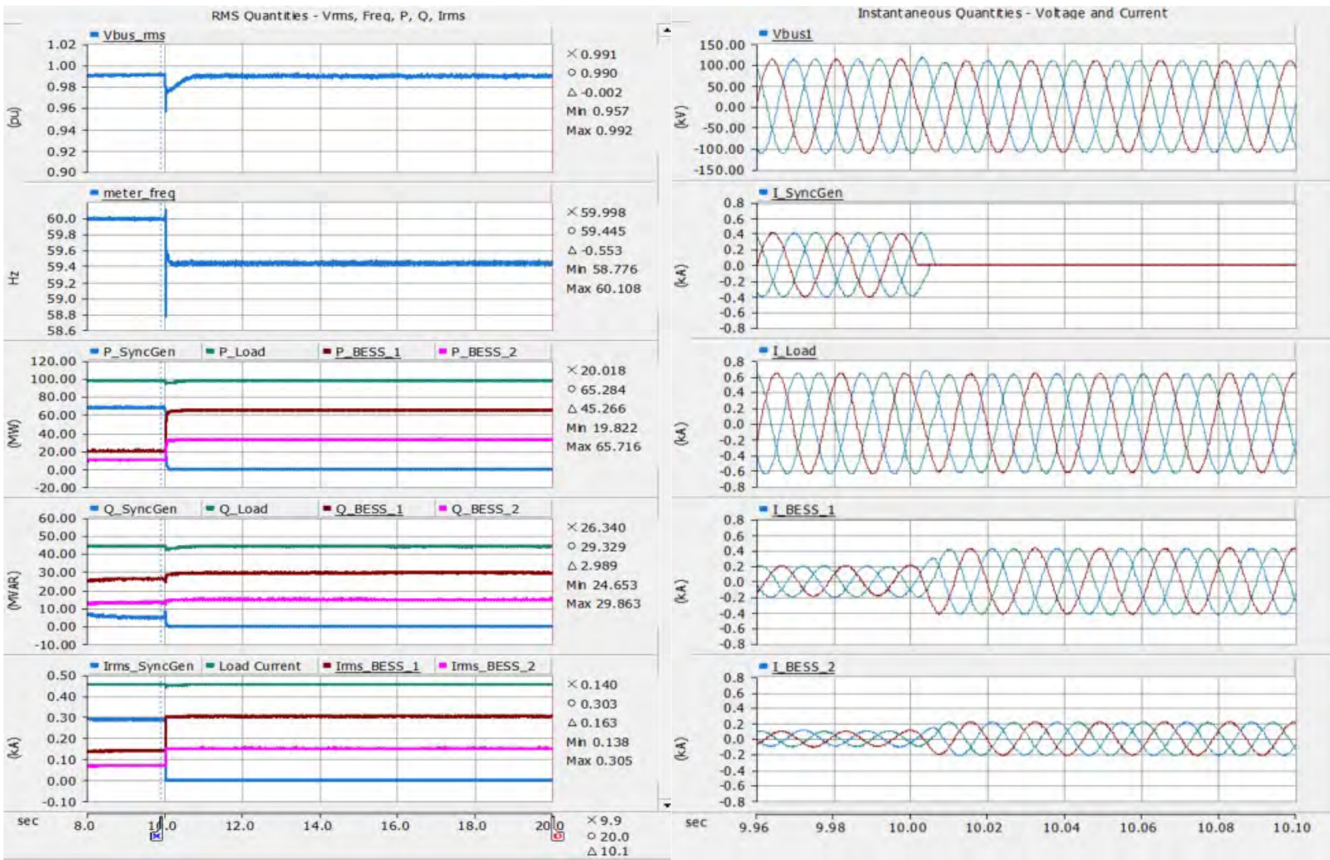

Figure 1 Test 1 Results with Different GFM Model

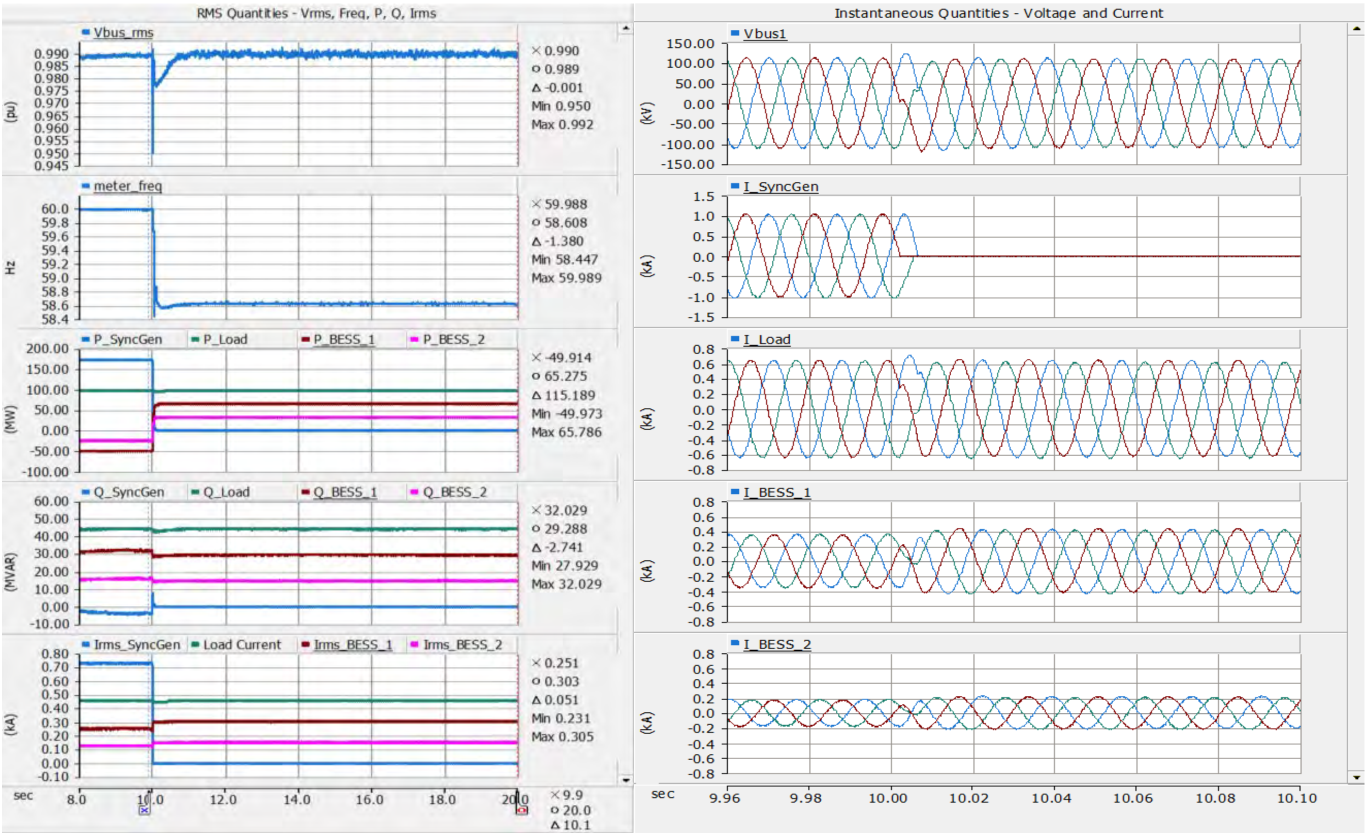

Figure 2: Test 2 Results with Different GFM Model

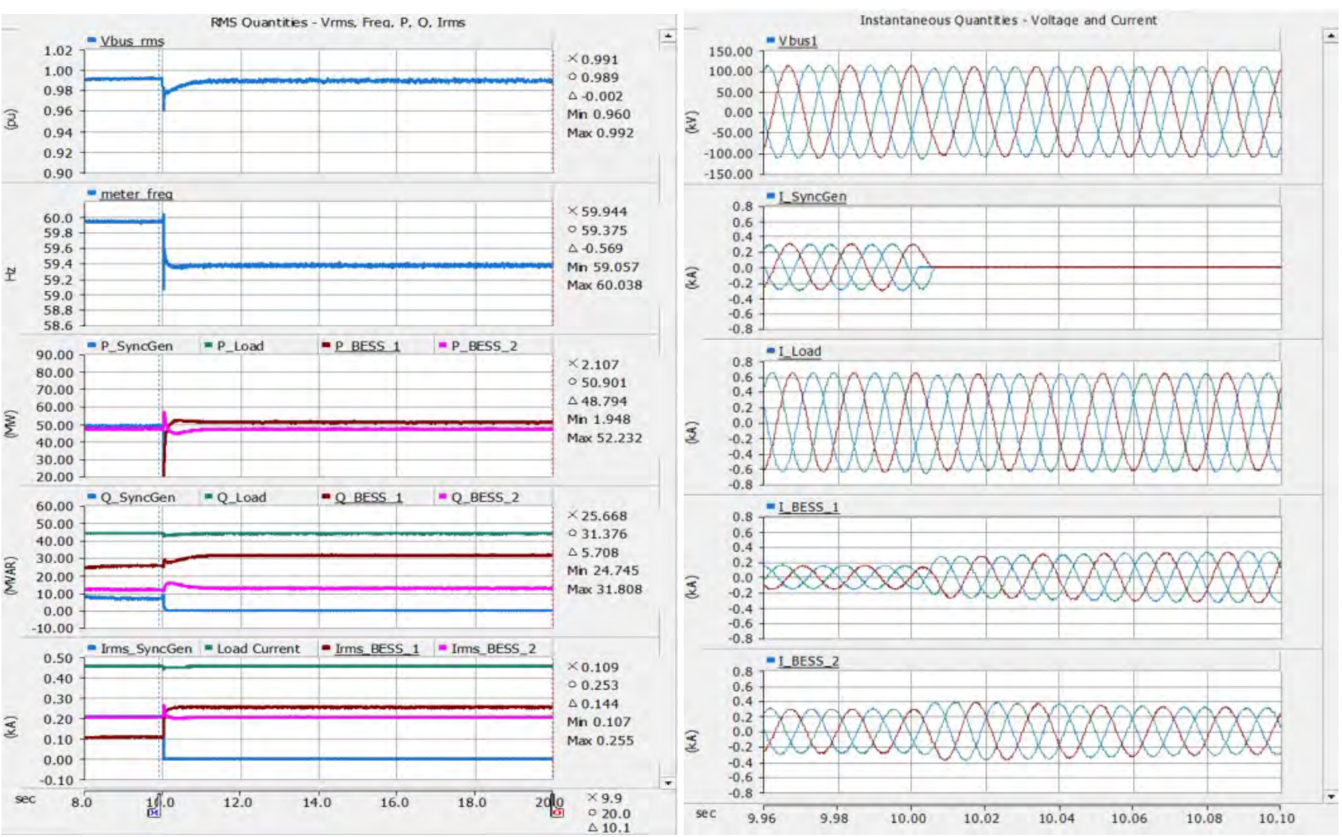

Figure B.3: Test 3 Results with Different GFM Model

Appendix C: Acknowledgements

NERC gratefully acknowledges the invaluable contributions and assistance of the following industry experts in the creation of this paper.

Name	Company
Andy Hoke	National Renewable Energy Laboratory
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Lucas Meubrink	SMA Solar Technology AG
Allan Montanari	SMA Solar Technology AG
Deepak Ramasubramanian	Electric Power Research Institute
Li Yu	Hawaiian Electric
Wei Du	Pacific Northwest National Laboratory
Nilesh Modi	Australian Energy Market Operator
Siddharth Pant	General Electric Company
Sam Maleki	Electric Power Engineers, LLC
Jimmy Zhang	Alberta Electric System Operator
Brad Rockwell	Kaua'i Island Utility Cooperative
Cameron Kruse	Kaua'i Island Utility Cooperative
Hongtao Ma	North American Electric Reliability Corporation
Ryan Quint	North American Electric Reliability Corporation
Alex Shattuck	North American Electric Reliability Corporation
Aung Thant	North American Electric Reliability Corporation

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Development of

White Paper: Grid Forming Functional Specifications for BPS-Connected Battery Energy Storage Systems

IRPS – Work Plan # 22
NERC
March 2023

RELIABILITY | RESILIENCE | SECURITY




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NERC IBR Strategy

Risk Analysis
- Event Analysis
- Disturbance Reports
- Alerts
- Lessons Learned

Interconnection Process Improvements
- Improvements to GIAs and GIP
- Enhanced Interconnection Requirements
- Modeling and Study Improvements
- IEEE 2800-2022

Best Practices and Education
- Reliability Guidelines
- Webinars and Workshops
- Outreach and Engagement
- Emerging Reliability Risk Issues

Regulatory Enhancements
- NERC Standards Projects
- BES Definition Review
- Inverter-Specific Requirements and Standards
- Risk-Based Compliance

White Paper Background

- White Paper: Grid Forming Functional Specifications for BPS-Connected Battery Energy Storage Systems
  - Follow up on a previous Grid Forming (GFM) white paper that was published in 2021
  - Provides functional specifications for Transmission Owners (TOs), Transmission Planners (TPs), and Planning Coordinators (PCs) to reference when establishing interconnection requirements
  - Provides information on currently in-service GFM resources and examples of GFM specifications, requirements, and grid codes currently in-use internationally
  - Includes recommendations to be utilized by TP and PC to implement GFM testing and to promote the interconnection of GFM resources
  - This white paper has undergone IRPS comment and numerous revisions were made to the address comments received. Changes made in the redline document are technical in nature and this white paper is currently undergoing non-substantive, editorial review through NERC Publications.

Industry Comments

- Comments from over 20 organizations
  - Multiple organization comments included multiple reviewers
- IRPS drafting subgroup met numerous times to address the comments
- General themes of the comments:
  - Clarification was needed for various aspects regarding the GFM functional tests
  - Clarification was needed regarding functional specifications
  - Clarification was needed regarding how GFM features will function when resources are near equipment limits
  - Additional tests may be needed to meet specific regional needs
- IRPS drafting subgroup made numerous revisions to address these comments

Action

- IRPS is seeking RSTC approval for this white paper

Questions and Answers

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

Action
Approve

Background
The Inverter-Based Resources Performance Subcommittee (IRPS) has reviewed the industry comments on revising the Reliability Guidelines: Performance, Modeling, and Simulations of BPS-Connected Battery Energy Storage Systems and Hybrid Power Plants.

IRPS has revised the guideline incorporating industry feedback, including a recommendation to refer to the relevant and specific sections in the IEEE standard for more information regarding quantitative technical minimum performance requirements.

Summary
IRPS is seeking RSTC approval of the revised guideline.

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

~~Reliability Guideline~~

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

~~June 2023~~

~~RELIABILITY | RESILIENCE | SECURITY~~

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Reliability Guideline

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

June 2023

Table of Contents

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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, resilient, 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 made up of six ~~RE~~Regional Entity boundaries as shown in the map and corresponding table below. The multicolored area denotes overlap as some load-serving entities participate in one ~~RE~~Regional Entity while associated Transmission Owners ~~(TOs)/~~/Operators~~ (TOPs)~~ 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 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 nor are they Reliability Standards; 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.

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~~Metrics~~

~~Pursuant to the Commission's Order on January 19, 2021, *North American Electric Reliability Corporation*, 174 FERC ¶ 61,030 (2021), reliability guidelines shall now include metrics to support evaluation during triennial review, consistent with the RSTC Charter.~~

~~Baseline Metrics~~

- ~~Performance of the BPS prior to and after a reliability guideline, as reflected in NERC's State of Reliability Report and Long Term Reliability Assessments (e.g., Long Term Reliability Assessment and seasonal assessments);~~
- ~~Use and effectiveness of a reliability guideline as reported by industry via survey; and~~
- ~~Industry assessment of the extent to which a reliability guideline is addressing risk as reported via survey.~~

~~Specific Metrics~~

~~The RSTC or any of its subcommittees can modify and propose metrics specific to the guideline in order to measure and evaluate its effectiveness.~~

- ~~Review of the number of category 1i events[1] involving utility-scale battery energy storage systems and hybrid inverter-based resources under the NERC Event Analysis program~~

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~~[1] Reference to the latest ERO EAP doc~~

Executive Summary

Interconnection queues across North America are seeing a rapid influx of requests for battery energy storage systems (BESS) and hybrid power plants.[2] While there are different types of energy storage technologies, BESS are experiencing a rapid increase in penetration levels due to favorable economics, policies, and technology advancements.[3] Similarly, BESS are most commonly being coupled with inverter-based generating resources, such as wind and solar photovoltaic (PV). Therefore, BESS and inverter-based hybrid power plants are the primary focus of this reliability guideline.

NERC previously published reliability guidelines that provided recommended performance and improvements to interconnection requirements and planning processes for newly interconnecting inverter-based resources; however, BESS and hybrid power plants were not specifically addressed in detail and 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. The reliability guideline presented here provides guidance, clarifications, and considerations not previously covered in the previous reliability guidelines, focusing specifically on BESS and hybrid power plants. This document also contains guidance for TOs, TPs, and PCs to further enhance their interconnection requirements and study processes for BESS and hybrid power plants.

The recommendations in this guideline should apply to all BPS-connected BESS 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 BESS and hybrid plants) is important for reliable operation of the North American BPS. TOs are encouraged to incorporate the recommended performance characteristics into their interconnection requirements per NERC FAC-001, and TPs and PCs are encouraged to incorporate the recommended modeling and studies approaches into their interconnection processes per NERC FAC-002.

This reliability guideline includes the recommended performance of BPS-connected BESS and hybrid power plants that all Generator Owners (GOs) and developers seeking interconnection to the BPS should consider. 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 BESS and hybrid power plants both in the interconnection study process, annual planning process, and for any specialized studies needed to ensure BPS reliability.

[2] 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 POI."

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

High-Level Recommendations

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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. Table ES.1 provides a set of high-level recommendations (categorized by performance, modeling, and studies) and their applicability[4] that encompass all aspects of the guidance contained throughout this reliability guideline.

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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 BESS and hybrid plants and should not be limited to only BES facilities. Many newly interconnecting BESS 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:** GOs of existing or newly interconnecting BESS 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 BESS and hybrid power plants should work closely with their respective TOs, Balancing Authorities, Reliability Coordinators (RCs), TPs, and PCs to ensure all entities have an understanding of the operational capabilities and limitations of the facilities being interconnected. BESS and hybrid plant developers, in coordination with equipment manufacturers, should also use the recommendation provided herein regarding BESS/hybrid plant performance when designing new facilities.	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 BESS and hybrid power plants. TPs and PCs should ensure that their modeling requirements include clear specifications for BESS 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 BESS 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. Capabilities like grid forming technology, operation in low short-circuit networks, the ability to provide primary and fast frequency response (FFR), and other functions more readily available in these new technologies should be fully utilized (as needed) and are essential reliability services (ERSs) for the BPS.	TOs, TPs, PCs, BAs, RCs, GOs, GOPs, developers, equipment manufacturers

[4] The applicability column for each of the recommendations made is solely intended to provide guidance for which entities are referenced in the recommendation (and should consider the recommendation made in their business practices).

Table ES. 1: High-Level Recommendations for BESS and Hybrid Plant Performance, Modeling, and Studies		
#	Recommendation	Applicable Entities
M1	**Models Matching As-Built Controls, Settings, and Performance:** All BESS and hybrid plant GOs (in coordination with the developer and equipment manufacturers) should ensure that the models used to represent BESS and hybrid power plants accurately represent 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. GOs should also provide updated models to the TP and PC that reflect as-built settings and controls after plant commissioning. The TP and PC should study any modifications to equipment settings that have an impact on the electrical performance of the equipment prior to changes being made, per the latest effective version of NERC FAC-002. 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 the 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
M2	**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"[5] 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. 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 methodologies for both interconnection studies and annual planning studies to ensure they are appropriate for a BPS with significantly more BESS 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

[5] "Real code" models are a type of black box model that implement the actual control code from the equipment. The real-code aspects of the model pertain mainly to the controller-related code in the turbine controls, inverter controls, protection and measurement algorithms, and plant-level controller.

Table ES. 1: High-Level Recommendations for BESS and Hybrid Plant Performance, Modeling, and Studies		
#	**Recommendation**	**Applicable Entities**
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. BESS 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

~~Background~~

~~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*,[6] 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 United States 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 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.[7]~~

~~Areas across North America are also seeking low-carbon power systems. For example, California requires[8] 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 by the end of 2045. 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[9] and is projected to have 55,000 MW of new storage by 2045.[10] At the same time, the risk and impact of wildfires in the area is leading California utilities, policymakers, and end-use customers toward more close consideration for grid resilience and flexibility. Energy storage systems, particularly BESS, and BESS 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, BESS 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.[11] California recently approved a proposed 1,500 MW battery at Moss Landing.[12] Southern California Edison currently has several hundred megawatts of BESS deployed in their region with much more in their interconnection queue.[13] **Figure B.1** shows a cursory review of the CAISO interconnection queue (captured in early 2020), where most new interconnection requests are either stand-alone BESS or hybrid plants that consist mainly of solar PV or wind combined with a BESS component. Elsewhere, in ERCOT there are over 1,500 MW of BESS are under construction and 7,500 GW more in advanced development.[14] These types of interconnection requests are observed across North America, and these newly connecting resources will need to operate reliably to provide ERSs and be modeled appropriately. They will also need be studied as part of the interconnection study process.~~

~~[6] U.S. Energy Information Administration (EIA), "Annual Energy Outlook 2020 with projections to 2050," Jan. 2020. [Online]: https://www.eia.gov/outlooks/aeo/pdf/aeo2020.pdf.~~

~~[7] 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.~~

~~[8] California Senate Bill No. 100: https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201720180SB100.~~

~~[9] https://www.cpuc.ca.gov/General.aspx?id=3462.~~

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

~~[11] https://www.lspower.com/ls-power-energizes-largest-battery-storage-project-in-the-world-the-250-mw-gateway-project-in-california-2/~~

~~[12] 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/~~

~~[13] https://www.edison.com/home/innovation/energy-storage.html~~

~~[14] https://insight.factset.com/ercot-battery-dynamics-set-to-follow-caiso-trends~~

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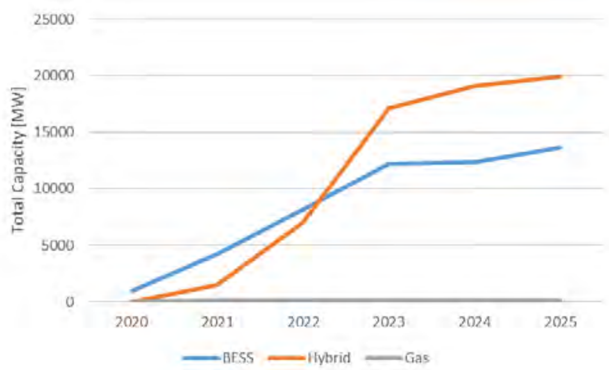

~~Figure B.1: Review of CAISO Interconnection Queue for Hybrid Resources and BESS~~

~~Generation interconnection queues are currently inundated with requests for new interconnections of BESS 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 BESS were primarily proposed for energy arbitrage and mitigating renewable resource variability, there has been more recent interest in installing BESS for broader services as a generating resource or even as a source of transmission services such as voltage support under "storage as transmission facility"[15] programs. Therefore, it is imperative to have clear guidance on how BESS and hybrid power plants should perform when connected to the BPS and also to have recommended practices for modeling and studying BESS 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.[16]~~

~~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 BESS and hybrid plants are considered inverter-based resources.~~

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~~15 https://cdn.misoenergy.org/20190109%20PAC%20Item%2003c%20Storage%20as%20a%20Transmission%20Asset%20Phase%20I%20Proposal%20(PAC%20004)307822.pdf~~

~~16 Other types of studies such as harmonics and geomagnetic disturbance studies are outside the scope of this guideline.~~

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Introduction

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:[17]

- **Battery Energy Storage:** There are many types of BESS: lithium-ion, nickel-cadmium, sodium sulfur, redox flow, and others.[18] 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 that 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 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.[19]
- **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 that can then be converted back to electric energy by using a steam turbine.[20] 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 contains 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 or ultracapacitors are high-power electrostatic devices with fast charging and discharging capability (on the order of 1–10 seconds) and low energy density. No chemical reactions occur during charging and discharging, so these units have 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

[17] https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/Master_ESAT_Report.pdf
[18] https://energystorage.org/why-energy-storage/technologies/solid-electrode-batteries/
[19] https://energystorage.org/why-energy-storage/technologies/hydrogen-energy-storage/
[20] https://www.siemensgamesa.com/products-and-services/hybrid-and-storage/thermal-energy-storage-with-etes

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- Providing ERSs like 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). The interactions that BESS and hybrid plants have with the BPS is the primary focus of this guideline, and the guidance provided also covers ways that industry can model and study these resources connecting to the BPS.

Fundamentals of Hybrid Plants with BESS

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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 follows:

- **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 POI.

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There are many types of hybrid power plants that combine synchronous generation, inverter-based generation, and energy storage systems;[21] 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.[22] Due to this fact, this guideline concentrates primarily on hybrid plants combining renewable (specifically inverter-based) generation with BESS technology.

The conversion of dc to ac current occurs at the power electronics interface. However, the way this conversion occurs within a hybrid plant affects how the resource interacts with the BPS, its ability to provide ERSs, 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.1~~Figure I.1 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.2~~Figure I.2 shows a simple illustration of another 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).[23] There are multiple 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.[24]

[21] Such as natural gas and BESS hybrid plants, combined heat and power with BESS, or multiple types of inverter-based generation technologies.
[22] Note that hybrid natural gas-BESS plants may be desirable in some areas where capacity shortages have been identified.
[23] 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
[24] https://www.dynapower.com/products/energy-storage-solutions/dc-coupled-utility-scale-solar-plus-storage/

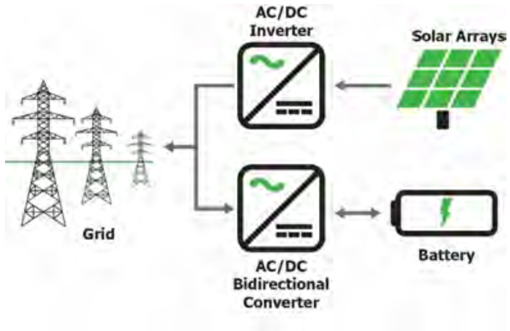

Figure I.~~1:~~.1: Illustration of AC-Coupled Hybrid Plant

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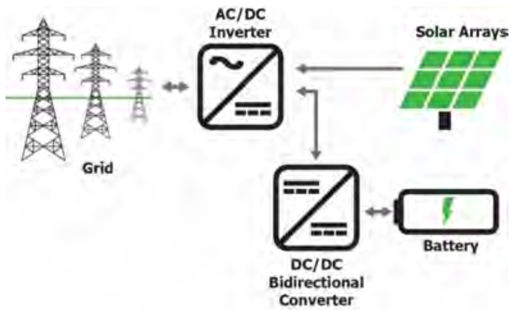

Figure I.~~2:~~.2: Illustration of DC-Coupled Hybrid Plant

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 BESS with renewable energy generating resources, including but not limited to the following:[25]

- **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.

[25] The benefits noted are also generally applicable to stand-alone energy storage devices such as BESS; 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.

- **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 BESS) 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 and enables it to continue operating when the generating resource output decreases.
- **Frequency Response Capability:** Adding energy storage to a renewable facility increases the ability of the plant to respond to underfrequency events while still operating the renewable component at maximum available power (given appropriate interconnection practices and agreements) as well as bringing some certainty to providing this service. Addition of battery storage to a synchronous generator facility may also allow the hybrid plant to provide FFR.[26] The energy storage component can initially charge or discharge rapidly, delivering initial performance of FFR, 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.

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[27] are differentiating co-located power plants from hybrid plants due to their key differences. Co-located power plants can be defined as follows:

- **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 POI.

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.

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[26] For example, 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 FFR until the combustion turbine is turned on to sustain the provided response.

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

~~:~~Background

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*,[28] 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 United States 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 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.[29]

Areas across North America are also seeking low-carbon power systems. For example, California requires[30] 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 by the end of 2045. 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[31] and is projected to have 55,000 MW of new storage by 2045.[32] At the same time, the risk and impact of wildfires in the area is leading California utilities, policymakers, and end-use customers toward more close consideration for grid resilience and flexibility. Energy storage systems, particularly BESS, and BESS 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, BESS 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.[33] California recently approved a proposed 1,500 MW battery at Moss Landing.[34] Southern California Edison currently has several hundred megawatts of BESS deployed in their region with much more in their interconnection queue.[35] **Figure I.3** shows a cursory review of the CAISO interconnection queue (captured in early 2020), where most new interconnection requests are either stand-alone BESS or hybrid plants that consist mainly of solar PV or wind combined with a BESS component. Elsewhere, in ERCOT there are over 1,500 MW of BESS are under construction and 7,500 GW more in advanced development.[36] These types of interconnection requests are observed across North America, and these newly connecting resources will need to operate reliably to provide ERSs and be modeled appropriately. They will also need be studied as part of the interconnection study process.

[28] U.S. Energy Information Administration (EIA), "Annual Energy Outlook 2020 with projections to 2050," Jan. 2020. [Online]: https://www.eia.gov/outlooks/aeo/pdf/aeo2020.pdf.
[29] 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.
[30] California Senate Bill No. 100: https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201720180SB100.
[31] https://www.cpuc.ca.gov/General.aspx?id=3462.
[32] Phil Pettingill, "Ensuring RA in Future High VG Scenarios – A View from CA", ESIG Spring Workshop. April 10, 2020.
[33] https://www.lspower.com/ls-power-energizes-largest-battery-storage-project-in-the-world-the-250-mw-gateway-project-in-california-2/
[34] 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/
[35] https://www.edison.com/home/innovation/energy-storage.html
[36] https://insight.factset.com/ercot-battery-dynamics-set-to-follow-caiso-trends

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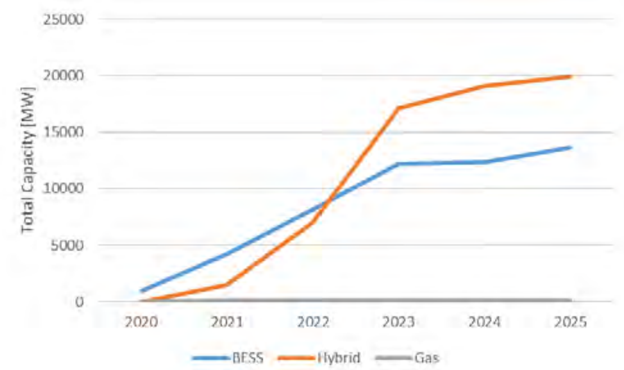

Figure I.3: Review of CAISO Interconnection Queue for Hybrid Resources and BESS

Generation interconnection queues are currently inundated with requests for new interconnections of BESS 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 BESS were primarily proposed for energy arbitrage and mitigating renewable resource variability, there has been more recent interest in installing BESS for broader services as a generating resource or even as a source of transmission services such as voltage support under "storage as transmission facility"[37] programs. Therefore, it is imperative to have clear guidance on how BESS and hybrid power plants should perform when connected to the BPS and also to have recommended practices for modeling and studying BESS 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.[38]

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 BESS and hybrid plants are considered inverter-based resources.

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

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

Chapter 1: BPS-Connected BESS and Hybrid Plant Performance

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BESS 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 to consider when describing the recommended performance for these facilities. This chapter describes the specific technological considerations that should be made when describing the recommended performance for these resources in more depth. The NERC Reliability Guideline: BPS-Connected Inverter-Based Resource Performance[39], as a precursor to IEEE 2800-2022, provided a foundation of recommended performance for BPS-connected inverter-based resources, including BESS and hybrid plants; however, the guideline is planned to be retired. For more information regarding quantitative technical minimum performance requirements, consider relevant and specific sections in IEEE 2800-2022[40].

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Recommended Performance and Considerations for BESS Facilities

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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[41] 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[42] 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. See **Capability Curve** section for more information.

[39] https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Inverter-Based_Resource_Performance_Guideline.pdf

[40] https://standards.ieee.org/ieee/2800/10453/

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[41] 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.

[42] 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 absorption or consumption where reactive power also has to be consumed.

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Table 1.1: High Level Considerations for BESS Performance

Category	Specifications and Comparison with BPS-Connected Inverter-Based Generators
Active Power-Frequency Control	Active power-frequency controls can be extended to the charging area of operation for BESS. The conventional droop characteristic can be used in both discharging and charging modes. Furthermore, a droop gain[43] 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[44] of active power-frequency control to support the BPS should be coordinated with system needs. The fast response of BESS 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 state of charge (SOC) is very low or very high (which may be specified by the BA), though that service can be procured by the BA. See **Active Power-Frequency Control** section for more information.
Fast Frequency Response	BESS are well-positioned to provide FFR to systems with a 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.[45] Sustained forms of FFR help arrest fast frequency excursions and overall frequency control. BESS are likely to be able to provide sustained FFR within their SOC constraints. With the ability of BESS 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 of lower short-circuit strength. See **Fast Frequency Response** section for more information.
Reactive Power-Voltage Control	BESS 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 BESS, applicable to both operating modes.
Reactive Current-Voltage Control	No significant difference from other BPS-connected inverter-based generating resources. BESS 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.

[43] Droop should be set using the same base for both charging and discharging mode of operation (i.e., rated active power, P_{max}), so that the same rate of response is provided regardless of charging or discharging.
[44] 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.
[45] 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

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Table 1.1: High Level Considerations for BESS Performance

Category	Specifications and Comparison with BPS-Connected Inverter-Based Generators
Inverter Current Injection during Fault Conditions	BESS should be configured to provide fault current contribution during large disturbance events that can support legacy BPS protection and stability.[46] 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 BESS since faults are typically cleared in fractions of a second. Additionally, limits on dc voltage magnitude can apply. See **Inverter Current Injection during Fault Conditions** section for more information.
Return to Service Following Tripping	BESS 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 BESS. 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. BESS should utilize grid forming operation, as appropriate (see below), to support BPS stability and reliability in low short-circuit strength operating conditions.
Grid Forming	BESS 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, BESS 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. See **Grid Forming** section for more information.
Fault Ride-Through Capability	No significant difference from other BPS-connected inverter-based generating resources. BESS 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.[47] 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.

[46] 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).

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

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Table 1.1: High Level Considerations for BESS Performance

Category	Specifications and Comparison with BPS-Connected Inverter-Based Generators
System Restoration and Blackstart Capability	BESS 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 BESS 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 BESS 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. See **System Restoration and Blackstart Capability** section for more information.
Protection Settings	No significant difference from other BPS-connected inverter-based generating resources.
State of Charge *(new)*	The SOC of a BESS affects the ability of the BESS to provide energy or other ERSs to the BPS at any given time.[48] In many cases, the BESS may have SOC limits that are tighter than 0–100%[49] 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 ERSs or energy to the BPS. These limits and how they affect BESS operation should be defined by the equipment manufacturers and plant developer, agreed upon by the GO, and provided to the BA, TOP, RC, TP, and PC. See **State of Charge** section for more information.
Oscillation Damping Support	BESS 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 BESS can operate in the charging mode in addition to the discharging mode, which provide greater capabilities of damping support.

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

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

- **Momentary Cessation:** To the greatest possible extent,[50] BESS should not use momentary cessation as a form of large disturbance behavior when connected to the BPS. Any existing BESS that use momentary cessation should eliminate its use to the extent possible, and its use for newly interconnecting BESS should be disallowed by TOs in their interconnection requirements. Sufficiently fast dynamic active and reactive current controls are more suitable.[51] 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 the BESS tripping. However, momentary cessation should not be used inside the curves, subject to limitations for legacy equipment. This recommendation applies for both charging and discharging operation.

[48] https://www.nrel.gov/docs/fy19osti/74426.pdf
[49] Or the values 0% and 100% can simply be defined as the normally allowable range of operation.
[50] 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.
[51] In rare cases, momentary cessation may be admissible based on reliability studies performed by the TP and PC on a case-by-case basis.

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- **Phase Jump Immunity:** Similar to other inverter-based resources, BESS should be able to withstand all expected phase jumps on the BPS; this applies during both charging and discharging operation. The TO (in coordination with their TP and PC) should clearly specify worst-case expected phase jumps during grid events so that newly interconnecting projects can test their performance against them.
- **Reactive Current-Voltage Control (Large Disturbances):** Fundamentally, there are no significant differences between BESS 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.
- **Reactive Power at No Active Power Output:** BESS 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:** BESS should adhere to any requirements set forth by its respective BA. In general, following any tripping or other off-line operation, BESS 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).
- **Return to Normal Operation Following Large Disturbance:** BESS output should return to pre-disturbance active power levels as soon as possible without any artificial ramp rate limit or delay imposed by the power plant controller. Plants connected to low short circuit strength systems or under other special circumstances may require a slower dynamic response to BPS faults and should be studied appropriately by the TP and PC during interconnection studies. In these circumstances, the plant performance necessary for BPS reliability takes precedence over these recommendations.
- **Balancing:** All BESS should have the capability to provide balancing services to the BA for the purposes of ensuring BPS reliability. BAs, TPs, PCs, and other applicable entities should understand what services BESS provide; however, the all BESS should have the capability to provide the BA with balancing services.
- **Monitoring:** BESS should be equipped with equipment that provides the functionality of a digital fault recorder (DFR), dynamic disturbance recorder, sequence of events recorder, harmonics recorder, and battery management system[52] monitoring capability. TOs (in coordination with the TOP, TP, and PC) should include clear requirements and specifications for the types of data needed for BESS facilities (and other inverter-based resources).
- **BESS Stability:** Appropriate studies should be conducted to ensure that the BESS would operate stably in its electrical environment and in any of its operating modes. For example, if the short-circuit strength is low, the TP and PC should study the operation of the hybrid resource in detail with EMT simulations as appropriate. Studies should also be conducted to ensure that no instability modes exist at higher frequencies. In addition,

[52] System-level BMS data related to SOC and state of health (SOH) should be accessible to the GOP, TOP, and RC (as deemed necessary) for independent evaluation to verify accuracy of reported metrics, assess operational issues, and correct any apparent miscalculations. All critical data and metrics (e.g., SOC and SOH) of the battery management system should have accuracy requirements established by the GO, which could be based on equipment standards (where applicable).

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the ability of newly interconnecting BESS to operate with grid forming technology[53] (described below) enables BESS 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: Integrating Inverter-Based Resources into Low Short Circuit Strength Systems*.[54]

- **Fault Ride-Through Capability:** BESS, 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 to operate BESS facilities safely and reliably when connected to the BPS. To ensure proper site coordination with the interconnecting TO, protection settings and coordination should be clearly documented and provided to the TO for approval by the BESS owner. Additionally, BESS owners should provide protection settings to their TP, PC, TOP, RC, and BA to ensure all entities are aware of expected performance of the BESS during planning and operations horizons.[55]

The following sub-sections outline the additional topics from Table 1.1 that warrant additional details and where BESS have specific considerations that need to be taken.

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Capability Curve

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BESS are generally four-quadrant devices that extend into the charging region. BESS inverters may be nearly symmetrical[56] (see Figure 1.1). From an overall plant-level perspective, the capability curves may be asymmetrical and further impacted by collector system losses and any dependencies on external factors, such as ambient temperature (if applicable). Capability curves should ensure to capture the gross and net ratings 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.

[53] 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.
[54] 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
[55] See NERC Reliability Standard PRC-027-1: https://www.nerc.com/_layouts/15/PrintStandard.aspx?standardnumber=PRC-027-1&title=Coordination%20of%20Protection%20Systems%20for%20Performance%20During%20Faults&Jurisdiction=United%20States
See NERC System Protection and Control Working Group technical reference document, *Power Plant and Transmission System Protection Coordination*: https://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%2020/SPCS%20Gen%20Prot%20Coordination%20Technical%20Reference%20Document.pdf
[56] Due to effects of BESS dc voltage and inverter derating due to temperature and altitude impacting reactive and active power output.

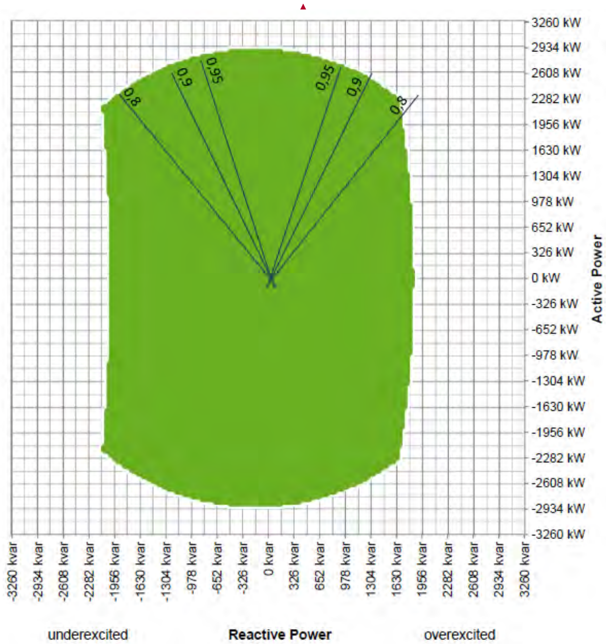

Figure 1.1: Example of 2.7 MVA BESS Capability Curve [Source: SMA America]

Active Power-Frequency Control

BESS 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 (i.e., rated active power, P_{max}) so that the 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 SOC 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; the BA may specify sustaining times. 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 on 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

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the need for faster-responding resources to ensure that unexpected underfrequency load shedding (UFLS) operations do not occur.[57]

BESS 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. BESS 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
- The ability to provide a specified power response for a predetermined 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 BESS for improving frequency response, particularly improving the nadir of system frequency following a large loss of generation. Figure 1.2 illustrates one study demonstrating these effects. The blue trace shows the response following a large generation loss for a synchronous generation-based system. The red plot shows the same system (with same amount of reserves) with the synchronous generation replaced with BESS (with one option of frequency control enabled). The green plots show the system with BESS 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 improves) 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.

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

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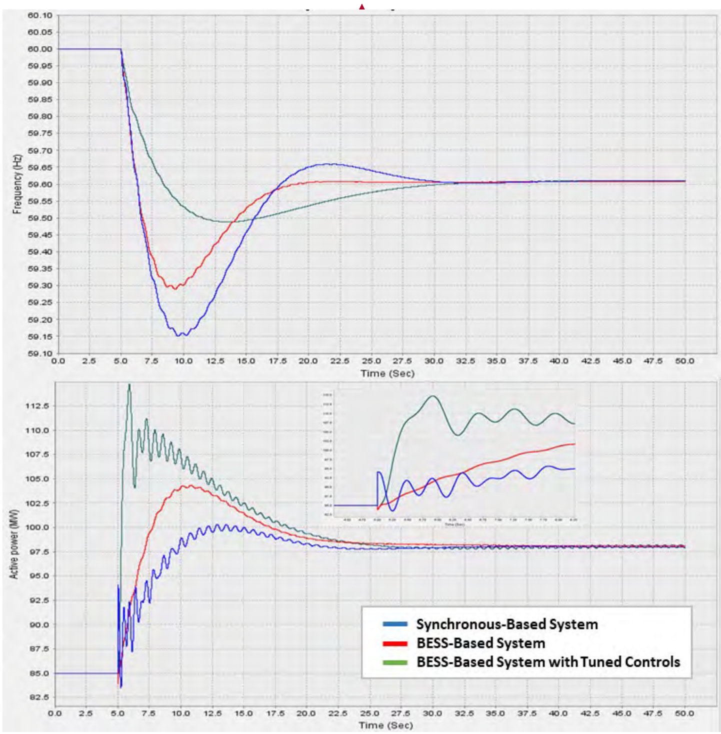

Figure 1.2: Demonstration of Impacts of a BESS on Frequency Response [Source: EPRI]

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

BESS 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 BESS during discharge operation and other BPS-connected inverter-based generators with respect to reactive power-voltage control. BESS should have the ability to support BPS voltage control by controlling their POM voltage within a reasonable range during normal and abnormal grid conditions.
- **Charging Operation:** BESS 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.

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Inverter Current Injection during Fault Conditions

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BESS 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. Inverter-based resources, including BESS, 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.

BESS will need to ensure adherence to SOC limits. BPS fault typically persists for fractions of a second, and thus, SOC should typically not be a concern; however, the SOC limits are always in effect and are closely monitored by BESS. 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. Furthermore, controls should be configured for each specific installation such that voltage support (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 one second; however, this will need to be studied by the TP and PC and configured accordingly.

Grid Forming

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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."[58] 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").[59] While there is currently no standard industry definition for grid forming technology, a broad definition can be as follows:

- **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.

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Four key aspects that enable achieving this operation mode are the following:

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

BESS 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 BESS 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

[58] 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.

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

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

Tesla's Grid Forming + Grid Following Philosophy

Tesla BESS 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 1.3). 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 subcycle 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 ERSs 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.

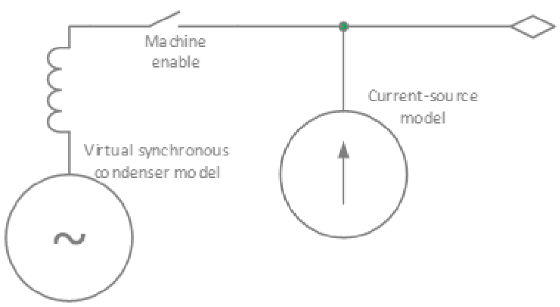

Figure 1.3: Concept of Tesla "Grid Forming + Grid-Following" Mode [Source: Tesla]

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 perform the following:

- 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 and detailed EMT studies that demonstrate the ability to operate under these conditions should be conducted
- Provide sufficient inrush current to energize transformers and transmission lines and start electric motors that necessitates the need to coordinate the BESS resource with the blackstart load; note that BESS, like other inverter-based resources, have limited ability to provide high levels of inrush current

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- Have assurance that the BESS will be available immediately after a large-scale outage requiring system restoration activities; BESS will need to be available for their RC and TOP 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 successfully executed.[60] Therefore, BESS energy ratings should be designed to achieve the required periods 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
- Make all control design, settings, configurable parameters, and accurate models available to the BA, TP, PC, TOP, and RC (in order to ensure proper integration into the overall system blackstart scheme and coordination between resources via appropriate engineering studies)
- Have remote startup and operational control capabilities to avoid requiring dispatch of personnel to the field

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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 ERSs to the BPS at any given time.[61] 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 the capability and operation of a BESS:

- **Provision of ERSs to the BPS:** All BESS 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 may 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 (i.e., 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.

[60] 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

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

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 equipment manufacturer, agreed upon by the BESS owner, and 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 1.4 shows an example of a BESS that provides 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 1.4 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.

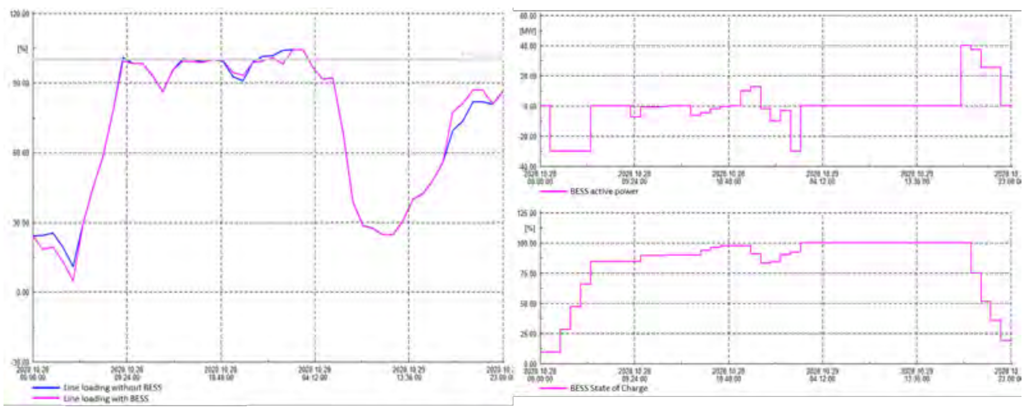

Figure 1.4: Example Time Series of BESS State of Charge
[Source: EPRI]

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 also establish a tighter 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 a high renewable output condition and could lead to insufficient damping support required to maintain stability for high power long distance

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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 area under a high renewable generation penetration condition with large power transfers to electrically distant load centers.[62]

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 BESS 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, TOs should develop requirements to ensure that the capability is activated and that BESS properly damps power oscillations in the range of 0.2 Hz to 2 Hz (typically) 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 retuned 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 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 they are coordinated at the plant-level; however, this guideline may refer to individual BESS or generation components within the facility where 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

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

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Chapter 1: BPS-Connected BESS and Hybrid Plant Performance

- Fault ride-through capability
- System restoration and blackstart capability
- Grid forming[63]
- 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 during both 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, a dc-coupled plant's capability to provide frequency control both for under- and over-frequency events will be further limited by the common inverter rating.
- **Monitoring:** BAs, TPs, PCs, independent system operators/regional transmission organizations (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 elaborates 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	There are 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[64] during charging and discharging operation.
Phase Jump Immunity	There is no significant difference from other BPS-connected inverter-based generating resources.

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

[64] 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.

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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 BESS 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 BESS during discharging. On the withdrawal side, capability will be equal to BESS 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. See **Capability Curve** section for more information.
Active Power-Frequency Controls	There is 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 the 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. See **Active Power-Frequency Controls** section for more information.
Fast Frequency Response	FFR capability will depend on the resources making up the hybrid plant. BESS are well-positioned for providing FFR to systems with high rate-of-change-of-frequency (ROCOF) due to absence of 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 varies with each Interconnection's specific needs.[65] Sustained forms of FFR help arrest fast frequency excursions but also help overall frequency control. BESS are likely to be able to provide sustained FFR within their SOC 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 the BA can procure that service. See **Fast Frequency Response** section for more information.

[65] 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 Power-Voltage Control (Small Disturbances)	There is 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, which are part of the hybrid. The BESS portion of the hybrid has 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). See **Reactive Power-Voltage Control (Small Disturbances)** section for more information.
Reactive Current-Voltage Control (Large Disturbance)	There is 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	There is no significant difference from other BPS-connected inverter-based generating resources.[66]
Inverter Current Injection during Fault Conditions	There is no significant difference from stand-alone BPS-connected inverter-based generating resources and BESS. See Inverter Current Injection during Fault Conditions section for more information.
Return to Service Following Tripping	There is 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	There is no significant difference from other BPS-connected inverter-based generating resources.
Monitoring	There is no significant difference from other BPS-connected inverter-based generating resources.
Operation in Low Short-Circuit Strength Systems	There is no significant difference from other BPS-connected inverter-based generating resources.
Grid Forming	The BESS portion of a hybrid plant has the unique capabilities to effectively deploy grid forming technology to help improve BPS reliability in the future of a high penetration of inverter-based resources. Newly interconnecting hybrid plants should consider using grid forming technology to support the BPS under these future conditions. See **Grid Forming** section for more information.

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[66] 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.

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Table 1.2: High Level Considerations for AC-Coupled Hybrid Plant Performance	
Category	**Comparison with BPS-Connected Inverter-Based Generators**
Fault Ride-Through Capability	There is 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.
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 and a designed energy rating that ensures energy availability for the entire period of restoration activities are needed. 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. See **System Restoration and Blackstart Capability** section for more information.
Protection Settings	There is no significant difference from other BPS-connected inverter-based generating resources.
Power Quality	There is no significant difference from other BPS-connected inverter-based generating resources.
State of Charge *(new)*	Similarly to the standalone BESS, the SOC of a BESS portion of the hybrid may affect the ability of the hybrid to provide energy or other ERSs to the BPS at any given time.[67] 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 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. See State of Charge section for more information.

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

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

Category	Comparison with BPS-Connected Inverter-Based Generators
Operational Limits *(new)*	Based on economics or design considerations, the 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. The hybrid owner should provide this information 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. The hybrid owner should provide this information 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. See Operational Limits section for more information.
Damping Support	BESS can have the capability of providing oscillation damping support, similar to synchronous genrators, HVDC/FACTS facilities, and other BPS-connected inverter-based resources. BESS can operate in both charging and discharging modes, which provides greater capabilities for damping support.

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 BESS:

- 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[68]
- Protection settings
- Damping support

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.

[68] 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.

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Chapter 1: BPS-Connected BESS and Hybrid Plant Performance

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 that simulation models would represent separately. The capability curve GO provides to the RC, TOP, BA, TP, and PC should explicitly document and provide for any contractual limits that may limit active power to a pre-determined level for inclusion in their tools and studies. Furthermore, 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. Figure 1.5 illustrates an example of an ac-coupled hybrid plant consisting of a solar PV generation component with a BESS component.

TOs should ensure their interconnection requirements are clear on how capability curves are provided for BESS 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.

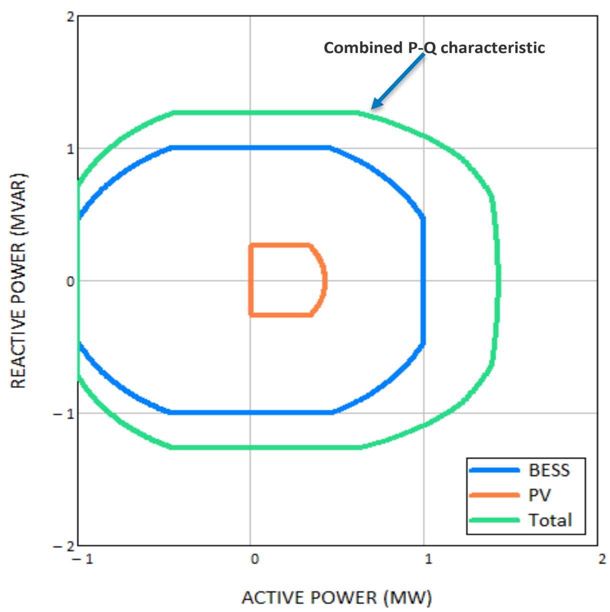

Figure 1.5: Example of AC-Coupled Solar PV + BESS Hybrid Plant Capability Curve [Source: NREL]

Active Power-Frequency Control

Active power-frequency controls can be extended to the charging region of operation for the BESS part of the hybrid as described in detail in standalone BESS section earlier. 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

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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

BESS 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 controls that are programmed into the inverter drive the active power output predominantly. Wind generating resources can provide FFR through tapping into kinetic energy of rotating mass of a wind turbine.[69] Such response, however, cannot be sustained. To obtain sustained FFR from hybrid plants containing wind/solar PV generating resources along with the 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.

An ac-coupled hybrid plant should have at least the following capabilities that 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
- The 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.
- **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 the BPS and may be required by TOs as part of their interconnection requirements or by BAs, TOPs, or RCs for BPS operations.

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

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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, it is difficult to control these resources' voltage; however, this issue is resolved in a hybrid power plant. 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, a hybrid power plant should continuously have the ability to control BPS voltage throughout the transition.

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State of Charge

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SOC considerations for the BESS portion of the ac-coupled hybrid plant are similar to those of a stand-alone BESS discussed earlier. The SOC of a BESS portion of the hybrid may affect the ability of the BESS to provide energy or other ERSs to the BPS at any given time.[70] The hybrid owner should define these limits and how they affect BESS operation and provide these definitions to the BA, TOP, RC, TP and PC. A BESS 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

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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.[71] TOs and BAs should clearly define the acceptable charging behavior from the hybrid plant and ensure that sufficient monitoring capability is available to verify this performance. The hybrid owner should provide the charging characteristic and any operational limitations to the BA, TOP, RC, TP and PC.

The 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. The hybrid owner should provide this information 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.

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

[71] 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 to 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

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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

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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[72] power flow model for a BPS-connected BESS facility. The power flow representation of a BPS-connected BESS facility includes the following components:

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- **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[73] (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, 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 BESS 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 (i.e., make and model of inverter) are used[74] 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 the 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 should also be modeled appropriately.

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- **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.

[72] 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.
[73] Some BESS may have more than one substation transformer, and each should be explicitly modeled.
[74] This occurs more frequently in inverter-based generating resources, either installed in different phases or often in large facilities.

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Elements in Figure 2.1 shown in red are denoted as 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. The elements described in black should be modeled in all BPS-connected BESS facilities. Common voltage levels are shown in Figure 2.1 for illustrative purposes.

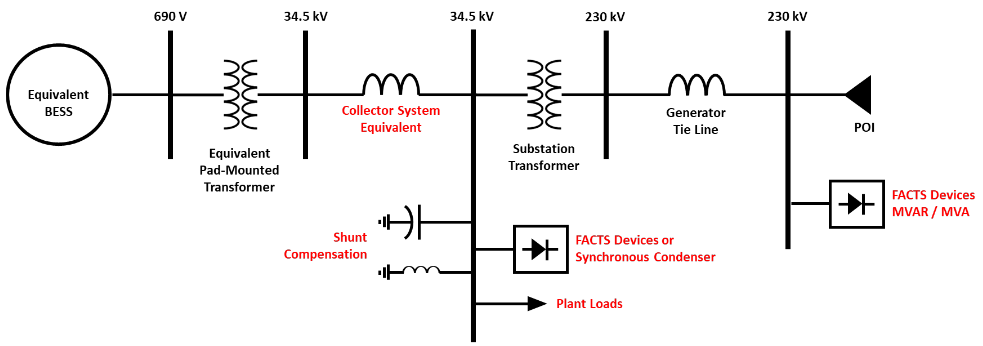

Figure 2.1: Generic Power Flow Model Example for BESS

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

- **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 from 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. In addition, 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 in either 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[75] or actual facilities installed in the field. Furthermore, 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[76] ac-coupled hybrid plant. Since the BESS and the generating resource are connected through the ac network, then each component should be represented

[75] During the interconnection study process.
[76] There are many different types of ac-coupled hybrid plant configurations; this is used as an example only.

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accordingly, as shown in Figure 2.2. An equivalent BESS generation, an equivalent pad-mounted transformer and an equivalent collector system (if needed to properly represent the electrical effects) should be represented. For the example shown in Figure 2.2, where the ac-coupling is at the low voltage 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 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.

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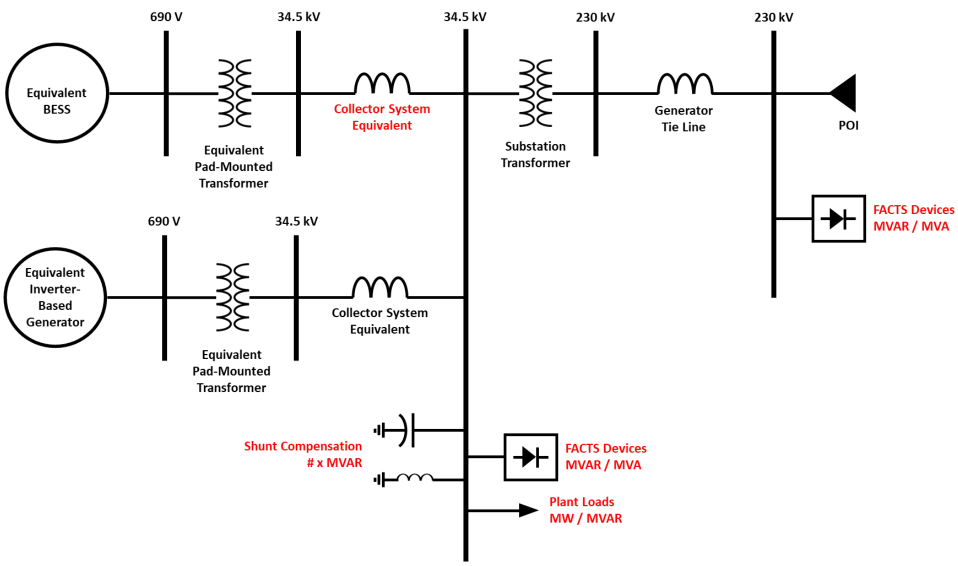

Figure 2.2: Generic Power Flow Model Example for AC-Coupled Hybrid Power Plants

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:** The 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. This includes at least the following:

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- **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 BESS 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 an automatic or effective 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.[77]

The WECC Renewable Energy Modeling Task Force (REMTF) has developed recommendations for software vendors to improve the capability for modeling BESS and hybrid plants,[78] 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 necessarily 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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[77] This is similar to configuring multiple synchronous generators to control the same bus voltage.
[78] 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

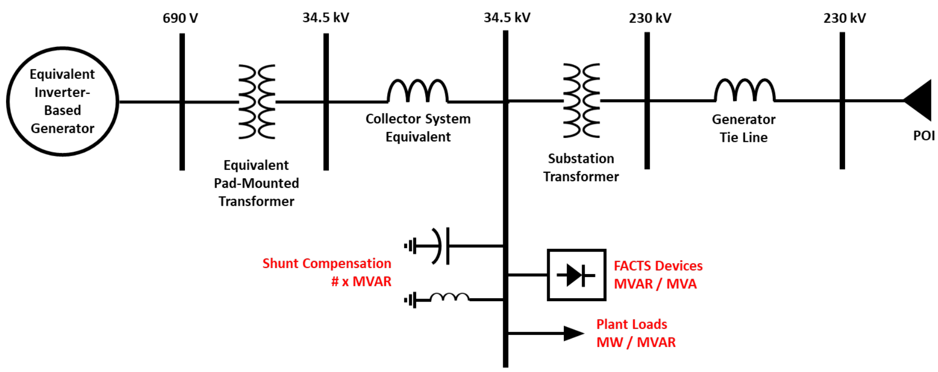

Figure 2.3: Generic Power Flow Model for DC-Coupled Hybrid Power Plants

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, 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. Droop gain should be configured appropriately to be consistent with per unit representation of the plant and the actual MW response from the BESS portion.

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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 BESS 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 EMT models.

Use of Standardized, User-Defined, and EMT Models

As with other inverter-based resources, the dynamic models used to represent BESS 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 the 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 BESS and hybrids during interconnection studies, during annual planning assessments, and any other studies being conducted. Some considerations for different model types include the following:

- **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 BESS and hybrid behavior and response characteristics during large disturbances. Standardized library models may not be able to represent fully nonlinearities in control, communications delays across technologies, dynamic rise times, etc. GOs should coordinate with their equipment manufacturers and any consultants developing plant-level models to ensure these models are appropriate and suitably parameterized. TPs and PCs should ensure that sufficient documentation is provided by the GO to verify that the actual field 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 should be documented and explained by the equipment manufacturers. User defined models that capture the “real code” of the inverters and plant-level controller installed in the field are preferred.

- **EMT Models:** EMT platform allows for the most accurate representation of the dynamic response of an inverter-based resource (including BESS and hybrid plants). TPs and PCs are recommended to require EMT models for newly interconnecting BESS and hybrid plants since these models are the most appropriate to test and analyze for ride-through capability, controls instability, unbalanced fault analysis, operation in low short-circuit strength conditions, and any anomalous controls or instability performance that may be identified during screening with 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. Reliability Guideline on EMT modeling [79] provides recommendations for the development of EMT model requirements, EMT model collection and model quality verification practices specifically for EMT models used to represent BPS-connected inverter-based resources in reliability studies

[79] Reliability Guideline: Electromagnetic Transient Modeling for BPS-Connected Inverter-Based Resources—Recommended Model Requirements and Verification Practices

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conducted by TPs and PCs. The recommendations are intended to help ensure that EMT models provided by Generator Owners (GOs) are representative of the expected behavior of the actual or planned facility to the greatest extent possible so that potential reliability risks are adequately captured in the modeling studies. TPs and PCs are recommended to establish EMT model requirements and model quality verification practices as per the guideline.

As more BESS and hybrid plants continue to interconnect to the BPS, it imperative that these resources are studied appropriately with 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. Generating resources should not be allowed to interconnect without first meeting all modeling requirements of the TPs and PCs.

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,[80] 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 BESS 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 BESS 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 BESS (see Figure 3.1). The standardized library models with variation of each module provide flexibility to simulate the overall plant dynamic behavior. The modules may not directly match control blocks in the field, but they 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 in this chapter. 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.

[80] ERCOT Model Quality Guide: ~~https://www.ercot.com/files/docs/2021/04/20/Model_Quality_Guide.zip~~https://www.ercot.com/files/docs/2021/04/20/Model_Quality_Guide.zip

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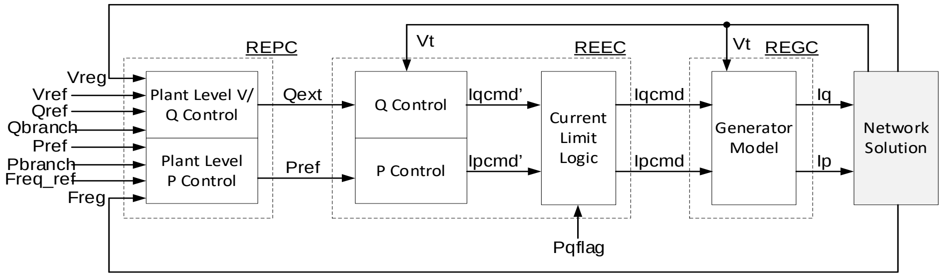

Figure 3.1: Block Diagrams of Different Modules of the WECC Generic Models[81]

The different modules used in representing the dynamic behavior of a BESS include:

1. **REGC (REGC_*)[82] 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.
2. **REEC (REEC_C/REEC_D)[83] 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.
3. **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.

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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.

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Table 3.1: Dynamic Models used to Represent BESS 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.

[81] WECC Solar PV Plant Modeling and Validation Guideline: https://www.wecc.org/Reliability/Solar%20PV%20Plant%20Modeling%20and%20Validation%20Guidline.pdf
[82] 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).
[83] REEC_D and REPC_B model descriptions: https://www.wecc.org/Administrative/Memo_RES_Modeling_Updates_083120_Rev17_Clean.pdf

Scaling for BESS Plant Size and Reactive Capability

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Model parameters are expressed in per unit of the generator MVA base except in REPC_B. The specification of MVA base is implementation-dependent.[84] 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

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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 (PF) control on a user-designated branch active power and power factor. This control function is available in REPC_B, not in REPC_A.

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

- Constant PF control 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

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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[85] of flag settings are not shown in Table 3.2 since they are not likely to be used for BESS operation.

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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 and local coordinated Q/V control	REEC + REPC	0	1	1	0
Plant-level V control and local coordinated Q/V control	REEC + REPC	0	1	1	1
Plant-level PF control and 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.

[84] For example, if MVA base is zero in reec_* or repc_*, then the MVA base entered for the regc applies to those models as well in the PSLF implementation. The user may specify a different MVA if desired. In the PSSE implementation, the MVA base is set in the power flow model.

[85] 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.

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 the following:

- 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 in **Table 3.3** 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,[86] 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 zero for BESS generators regulating frequency.

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 Table 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 zero. Similarly, when SOC reaches SOCmin (i.e., depleted of energy), discharging is disabled by adjusting ipmax from a positive value to zero. This requires the user to set SOCini based on the dispatching condition being analyzed. A common source of error has been that the BESS is in the charging mode with SOCini = 1 and the Pgen is forced to zero 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.

[86] 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

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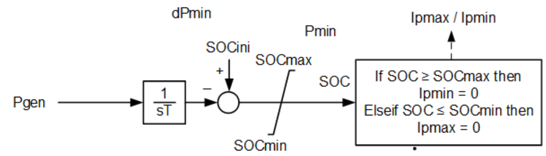

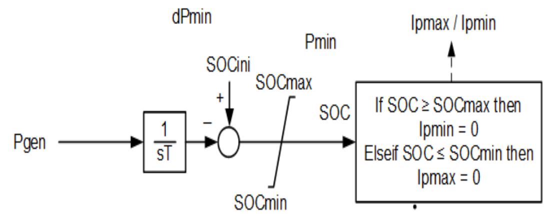

Figure 3.2: Block Diagram of the Charging/Discharging Mechanism of the BESS

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 assess compliance with the voltage and frequency ride-through requirement fully. 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. In addition, the frequency calculations in a positive-sequence simulation tool are 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.[87]

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 BESS Dynamic Modeling 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 be 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 be 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.

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

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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[88]	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

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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 (parameter kwi) need to be tuned for different operating conditions.

Active Power Control

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Hybrid power plants may have 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. This should be carefully considered in all models.

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 generator 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.

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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

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

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

Component	BaseLoad Flag	Module
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, the user 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 those discussed in the BESS Dynamic Modeling section above.

Electromagnetic Transient Modeling for BESS and Hybrid Plants

Recommendations pertaining to EMT modeling of BESS and hybrid power plants are very similar to those outlined in other NERC reliability guidelines.[89] All TPs and PCs should establish EMT modeling requirements for all newly interconnecting BESS 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 equipment manufacturers and GOs provide documentation to GOs to explain how the plant controller works and how the model(s) map to those controls.

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

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Chapter 4: BESS and Hybrid Plant Short Circuit Modeling

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BESS 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 BESS and hybrid plants as new capabilities and features for existing tools become available. At a high-level, the recommendations for modeling BESS and hybrid plants are nearly identical to other full-converter, inverter-based generating resources (i.e., Type 4 wind, solar PV, voltage source converter HVDC, and other FACTS devices).[90] The modeling practices described in this chapter should help industry develop standardized approaches for modeling BESS and hybrid plants (similar to other inverter-based resources) that capture the key performance characteristics and other nuances[91] involved with modeling each specific facility appropriately as well as represent equipment ratings.

BESS Short Circuit Modeling

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The IEEE Power System Relaying and Control 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*.[92] This report advised 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.[93] 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 (i.e., 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 BESS, 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.[94]

The IEEE Power System Relaying and Control Committee Working Group 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. Furthermore, inverter controls may take time to reach a steady-state fault current level so the report recommends that fault current data is 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 BESS, a 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 requirements are clear regarding the type of information (and

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[90] 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

[91] Such as capturing different control algorithms and any additional short-circuit current from BESS due to additional energy on the dc bus.

[92] 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

[93] 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.

[94] BESS SOC is closely managed and not expected to be operated near the edge of its charge or discharge limit during normal operation.

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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. A negative power factor angle (i.e., current lags voltage) means that 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. The ac-coupled plants should have the generating component and the BESS component modeled separately. The inverters used may be from different manufacturers, from different models, and have different control philosophies that need to each be represented appropriately~~.~~

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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) revolves around the assumptions regarding charging and discharging operating points under various system conditions when compared to other resources. This chapter describes considerations to be accounted for in these studies that model the various dispatches and study 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 while keeping in mind that 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, any qualified changes to battery management system (BMS) firmware or site controls, 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 BESS and hybrid plants from providing dynamic services for 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 POI (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. TPs and PCs will need to make these considerations as they develop their study approaches. In general, BESS 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.[95] **Table 5.1** was constructed with these assumptions in mind with exceptions noted.

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

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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, a BESS may be charging to prepare for a time later in the day when the wind is expected to die down if there is high wind output at peak load. 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 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 it may be a feasible scenario for ac-coupled hybrids in some situations depending on localized transmission constraints.

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Chapter 5: Studies for BESS and Hybrid Plants

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[96] of voltage control devices).

BESS can operate in different operating modes that may change over time. Examples include active power-frequency control, peak shaving, and energy arbitrage. 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 or BMS firmware of an existing BESS is changed or updated, additional interconnection studies may be required per the latest version of the NERC FAC-002 Reliability Standard, as this would constitute a qualified change of the existing facility. Studies of qualified changes 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; see example scenarios as follows:

- 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)

[96] 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.

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A key aspect to consider, particularly with the second and third scenarios in this list, 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 the TP and PC will perform. Again, any modifications to the facility that result in its electrical behavior, operational characteristics, or performance to change should be studied through the qualified change 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[97]	Needed	Needed to study charging mode	May be needed to study different operating conditions

In all cases in Table 5.2 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 BESS 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 BESS and hybrid plants in the future and will need to consider the operational limitations and energy ratings of the BESS and hybrid plants. Planners will need to consider the impact of BESS SOC and the duration of charge available to ensure that the operational solution can remain in place until other automatic or operator actions

[97] 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.

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Chapter 5: Studies for BESS and Hybrid Plants

take place. This is particularly important when performing steady-state contingency analysis, where TPs and PCs will need to closely consider the duration of the outage and the energy available from BESS and hybrid plants to support the BPS post-contingency.[98] 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 by 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 BESS 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 BESS will be sized with sufficient energy to meet blackstart requirements (in terms of sustained power output); however, it is likely that BESS 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 the following:

- **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 the 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.

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

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CAISO BESS and Hybrid Study Approach Example

This section provides a brief description of the CAISO approach for studying BESS 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 the following:

- **Discharging Assessment:** This assessment includes gross peak and off-peak daytime scenarios with dispatch shown in Table 5.3. For hybrid power plant requests, the 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. Careful consideration should be made during the interconnection process regarding facilities with planned RASs. As the number of RASs increase on the BPS, the need for a comprehensive system review should be considered.

Table 5.3: CAISO Reliability Assessment Dispatch Assumptions

Condition	Peak	Peak Charging	Shoulder Peak Charging	Off-Peak Daytime	Off-Peak Nighttime Charging
Load Level[99]	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[100]	Max charging[101]	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				

[99] 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.
[100] Maximum steady-state positive output associated with the maximum net output in the Interconnection Request
[101] Maximum steady-state negative output for re-charging of the energy storage facility

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Chapter 5: Studies for BESS and Hybrid Plants

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

CAISO also performs deliverability assessments[102] 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 BESS 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.

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

Appendix A: ~~–~~Relevant FERC Orders to BESS and Hybrids

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The Federal Energy Regulatory Commission (FERC) recently issued orders pertaining to electric storage resources that are relevant to the guidance contained in this reliability guideline. FERC defined an electric storage resource as follows:

- **Electric Storage Resource (FERC Definition):**[103] 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[104] (February 15, 2018), FERC required RTOs and 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 SOC. To the extent that electric storage resources are providing ancillary services, such as frequency regulation, an electric storage resource managing its SOC 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 IRPS; rather, they are provided here only as a reference.

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Table A.1: FERC Participation Model Parameters

Physical or Operational Characteristic	Definition
State of Charge	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 SOC for the market interval being offered into.
Maximum State of Charge (SOC_{max})	A SOC 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% SOC).[105]
Minimum State of Charge	A SOC 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% SOC).

[103] FERC Order No. 841, paragraph 29.
[104] https://ferc.gov/sites/default/files/2020-06/Order-841.pdf
[105] The IRPS notes that the base for defining the percentage SOC is not defined and therefore up to interpretation by the ISO/RTO.

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Table A.1: FERC Participation Model Parameters	
Physical or Operational Characteristic	**Definition**
Maximum Charge Limit	The maximum MW quantity of electric energy [power][106] 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."

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FERC Order No. 842

In Order No. 842[107] (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.[108] 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 do the following:

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

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

[108] 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 Large Generator Interconnection Agreement (LGIA) or Attachment 5 of the Small Generator Interconnection Agreement (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 summary, 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 BESS and hybrid plants can be configured to support BPS frequency response needs.

FERC Order No. 845

In Order No. 845[109] (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 that are greater than 20 MW had the option to interconnect pursuant to the Large Generator Interconnection Procedures and 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.

Furthermore, 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[110] (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. Furthermore, the Commission stated that transmission providers may enter into non-conforming LGIAs "when necessary" in order to accommodate a particular electric storage resource.

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

~~Contributions~~

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Guideline Information and Revision History

Guideline Information	
Category/Topic: BESS Modeling	**Reliability Guideline/Security Guideline/Hybrid:** Reliability Guideline
Identification Number: RG – MOD- 0623	**Subgroup:** Inverter-Based Resource Performance Subcommittee

Revision History		
Version	**Comments**	**Approval Date**
2		

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Metrics

Pursuant to the Commission's Order on January 19, 2021, *North American Electric Reliability Corporation*, 174 FERC ¶ 61,030 (2021), reliability guidelines shall now include metrics to support evaluation during triennial review consistent with the RSTC Charter.

Baseline Metrics

All NERC reliability guidelines include the following baseline metrics:

- BPS performance prior to and after a reliability guideline as reflected in NERC's State of Reliability Report and Long Term Reliability Assessments (e.g., Long Term Reliability Assessment and seasonal assessments)
- Use and effectiveness of a reliability guideline as reported by industry via survey
- Industry assessment of the extent to which a reliability guideline is addressing risk as reported via survey

Specific Metrics

The RSTC or any of its subcommittees can modify and propose metrics specific to the guideline in order to measure and evaluate its effectiveness, listed as follows:

- Review of the number of category 1i events[111] involving utility-scale battery energy storage systems and hybrid inverter-based resources under the NERC Event Analysis program

Effectiveness Survey

On January 19, 2021, FERC accepted the NERC proposed approach for evaluating Reliability Guidelines. This evaluation process takes place under the leadership of the RSTC and includes:

- industry survey on effectiveness of Reliability Guidelines;
- triennial review with a recommendation to NERC on the effectiveness of a Reliability Guideline and/or whether risks warrant additional measures; and
- NERC's determination whether additional action might be appropriate to address potential risks to reliability in light of the RSTC's recommendation and all other data within NERC's possession pertaining to the relevant issue.

NERC is asking entities who are users of Reliability and Security Guidelines to respond to the short survey provided in the link below.

Guideline Effectiveness Survey [insert hyperlink to survey]

[111] https://www.nerc.com/pa/rrm/ea/ERO_EAP_Documents%20DL/ERO_EAP_v4.0_final.pdf#search=EAP

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Revision of

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

Julia Matevosyan , IRPS Chair
Jody Green, IRPS Sponsor
NERC Reliability and Security Technical Committee

June 21, 2023

RELIABILITY | RESILIENCE | SECURITY




NERC IBR Strategy

Risk Analysis	Interconnection Process Improvements	Best Practices and Education	Regulatory Enhancements
Event Analysis	Improvements to GIAs and GIP	Reliability Guidelines	NERC Standards Projects
Disturbance Reports	Enhanced Interconnection Requirements	Webinars and Workshops	BES Definition Review
Alerts	Modeling and Study Improvements	Outreach and Engagement	Inverter-Specific Requirements and Standards
Lessons Learned	IEEE 2800-2022	Emerging Reliability Risk Issues	Risk-Based Compliance

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

- The Inverter-Based Resources Performance Subcommittee (IRPS) has reviewed the industry comments on revising the Reliability Guidelines.
- IRPS has revised the guideline incorporating industry feedback, including a recommendation to refer to the relevant and specific sections in the IEEE standard for more information regarding quantitative technical minimum performance requirements.

Action

- IRPS is seeking RSTC approval for the revision of the guideline.

Questions and Answers

Retirement of Two IRPS Reliability Guidelines

Action

Approve

Background

The Inverter-Based Resources Performance Subcommittee (IRPS) has reviewed the industry comments on revising the following reliability guidelines related to modeling, performance and interconnection of bulk power system (BPS) connected inverter-based resources:

- BPS-Connected Inverter-Based Resource Performance, September 2018
- Improvements to Interconnection Requirements for BPS-Connected Inverter-Based Resources, September 2019

A common theme from industry feedback was to review and align the guidelines with IEEE 2800-2022 Standard for Interconnection and Interoperability of Inverter-Based Resources (IBRs) Interconnecting with Associated Transmission Electric Power Systems and consider retiring the guideline altogether if deemed appropriate. IEEE 2800-2022 is a voluntary standard providing uniform technical minimum requirements for the interconnection, capability, and lifetime performance of inverter-based resources interconnecting with transmission and sub-transmission systems. As such, many of the requirements overlap with the guidance given in the above guidelines. In fact, many industry experts contributed to both. The IEEE standard provides better coverage with more state-of-the-art performance requirements. For the most part, it covers what IBR facilities should be capable of, both functions and their performance characteristics.

As a precursor to IEEE 2800, the guidelines were instrumental in providing guidance to the industry until IEEE 2800 was published. Although the industry has yet to widely adopt the IEEE standard, a voluntary standard, having two sources of information creates confusion and therefore is counterproductive to the intent of both. IRPS in general agrees that the guidelines have served their purpose. For reasons above, IRPS has decided to honorably retire the aforementioned guidelines.

As retired guidelines, they will continue to provide useful context, both historical and technical. The new guideline can clarify certain relevant sections in the IEEE standard, fill in gaps and provide guidance on adopting the IEEE standard and considerations for choosing and configuring relevant grid support functions.

Summary

IRPS is seeking RSTC approval of honorably retiring the aforementioned reliability guidelines.

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Retirement of Two IRPS Reliability Guideline

Julia Matevosyan, IRPS Chair
Jody Green, IRPS Sponsor
NERC Reliability and Security Technical Committee
June 2023

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Retirement of Two IRPS Reliability Guidelines:

- BPS-Connected Inverter-Based Resource Performance, September 2018
- Improvements to Interconnection Requirements for BPS-Connected Inverter-Based Resources, September 2019

Review Summary

- IRPS has reviewed the industry comments on revising the following reliability guidelines.
- A common theme from industry feedback was **to review and align** the guidelines with IEEE 2800-2022 *Standard for Interconnection and Interoperability of Inverter-Based Resources (IBRs) Interconnecting with Associated Transmission Electric Power Systems* and **consider retiring** the guideline altogether if deemed appropriate.
- IEEE 2800-2022 is a voluntary standard providing uniform technical minimum requirements, many of which overlap with the guidance given in the above guidelines.
- The IEEE standard provides better coverage with more state-of-the-art performance requirements.
- As a precursor to IEEE 2800, the guidelines were instrumental in providing guidance to the industry until IEEE 2800 was published.
- Having two sources of information creates confusion and therefore is counterproductive to the intent of both.
- IRPS in general agrees that the guidelines have served their purpose and at this time, it is better to focus on adoption of IEEE 2800.
- For those reasons, IRPS has decided to honorably retire the aforementioned guidelines.

Action

- IRPS is seeking RSTC approval for the retirement of the guidelines.

Questions and Answers

Electromagnetic Transient Modeling Task Force (EMTTF) Work Plan

Action
Information

Background
The Electromagnetic Transient Modeling Task Force (EMTTF) has developed a work plan that was approved by the Inverter-Based Resource Performance Subcommittee (IRPS). The EMTTF would like to share the work plan information with the RSTC.

Summary
The purpose of the EMTTF is to support and accelerate industry adoption of electromagnetic transient (EMT) modeling and simulation in their interconnection and planning studies of bulk power system (BPS)-connected inverter-based resources. EMTTF deliverables include guidance and reference materials to Transmission Planners (TPs) and Planning Coordinators (PCs) embarking on EMT modeling and simulations to more adequately assess BPS impacts and reliability risks of interconnecting inverter-based resources and technical documents to support BPS planning under increasing penetrations of BPS-connected inverter based resources.

The EMTTF has developed the work plan over several meetings, ensuring the work items are aligned with the task force's purpose, actions and deliverables as laid out in the TF's Scope.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Work Plan

Electromagnetic Transient Modeling Task Force (EMTTF) – For Information Only

Miguel Angel Cova Acosta, EMTTF Chair
Jody Green, EMTTF Sponsor
NERC Reliability and Security Technical Committee

June 21, 2023

RELIABILITY | RESILIENCE | SECURITY




Electromagnetic Transient (EMT) Modeling Task Force (EMTTF)

- EMTTF has developed a work plan and presented it to IRPS.
- The work plan was discussed at IRPS May monthly meeting and received a consensus approval.

Electromagnetic Transient (EMT) Modeling Task Force (EMTTF) Work Plan

#	Task Description	Target Completion	Status
1	**EMT Modeling Standard Monitoring and Support** Monitor and support the activities of Standard Project 2022-04 EMT Modeling	Ongoing	EMT SAR review
2	**Reliability Guideline: Electromagnetic Transient Modeling and Simulations** Screening and Studies, Application and Implementation of Results (High Priority) (Related to 2021 NERC RISC Report Recommendations)	Q1 2024	New task.

Electromagnetic Transient (EMT) Modeling Task Force (EMTTF) Work Plan

#	Task Description	Target Completion	Status
3	**Organized Repo of Curated EMT Modeling Resources ("EMT Curriculum")** Repository of carefully curated EMT modeling and study references organized in such a way that a beginner can self-guide their learning curve • Recommended modeling and study practices, including verification, and validation of models, analysis approach and results, • References to educational materials, tutorials and workshop presentations, case studies, automation approaches, • Frequently asked questions (FAQs) gathered from event Q&A sessions, webinars, and other outreach efforts) (High Priority)	Q4 2024	New task.
4	**White Paper: Case Study on Adoption of EMT Modeling and Studies in Interconnection and Planning Studies for BPS-connected IBRs** Identify TPs and PCs adopting EMT modeling and studies in their interconnection and planning studies for BPS-connected IBR and document challenges and progress	Q4 2023	New task.

Electromagnetic Transient (EMT) Modeling Task Force (EMTTF) Work Plan

#	Task Description	Target Completion	Status
5	**White Paper: Assessment of The Need for EMT Modeling and Simulation in Offline Operation Studies and Requirements** Identify the EMT model use cases in offline operation studies, unique challenges and requirements that differ from interconnection and planning study use cases	Q4 2024	New task.

Questions and Answers

Implementation Guidance:
Usage of Cloud Solutions for BES Cyber System Information (BCSI)

Action
Endorse

Background
Industry interest in adopting commercially available off-premise cloud services continues to increase substantially. Understanding security and compliance in these new and sometimes complex environments has been a common challenge in the industry. In particular, a key challenge has been understanding how, and whether, a Cloud Service Provider's personnel and/or any third-party service provider have access to BCSI, and the associated compliance impacts.

Summary
The Security Working Group has developed the proposed *Implementation Guidance Usage of Cloud Solutions for BES Cyber System Information (BCSI)*. This Implementation Guidance document was developed to outline considerations and potential approaches that a registered entity could utilize to comply with the following future-effective Reliability Standards and requirements:

- CIP-004-7 – Cyber Security – Personnel & Training
  - Requirement R6, Parts 6.1-6.3 – Access Management for BES Cyber System Information
- CIP-011-3 – Cyber Security – Information Protection
  - Requirement R1 (Parts 1.1 and 1.2) – Information Protection Program

The SWG is asking the Reliability and Security Technical Committee (RSTC) to endorse the *Implementation Guidance Usage of Cloud Solutions for BES Cyber System Information (BCSI)*. Upon RSTC endorsement, it will then be submitted to the ERO requesting formal endorsement as Implementation Guidance.

NERC Reliability and Security Technical Committee

Implementation Guidance:

Usage of Cloud Solutions for BES Cyber System Information (BCSI)

CIP-004-7 R6, parts 6.1-6.3
CIP-011-3 R1, parts 1.1 and 1.2

April 18, 2023

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Introduction

NERC "Implementation Guidance provides a means for registered entities to develop examples or approaches to illustrate how registered entities could comply with a standard [or requirement within a Standard] that are vetted by industry and endorsed by the ERO Enterprise. The examples provided in the Implementation Guidance are not exclusive, as there are likely other methods for implementing a standard."[1] This Implementation Guidance document was developed to outline considerations and potential approaches that a registered entity could utilize to comply with CIP-011-3 R1 and CIP-004-7 R6. Both of these standards were modified to clarify and provide a secure path towards utilization of modern third-party off-premises electronic data storage and analysis systems (e.g., cloud services).

Figure 1 illustrates the high-level relationship between CIP-011-3 R1 and CIP-004-7 R6, and explains why you will see guidance on CIP-011-3 R1 before CIP-004-7 R6 within this document:

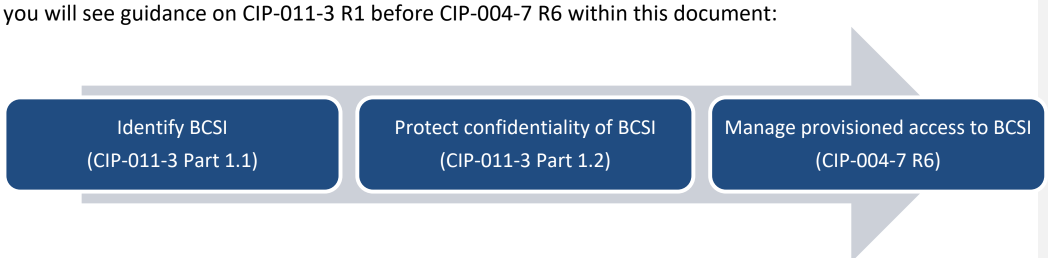


Figure 1 - Relationship between CIP-011-3 R1 & CIP-004-7 R6

Figure 1 is an excerpt from the U.S. General Services Administration (GSA) Cloud Information Center's (CIC) publication on Cloud Security, and is helpful in better understanding the various cloud services. The GSA CIC acts as a centralized location to share guidance and best practices on cloud-related topics with federal agencies, including security, without bias toward particular cloud contract vehicles, vendors or solutions. The publication states:

> "When it comes to cloud, security is always a concern, and should be appropriately addressed by any organization (e.g., consumer) evaluating or using a cloud solution.
>
> The following graphic illustrates the differences in security responsibilities between cloud consumers and Cloud Service Providers (CSPs) for each cloud service model (IaaS, PaaS, SaaS) in comparison to an organization owned and managed data center."

[1] NERC Compliance Guidance Policy, November 5, 2015, available at: https://www.nerc.com/pa/comp/guidance/Documents/Compliance Guidance Policy.pdf

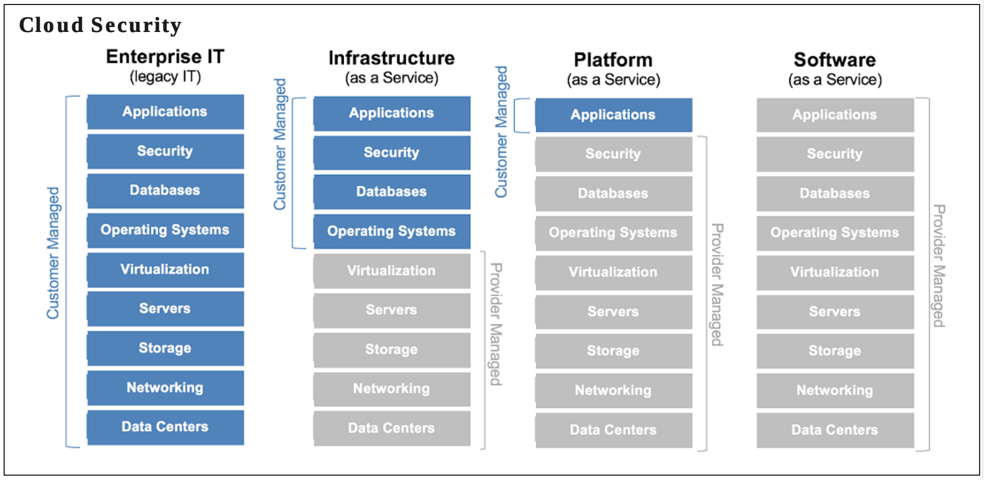


Figure 2 – Security responsibilities by cloud service model

The figure above depicts the typical division of security responsibilities in a cloud environment, however these roles and responsibilities do not suggest or imply transference of compliance responsibilities from the Responsible Entity to a third-party. Responsible Entities are the data owners. As owners of the data, they must ensure the custody and handling of that data have the required security controls applied to their environment(s) inclusive of third-parties; and Responsible Entities must have the ability to demonstrate compliance with CIP-004-7, and CIP-011-3. Demonstration of compliance is described in further sections but may include a combination of electronic technical controls, and/or implementation of administrative methods to protect BCSI.

Additionally, any mention of specific vendors and their services in this document is not considered an endorsement of any kind. The scenarios referenced under each Requirement are intended to illustrate security concepts and the compliance impacts associated with each.

Goal / Problem Statement

Many vendors are phasing out their on-premises solutions and migrating them to the cloud or building new solutions using only cloud services/environments. Responsible Entities also need increased choice, greater flexibility, higher availability, and reduced-cost options to manage their BES Cyber System Information (BCSI), which includes the use of third-party off-premises cloud solutions. Understanding security and compliance in these new and sometimes complex environments has been a common challenge in the industry. In particular, understanding how and whether CSP personnel and/or any 3rd party service provider have access to BCSI, and the associated compliance impacts, requires a full understanding of the environment and available protections (technical or administrative).

Scope

This Implementation Guidance has been developed to provide examples of the protection and access management of BCSI, in an off-premises cloud environment. In some cases, guidance is provided for the following three NIST-defined cloud service offering models:

- **Software as a Service (SaaS)** – The capability provided to the consumer is to use the provider's applications running on a cloud infrastructure. The applications are accessible from various client devices through either a thin client interface, such as a web browser (e.g., web-based email), or a program interface. The consumer does not manage or control the underlying cloud infrastructure including network, servers, operating systems, storage, or even individual application capabilities, with the possible exception of limited user-specific application configuration settings.
    - In this model, the application provider may contract with a cloud service provider (CSP) to host the application, or the application provider may own, manage and operate their own cloud environment. Either way, all of the underlying infrastructure, middleware, app software and app data are located in the cloud provider's data center and managed by the application provider.

- **Platform as a Service (PaaS)** – The capability provided to the consumer is to deploy onto the cloud infrastructure consumer-created or acquired applications created using programming languages, libraries, services, and tools supported by the provider. The consumer does not manage or control the underlying cloud infrastructure including network, servers, operating systems, or storage, but has control over the deployed applications and possibly configuration settings for the application-hosting environment.

- **Infrastructure as a Service (IaaS)** – The capability provided to the consumer is to provision processing, storage, networks, and other fundamental computing resources where the consumer is able to deploy and run arbitrary software, which can include operating systems and applications. The consumer does not manage or control the underlying cloud infrastructure but has control over operating systems, storage, and deployed applications; and possibly limited control of select networking components (e.g., host firewalls).

This document outlines considerations and potential approaches that a Registered Entity could utilize to comply with CIP-011-3 R1 and CIP-004-7 R6, however, is not intended to be exhaustive considering the numerous services available and implementation choices. For example, the document does not include specific examples for use of data masking, whitelisting/blacklisting of IP ranges, etc., although Entities may choose to implement those controls in lieu of, or in addition to, those described in this document as part of their Information Protection Program.

Operations of a PACS (Physical Access Control System), EACMS (Electronic Access Control or Monitoring System) or BCS (BES Cyber System)[2] in the cloud is not addressed in this guidance.

[2] See the NERC Glossary of Terms for definitions of PACS, EACMS and BCS: https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf

This document is not intended to establish new requirements under NERC's Reliability Standards, modify the requirements in any existing Reliability Standards, nor provide an interpretation under Section 7 of the Standard Processes Manual.

Definitions

- **Cloud:** Off-premises servers that are accessed over the Internet, and the software and databases that run on those servers[3].
- **Cloud Service Provider (CSP):** Third-party or parties involved in hosting the Responsible Entity's BCSI service in an off-premises cloud. This can be the application/software provider, the cloud platform provider, the underlying infrastructure host and/or third-party services. In some cloud implementations, there is more than one CSP involved.
- **Just-In-Time Access:** a security practice/control where the privilege granted to temporarily access applications or systems is limited to predetermined periods of time, on an as-needed basis.
- **Underlay (security of the cloud):** Infrastructure implemented by the Cloud Service Provider that runs all services offered by the Cloud Service Provider. This infrastructure could comprise the hardware, software, networking, and facilities that run cloud services. The security controls associated with this infrastructure are likely verified through certifications or other internal/external activities such as penetration testing.
- **Overlay (security in the cloud):** The portion of the cloud service/product that sits on top of the underlay and is developed by the customer, or has been developed for the customer's use. This is how the Responsible Entity generally accesses their BCSI.

Depending upon a Responsible Entity's implementation and specific services, their BCSI may reside within the Overlay (as is more common with SaaS) or may reside in the Underlay (as is more common in a PaaS or IaaS implementation). Figure 3 is a generalized diagram of a cloud environment depicting the division between the Overlay and Underlay.

Commented [A1]: The diagram in figure 3 needs to be replaced, per ERO feedback. Matt Brewer is working on this.

[3] For more detail, please refer to this Cloudflare, Inc. article: https://www.cloudflare.com/learning/cloud/what-is-the-cloud/

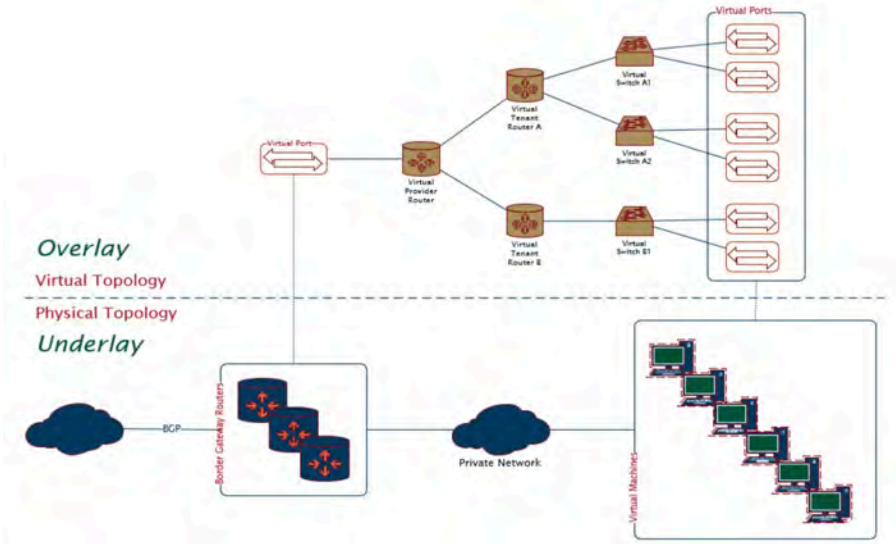


Figure 3 – Example diagram of a cloud environment to depict the division between the Overlay and Underlay

CIP-011-3 – Cyber Security – Information Protection

Requirement R1

R1. Each Responsible Entity shall implement one or more documented information protection program(s) for BES Cyber System Information (BCSI) pertaining to "Applicable Systems" identified in CIP-011-3 Table R1 – Information Protection Program that collectively includes each of the applicable requirement parts in CIP-011-3 Table R1 – Information Protection Program.

Requirement R1, Part 1.1

CIP-011-3 Table R1 – Information Protection Program			
Part	**Applicable Systems**	**Requirements**	**Measures**
1.1	High Impact BES Cyber Systems and their associated: 1. EACMS; and 2. PACS Medium Impact BES Cyber Systems and their associated: 1. EACMS; and 2. PACS	Method(s) to identify BCSI.	Examples of acceptable evidence may include, but are not limited to, the following: • Documented method(s) to identify BCSI from the entity's information protection program; or • Indications on information (e.g., labels or classification) that identify BCSI as designated in the entity's information protection program; or • Training materials that provide personnel with sufficient knowledge to identify BCSI; or • Storage locations identified for housing BCSI in the entity's information protection program.

As indicated in the last bullet of the Measures, a Responsible Entity may still utilize "designated storage locations" as a method to identify BCSI, as contemplated in CIP-004-6. As it relates to a cloud environment, an example of this could be a specific site or folder within an application that has been designated as a BCSI repository.

However, a Responsible Entity may utilize other options within a cloud environment to identify BCSI. Some examples include, but are not limited to:

- File-level tagging via metadata or labels,
- Application-level whereby the entire application has been designated as a BCSI storage location,
- A designated container/space within a CSP-provided environment.

Requirement R1, Part 1.2

CIP-011-3 Table R1 – Information Protection Program			
Part	**Applicable Systems**	**Requirements**	**Measures**
1.2	High Impact BES Cyber Systems and their associated: 1. EACMS; and 2. PACS Medium Impact BES Cyber Systems and their associated: 1. EACMS; and 2. PACS	Method(s) to protect and securely handle BCSI to mitigate risks of compromising confidentiality.	Examples of evidence for on-premise BCSI may include, but are not limited to, the following: • Procedures for protecting and securely handling, which include topics such as storage, security during transit, and use of BCSI; or • Records indicating that BCSI is handled in a manner consistent with the entity's documented procedure(s). Examples of evidence for off-premise BCSI may include, but are not limited to, the following: • Implementation of electronic technical method(s) to protect electronic BCSI (e.g., data masking, encryption, hashing, tokenization, cipher, electronic key management); or • Implementation of physical technical method(s) to protect physical BCSI (e.g., physical lock and key management, physical badge management, biometrics, alarm system); or • Implementation of administrative method(s) to protect BCSI (e.g., vendor service risk assessments, business agreements).

Here are some conditions that Responsible Entities should consider when implementing Part 1.2:

- If BCSI is not encrypted, only password protection of the storage hardware alone may not be sufficient protection. In this situation, a Responsible Entity should address physical and administrative protection of electronic BCSI.
- If CSP personnel has access to BCSI in the Overlay and/or the Underlay, then this should be accounted for and addressed by the Responsible Entity's Information Protection Program.
- Responsible Entities need to understand and identify how personnel (CSP or their own) can obtain access to BCSI in the Overlay and/or the Underlay. For example:
  - eDiscovery tools typically utilized by legal staff,
  - Administrator roles within the cloud environment that provide access to BCSI,
  - Emergency/ Break-Glass accounts that provide access to BCSI.

- Responsible Entities would need to understand and address how their BCSI is being protected if in a multi-tenant environment (e.g. encryption, authentication to AD, etc.)

Software as a Service (SaaS), Platform as a Service (PaaS), Infrastructure as a Service (IaaS)
The Measures for part 1.2 provide examples of the evidence that could be utilized to demonstrate compliance. More specific compliance evidence examples could include but are not limited to:

1. Implementation of electronic technical method(s) to protect BCSI:
    a. This could include evidence of encryption keys utilized at a container or application/software-specific level. Entities should also ensure the level of encryption used by default or that can be configured follows encryption best practices[4]. Additional technical methods may be needed depending on how the encryption keys are managed:
        i. Vendor-owned and managed keys: Detection/notification controls could be implemented to ensure that the keys are not utilized when not authorized by the Responsible Entity.
        ii. Customer-owned keys – managed within the cloud vault: Detection/notification controls could be implemented to ensure that the key vault is not accessed without authorization by the Responsible Entity.
        iii. Customer-owned keys – managed on-premises or in a separate cloud: Service contract and diagram showing how the keys to fully unencrypt BCSI is not stored in the cloud with the BCSI.
        iv. Customer-owned keys – cloud-based Hardware Security Module (HSM) with Federal Information Processing Standards (FIPS) level 4 protection (tamper-resistant controls): Service contract and CSP procedure to explain how the keys are managed.
    b. Access control Lists
    c. Data masking/ anonymization
    d. Multi-factor authentication
    e. Technical tools that prevent BCSI from being transmitted in clear text outside of an encrypted container (e.g. inability to attach documents to email, automated scan of documents attached to emails prior to sending, etc.)
    f. Utilizing a distributed model for data storage, where the Responsible Entity's data is split up across multiple locations (e.g. Blockchain)
2. Implementation of administrative methods to protect BCSI:
    a. Vendor service agreements and/or vendor service risk assessments that specifically address the confidentiality of the Responsible Entity's information or specifically address the CSP's access management controls/obligations.
    b. Vendor's certification, including security controls that reduces the risks of compromising the confidentiality of Responsible Entity's BCSI; and third-party audit

[4] One source for cyber industry encryption best-practice information is Federal Information Processing Standards (FIPS) 140-2.

reports validating those security controls are effective and being followed, such as FedRAMP Audit reports, SOC 2 Type 2 reports or similar.

c. Electronic banners to remind personnel of certain handling actions to either take or not take in order to ensure the confidentiality of BCSI.

CIP-004-7 – Cyber Security – Personnel & Training

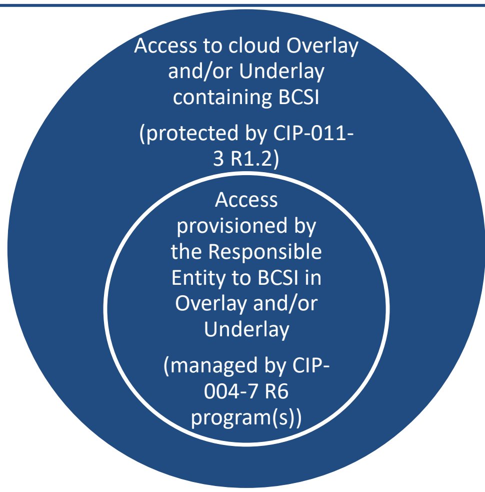
Requirement R6

R6. Each Responsible Entity shall implement one or more documented access management program(s) to authorize, verify, and revoke provisioned access to BCSI pertaining to the "Applicable Systems" identified in CIP-004-7 Table R6 – Access Management for BES Cyber System Information that collectively include each of the applicable requirement parts in CIP-004-7 Table R6 – Access Management for BES Cyber System Information. To be considered access to BCSI in the context of this requirement, an individual has both the ability to obtain and use BCSI. Provisioned access is to be considered the result of the specific actions taken to provide an individual(s) the means to access BCSI (e.g., may include physical keys or access cards, user accounts and associated rights and privileges, encryption keys).

Depending upon a Responsible Entity's implementation and specific services, their BCSI may reside within the Overlay (as is more common with SaaS) or may reside in the Underlay (as is more common with PaaS and IaaS). As it pertains to an off-premises cloud environment, the Responsible Entity may document within their access management program(s) that provisioned access pertains to access to BCSI in the Overlay and/or Underlay that is authorized by the Responsible Entity. They may also further clarify that this does not include:

- access to information within the Overlay and/or Underlay, which includes BCSI, that is authorized by the CSP for their personnel (such as may be needed for workflow management, etc.) This should be addressed by the Responsible Entity's CIP-011 Information Protection Program.
- access to the Underlay that may be needed by CSP personnel for maintenance (patching, updates, etc.) of the Underlay infrastructure. This should be addressed by the Responsible Entity's CIP-011 Information Protection Program.

This diagram depicts at a high-level how access to a Responsible Entity's Overlay and/or Underlay (containing BCSI) could be protected between CIP-004-7 R6 and CIP-011-3 R1:



Requirement R6, Part 6.1

CIP-004-7 Table R6 – Access Management for BES Cyber System Information			
Part	**Applicable Systems**	**Requirements**	**Measures**
6.1	High Impact BES Cyber Systems and their associated: 1. EACMS; and 2. PACS Medium Impact BES Cyber Systems with External Routable Connectivity and their associated: 1. EACMS; and 2. PACS	Prior to provisioning, authorize (unless already authorized according to Part 4.1.) based on need, as determined by the Responsible Entity, except for CIP Exceptional Circumstances: 6.1.1. Provisioned electronic access to electronic BCSI; and 6.1.2. Provisioned physical access to physical BCSI.	Examples of evidence may include, but are not limited to, individual records or lists that include who is authorized, the date of the authorization, and the justification of business need for the provisioned access.

Here are some conditions that Responsible Entities should consider when implementing Part 6.1:

- Responsible Entities should assess and account for all entities (i.e. CSP, Responsible Entity) they are authorizing BCSI access to in the Overlay and/or Underlay, including external parties, in order to ensure all "provisioned access" is identified and authorized; in some implementations this could be multiple parties (for example but not exhaustive: for IaaS, CSP only; for SaaS, software/application provider and CSP if the software/application provider is using a CSP other than itself; for PaaS, platform provider, application provider(s), and CSP)
- Evaluate and identify any shared accounts that are provisioned access to BCSI and ensure individuals are authorized to those accounts. An example of shared accounts in a cloud environment could include emergency or break-glass accounts.

Example compliance approaches have been detailed below, organized by service type and specific example scenarios.

Software as a Service (SaaS) – BCSI is in the Overlay, not Underlay

1. Scenario 1: CSP personnel do not have persistent access to BCSI. CSP personnel may have persistent access to the Responsible Entity's environment/container, but not to the BCSI due to implemented controls. CSP access to BCSI is permitted and controlled by the Responsible Entity with a "Just-In-Time" process. Compliance evidence examples could include but are not limited to:
    a. Documentation of the "Just-In-Time" process and that it has been activated/enabled.
    b. Documentation of each "Just-In-Time" session including the business need, start and end date, and the Responsible Entity's approval. Examples of evidence sources include but are not limited to: 1) the customer/Responsible Entity's ticketing system, 2) "Just-In-Time" usage logs, and 3) customer/Responsible Entity Overlay security and/or audit logs.
2. Scenario 2: The Responsible Entity authorizes CSP personnel to have persistent access to BCSI. This could consist of access to BCSI in clear text or where the individual has access to the encrypted BCSI and the key(s) to unencrypt it. Compliance evidence examples could include but are not limited to:
    a. Documented process for how CSP personnel provisioned access is authorized based on need, whether authorized directly by the Responsible Entity or indirectly by a contractual agreement with the CSP, and one of the following
        i. List of CSP personnel with provisioned access. This would include 1) access to BCSI in clear text, and 2) access to both encrypted BCSI and the encryption keys.
        ii. Authorization records for CSP personnel access. This could include procedural authorization (such as in an access management program/procedure for specific groups of personnel), or individual records of authorization (such as in-service tickets, Just-In-Time access requests, etc.)
        iii. If i. and ii. are not available to the Responsible Entity, then third party audit reports providing reasonable assurance/confirms that the documented authorization process is being followed could be utilized. This could include FedRAMP audit reports, SOC 2 Type 2 reports or similar.
3. Scenario 3: CSP personnel cannot access BCSI. In this scenario, CSP personnel would not have the possibility of obtaining provisioned access, however compliance auditors may want to verify for reasonable assurance. Compliance evidence examples could include but are not limited to:
    a. Diagram(s), processes and/or narrative depicting how CSP personnel are prevented from accessing BCSI. Diagram(s) may include Entity-specific cloud architecture diagrams for the environment hosting BCSI, and/or diagrams provided by the CSP describing their security controls.

b. Evidence of implementation of technical controls preventing CSP personnel from accessing Entity BCSI including: Application programming interface (API) calls identifying who has access to resources owned by the Entity in the cloud environment and associated API logs, evidence of encryption controls implemented by the Entity including access to/management of encryption keys, identity and access management policies implemented by the Entity controlling access to Entity BCSI and list of users.
c. Business Agreements and/or Contracts that include clauses related to customer data privacy and protections as described in the diagram processes, and/or narrative.

Platform as a Service (PaaS) – BCSI can be in the Overlay and Underlay, depending upon the implementation of cloud services

Evidence examples provided under SaaS apply here as well. However, entities need to understand and account for platform providers if the Responsible Entity provisions their access to the Overlay, which may be different than the application/software provider.

Infrastructure as a Service (IaaS) – BCSI can be in the Overlay and Underlay, depending upon the implementation of cloud services

Evidence examples provided under SaaS apply here as well. However, entities need to understand and account for infrastructure providers if the Responsible Entity provisions their access to the Overlay, which may be different than the application/software provider.

Requirement R6, Part 6.2

Part	Applicable Systems	Requirements	Measures
6.2	High Impact BES Cyber Systems and their associated: 1. EACMS; and 2. PACS Medium Impact BES Cyber Systems with External Routable Connectivity and their associated: 1. EACMS; and 2. PACS	Verify at least once every 15 calendar months that all individuals with provisioned access to BCSI: 6.2.1. have an authorization record; and 6.2.2. still need the provisioned access to perform their current work functions, as determined by the Responsible Entity.	Examples of evidence may include, but are not limited to, the documentation of the review that includes all of the following: • List of authorized individuals; • List of individuals who have been provisioned access; • Verification that provisioned access is appropriate based on need; and • Documented reconciliation actions, if any.

Here are some conditions that Responsible Entities should consider when implementing Part 6.2:

- Where shared cloud accounts permit access to BCSI, such as those utilized for break glass or emergencies, the Responsible Entity should ensure that the individuals provisioned access to these accounts are evaluated as part of this review. This implies that the Responsible Entity has a process for authorization to the shared cloud accounts.
- Exception reporting is commonly found in a cloud environment and could be utilized as evidence for part 6.2.1, however the Responsible Entity should be prepared to demonstrate/show the logic behind the report to ensure all provisioned access is being included and compared to

authorization records. In this case, a separate process would be needed to verify the continued need for access for compliance with part 6.2.2.

Software as a Service (Saas), Platform as a Service (PaaS), and Infrastructure as a Service (IaaS)

The Measures for part 6.2 provide examples of the evidence that may be utilized to demonstrate compliance. Below are specific examples that may be available/utilized, as it relates to a cloud service and how access is managed:

1. Scenario 1: Responsible Entity performs all access provisioning to BCSI in the Overlay.
    a. List of authorized individuals:
        i. Output from the Responsible Entity's identity and access management system or other similar access management processes.[5]
    b. List of authorized individuals who have been provisioned access:
        i. Report or screenshot of accounts and/or roles within the cloud service that have provisioned access to BCSI
        ii. If all accounts authenticate to the Entity's on-premises active directory, then a report or screenshot of all active directory accounts that have provisioned access to BCSI within the cloud service
    c. Verification that provisioned access is appropriate based on need:
        i. Output from the Responsible Entity's access management system/process showing verification that the access is still appropriate based on need.
        ii. Evidence of an access review by each individual's manager attesting that access is still appropriate based on need.
        iii. Evidence of an access review of each role and the associated individuals with provisioned access. This review should include an evaluation that the role's access is still appropriate based on need and that the individuals assigned to the role are still appropriate for their current work function(s).
    d. Documented reconciliation actions, if any:
        i. Dated documentation comparing the list of who has been provisioned access in the source system against the list of who has been authorized, the identification of any deltas between the two lists, and the corrective actions taken.
        ii. Exception reports showing only deltas (or null results) between provisioned access and authorization; in addition, evidence of the logic/configuration behind the exception report.

[5] Where a Just-In-Time process is utilized for CSP personnel access, this would include any such active access session at the time of the review.

iii. Additional evidence demonstrating corrective actions were taken could include, but are not limited to:

(1) Completed tickets from the Responsible Entity's tracking system showing that corrective action was taken.

(2) Email instruction from the reviewer to the asset owner to take corrective action.

2. Scenario 2: CSP performs all access provisioning to BCSI in the Overlay, after authorization has been provided by the Responsible Entity.
   a. A documented process on how the CSP reviews provisioned access at least once every 15 months, and
   b. Records of the review process, or third-party audit reports validating that the review process is being followed (such as FedRAMP Audit reports, SOC 2 Type 2 reports or similar).
3. Scenario 3: Hybrid Responsible Entity performs all access provisioning for their personnel, and the CSP performs all access provisioning for the CSP personnel.
   a. Please refer to the examples provided for scenarios 1 & 2 above

Requirement R6, Part 6.3

6.3	High Impact BES Cyber Systems and their associated: 1. EACMS; and 2. PACS Medium Impact BES Cyber Systems with External Routable Connectivity and their associated: 1. EACMS; and 2. PACS	For termination actions, remove the individual's ability to use provisioned access to BCSI (unless already revoked according to Part 5.1) by the end of the next calendar day following the effective date of the termination action.	Examples of dated evidence may include, but are not limited to, access revocation records associated with the terminations and dated within the next calendar day of the termination action.

Here are some conditions Responsible Entities should consider when implementing Part 6.3:

- Responsible Entities should have a clear understanding as to how provisioned access to BCSI is revoked in the cloud. For example, if access is revoked via a connection from the Responsible Entity's active directory to the cloud active directory, then the Responsible Entity should review the synchronization cycles to ensure they occur frequent enough to meet the end of the next calendar day in all scenarios.
- If emergency/break-glass accounts are used, particularly if they do not authenticate back to the Responsible Entity's active directory, then the Responsible Entity should consider and address how to ensure a terminated individual's ability to use provisioned access to BCSI via those account credentials is revoked. For example, if the credentials are believed to be known to the individual, the Responsible Entity could change the password to those accounts as a means to remove their ability to access BCSI.

Software as a Service (SaaS), Platform as a Service (PaaS), and Infrastructure as a Service (IaaS)

The Measures for part 6.3 provide an example of the evidence that may be utilized to demonstrate compliance. Below are some more specific evidence examples that may be available/utilized, as it relates to a cloud service and how access is managed:

1. Scenario 1: Responsible Entity performs revocation of all provisioned access to BCSI in the Overlay. Examples of evidence may include but are not limited to:
   a. Evidence demonstrating the termination effective date for the individual.
   b. Access revocation record from the cloud audit log showing date and time when access for the terminated individual was revoked.
   c. Completed and dated ticket showing action taken to revoke a terminated individual's access.
   d. If the terminated individual's account(s) authenticates to the Responsible Entity's on-premises active directory, then a report or record showing when the individual's active directory account was disabled; in addition, evidence of the active directory synchronization setting/configuration.
2. Scenario 2: CSP performs revocation of all provisioned access to BCSI in the Overlay. Examples of evidence may include but are not limited to:
   a. Evidence demonstrating the termination effective date for the individual.
   b. A documented process on how the CSP terminates provisioned access before the end of the next calendar day, and either 1) dated records of the provisioned access revocation or, 2) audit reports validating that the provisioned access revocation process is being followed, such as FedRAMP Audit reports, SOC 2 Type 2 reports or similar.
   c. Access revocation record from the customer/Responsible Entity's Overlay security and/or audit logs showing date and time when access for the terminated individual was revoked.
   d. Completed and dated ticket showing action taken to revoke a terminated individual's access.
   e. If the terminated individual's account(s) authenticates to the CSP-managed cloud application active directory, then a report or record showing when the individual's active directory account was disabled.
3. Scenario 3: Hybrid performance of revocation: Responsible Entity revoked all provisioned access to BCSI in the Overlay for their personnel, and the CSP revokes all provisioned access to BCSI in the Overlay for the CSP personnel.
   a. Please refer to the examples provided for scenarios 1 & 2 above.

Periodic Review

This document will be reviewed and updated upon initiation of a standards development project to modify the CIP-004-7 and/or the CIP-011-3 Standard, or as the need to modify has been determined by the NERC Security Working Group or Reliability and Security Technical Committee.

Appendix A –Examples of Cloud Services

To aid readers in better understanding the three models of cloud service, below are some examples of current services in the market. (Note: The services in this list will likely change over time.) Please note that this list should not be considered as an endorsement of any kind.

Software as a Service (SaaS)

- Web-based email services such as Outlook and Gmail
- Microsoft 365 (includes apps such as SharePoint Online, Exchange Online, Teams, etc.)
- ServiceNow Enterprise CX (IT asset inventory and ticketing system)

Platform as a Service (PaaS)

- Microsoft Azure
- ServiceNow Now Platform
- SAP Cloud
- AWS Elastic Beanstalk
- Google App Engine

Infrastructure as a Service (IaaS)

- Amazon Web Services (AWS)
- IBM Cloud
- Microsoft Azure
- Commvault Backup & Recovery
- Faction

Proven Compliance Solutions Inc.

Proposed Implementation Guidance: Usage of Cloud Solutions for BCSI

- Developed by the Security Working Group

June 2023

PROVEN COMPLIANCE SOLUTIONS

Security Working Group SubTeam Members

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- Ryan Alpers, Manitoba Hydro
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- John Dirks, SRP
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- Tony Freeman, ReliabilityFirst
- Frank Kapuscinski, ReliabilityFirst

PROVEN COMPLIANCE SOLUTIONS

Why was this Guidance Developed?

1. Many vendors are phasing out their on-premises solutions and migrating them to the cloud or building new solutions using only cloud services/environments.
2. Responsible Entities need increased choice, greater flexibility, higher availability, and reduced-cost options to manage their BES Cyber System Information (BCSI), which includes the use of third-party off-premises cloud solutions.
3. Understanding security and compliance in these new and sometimes complex environments has been a common challenge in the industry.

Scope of the Guidance

- BCSI in an off-premise cloud environment
  - SaaS – Software as a Service
  - PaaS – Platform as a Service
  - IaaS – Infrastructure as a Service
- Considerations, approaches and evidence examples as it relates to:
  - CIP-004-7 R6, parts 6.1-6.3
  - CIP-011-3 R1, parts 1.1 and 1.2

Does NOT address or provide guidance related to BES operations in the cloud.

Implementation Guidance Development History

- **June 2020** – V1 endorsed by CIPC/RSTC; submitted to ERO for endorsement
- **Oct. 2020** – ERO Enterprise did not endorse V1; provided detailed feedback verbally
- **Apr. 2021** – V1 modified to address ERO Enterprise feedback
- **June 2021** – V2 endorsed by RSTC; submitted to ERO for endorsement
- **Nov. 2021** – ERO Enterprise did not endorse V2; provided detailed feedback verbally
- **Apr. 2022** – ERO announces more collaborative process
- **Jan. 2023** – V3 submitted to ERO Enterprise for informal feedback
- **March 2023** – Informal feedback received on V3
- **May 2023** – V3 submitted for RSTC endorsement (June meeting)
- **June 2023** – RSTC decision; if endorsed, V3 will be submitted to ERO for endorsement

Here are some of the key concepts that are clarified by the Implementation Guidance

Key Concept: High-Level Perspective

Figure 1 illustrates the high-level relationship between CIP-011-3 R1 and CIP-004-7 R6, and explains why you will see guidance on CIP-011-3 R1 before CIP-004-7 R6 within this document:

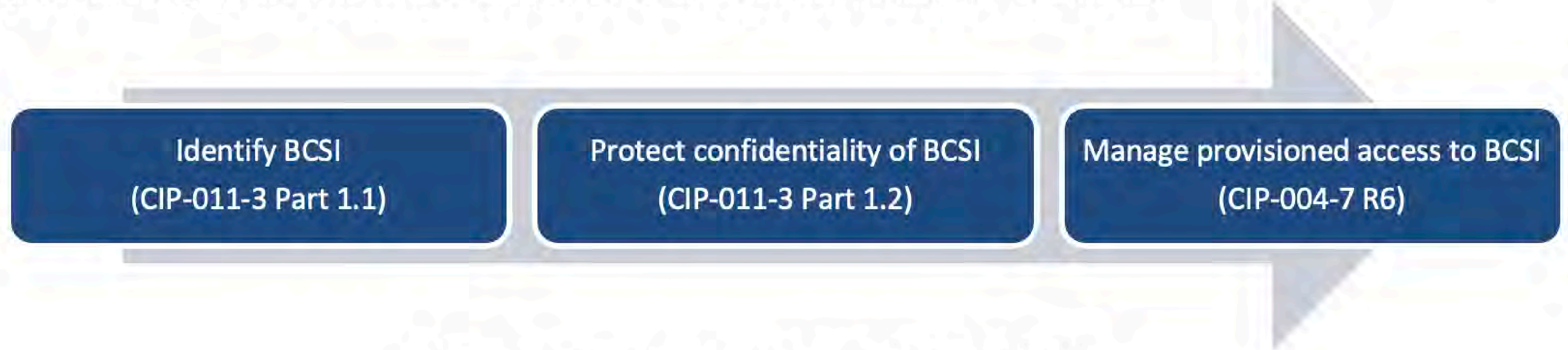

Figure 1 - Relationship between CIP-011-3 R1 & CIP-004-7 R6

Key Concept: Shared Responsibility Model

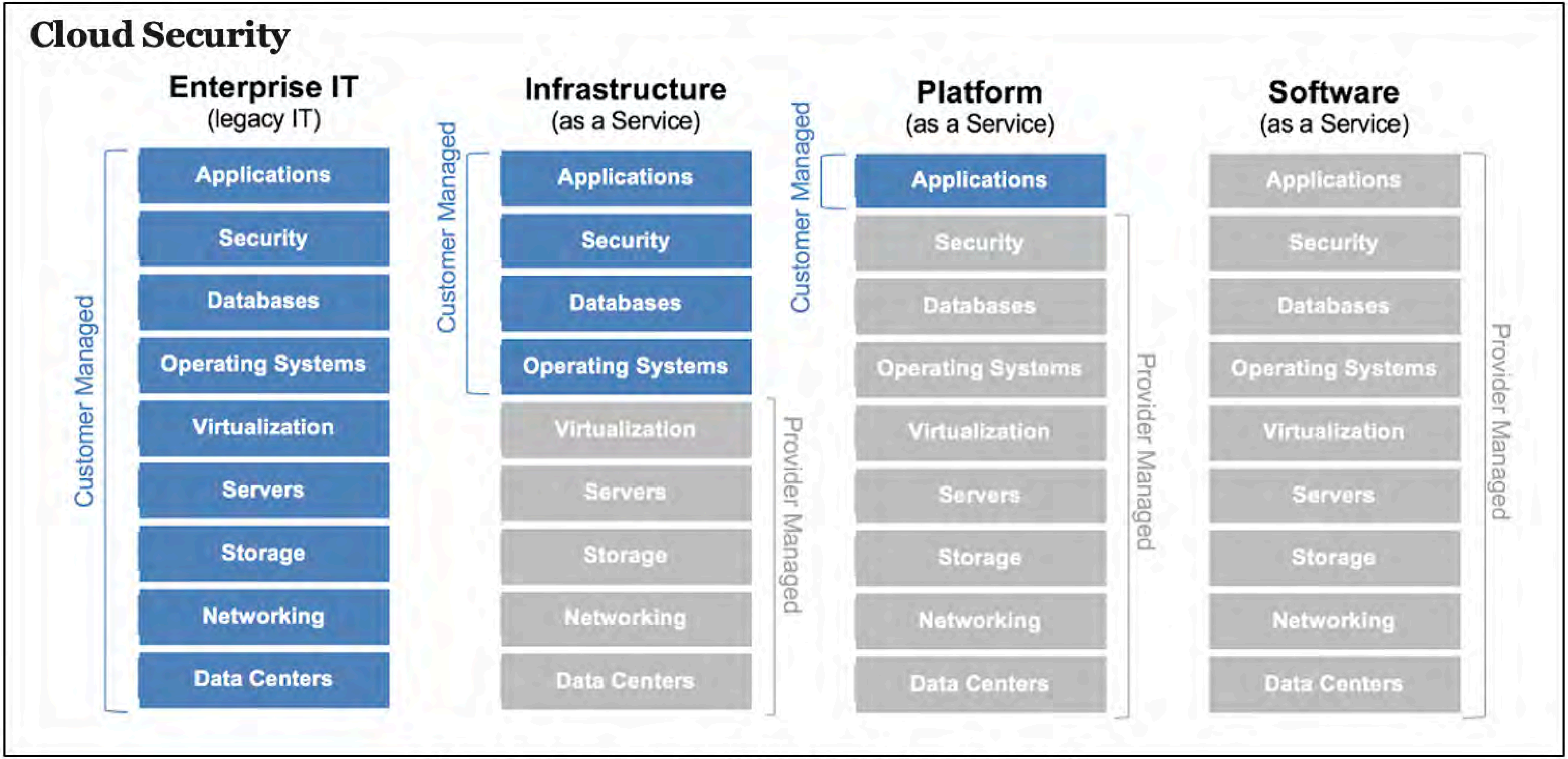

Figure 2 – Security responsibilities by cloud service model

Key Concept: Overlay vs. Underlay

Depending upon a Responsible Entity's implementation and specific services, its BCSI may reside within the Overlay (as is more common with SaaS) or may reside in the Underlay (as is more common in a PaaS or IaaS implementation).

Figure 3 is a generalized diagram of a cloud environment depicting the division between the Overlay and Underlay.

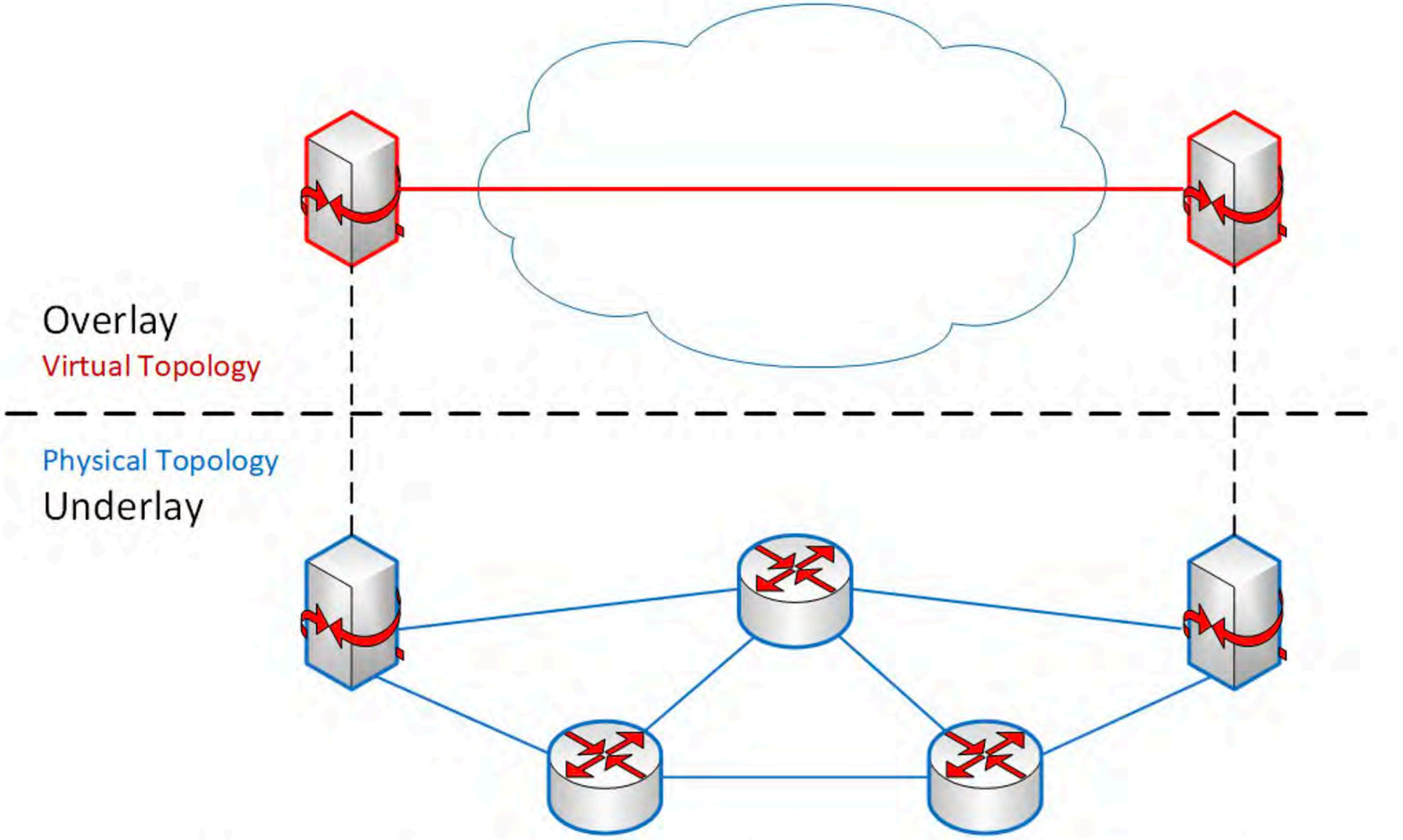

Figure 3 – Example diagram of a cloud environment to depict the division between the Overlay and Underlay

Key Concept: Access vs Provisioned Access

Access to cloud Overlay and/or Underlay containing BCSI

(protected by CIP-011-3 R1.2)

Access provisioned by the Responsible Entity to BCSI in Overlay and/or Underlay

(managed by CIP-004-7 R6 program(s))

Questions?

Mapping of CIP Reliability Standards to NIST Cyber Security Framework

Action

Information

Background

An ever-expanding base of documents, products, and services have necessitated an automated means of relating these resources in a consistent and authoritative manner. The National Online Informative References (OLIR) Program is a National Institute of Standards and Technology (NIST) effort that enables subject matter experts (SMEs) to define standardized online informative references between elements of their documents, products, and services and elements of NIST documents.[1]

OLIRs are formatted in a consistent manner and displayed in a centralized location – the OLIR Catalog.[2] Document owners and security practitioners can refer to the OLIR Catalog if they wish to identify and compare the security controls and standards from their own organization with those that have been developed by other organizations, or the OLIR information can simply facilitate communication with owners and users of other documents. Document owners also have the flexibility to update their documents and then update their OLIRs according to the unique requirements and schedules of their organization.

Summary

NIST and the North American Electric Reliability Corporation's (NERC) Security Working Group (SWG), in a joint effort, mapped the elements between the Cybersecurity Framework Core (CSF) v1.1 and the Critical Infrastructure Protection (CIP) Cyber Security Reliability Standards. This mapping provides a better understanding of measures that enhance the security of the national grid.

The SWG provided expertise to map the relevant CIP Reliability Standards to the NIST document. The mapping is a NIST tool that depicts how requirements from each framework/standard relate to one another. The mapping does not direct performance of specific activities nor does it make recommendations or provide compliance guidance. NIST's process typically requires a 30 day initial public review; however, the review period for this mapping has been extended to 45 days to ensure industry has sufficient time to review. The SWG has published an announcement to alert industry to that.

While the primary audience for the OLIR is members of the Energy Sector Critical Infrastructure, electric segment, especially NERC registered entities, the information will be publicly accessible so any user can use published criteria from NIST as a common reference for identifying useful security measures and controls that enhance security and mitigate risks.

[1] https://csrc.nist.gov/Projects/olir
[2] https://csrc.nist.gov/projects/olir/informative-reference-catalog

Throughout an OLIR’s life cycle, any user can submit suggested edits/revisions, comments, or questions to NIST, who will forward feedback to the developer. For this project, the SWG will remain as the assigned developer and has established a process for responding to feedback.

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NIST CSF to NERC CIP Standards Mapping

Navigating the Mapping on the NIST National Online Informative Reference (OLIR) Program

2023

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Background

- 2019-2021, NERC SWG published the mapping between the CIP Cyber Security Standards and the NIST Cybersecurity Framework v1.1.
- 9/29/2021, NIST published a Cybersecurity White Paper, “Benefits of an Updated Mapping between the NIST Cybersecurity Framework and the NERC Critical Infrastructure Protection Standards.”
- 2022-2023, joint effort between NIST and NERC SWG revised and updated the mapping and reformatted into the OLIR format.

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Background

- The National Online Informative References (OLIRs) Program is a NIST effort to facilitate subject matter experts in defining standardized online informative references between elements of their documents (Reference Document) and elements of NIST documents (Focal Document).
- 5/30/2023, NIST published the mapping for a 45-day public comment period.

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CSF Core and CIP Descriptions

- CSF Core Consists of Three (3) Elements:
  - Functions- basic cybersecurity activities at their highest level.
  - Categories- subdivisions of a Function into groups of cybersecurity outcomes.
  - Subcategories– divide a Category into specific outcomes of technical and/or management activities.
- CIP Consists of a Family of Standards:
  - Mandatory for the electricity segment of the Energy Sector.
  - Twelve (12) Cyber Security and one (1) Physical Security Standard work collectively.

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Understand The Mapping

- An *informative reference* is a relationship between an element of one document relating to an element of another document.
- Focal Document – NIST document as the basis for comparison.
- Reference Document – Document being compared to Focal Document.
- Mapped Each CIP Standard Requirement to the CSF Function, Category, and Subcategory.
- Mapped elements are further categorized by:
  - Rationale,
  - Relationship, and
  - Strength of Relationship.

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Understand The Mapping: Rationale

- Rationale Options for each Informative Reference:
  - Semantic—the two elements have the same meaning; the same thing
  - Functional—the two elements achieve the same result or outcome
  - Syntactic—the two elements use the same words or have identical syntax

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Understand The Mapping: Relationship

- Relationship Options for Each Informative Reference:
  - Subset of—the NERC CIP standard language covers everything that is in the CSF Subcategory and has even more
  - Superset of—the CSF Subcategory language covers everything that is in the NERC CIP standard and has even more
  - Intersects with—the CSF Subcategory language and the NERC CIP standard language have some common concepts, and they each have unique concepts not covered by the other
  - Equal to—the concepts in both the CSF Subcategory and the NERC CIP standard have all the same concepts and nothing different
  - Not related to—NIST CSF element and NERC CIP element do not have anything in common

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Understand The Mapping: Strength of Relationship

- Strength of Relationship
  - Subjectively quantify the SOR between elements to provide users with additional insight into the implied bond between reference elements asserted by the Developer (SMEs).
  - SOR metric score between 1 and 10, 10 being the strongest.
  - For simplicity, we only used 2, 5, and 8 options in our effort

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Understand The Mapping: Mapping CSF Core and CIP Elements

Focal Document Element	Focal Document Element Description	Rationale	Relationship	Reference Document Element	Reference Document Element Description	Comments (optional)	Strength of Relationship (optional)
ID	Develop an organizational understanding to manage cybersecurity risk to systems, people, assets, data, and capabilities					No Mapping	
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 organizational objectives and the organization's risk strategy.					No Mapping	
ID.AM-1	Physical devices and systems within the organization are inventoried	Semantic	superset of	CIP-002-5.1a-R1	R1 Implement a process that considers these assets for parts 1.1 through 1.3 i. Control Centers and backup Control Centers ii. Transmission stations and substations iii. Generation resources iv. Systems for restoration, including Blackstart and Cranking Paths v. Special Protection Systems vi. Specifically identified Distribution Providers, Protection Systems R1.1 Identify high impact BES Cyber Systems, Attachment 1, Section 1 R1.2 Identify medium impact BES Cyber Systems, Attachment 1, Section 2 R1.3 Identify low impact BES Cyber System, Attachment 1, Section 3 (a list not required)	Selected 'Semantic' because elements have similar meanings. Selected 'superset of' because ID.AM-1 is about inventorying all systems, while R1 is about inventorying BES Cyber Systems. Strong relationship strength.	8

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OLIR Project Sub-Team

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- Jeffrey Marron, NIST
- Karl Perman, EnergySec
- David Vitkus, WECC

Questions and Answers

White Paper: Zero Trust for Electric OT
(NERC Security Integration and Technology Enablement Subcommittee)

Action
Approve

Background
SITES formed a subteam for Zero Trust to develop this whitepaper with the purpose of providing clarity to the electric industry on the applicability of concepts to electric operations technology environments and enabling valuable use cases addressing barriers to adoption such as legacy technology and compliance. This whitepaper has been updated after RSTC and further SITES and SWG comments and review.

Summary
The SITES white paper informs the electricity sector on zero trust (ZT) concepts and provides considerations and recommendations regarding the adoption of ZT controls in operational technology (OT) and industrial control system (ICS) environments. The paper leverages the concept ZT maturity models for varying levels of implementation by registered entities and recommends entities develop their own roadmap for security and technology maturation. Finally, the paper describes considerations regarding ZT adoption by registered entities and the NERC Critical Infrastructure Protection (CIP) standards.

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White Paper

Zero Trust Security for Electric Operations Technology
May 2023

Executive Summary

Zero trust (ZT) offers the electric industry a clear direction forward for continual improvement to securing our critical infrastructure against emerging threats to operations technology (OT)—including ransomware and the proliferation of industrial control system malware tools, such as Pipedream. ZT is a collection of concepts intended to drive least privilege further, building upon and enhancing historical controls and perimeter-based security models rather than tearing them down. Industry needs to continue to develop equipment and software as well as people, processes, policies, and governance capable of delivering on ZT principles. Entities should invest in staff training for ZT, develop OT security programs, design roadmaps based on a ZT maturity model for the development of ZT architecture (ZTA) at the right pace for their organization. Additionally, using a thoughtful implementation process will allow organizations to incorporate ZTA incrementally and should be done in collaboration with OT integrators and vendors. OT networks and legacy devices may create constraints that require hybrid approaches to solve. No single product or tool on the marketplace provides a complete ZTA, and organizations may already have infrastructure and controls in place that qualify as components of a ZTA. Finally, entities are encouraged to stage rollouts of ZTA starting with information technology (IT) networks and demilitarized zones (DMZ) to build familiarity with the complexities, challenges, and impacts of the controls and technology before implementing in the OT space.

Introduction

The purpose of this white paper is to inform the electricity sector about ZT concepts and to provide considerations and recommendations regarding the adoption of ZT controls in OT and industrial control system (ICS) environments. This paper describes some of the key differences between OT and IT environments; however, this paper’s focus is specifically on the implementation considerations in the OT environment. This paper also leverages the concepts of ZT maturity models for varying levels of implementation by registered entities. Lastly, this paper describes considerations regarding ZT adoption by registered entities and the NERC Critical Infrastructure Protection (CIP) standards. One threat today that has driven the need for ZT principles is ransomware. When ransomware compromises one device inside a typical network perimeter, it then uses the inherent trust of network peers to spread to other devices. In the case of enterprise networks, this may compromise dozens, hundreds, or tens of thousands of network peers through the inherent trust inside the perimeter. Another example is known as “pivoting,” where an attacker may gain access to one device through a legitimate communication allowed through a network perimeter but then launches attacks from that device and compromises other more critical systems within the perimeter. ZT aims to strengthen security with controls better able to detect, mitigate, or prevent such threats.

What is ZT?

Computer networks have been traditionally designed to follow a “bastion” model wherein strong, multilayered defenses are utilized to mitigate intrusion. Defenses inside the bastion are typically far less robust, and the average process or user can traverse a network, system, or application to access those resources they desire once admitted. Internal security controls and monitoring are potentially less robust and assume that a running process, service, or authenticated user is “trusted” so their actions receive less scrutiny than they do at the network boundary. ZT principles are designed to mitigate these types of “inherent trust” issues. The concept of ZT shifts cyber security control design philosophy from the old adage of “trust, but verify” to “never trust, constantly verify.” No device gains inherent trust from its network location even if it is a local network peer. In a ZTA, no user or device is implicitly trusted and undergoes access and authorization tests continually. There is no default visibility or access on networks; any and all access must be enabled via policy. Policy, not topology, governs visibility and access between devices. Additionally, ZT principles drive access decisions to be much more granular, granting access to individual resources, services, or limited network access with potentially different tests for each access request and ongoing tests to maintain access. As ZTAs mature, access can be granted based on user ID, method of authentication, state of the user’s device, protocol security level, and numerous other variables to build deeper, fuller trust that the access being granted is currently authorized. ZTA aims to fill internal control gaps and reinforce perimeters with additional or more effective controls rather than tear them down.

ZT as Defined by the National Institute of Standards and Technology

The National Institute of Standards and Technology (NIST) defines ZT as a collection of concepts and ideas designed to minimize uncertainty in enforcing accurate, least privilege per-request access decisions in information systems and services in the face of a network viewed as compromised.[1] The basic premise of ZT is that there is no implicit trust granted to user or systems based on their physical or network location because there is no trust of any network, user, or device.[2]

NIST further defines ZTA as an enterprise cyber security plan that utilizes ZT concepts and encompasses component relationships, workflow planning, and access policies. Therefore, a ZT enterprise is the network infrastructure (physical and virtual) and operational policies that are in place for an enterprise as a product of a ZTA plan.[3]

Tenets of ZT from NIST

ZTA is designed and deployed with adherence to the following ZT basic tenets:

- ***All data sources and computing services are considered resources.*** A network may be composed of multiple classes of devices. A network may also include small footprint devices, such as sensors and collectors, that send data to aggregators/storage, software-as-a-service applications, and more. Also, an enterprise may decide to classify personally owned devices as resources if they can access enterprise-owned resources.
- **All communication is secured regardless of network location.** Network location alone does not imply trust. Access requests originating from trusted devices and trusted network locations (e.g., located on enterprise-owned network infrastructure) should be held to the same minimum level of

[1] https://csrc.nist.gov/glossary/term/zero_trust
[2] https://www.nerc.com/pa/Stand/Project 201602 Modifications to CIP Standards RF/2016-02_CIP-005_and_Zero_Trust_Webinar_Slides_02192020.pdf
[3] https://nvlpubs.nist.gov/nistpubs/SpecialPublications/NIST.SP.800-207.pdf

security scrutiny as requests originating from anywhere else, including untrusted devices, public internet, partner WANs, etc. In other words, trust should not be automatically granted based on the device being on an enterprise network infrastructure. All communication is done in a secure manner, protecting confidentiality and integrity and providing source authentication.

- **Access to individual enterprise resources is granted on a per-session basis.** Trust in the requester is evaluated before the access is granted; access should also be granted with the least privileges needed to complete the task. Additionally, authentication and authorization to one resource will not automatically grant access to a different resource.
- **Access to resources is determined by dynamic policy—including the observable state of client identity, application/service, and the requesting asset—and may include other behavioral and environmental attributes**. An organization protects resources by defining what resources it has, who its members are (or the ability to authenticate users from a federated community), and what access to resources those members need. For ZT, client identity can include the user account (or service identity) and any associated attributes assigned by the enterprise to that account or artifacts to authenticate automated tasks. Requesting asset state can include device characteristics like software versions installed, network location, time/date of request, previously observed behavior, and installed credentials. Behavioral attributes include, but are not limited to, automated subject analytics, device analytics, and measured deviations from observed usage patterns. Policy is the set of access rules based on attributes that an organization assigns to a subject, data asset, or application. Environmental attributes may include factors like requestor network location, time, reported active attacks, etc. These rules and attributes are based on the needs of the business process and acceptable level of risk. Resource access and action permission policies can vary based on the sensitivity of the resource/data. Least-privilege principles are applied to restrict both visibility and accessibility.
- **The enterprise monitors and measures the integrity and security posture of all owned and associated assets.** No asset is inherently trusted. The enterprise evaluates the security posture of the asset when evaluating a resource request. An enterprise implementing ZTA should establish continuous diagnostics and mitigation or a similar system to monitor the state of devices and applications and should apply patches/fixes as needed. Assets that are discovered to be subverted, have known vulnerabilities, and/or are not managed by the enterprise may be treated differently (including denial of all connections to enterprise resources) than devices owned by or associated with the enterprise that are deemed to be in their most secure state. This may also apply to associated devices (e.g., personally owned devices) that may be allowed to access some resources but not others; this also requires a robust monitoring and reporting system in place to provide actionable data about the current state of enterprise resources.
- **Resource authentication and authorization are dynamic and strictly enforced before access is allowed.** This is a constant cycle of obtaining access, scanning and assessing threats, adapting, and continually re-evaluating trust in ongoing communication. An enterprise implementing a ZTA would need to have identity, credential, and access management as well as asset management systems in place. This includes the use of multifactor authentication for access to some or all enterprise resources. Continual monitoring, with possible re-authentication and reauthorization, occurs throughout user transactions as defined and enforced by policy, (e.g., time-based, new resource

requested, resource modification, anomalous subject activity detected) that strives to achieve a balance of security, availability, usability, and cost-efficiency.

- **The enterprise collects as much information as possible about the current state of assets, network infrastructure, and communications and uses it to improve its security posture.** An enterprise should collect data about asset security posture, network traffic, and access requests; process that data; and use any insight gained to improve policy creation and enforcement. This data can also be used to provide context for access requests.

To summarize, an authenticated user or process accesses data through the intermediation of applications in a ZT world. Network based access, such as that conferred by virtual private networks, is avoided while still potentially used, is no longer relied on as the sole source of authentication and encryption; instead, further bolstering those same protections that are already necessarily included in the ZT system and software. Identity management and access controls (e.g., conditional, role based) are enforced at the application. The world of ZT thus resembles modern mobile applications, and many of the services in use today use this model, such as Office 365. ZT embeds comprehensive security monitoring; granular, dynamic, and risk-based access controls; and system security automation in a coordinated manner throughout all aspects of the infrastructure in order to focus specifically on protecting critical assets (data) in real-time within a dynamic threat environment. This data-centric security model allows the concept of least privileged access to be applied for every access decision where the answers to the questions of who, what, when, where, and how are critical for appropriately allowing or denying access to resources.

ZT Maturity Model

ZT should be considered a forward-thinking strategy for control design. However, while real-time, trustless, and policy-based algorithmically-driven access decisions across an organization's technology footprint are a pinnacle to be strived for, it is best to realize a sliding scale maturity model from implicit trust controls to less trust and then to trustless. Across all industries, ZT is a paradigm shift that is accompanied by a roadmap to gradually implement least-trust controls. It is important to understand that available technology solutions can provide incremental steps forward on an entity's ZT maturity roadmap, but no single product, tool, or policy will achieve a complete ZTA. Furthermore, vendors may or may not advertise their products as ZT, as ZT is more a collection of concepts for designing controls that more effectively enforce least privilege security. Carefully planning a transition into ZT controls may allow an entity to manage the risks of difficult design challenges, including choosing on-device deployment (endpoint protection) of ZT controls versus stand-alone solutions like internal network security monitoring solutions. Additionally, granting the time and resources to rollout endpoint protection systems carefully and gradually is paramount to avoiding potentially dangerous operational impacts.

When examining the application of ZT controls in an OT environment, entities may find that not all systems or networks are viable for implementation of all ZT controls. Products and tools designed for OT may lean towards improving detective capabilities over prevention to enable compatibility with sensitive OT requirements and legacy assets. However, limitations can still arise, and hybrid design approaches may represent an optimal solution.

The Cybersecurity and Infrastructure Security Agency (CISA) has defined a ZT maturity model with five distinct pillars (see **Figure 1**). Each pillar may be advanced independently, but an organization is likely to see cross-pillar interoperability and dependencies that require process and technology coordination as they reach advanced maturity.

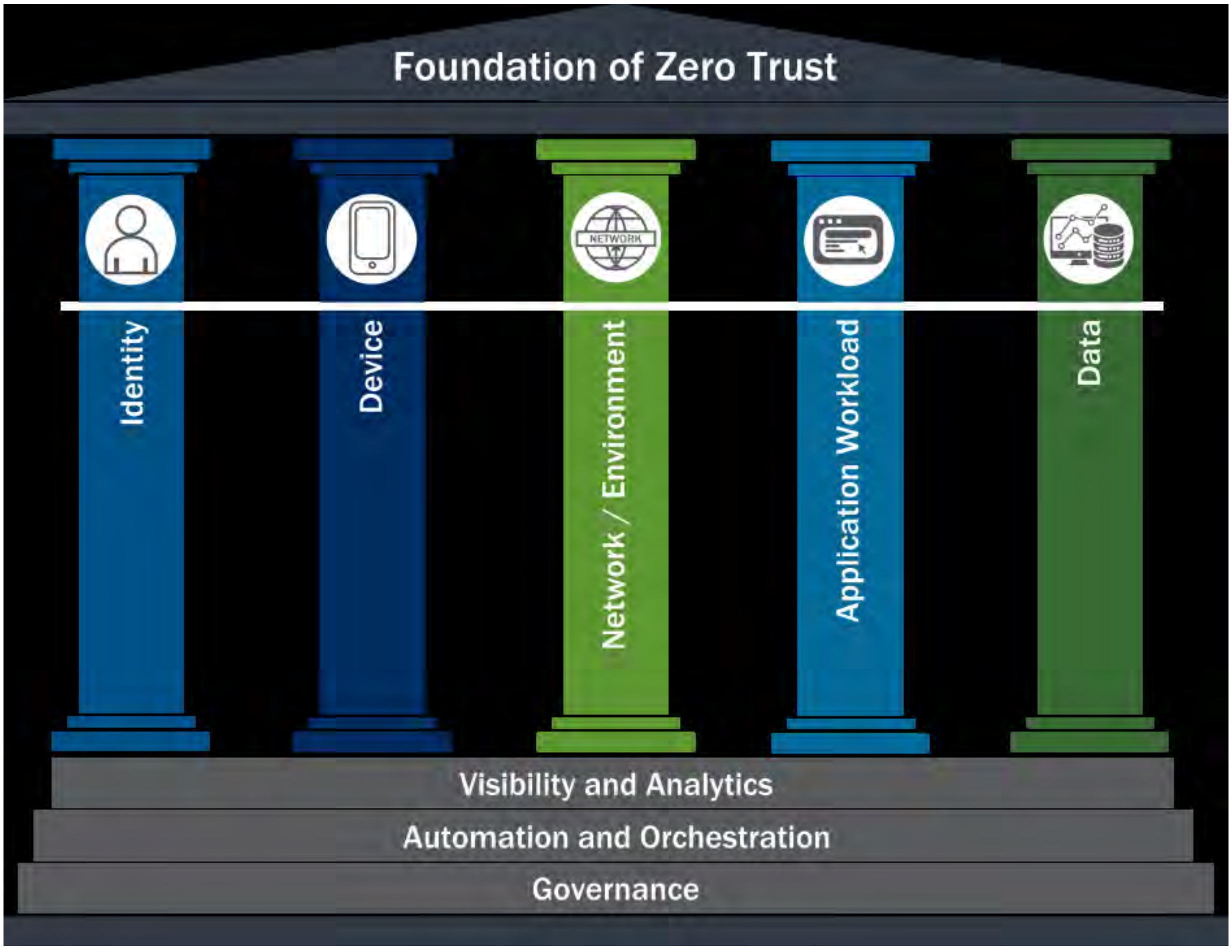

Figure 1: CISA's Foundation for ZT

CISA's maturity model shown in **Figure 2** further develops these pillars across three levels of maturity: traditional, advanced, and optimal.

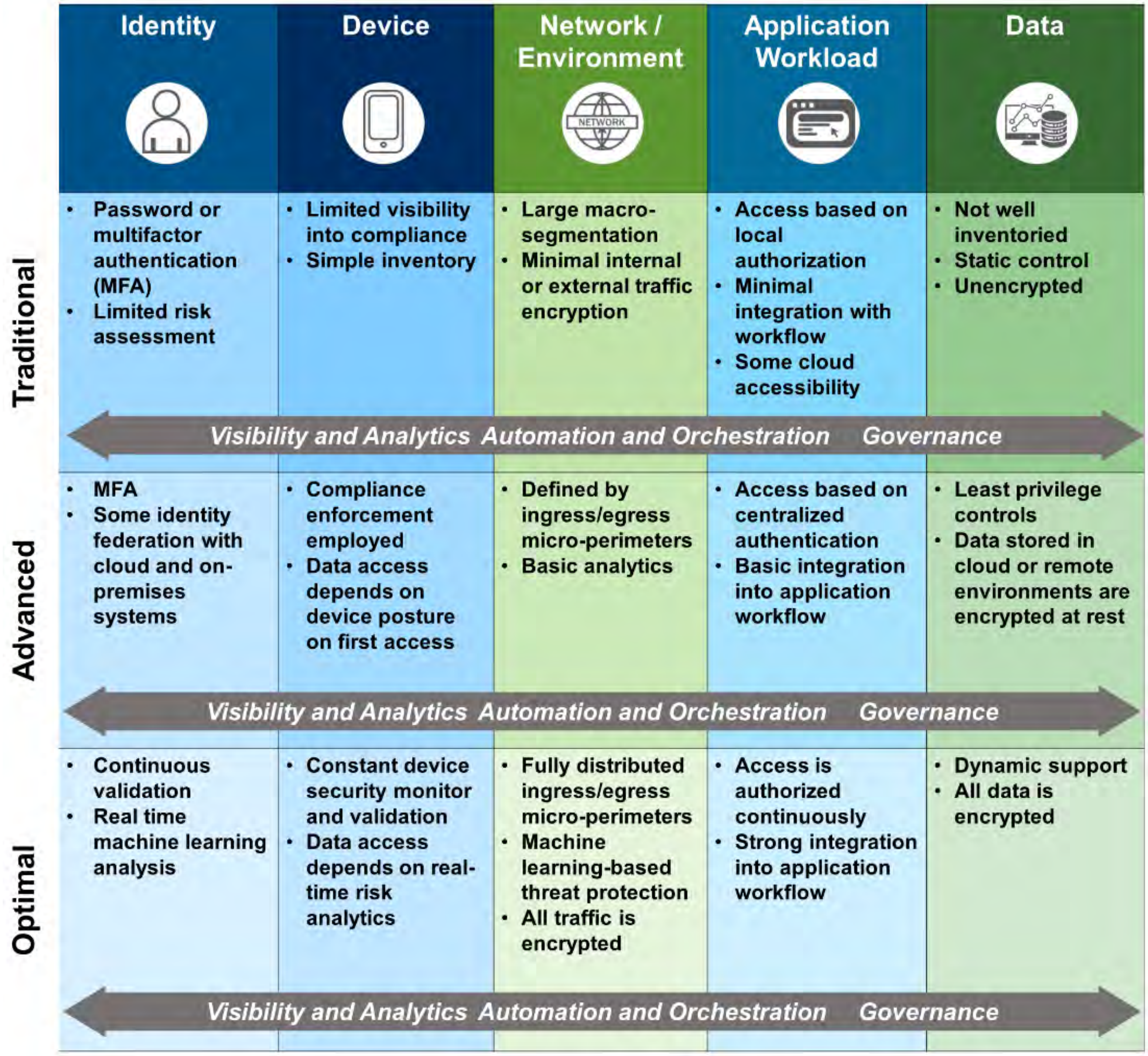

Figure 2: CISA's ZT maturity model

Application of Principles

Trustless Example

What does it mean to be trustless? Consider an example of a system operator logging into a supervisory control and data acquisition (SCADA) human-machine interface or workstation and opening their application client. First, it is taken for granted that the workstation has network access; however, under a ZTA implementation, trustless network access controls would replace this assumed or implied workstation network access authorization. A ZT policy decision engine would perform an algorithmic evaluation of a number of risk factors, such as the workstation's current security patch levels, completed anti-malware scans status, mac address validation, security certificate validation, and/or access authorization to the specific network subnet or virtual local area network (VLAN), such as the control center operator VLAN. Passing all checks results in the workstation being granted network access, but failing one or more tests could result in a quarantining action whereby the network connection is reassigned to a remediation VLAN that limits connectivity to only what is necessary for the system to communicate with patching, anti-virus, and other system management servers. Additionally, it is important to understand that in a truly trustless design, the access decision is one that is continually re-evaluated over time. This ensures adherence to security polices and doesn't allow perpetual access based off prior access decision outcomes.

Similarly, when an operator attempts to authenticate into their SCADA client, additional ZT policies are evaluated against the policy engine: Does the operator have the proper roles or group membership assignments necessary to be authorized for the SCADA application? Does this access request fall within normal operating hours as defined within the policy? Does this login match with the user's previous system usage behavior?

These factors are combined with the source system (the workstation) evaluations previously mentioned. What is the real-time security risk state of the organization at this time? For example, has malware recently been detected? All of these real-time and dynamic evaluations determine if access is granted and to what extent. Dependent on the measured and evaluated risk of the request, access could be denied, granted, or granted with lesser privileges until remediation is achieved. Alternatively, the authentication could be elevated to a multi-factor authentication prompt to address elevated risk.

The example controls given above may seem excessive, or they may be perceived as creating undo operational risk. These are fair concerns and they emphasize the need for utilities to approach ZT with their own roadmap to maturity in collaboration with their OT vendor(s). Controls at the upper end of ZT maturity, especially preventative controls, come with an equal cost of technical complexity and administrative burden due to the system and communication knowledge required to design and upkeep ZT policies that will not cause operational disruptions.

ZT in OT / ICS Environment

In OT/ICS environments, it is important to consider ZT in terms of securing and protecting critical processes, not just data. In other words, when implementing ZT in OT/ICS one must not only consider access and authorization to the data hosted by a data source but managing access to the data source device itself.

Within many (most) OT/ICS environments, a distinction has to be made between the different subsystem capability and functional (Purdue model[4]) levels when considering the implementation of ZT (see **Figure 3**).

[4] Purdue Enterprise Reference Architecture - Wikipedia

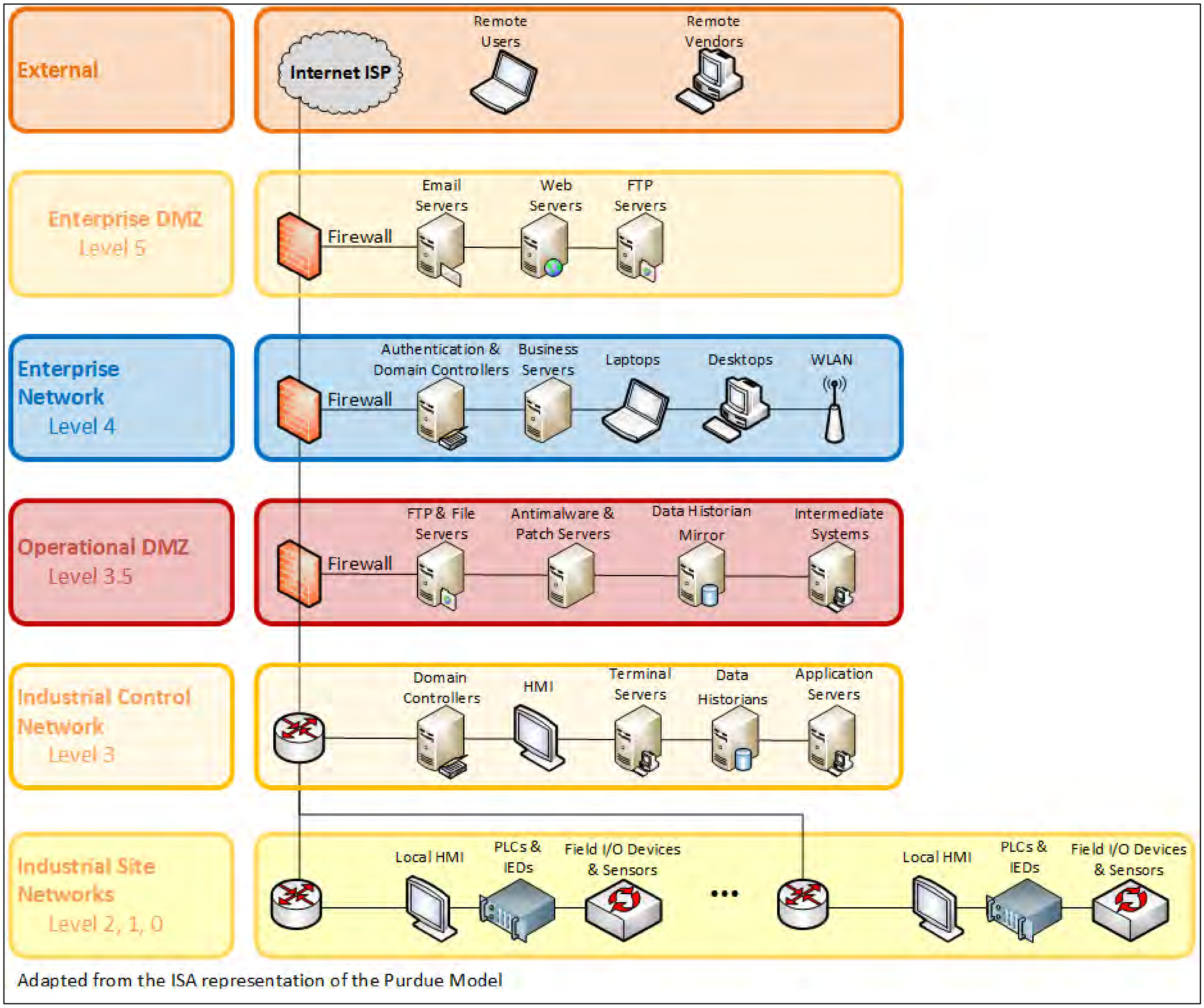

Figure 3: ICS Network by Purdue Model

Lower level (Purdue level 0–1) ICS systems and devices (e.g., IEDs, PLCs, sensors) lack the capability of granular access controls on the device itself and instead rely on perimeter, gateway, and/or front end systems to implement ZT controls.

However, many OT support and control systems (Purdue Level 3 and up), such as historians, human-machine interfaces, PACS, and EACMS, are built on platforms that allow for on-device deployment of ZT controls through granular access management via built-in capabilities or through the use of add-ons, such as endpoint security applications.

The Purdue model is useful for understanding concepts like network segmentation and grouping devices based on function and/or criticality. However, since ZT does not base authorization and trust on the physical or network location of devices and systems, an alternate approach to the Purdue model needs to be considered for devices and systems that are not capable of deploying ZT access controls. The ISA/IEC 62443 model of security zones and conduits (see Figure 4) offers a more granular approach for identifying appropriate and applicable ZT controls that can be implemented within an ICS/OT environment.

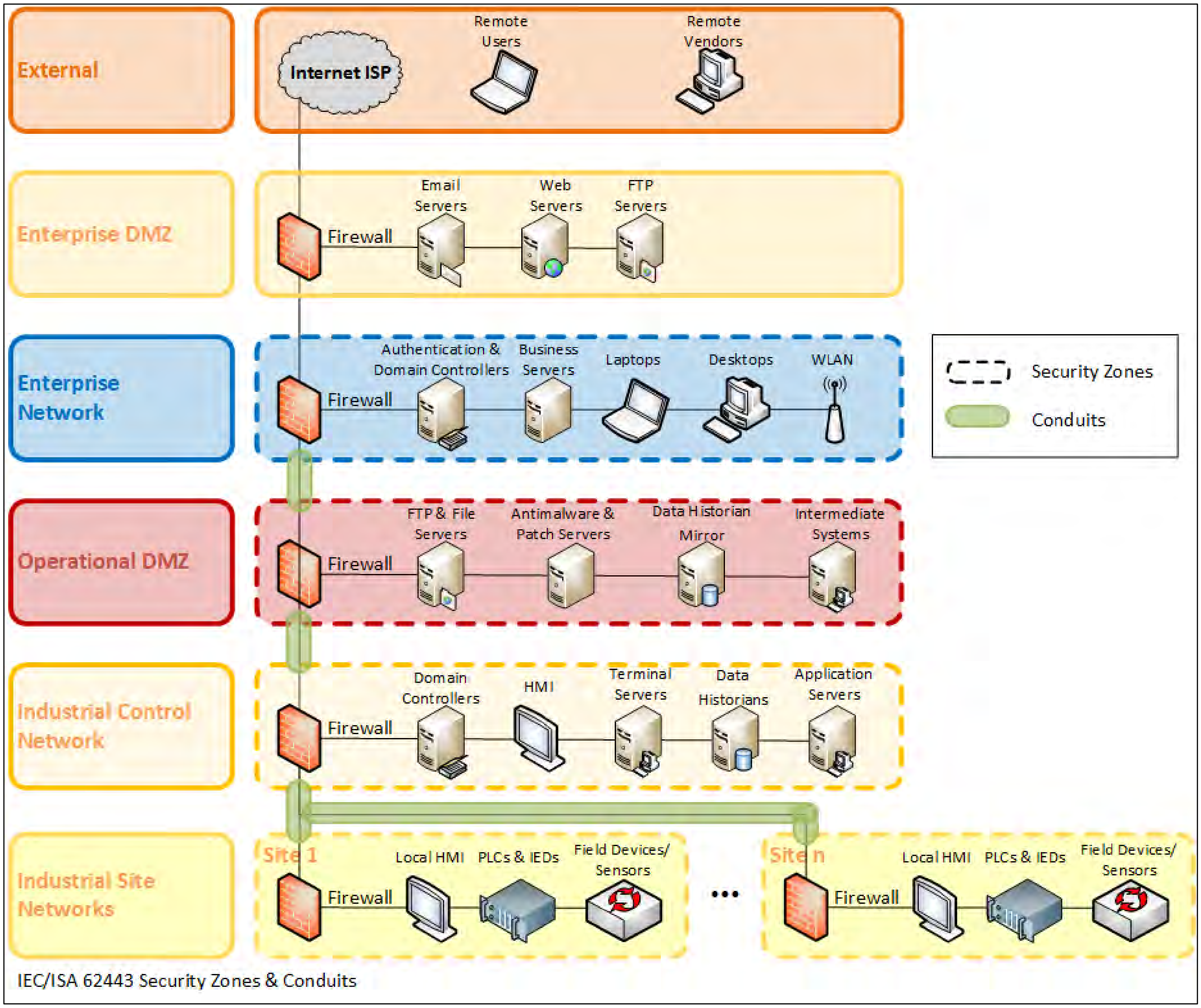

Figure 4: ICS Network by IEC/ISA 62443 Model

Grouping systems and devices that are on the same level within the Purdue model into different security zones allows for establishing ZT access controls even between peer systems on the same level, thus achieving a hybrid design. Security zones can be defined by facility, location, or subsystem within a facility. For example, a utility can define each substation as a single security zone or create separate zones within each substation for an approach that parallels establishing NERC CIP electronic security perimeters (see Figure 5).

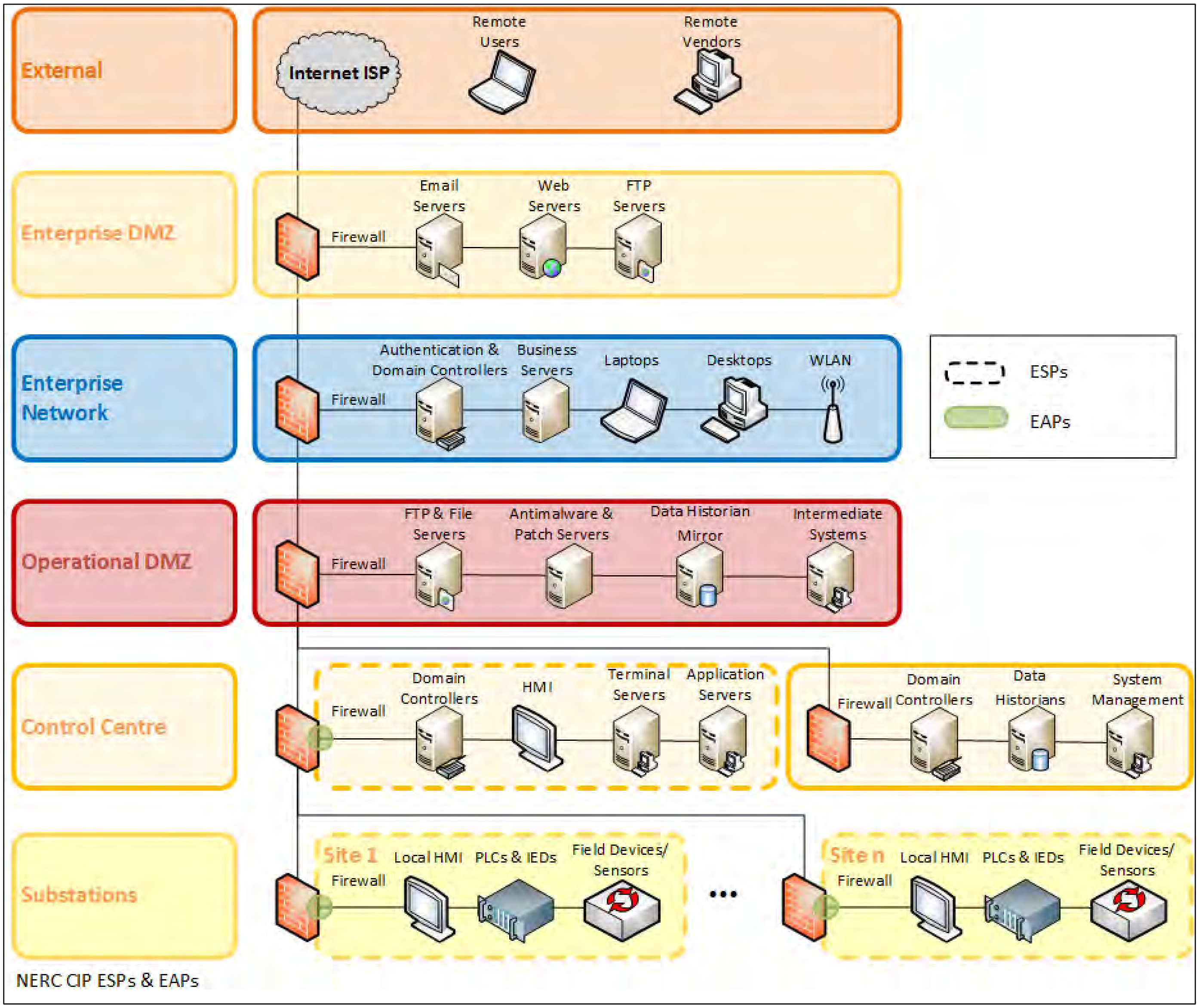

Figure 5: ICS Network by NERC CIP Electronic Security Perimeters

This hybrid approach to ZT can be implemented at a zone level in the areas where the devices within that zone are not capable of implementing host-based security controls (e.g., a substation security zone firewall filtering external inbound/outbound traffic at an application-level) and more granular controls in security zones where the devices are capable of host-based security controls (e.g., a server in the ICS demilitarized zones (DMZ) that filters all connections to the services it hosts). See **Figure 6**.

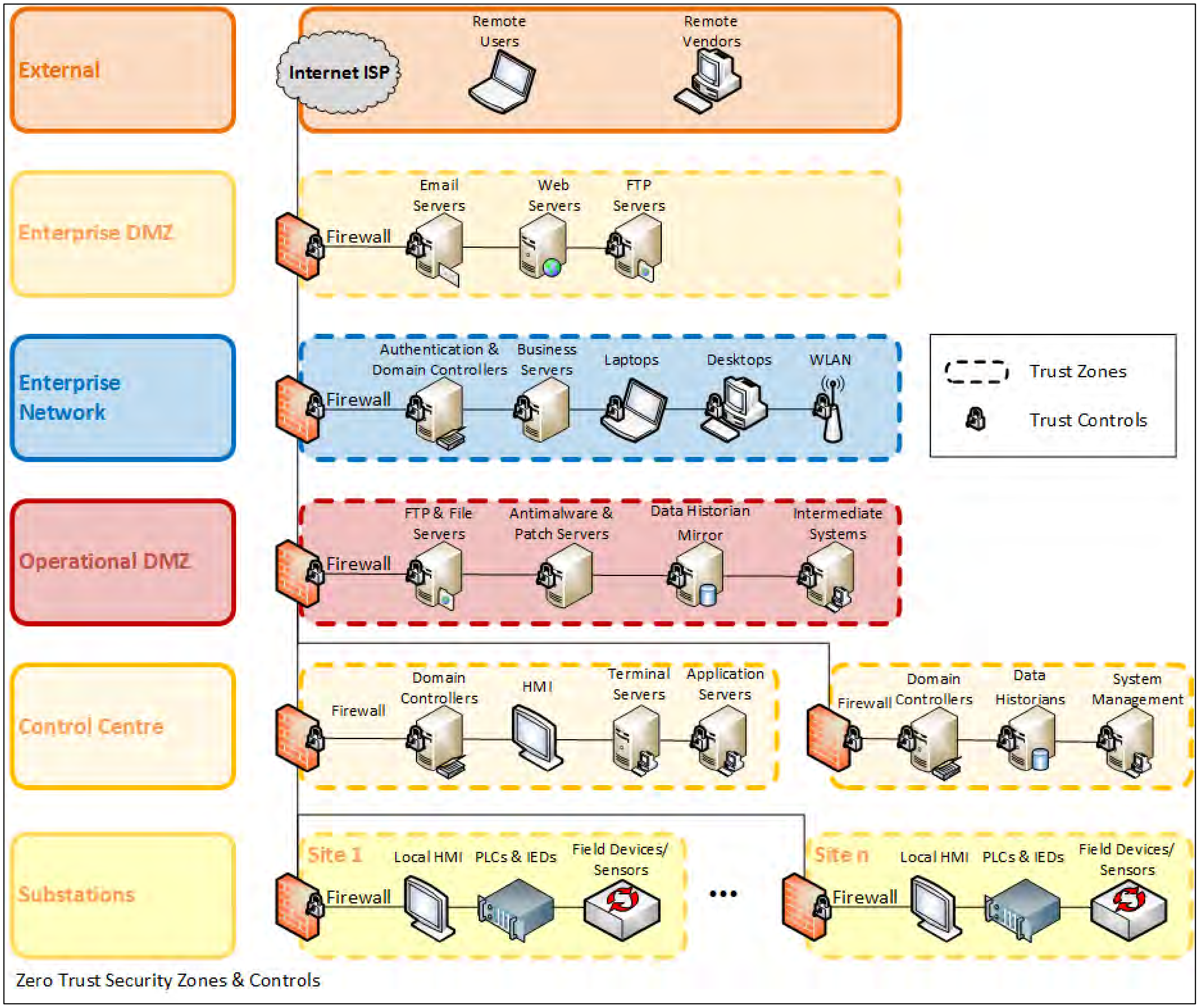

Figure 6: ICS Network by Trust Zones

In light of these mixed capability environments and other factors, there is no "one size fits all" approach that can implement ZT across an organization's entire OT/ICS environment. Rather, the components of ZTA need to be separated and applied where they are capable of being deployed. The ability and extent to which ZTA components can be deployed must be assessed on a site, facility, and subsystem basis. However, assets planned for the future are alleviated of some of these constraints, and ZTA should be part of the design and planning phases moving forward.

Another important consideration when implementing ZT is exception and failure handling. In most IT environments, it is safe and appropriate to block access (fail-closed) when authentication and authorization cannot be definitively established. In an OT/ICS environment, ZT cannot be deployed in a fail-closed implementation for every subsystem or resource. There are always critical subsystems and resources that have to fail-open and be able to communicate and coordinate, otherwise the system itself may fail or cease to function and/or lead to cyber-physical impacts, including the potential for loss of life.

Benefits and Challenges for OT / ICS

While the need to secure the bulk power system's critical infrastructure is greater than ever before, and the paradigm shift to ZT is the obvious direction for the future of cyber security, there is still a clear need to approach the use case of ZTA for electric OT systems with caution and careful analysis. Additionally, smaller utilities must be wary of advancing too quickly into the cutting edge and taking on too great an administrative or technological burden without appropriately evolving their governance processes and support staff to achieve ZT maturity. The practical use-case for electric OT is explored through benefits, challenges, and recommendations.

Benefits

- Reduced threat surface and associated risk reduction due to increased monitoring controls
- Maximized use of authentication
- Increased visibility tools for security operations into all resource activity (e.g., users, processes, services)
- The ability to dynamically provide access based on real-time assessments
- Reduce an attacker's ability to move laterally and improve the capability to detect lateral movement
- Reduce or improve detection of data exfiltration
- Protection against both internal and external threats
- Improved overall security posture
- Potential for earlier detection of threats providing for quicker response and mitigation
- Tools provide granular details assisting with compliance requirements (e.g., patch management, ports and services, identity management, configuration management, incident response)
- Automated and dynamic processes and controls to quickly adapt to changing threats
- Improves the probability of early detection for malicious or unauthorized access

Challenges

- Early adopters may face challenges with the lack of standardization and lose the benefit of lessons learned from other early adopters.
- High-end ZT implements preventative controls alongside detective controls. Improperly implemented preventative controls could pose additional operational risks for electric OT systems. Comprehensive testing is required including scenarios for handling false positives.
- Diversity of vendor technology offerings may lead to an incomplete approach that may create control gaps.
- Integrating ZT with legacy devices is challenging due to incompatibility with many control solutions using agent/server implementations, SSL certificates, or secure protocols.
- Integrating ZT in networks with extremely low latency requirements (e.g., teleprotection communication) is challenging due to the constraints on viable ZT security solutions.

- There are increased administrative and technical burdens due to the overall complexities associated with ZTA.
- ZT models rely on strictly defined permissions within policies. People, roles, locations, and hardware assets may change, so ZT policies require upkeep and maintenance to be effective.
- At the higher ends of ZTA, deep knowledge of the system, OT devices, and all OT communications is necessary to configure policy allowance of data flows.

Recommendations

- Invest in staff training to better understand ZT concepts, technology offerings, and implementation risks
- Develop or improve cyber security governance when addressing remediation efforts identified in cyber vulnerability assessments, risk assessments, incident response activities, or other internal assessments by taking advantage of these opportunities to advance organizational ZT maturity
- Prioritize establishing an OT cyber security program or improving existing programs
- Perform a cyber-risk assessment of electric OT systems
- Take an asset inventory or validate existing inventories
- Perform a comprehensive controls assessment of the electric OT systems to identify ZT control improvement opportunities.
- Develop a ZT roadmap in order to transition to a ZTA (utilize existing models like CISA's ZT maturity model):
  - Within the roadmap, define maturity transition steps for OT (independently from IT if necessary)
  - Prioritize specific controls that build a foundation to move to ZTA in a hybrid manner (e.g., micro-segmentation, SDN, identity management, MFA)

Implementation Effort

For OT/ICS environments, implementing ZT is an evolutionary process that requires coordination between multiple business units and disciplines. Vertically integrated utilities have multiple groups that hold responsibility for different areas and components of their OT/ICS environment, such as field operations, substations, control centers, engineering, and IT and security. Regardless of the organizational model, leadership buy-in and direction is critical to these undertakings.

Making changes to site network infrastructure as well as access management processes and controls may likely only be feasible when a facility is new, is undergoing major upgrades, or during large scheduled maintenance outages and must be carefully planned, deployed, and validated to help ensure no negative impact to operations. Because of this, it will likely take years with careful planning and full support from all operational areas and leadership to implement ZT in stages across an organization's entire OT/ICS environment. However, some organizations may find that legacy systems and facilities may not be feasibly updateable to ZTA. These entities will need to account for any residual risks from such facilities if they deem ZT controls are necessary for risk mitigation.

For many organizations, the first steps in staging and applying ZT in OT/ICSs will follow after implementing ZT in their IT environments and then most probably targeting the IT/OT DMZs and operational control centers. These areas typically utilize more modern and flexible digital platforms with multipurpose commodity operating system-based servers and workstations as well as advanced network infrastructures that undergo more frequent refresh cycles and upgrades. These comparatively abbreviated refresh cycles allow for more opportunities to move toward ZTA and are more likely to provide full-scale redundancy to mitigate unforeseen negative impacts of a staged ZTA rollout. Deploying ZT within the IT/OT DMZs and control centers also provides the best cost/benefit return as it addresses a majority of the concerning attack surface and threat landscape and has the potential for the least impact to the system in the event the controls block access for a service and/or user.

As previously discussed, due to the large range of OT/ICS system device capabilities and associated limitations, it may not be realistic to consider a device level approach for implementing ZT beyond the DMZs and control centers. Instead, an organization may need to consider hybrid approaches to bring ZT benefits into OT networks.

However, advances in technology and enhanced industry needs in the face of evolving and sophisticated cyber threats means OT equipment manufacturers are increasingly offering more robust cyber security capabilities in their product lines that will help facilitate industry wide movement to systems designed with and capable of ZTA. These more modern systems include authentication and cryptographic mechanisms (among other things) and are less of a technical challenge to implement. Entities should consider these newer technology offerings when creating their ZT roadmaps.

Compliance Consideration

General Approach

Entities must maintain their current compliance programs and responsibilities regardless of adopting any new cyber security controls and associated architectures, such as ZT. Consideration of purposed implementations must be evaluated against applicable CIP standards as would any change to the environments subject to CIP jurisdiction.

Identity and Resource Management

With ZT controls, processing an authorization request for system access may be enhanced to include additional evaluation criteria, such as device security posture, time-based behavioral data, and current organizational risk. But these are in addition to system privileges or permissions pre-mapped to roles, groups, or other identity criteria of accounts that form a strong basis of any authorization control. An organization’s processes that govern baseline system privileges or permissions are designed with business justification, and they follow role-based access control (RBAC) per best practices and are likely best suited as evidence for the control objectives associated to electronic access authorization.

Authentication

Some ZTAs may utilize a service gateway to intercept all incoming requests for resource (system or data) access and present the point of authentication at that gateway. Other solutions may include certificate management, including for public key infrastructure and reliance on external root authority servers. In the design of these ZT solutions, the same CIP compliance considerations must be given to the new technological components as is given to existing applicable systems, such as electronic access control and monitoring systems and BES cyber assets.

Software Defined Networking

Organizations should carefully consider how to align dynamic and policy-based software defined networking **(**SDN) with CIP's use of logical network access and defined ESP's. When employing ZT policies with SDN, both the network location of individual systems and allowed inbound or outbound communication at network boundaries access control lists can be dynamic. The policy rules established at the SDN controller may offer criteria to redirect or disable communication (causing dynamic update to ACL's) as well as relocate or quarantine systems (causing VLAN change). However, there is often a resulting "base state" of configuration for the network through these policies and then a "deviation state" due a higher state of security or reliability need. As a single system example, SDN policy may result in an assignment of a virtual desktop to a particular VLAN. It may then deviate from that assignment when an additional policy-based evaluation identifies that the workstation is missing recent security patches. This moves the system out of its base state assigned VLAN within an electronic security perimeter and into a deviation state quarantine VLAN (likely a DMZ, potentially outside the ESP) that only allows the necessary ACL-restricted communication to serve security patching services. To aid in evidencing requirements for ESP's and inbound/outbound communication, it is recommended to orient written control processes to maintain CIP compliance around the use of SDN's policies by clearly explaining base state versus deviation states. Such efforts require collaboration and input from subject matter experts within the organization, including compliance, security, and network engineers.

ZT Controls Guidance

Among the types of controls making up ZTA, some are more suited than others for deployment across electric OT and IT-centric systems. Table 1 provides general guidance on control compatibility for various environments. Furthermore, design guidance is provided for common ZT controls.

Table 1: Control Compatibility

	Control Center & OT DMZ	Substations	Generation DCS
Network Segmentation and Software Defined Networks	👍👍	👍👍	👍👍
Application Layer (Deep Packet) Inspection) Gateways	👍👍	👍	👍
Secure Remote Access	👍👍	👍	👍
Secure Protocols	👍👍	👎	👎
Endpoint Protection	👍👍	👎	👎
Enhanced Identity Access Management	👍👍	👍	👍

Legend: 👍👍 *: Multiple/widely supported options; granular device-specific controls can be implemented*

👍 *: Limited/complex options, dependent on system-specific architecture; likely only system/site/network level controls can be implemented*

👎 *: Very limited, if any, options, dependent on system-specific architecture; may not be feasible to deploy controls (cost/benefit, operational impacts)*

Network Segmentation and Software Defined Networks

Network segmentation allows entities to limit attack surfaces and disrupt or detect lateral network movement of attackers. It is a critical component and an early maturity step for ZT roadmaps. SDN allows organizations to create network segmentation faster and easier through automatic configuration of firewalls, switches, and routers. It offers more agile and flexible approaches to isolate or segment both VLANs and application layer network traffic over traditional tools through the use of policy-based configuration and security to establish least trust. The following are aspects of SDN and network segmentation as part of successful ZTA implementations:

- Establish security zones with application layer inspection gateways between zones
- Network segmentation of group related workloads for the purpose of establishing granular VLANs
- Separate management traffic from operational traffic even within single facility/site
- Use secure logical overlay networks to establish SDN and build software defined perimeters
- Provides means to implement ZT for devices not capable of deploying on-device security

- Network Access Controls–Provides conditional network access upon policy-based security assessment of end point device configurations and/or behaviors

Application Layer (Deep Packet) Inspection Gateways

A variety of devices are capable of traffic monitoring or control, contributing to ZT maturity by inspecting network packets up to the application layer. These devices work hand-in-hand with SDNs. Different solutions may be deployed either internally or at the perimeter of networks. Some may include additional features that enable network and data flow mapping, asset and configuration inventories, and intrusion detection or intrusion prevention capabilities. Examples of these technologies and their feature sets include the following:

Next Generation Firewalls

- Deployed at perimeters (north/south traffic) or internally if software-based (east/west traffic) to establish security zones
- Application-level access control for inbound/outbound traffic
- Malicious code detection
- Support for OT protocols–provides packet-level ability to allow/deny protocol-specific messages
- SSL decryption for packet inspection

Data-diodes

- Deployed at perimeters or internally
- Enforcement of one-way communications for strict data flow control

Passive Security Monitoring

- Ability to monitor OT/ICS traffic protocols, flows, and time analysis attributes providing insights into normal network conditions and detection of anomalous conditions
- Support for OT protocols–provides packet-level ability to recognize protocol-specific messages

Secure Remote Access

Secure remote access includes solutions that provide access to applications and services that utilize connection brokering, encryption, and intermediate systems. Depending on individual solution capabilities, additional features may include trustless policy-based identity and access management to grant conditional access. Examples of secure remote access solutions include service gateways and terminal servers with virtual application delivery or virtual desktop availability deployed at a network perimeter within a secure DMZ. Other features may include the following:

- Support for multifactor authentication and single sign-on
- Session policy controls: re-authentications and session timeouts
- Session monitoring and enhanced logging
- Data loss prevention

- Bandwidth control
- Inline malware prevention

Secure Protocols

An important aspect of integrating security into an entity's technology footprint with an emphasis on ZT is to standardize use of secure protocols over legacy and unsecure protocols. It is crucial that industry continues to push their original equipment manufacturers to support and build in functionality for leading protocol innovations. Likewise, it is the responsibility of entities to ensure that the selection and procurement of new technology prioritizes compatibility with the newest protocols. Furthermore, entities should consider that implementation and configuration includes architecting the ability to turn on or switch to an updated protocol later when all integrations and endpoints are fully compatible. If this designed-in approach is not taken, it is much more likely that a legacy/unsecure protocol will continue to be utilized due to the inconvenience and technological burden of change. Finally, it should be noted that intermediate technology, such as port servers, proxies, or gateways, may be necessary to facilitate secure protocol use in OT networks due to the presence of legacy devices. Below are examples of secure protocols being evaluated for use in the electricity OT field:

- mTLS
- IPSEC
- DNP3-SA v5/v6
- IEC62351

Endpoint Protection

Endpoint protection solutions include endpoint detection and response with signature-based and heuristic analysis to continuously monitor, detect, and respond to cyber threats (like ransomware and malware) as well as active intrusions by threat actors. Other solutions specialize in detection through configuration baseline monitoring of file integrity, software, services, and logical network ports. Additional features may include the following:

- Policy-based application whitelisting
- Unified endpoint management
- Host based software firewalls
- Endpoint security auditing
- Domain and URL web filtering

Enhanced Identity and Access Management

The concept of least privilege is not new, but it is brought forth with renewed vigor in the paradigm shift of a ZT controls philosophy where the achievement of the "least" is examined in greater detail. Therefore, identity and access management under a ZT maturity roadmap can provide technology solutions to further scrutinize the how, what, and when for authorization, authentication, and access to applications and data. Newer technologies incorporate sophisticated policy based intelligence to support both RBAC or attribute-based access control (ABAC) strategies while enabling risk-based decisions, such as raising authentication from single factor to multi factor and granting reduced privilege to a resource. For example, instead of outright success or deny of access, dynamic access may be granted while locking out some features, specific categories of data, or by simply reducing privileges to read-only over full edit/full control.

The implementation between ABAC and RBAC are significantly different with more complexity and automated control being delivered with ABAC and easier implementation but less granular controls with RBAC. Both are well worth exploring for implementation to support ZT practices. Additionally, entities may consider requiring out of band approval for system management access. This is a best practice implementation to remediate the ability of an attacker to approve elevated system access on a node they have successfully infiltrated. The out of band approval process restricts request and access granting to systems and networks that are not accessible by the grantor systems and networks.

Public key infrastructure (PKI) can be used to support identity and access management controls by providing a robust framework for secure authentication, authorization, and encryption. PKI employs digital certificates, which are issued and validated by trusted certificate authorities, to establish trust between parties. Through the use of asymmetric cryptography, PKI enables the secure exchange of digital signatures and encrypted data, ensuring that only authorized individuals or entities can access specific resources.

Conclusion

ZT offers the electric industry a clear direction forward for continual improvement to securing our critical infrastructure. ZT is a paradigm shift that builds on and enhances existing controls and capabilities of cyber security plans. Security policy enforcement becomes data-centric (what data requires protection) instead of network-centric or device-centric. The emphasis is on entity identity and context over location within a perimeter. Research and testing must be completed to successfully transition with minimal disruption.

Industry also needs to continue to develop equipment and software as well as people, processes, policies, and governance capable of delivering on ZT principles. Advanced applications (e.g., real time contingency applications) and support applications (e.g., historians) offer likely paths for testing of implementations of ZT controls. Engineering access to equipment also offers a possible avenue to enable and test these concepts. Entities can collaborate and assist one another through memberships in various organizational groups. Government can provide tax incentives for infrastructure investments, grants for industry organizations promoting cyber security, and funding to assist less capable smaller entities with the process of moving to a more defensible electric infrastructure.

ZT implementation requires attention, focus, and planning. Stakeholder buy-in and executive support at the highest levels are essential for success. Developing a ZT environment in the OT space will take time and deliberate action. Some organizations have not started, some already have existing network infrastructure or controls in place that may classify at part of a ZTA while some may have already begun the transition to ZT. Regardless of where an entity is currently, all organizations should take the necessary steps to assess the value of ZT to their IT and OT security programs in support of BPS infrastructure and develop a roadmap to mature technology and controls towards ZTA with an emphasis on realistic time lines and resources to move themselves forward on the maturity scale. A well thought out implementation process will allow an organization to incorporate ZT incrementally and in collaboration with OT integrators and vendors as appropriate. It is crucial for the industry to take these steps of maturity to ensure resilience of the BPS against cyber threats and protect the critical function of providing secure and reliable electricity.

Appendix A: References and Resources

Control Design

- NIST SP 800-207 - Zero Trust Architecture
- NSA - Segment Networks and Deploy Application-Aware Defenses
- NIST SP 800-162 - Guide to Attribute Based Access Control (ABAC) Definition and Considerations

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White Paper

Zero Trust for Electric OT

Brian Burnett, SITES chair, North Carolina Electric Cooperatives
Marc Child, RSTC sponsor, Great River Energy
Reliability and Security Technical Committee Meeting
June 22, 2023 | St. Paul, MN

RELIABILITY | RESILIENCE | SECURITY

Purpose

The paper informs on zero trust (ZT) concepts and provides considerations and recommendations regarding the adoption of ZT controls in operational technology (OT) and industrial control system (ICS) environments. The paper leverages CISA’s Zero Trust Maturity Model for varying levels of implementation by registered entities and recommends entities develop their own roadmap for security and technology maturation. Finally, the paper describes considerations regarding ZT adoption by registered entities and the NERC Critical Infrastructure Protection (CIP) standards.

Background

- Drivers
  - Innovation leading to increased connectivity into critical electric OT networks, including monitoring, data transference, and remote access to substations and generation facilities
  - Proliferation of available technology solutions advertised under the ZT umbrella by vendors, including penetration into the OT market space
  - Paradigm shift within the cyber security industry for trust zones or “castle mentality” to be replaced or enhanced with boundary less, trustless based security controls to keep up with the increasing danger of cyber threats

Approach

- This white paper serves to:
  - Educate on ZT fundamental concepts, viable controls for electric OT, and benefits/challenges of implementation for electric OT
  - Recommend entities develop a technological roadmap and follow a ZT maturity model
  - Provide compliance considerations for registered entities
  - Provoke additional thought leadership on ZT in the electric sector

Whitepaper Activities

- Submitted at December 2022 Reliability and Security Technical Committee (RSTC agenda – request for comments
- RSTC comment period: 12/7/2022 – 2/1/2023
- 1 RSTC comment received, and formal responses by Security Integration and Technology Enablement Subcommittee (SITES) provided
- Additional review and comments by SITES and Security Working Group (SWG) members incorporated

Whitepaper Updates

- Executive summary added
- Recommendation made more firm to take hybrid approaches to address legacy OT networks and devices that present constraints to ZT architecture
- Relaxed language implying “ZT or Bust”, instead better reflecting ZT is a paradigm for control enhancements
- Various small improvements for clarity of concepts

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Restatement of Request

SITES requests the RTSC to approve this whitepaper for publishing on NERC.com.

Questions and Answers

Probabilistic Assessment Working Group 2022 ProbA Regional Risk Scenarios Report

Action
Approve

Summary
The final report was prepared by the PAWG during the 2022 Probabilistic Assessment (ProbA) cycle with inputs from the six Regional Entities and 20 Assessment Areas. Assessment Areas developed tailored risk scenarios (e.g., ERCOT examined impacts of Impact of transmission limits on reliability indices with large transfer) and assessed the effect that the scenarios would have on the probabilistic indices reported in the 2022 ProbA Base Case. This scenario analysis provides insights into area specific reliability risk using probabilistic methods. The report was reviewed by RSTC members and returning the report back to the RSTC for approval. RAS will review findings and consider them for addition to the 2023 Long-Term Reliability Assessment (LTRA).

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2022 NERC Probabilistic Assessment

Regional Risk Scenario Sensitivity Case Report

Bryon Domgaard, PAWG Chair
NERC Reliability and Security Technical Committee
June 21, 2023

RELIABILITY | RESILIENCE | SECURITY




Motion

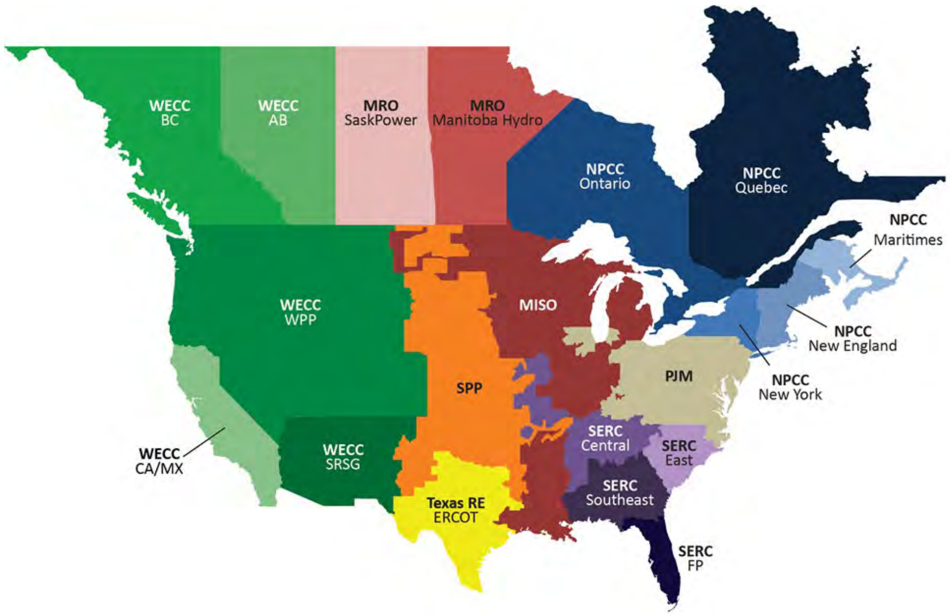
Motion to approve the Probabilistic Assessment Working Group (PAWG) 2022 ProbA Regional Risk Scenario Sensitivity Case Report

Overview

- On a biennial basis, the NERC PAWG performs a Probabilistic Assessment (ProbA) Base Case to supplement the annual NERC Long Term Reliability Assessment (LTRA) analysis
  - 2022 ProbA Base Case published in the 2022 LTRA (Dec. 2022)
- PAWG encouraged regional flexibility in the 2022 ProbA Sensitivity Case by developing a Regional Risk Scenarios Model
  - Planners studied area-specific reliability risks and underlying uncertainties using probabilistic methods (EUE, LOLH indices)
- Assessment utilized a comprehensive peer-review process in coordination with the RAS

Approach

- Maintained the calculation of EUE and LOLH probabilistic indices for Base and Scenario Cases
- Evaluate sensitivities against purported risks by comparing Base and Scenario Cases
- Required year 4, optional year 2* for Sensitivity Case
  - LTRA: 10-year study period
  - *Regional Entity and Assessment Area discretion based on need and anticipated resource changes as reported in the LTRA



Approach: Study Scenarios

- Unique scenarios utilized by Region (6), Assessment Area (20) to study Reliability Assessment risks identified in the LTRA
- Scenarios intentionally stressed assumptions to study their associated impacts
- 2022 ProbA Sensitivity Scenarios

MISO: Place more granular outage rates on each season.

Manitoba Hydro : Variations in low water conditions with external assistance limitations

SaskPower: Increase of end of life failures of a coal unit in its last year of operation

SPP: Focus on extreme weather as a risk, specifically on the impact of severe cold weather conditions

NPCC: Planned/expected future capacity or resources may not materialize

PJM: Planned/expected future capacity or resources may not materialize

SERC: Focus on extreme weather as a risk and is looking to assess the impact of severe cold weather

ERCOT: Impact of transmission limits on reliability indices with large transfer

WECC: Impacts to resource adequacy associated with drought conditions and its impact on resources.

2023 Review Timeline

- March RSTC Presentation and request for reviewers
  - Two reviewers from RSTC
- PAWG met to address the comments received
  - PJM provided addendum to the ProbA section for awareness of recent PJM retirement study that was completed subsequent to their ProbA submittal early this year.

Results

- Sensitivity results varied across the Assessment and are dependent on underlying study assumptions
  - Some Areas demonstrated reported risks were insignificant or could be mitigated using preventive planning and operating measures
- Results provide an understanding of the reliability across all hours using probabilistic methods (instead of just the peak hour)
  - Provides NERC a way to characterize more “what-ifs” scenarios and the ability to benchmark system risks
- PAWG stress the importance of the coordination between industry operations and planning personnel to further develop assumptions and scenarios for use in probabilistic reliability assessments
  - These studies can illuminate industry discussions and decision-making, reinforcing the fundamental need for future scenarios that address reliability concerns.

Request

- Seeking RSTC approval to post and complete this Work Plan item

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Draft 2022 NERC Probabilistic Assessment (ProbA)

Regional Risk Scenario Sensitivity Case
June 2023

RELIABILITY | RESILIENCE | SECURITY

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Questions and Answers

6GHz Task Force White Paper

Action
Information

Background
The 6 GHz Task Force (6GHZTF) will provide an update on the task force's recent activities and upcoming activities for the remainder of the year. The 6GHZTF is currently working on a whitepaper that details information on how to establish a 6 GHz baseline and steps for recognizing communication interference. The whitepaper's recommendations, will be incorporated into a webinar and upcoming Level 2 Alert.

Summary
FCC Action

- In April 2020, the Federal Communications Commission (FCC) issued a Report and Order that partially opened the 6 GHz band of radio spectrum to unlicensed users. Furthermore, there is a pending Notice of Further Proposed Rulemaking with the FCC to fully open the 6 GHz band to unlicensed use and cause additional harmful interference to proliferate in this radio spectrum band.
- In 2020, a consortium of electric industry associations published a report on the Impact of Proposed Wi-Fi Operations on Microwave Links at 6 GHz. The report identifies impacts to electric power operations. Additional follow-on work by EPRI and various affected stakeholders have shown—through testing--impacts to their critical electric infrastructure communications due to increased congestion and interference on the 6GHz wireless communication band. As adoption of the new technology increases, the risk to BPS operations may increase.
- Prior to this ruling, the 6GHz licensees had exclusive use of the assigned frequency and the concern for communication interference was minimum/non-existent and more easily identified due to licensing requirements.

6GHz Task Force

RSTC Update

Jennifer Flandermeyer, 6GHZTF Chair

Reliability and Security Technical Committee Meeting

June 21, 2023

RELIABILITY | RESILIENCE | SECURITY




TF Purpose

- The NERC 6GHZ Task Force (6GHZTF) scope document includes deliverables to:
  - Identify penetration and Bulk Power System users relying on 6 GHz
  - Develop suggested recommendations related to Impact Assessment to effectively assess communication disruption risks in operations of the Bulk Power System.

The whitepaper presented here details information on how to establish a 6 GHz baseline and steps for recognizing communication interference.

Impact Assessment

- Communication Interference
  - In general terms (regardless of communication medium), communication interference for the electric utility industry would have the following characteristics:

Function	Impacts of Communication Interference
Voice	Delay in (or loss of) clear, concise communication among operating personnel (includes field personnel)
SCADA - Data	Poor data quality or loss of data (monitoring)
SCADA – Control	Control timeouts, possible delay in operator action, Inability to send control commands
Relay Protection	Faulty operations due to poor data quality/loss of communication

Next Steps

Baseline Interference Whitepaper

Webinar

NERC 2 Alert

Consider transition to Telecom Working Group

Questions and Answers

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Appendix

- Background Information
- Impact Assessment
- Reliability Risk

Background

- FCC Action
  - In April 2020, the Federal Communications Commission (FCC) issued a Report and Order that partially opened the 6 GHz band of radio spectrum to unlicensed users. Furthermore, there is a pending Notice of Further Proposed Rulemaking with the FCC to fully open the 6 GHz band to unlicensed use and cause additional harmful interference to proliferate in this radio spectrum band.

Background

- FCC Action
  - In 2020, a consortium of electric industry associations published a report on the Impact of Proposed Wi-Fi Operations on Microwave Links at 6 GHz. The report identifies impacts to electric power operations. Additional follow-on work by EPRI and various affected stakeholders have shown—through testing--impacts to their critical electric infrastructure communications due to increased congestion and interference on the 6GHz wireless communication band. As adoption of the new technology increases, the risk to BPS operations may increase.
  - Prior to this ruling, the 6GHz licensees had exclusive use of the assigned frequency and the concern for communication interference was minimum/non-existent and more easily identified due to licensing requirements.

Impact Assessment

- Communication Interference
  - A visual of communication interference is a television with rabbit ear antenna. The picture would appear 'snowy' until the rabbit ears were appropriately adjusted. Communication interference is often intermittent and occurs at the most inopportune time.
  - Given the functions that could be impacted by harmful interference and the characteristics or likelihood for interference to occur at inopportune times, there is a higher likelihood of increase reliability risk.
  - Furthermore, given the unlicensed users that will be the source of the harmful interference, it will be difficult for Bulk Power System owners and operators to identify sources to remedy expeditiously.

Reliability Risk

- Reliability Risk Priorities
  - The 2021 ERO Reliability Risk Priorities Report identifies four risk profiles:
    - https://www.nerc.com/comm/RISC/Documents/RISC%20ERO%20Priorities%20Report_Final_RISC_Approved_July_8_2021_Board_Submitted_Copy.pdf
    - Risk Profile #1 Grid Transformation
    - Risk Profile #2 Extreme Events
    - Risk Profile #3 Security Risks
    - Risk Profile #4 Critical Infrastructure Interdependencies
  - While each profile references communication, Profile 3 (Security Risks) and Profile 4 (Critical Infrastructure Interdependencies) are most relevant to communication interference.

White Paper: Overview of Energy Reliability Assessments – Volume 1

Action

Approve

Background

The Energy Reliability Assessment Task Force (ERATF) is tasked with assessing risks associated with unassured energy supplies stemming from the variability and uncertainty from renewable energy resources, limitations of the natural gas system and transportation procurement agreements, and other energy-limitations that inherently exist in the future resource mix.

During the March 2023 RSTC meeting, the ERATF submitted the white paper to the RSTC and requested that it gets posted for a 45-day industry comment period. The purpose of the white paper is to describe what an energy reliability assessment is, why it important to do the analysis, and defines the elements of an energy reliability assessment including ancillary services.

Summary

The 45-day comment period is completed, the ERATF Tiger team has finished addressing the comments on May 5, and the ERATF met on May 17 to approve the whitepaper.

The NERC Energy Reliability Assessment Task Force published the white paper: *Considerations for Performing and Energy Reliability Assessment* in March, requesting industry feedback via a 45-day comment period. The team received numerous comments from several organizations and individuals, all of which were taken into consideration and contributed to the final draft. The drafting team thanks all contributors and has accepted most of the recommendations that were provided.

The majority of comments addressed phrasing and other document structuring, and were generally accepted into the final draft. Additional comments that were provided offered suggested additional language that, intended to better explain complex concepts, further expound on enumerated lists, or improve general readability of the white paper. The majority of those comments were also accepted and included in the final draft with the exception of repetitive additions (i.e., already discussed in the existing text) and conflicting comments from multiple commenters.

General comments were provided by a handful of respondents either lending support to the overall paper, for which the drafting team offers thanks, and others that tended to be out of scope for this white paper. A select few comments addressed NERC Standards and potential conflicts with the white paper. While it is not expected that the white paper will be in conflict with any Standards, it should be noted that NERC Standard requirements will always take precedence over the contents of a white paper, and that nothing in the white paper is intended to be enforceable as it is written in this document. This specific white paper is not intended to suggest implementation guidance for any existing Standards but may be used to inform Standard developers during the drafting process.

Finally, some comments were considered to be recommending that more detail be added into the white paper than was originally intended for this volume. The drafting team is currently working on a second volume that will provide more detail, including more specifics on how to perform an energy reliability assessment as well as begin to craft metrics to demonstrate success and begin to specify what an analysis tool would be capable of doing. Those comments will be considered and reviewed while drafting volume 2, expected to be published in late 2023.

The drafting team thanks all of those who reviewed the white paper and provided feedback. We realize that the concept of energy reliability is a change in how the power system is studied and evaluated, and are hopeful that the white paper will help entities to better understand the concepts and philosophies being considered as the evolution of the system continues.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Considerations for Performing an Energy Reliability Assessment

ERATF White Paper

March 2023

RELIABILITY | RESILIENCE | SECURITY

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

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 NERC and the six Regional Entities, is a highly reliable, resilient, 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 made up of six Regional Entity boundaries as shown in the map and corresponding table below. The multicolored area denotes overlap as some Load-Serving Entities participate in one Regional Entity 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

Introduction

Energy reliability assessments are critical for assuring the reliable operation of the Bulk Power System (BPS) as the penetrations of variable generation resources and/or just-in-time ~~energy supplies~~fuels increase. In turn, dispatchable and quick start units are relied upon for flexibility, where sources such as energy storage and natural gas-fired generation deliver energy to support intra-hour and inter-hour ramping to match variations in demand and energy production from the rest of the fleet. Energy reliability assessments account for the finite nature of stored fuels and their replenishment characteristics. In addition, the availability of natural gas to supply electric generation can impact BPS reliability during high natural gas demand periods throughout the year. Energy reliability assessments provide assurance to planners and operators that resources can supply both electrical energy and ancillary services needs across a span of time.

In this paper, we refer to two main categories of fuels. The first is **stored fuel** (e.g., coal pile onsite, water reservoir, energy storage in battery) and the other is **just-in-time fuel** (e.g., natural gas from pipelines, sunlight on photovoltaic (PV) panels, wind through wind turbines, run-of-river hydro). **Just-in-time energy resources** are reliant on just-in-time fuels.

NERC, working with the electric industry, developed this whitepaper focused on energy assurance and efforts needed to ensure the reliable operations of the BPS. These efforts began in late 2020 and are continuing today as presented in **Figure I.1.**

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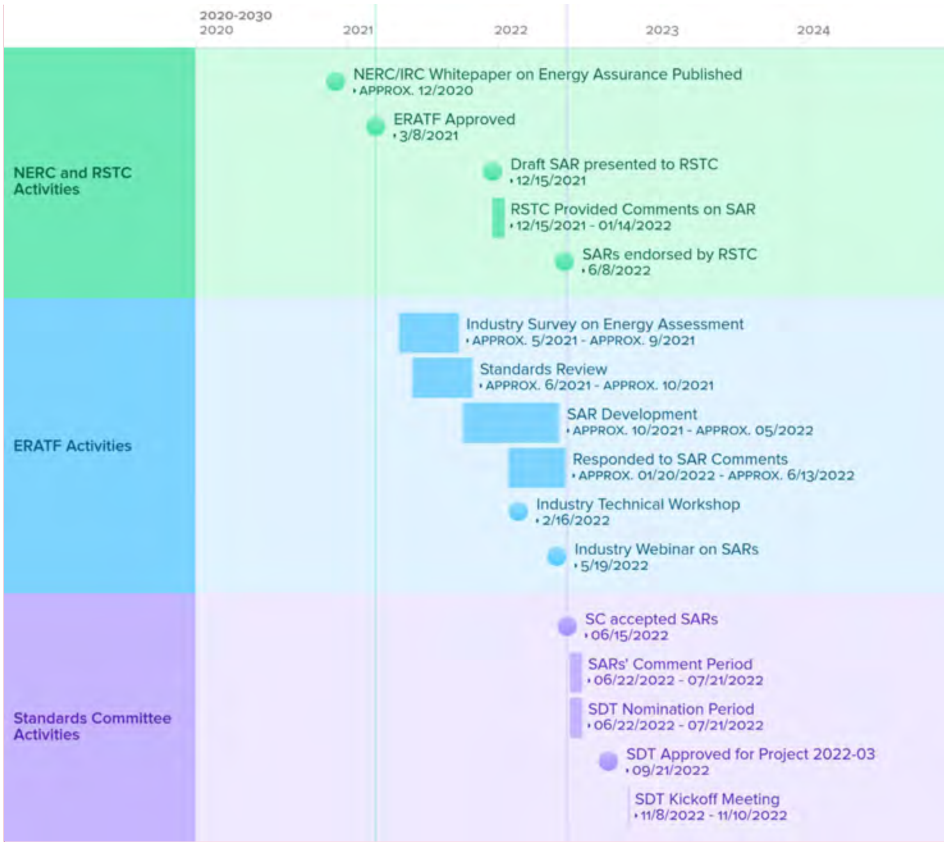

Figure I.1: Timeline of Relevant Energy Reliability Assessment Work at NERC

Commented [TMK1]: David to add acceptance of final SARs

Purpose

The purpose of this whitepaper is to clarify what an energy reliability assessment is and recommend elements for consideration when performing an assessment. As part of ongoing BPS planning and operations, many entities have started incorporating some limited energy reliability assessments (e.g., uncertainty around variable generation output and natural gas delivery) into reliability studies that produce key risk metrics; however, there is inconsistency among entities on whether or not energy reliability assessments are performed at all. While organizations in different regions may implement energy analyses differently to focus on their most significant energy risks, the core principles and elements of the analyses are similar.

Chapter 1 of this whitepaper describes what an energy reliability assessment is and recommends elements for consistent evaluation across the industry. The whitepaper clarifies the distinctions between capacity reliability assessments and energy reliability assessments and examines the differences between the deterministic and probabilistic approaches in performing both assessment types. Chapter 2 provides a more in-depth discussion of some elements to consider for an energy reliability assessment related to supply and demand and includes a separate discussion on distributed energy resources (DER) that can blur the line between supply and demand.

Background and Rationale

As the North American electricity sector evolves, planners and operators must increasingly acknowledge uncertainties and risks with the increased use of just-in-time fuels (i.e., fuels consumed immediately upon delivery), stored fuel with limited energy resources, and demand side resources. Extreme weather events that impact generation resources, fuels, and load coincidentally have exposed the threats to BPS reliability due to insufficient energy even with sufficient capacity ostensibly available.[1] ~~Unassured deliverability of fuel supplies including weather-dependent fuel availability, inconsistent output from variable energy resources, and volatility in forecasted load can result in insufficient amounts of energy available from the generation resource mix needed to serve electrical demand and ensure the reliable and resilient operation of the BPS throughout each hour of the time-period being evaluated.~~ Unassured deliverability of fuel supplies and volatility in load can introduce additional risks to the reliable and resilient operation of the BPS.

Historically, analyses of energy available to the BPS focused on capacity reserve levels across peak demand time periods. These assessments included assumptions on equipment failures (e.g., mechanical failures) but often assumed that the requisite fuel would always be available. This is an acceptable assumption when fuel availability is assured. Methods of increasing confidence in fuel availability include, for example, ~~with either firm~~ fuel contracts ~~(commodity plus transportation capacity)~~, on-site storage (e.g., oil, coal, reservoir-based hydro), or required periodic and predictable fuel replacement (e.g., nuclear).

The availability of dispatchable generation with diverse fuel types promote~~d~~s flexibility in providing energy for the BPS should one fuel type become unavailable.

Today's electricity system includes just-in-time energy resources along with additional supply chain pressures. This creates additional complexities and decreases confidence that energy will be available to serve load. As a result, there is a need to conduct energy reliability assessments in addition to capacity assessments[2] to identify new challenges. Potential findings and applications of energy reliability assessments could include but not limited to:

~~1.~~ • identifying unexpected and unstudied energy issues in non-peak hours, a risk that would not be identified by traditional analyses focusing on capacity across the peak summer and winter demand periods;

Commented [CC2]: Is the inclusion of "for example" here okay?

Commented [MH3]: For emphasis, consider replacing the last sentance with " As a result, it is paramount that energy reliability assessments are conducted in addition to…"

Commented [LA4]: Layne suggests this is not needed and I agree

Commented [PJM5]: I would like to see this expanded or another bullet added about operations time frame instead of just operations planning. This actually is kind of linked with the above "forecast error" and the ability of resources to respond to dispatch requests…essentially energy regulation

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[1] The industry need is described in the *Ensuring Energy Adequacy with Energy-Constrained Resources* white paper, presented to the RSTC, December 2020. https://www.nerc.com/comm/RSTC/ERATF/ERATF Energy Adequacy White Paper.pdf

[2] For additional information, read Electric Power Research Institute, Resource Adequacy Philosophy: A Guide to Resource Adequacy Concepts and Approaches, EPRI, Palo Alto, Dec 2022. Link: https://www.epri.com/research/programs/067417/results/3002024368

- ~~2.~~ in areas with many variable energy resources, highlighting the value of having dispatchable resources with sufficient fuel available and ready to respond when needed;
- ~~3.~~ evaluating whether ~~stored energy~~energy storage resources have sufficient energy to provide both balancing and energy;
- evaluating whether energy storage resources are sized appropriately (~~power~~ capacity and energy) to provide balancing;
- ~~4.~~ evaluating renewable resource generation and load forecasting uncertainties to ensure appropriate levels of balancing reserves;
- ~~5.~~ in areas with high concentrations of distributed energy resources (DERs)~~ and flexible/controllable load programs~~, identifying complications with operational challenges resulting from added volatility into energy forecasts; ~~or~~
- ~~6.~~ assessing uncertainties or risks when the natural gas-fueled resources are subject to fuel curtailment or interruption (by virtue of fuel acquisition contracts) during peak fuel demand periods, especially where variable energy resources increase reliance on natural gas as a balancing resource;
- ~~7.~~ considering the design of natural gas pipeline systems and the availability of primary and secondary natural gas transportation paths which can impact individual generators and BPS reliability under pipeline disruptions such as natural gas supply chain scenarios (e.g., pipeline disruptions, wellhead freeze offs, compressor station outages, etc.); ~~and~~
- considering additional factors in the operational planning time frame, like anticipated performance of natural gas-fired units given recent run times, energy market pricing, environmental constraints, or testing results.
- evaluating the potential impact of extreme weather events and implications for system resiliency~~.~~;
- assessing the impact on resource and transmission planned outage scheduling and approvals during ~~traditional~~ resource maintenance seasons; and~~.~~
-
- ~~8.~~ identification of periods when the replenishment~~rapid refill~~ of ~~liquid~~ fuel inventories are needed but are constrained by severe weather, transportation limitations, ~~liquid~~ pipeline outages/maintenance, etc.

The variability of renewable generation, demand volatility, the need for sufficient energy from dispatchable generation resources, and the potential for natural gas supply and transportation interruptions all combine to highlight the need for energy reliability assessments that analyze all hours of a given study period rather than just the peak hours.

Energy Reliability Today

Energy assurance and fuel assurance risks are becoming more apparent as extreme weather has resulted in energy deficits (as opposed to capacity deficits) in recent years. During the past 10 years, there have been multiple extreme events across North America that have jeopardized BPS reliability where insufficient energy ~~availability~~ production had already impacted BPS operations. The following are some examples of those events[3]:

- In February 2011[4], an arctic cold front in the southwest United States resulted in generation outages and natural gas facility outages.
- In January 2014[5], a polar vortex affected the central and eastern United States and Texas.
- In January 2018[6], the south-central United States experienced many generation outages resulting in emergency measures.

[3] These listed events do not include all events or near miss events which entities have identified.
[4] Outages and Curtailments During the Southwest Cold Weather Event of February 1-5, 2011 - FERC and NERC
[5] Polar_Vortex_Review
[6] 2019 FERC and NERC Staff Report: The South Central United States Cold Weather Bulk Electric System Event of January 17, 2018

Commented [JF6]: I think quantifying the value of dispatchable resources is very important. Does the term "ready to respond when needed" refer to possibly establishing a type of "reliability" reserve, which would keep such resources committed (operating) so they could ramp up generation when needed?

Commented [LA7]: Layne: This may be a result but that is outside the scope of this paper. Good comment.

Commented [JF8]: Does the term "to provide both balancing and energy" mean that limited energy (fuel) resources can provide a limited amount of both incremental and decremental reserves while also being used to serve energy load?

Commented [LA9]: Layne: Yes that is the intent

Commented [JF10]: Perhaps using the term "capacity" here would be more consistent.

Commented [JF11]: I would add that it is critical to assess, as accurately as possible, renewable resource and load forecasting uncertainties to ensure that appropriate levels of balancing reserves are planned.

Commented [LA12]: Layne: Don't know if this is needed but if it is liked we can keep.

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Commented [WP13]: It might be helpful to include a glossary to define terms such as "flexible loads." If that is too big of a task, then add some definitions using footnotes.

Commented [LA14]: Layne: Should this definition be added to the box above?
AL: I don't think this is the paper to be defining flexible loads. I'd hope most of our readers know what this means anyway

Commented [WP15]: This is easier said than done. For example, ERCOT has proposed rule changes to require generators to provide natural gas purchase, availability and storage data associated with the day-ahead market. Such data will help in ...

Commented [LA16]: Layne: Agree that it may be difficult bu ...

Commented [IESO17]: "... increased reliance on natural ...

Commented [LA18]: I think this addresses the comment

Commented [JF19]: One other factor that you may want to ...

Commented [JF20]: These last bullets on the gas supply are ...

Commented [LA21]: Thank you agree

Commented [IESO22]: I suggest adding the following bullet ...

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Commented [PJM23]: I know the first three as capacity ...

Commented [LA24]: Layne: We could expand the descriptio ...

Commented [ISO-NE25]: footnote URLs point to a local drive

Commented [EP26]: NERC Staff – verify that all the links work

- In 2021, California's Oroville hydroelectric facility was shut down when reservoir levels, due to drought conditions, dropped below its minimum operating elevation.
- In February 2021, a cold weather event impacted fuel and energy availability in the states of Mississippi, Louisiana, Arkansas, Oklahoma, and Texas.

Energy reliability assessments that look at extreme events are needed to analyze subsequent impacts to the reliable operation of the BPS under adverse conditions. It is beneficial to perform a~~A~~ssessments ~~should be performed~~ to identify conditions where energy supply would be stressed, and identify actions that may be needed to mitigate the potential loss of load.

NERC, and its many industry committees and working groups, have done considerable work to address these events. The Electric-Gas Working Group (EGWG) created the *Reliability Guideline - Fuel Assurance and the Fuel-related Reliability Risk Analysis for the Bulk Power System* to help perform fuel assurance studies, and the Reliability Issues Steering Committee published the *2021 ERO Reliability Risk Priorities Report*, identifying risks to the BPS. Efforts like these highlight emerging risks that the industry needs to focus on~~, but more further direction, and guidance, and standardization is needed to holistically address these concerns~~. A more detailed discussion of the need for energy reliability assessment can be found in the "Energy Assessments with Energy–Constrained Resources in the Planning Time Horizon"[7] and "Energy Assessments with Energy–Constrained Resources in the Operations and Operations Planning Time Horizons"[8] SARs and associated technical justification document[9].

As part of long-term planning, the number of entities that incorporate energy reliability assessments into reliability studies is growing. These studies often produce key metrics on resource adequacy including Loss of Load Expectation (LOLE), Loss of Load Hours (LOLH), and Expected Unserved Energy (EUE)[10].

For example, *WECC's Western Assessment of Resource Adequacy*[11] incorporates multiple energy risk drivers, including extreme weather, changing climate patterns, significant increases in variable energy resources, the reliance of sub-regions on imports, coincidence of demand spikes over larger geographic areas, and others. The results of WECC's energy reliability assessments from the probabilistic model are fed into a deterministic production cost model to assess its energy needs in the operating time horizon. This assessment can be used to assess expected conditions as well as specific conditions that could threaten energy assurance. For example, cases previously evaluated were a low hydrological or drought condition and an extreme high demand scenario. WECC uses this study to inform Balancing Authorities (BA) of supply and demand conditions that could result in loss of load and holds webinars to ensure the results of the energy assessments are communicated clearly to all stakeholders. This process has contributed to the reexamination of demand and supply forecasts focusing on extreme events.

In Quebec, a primarily hydrological system, energy reliability assessments are a ~~required as~~ part of its regulatory requirements. An assessment is performed for the internal demand, which represents 99%~~most~~ of the total demand ~~(99%)~~. This assessment covers a period of ten-years and is performed for the 50/50 scenario demand. Unserved energy and surplus of generation are metrics used to identify risks. Further, two energy criteria are used:

[7] "Energy Assessments with Energy–Constrained Resources in the Planning Time Horizon"
[8] "Energy Assessments with Energy–Constrained Resources in the Operations and Operations Planning Time Horizons"
[9] "Energy Assessment Technical Justification"
[10] For more information on these metrics, see Electric Power Research Institute, Resource Adequacy for a Decarbonized Future: A Summary of Existing and Proposed Resource Adequacy Metrics, EPRI, Palo Alto, CA. April, 2022. Link: https://www.epri.com/research/products/000000003002023230
[11] WECC Assessment of Resource Adequacy

Commented [Dom27]: In December 2022, Winter Storm Elliott's severe cold weather impacted the southeast United States, demonstrating that there continues to be a disconnect between gas markets and electric demand issues.

Commented [PJM28]: Analysis of extreme events is OK but what do we do with the results? Not for this paper but a big question. Building for extreme events will be costly.

Commented [LA29]: Layne: Agree, not for this paper

Commented [CC30]: Per prior discussion should, should be changed to something like – "it is beneficial to…."

Commented [PJM31]: Second paragraph after the bulleted list of events – Should not be addressed in this paper. As I mentioned above, what we do with the results of analysis is yet to be decided. It is not this paper's job to "holistically address these concerns"

Commented [LA32]: Layne: I think the paragraph is fine but let's discuss. This paragraph is only stating what has been done. I guess we could delete the sentence about the holistic approach.

Commented [ISO-NE33]: Add footnote with a link

Commented [BL34]: Done. I don't know how to change the link to the name but I know it can be done.

Commented [ISO-NE35]: Add footnote with a link

Commented [LA36]: done

Commented [JF37]: The NW Power and Conservation Council has been using probabilistic methods to assess both capacity and energy adequacy since the late 1990s. Their work explicitly includes effects of many future unknowns, including climate change. Their latest report (https://nwcouncil.org/reports/2023-1/) may be worth referencing here as another example.

Commented [LA38]: Layne: I don't think we need any more than what we have. This is just a list of examples.

1. The supply plan must satisfy a scenario of demand that is one standard deviation beyond the 50/50 scenario at five years notice (including demand and weather uncertainty), without incurring a dependency greater than 6 TWh per year from the short-term horizon markets~~,~~.
2. The supply plan must maintain a sufficient energy reserve to hedge against possible low inflow deficits of 64 TWh over two consecutive years and 98 TWh over four consecutive years.

Operations planning entities have also started incorporating some of the uncertain variables (e.g., fuel availability) into short-term horizon reliability studies that are used to produce key operations reliability metrics. For example, CAL-ISO does an annual flexible capacity analysis to determine the monthly flexible needs on the system. In addition, ISO New England (ISO-NE) has Operating Procedure 21 (OP-21 - Operational Surveys, Energy Forecasting & Reporting and Actions During An Energy Emergency) which is~~ISO-NE currently has an Operating Procedure (OP)~~ specifically designed to assess energy within a 21-day future forecast period. This operating procedure was developed for the winter of 2005/2006, following severe damage to both oil and natural gas infrastructure in the Gulf of Mexico caused by Hurricanes Rita and Katrina. The OP was redesigned for the winter of 2018/2019, to fully integrate weekly generator fuel surveys into its overall energy assessment process. The objectives of the OP are:

1. To facilitate strong lines of communication among Independent System Operators (ISO), interstate natural gas pipelines, Liquefied Natural Gas (LNG) import facilities, gas Local Distribution Companies (LDC), and owners/operators of generating units (resources) regarding all matters relating to resource fuel availability and environmental limitations.

~~2.~~1. To facilitate identification of critical infrastructure of the interstate natural gas pipeline system to ensure critical components are not included in automatic or manual load shed schemes.

~~3.~~2. To alert regional stakeholders of actual or anticipated near-term energy deficiency conditions such that stakeholders with resources in short supply of fuel, or with potential environmental limitations, can take action to replenish fuel supplies and/or take action to mitigate environmental limitations.

~~4.~~3. To alert regional stakeholders of potential energy deficiencies such that they may take action to shorten or reschedule maintenance or repairs to transmission facilities or resources throughout the region.

~~5.~~4. To raise the awareness of New England consumers, market participants, stakeholders, officials of the New England states, regional and national regulators, and regional and national reliability organizations of potential energy deficiencies that may be faced by the region.

~~6.~~5. To allow for timely implementation of load and capacity relief available within actions of ISO-NE Operating Procedure No. 4 – Action During A Capacity Deficiency (OP4) or through implementation of load shedding through ISO-NE Operating Procedure No. 7 – Action in an Emergency (OP7), in order to address future capacity deficiencies expected as a result of an Energy Emergency.

While these examples demonstrate excellent ways that the industry is informing and developing action plans using energy reliability assessments, there is inconsistency among entities on if, when, and how the assessments are performed. Currently Reliability Standard, TPL-001-4 calls for modeling~~out~~ the loss of a large natural gas pipeline (and subsequent loss of interconnected gas-fired generation) as an extreme event that should be studied for areas with significant natural gas-fired generation, but beyond this mention, ~~existing~~ current NERC Reliability Standards do not explicitly require identification and mitigation of scenarios that identify energy assurance risks to the reliable operations of the BPS.

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Commented [CC39]: Recommend double checking this isn't going beyond the plain terms of the standard. Otherwise recommend shifting the tone slightly to avoid the word should.

Chapter 1: What is an Energy Reliability Assessment?

Energy reliability assessments are performed inconsistently across regions. While some entities perform energy assessments, currently~~To date~~, no formal definition of an energy reliability assessment exists, and consequently, the elements and methods evaluated are not consistent and are not clearly differentiated from capacity reliability assessments. For the purposes of this whitepaper, an energy reliability assessment is described as:

An evaluation of resources that supply electrical energy and ancillary services for the BPS to reliably meet the expected demand and operating reserves during the associated time-period. It is advisable that t~~T~~his evaluation ~~should~~ include the following:

- ~~1.~~ Consideration of impacts associated with limited resource availability and depletion over time, including constraints imposed by the unassured and limited supply of fuel and other consumable resources (e.g., cooling water) that may be depleted or unavailable and ~~required~~ necessary for the reliable operation of a power plant, especially resources depleted by multiple generators simultaneously.
- ~~1.~~ Consideration of the combined limitations (including emissions limitations) applicable to all resources and transmission.
- ~~Calculation~~ Representation~~of the potential impact~~ of load ~~forecast~~ uncertainty and the impacts of load reduction resources such as curtailable load programs and distributed energy resources and resource depletion, including energy storage and hydro resources. .
- Consideration of variable generation uncertainty and energy resource depletion, including energy storage and hydro resources.
- ~~2.~~ Consideration of common-mode failures within regional fuel supply infrastructure.

In an energy reliability assessment, fuel is any energy source from which a generator extracts energy and converts that energy into electrical power. These inputs used to produce electric power include, but are not limited to, combustible fuels (e.g., coal, oil, biomass, hydrogen, natural gas) and other energy sources (e.g., uranium, hydrogen, wind, water, sunlight, heat). ~~There are two types of fuel – either stored fuel (e.g., coal pile onsite, water reservoir, energy storage in battery) or just-in-time fuel (e.g., natural gas from pipelines, sunlight on photovoltaic (PV) panels, wind through wind turbines, run-of-river hydro).~~

Capacity versus Energy

While considering generation capacity is necessary for an energy reliability assessment, it is important to clearly distinguish capacity and energy ~~should be clearly distinguished~~ to properly evaluate BPS concerns and determine mitigation strategies. Capacity is the maximum output an electric generator can ~~physically~~ produce based on specified operating conditions, measured in megawatts (MW). Energy is the amount of electricity a generator produces or potentially produces over a specific time-period, measured in megawatt-hours (MWh). Energy availability depends on both the available capacity and the availability of fuel (both stored and just-in-time fuels) as well as other ~~required~~necessary inputs (e.g., cooling water) to produce a consistent supply of electrical energy.

Capacity Assessment versus Energy Reliability Assessment

Energy reliability assessments differ from capacity assessments in that energy reliability assessments examine a span of time over all hours rather than ~~a single,~~ independent points in time. Both types of assessments are valuable while providing different insights. A capacity assessment evaluates a snapshot in time with limited regard for the system conditions during previous and subsequent periods of time. Even for capacity reliability assessments that perform hourly simulations, the assessments usually treat each hour as independent without considering energy assurance issues related to depletion of energy resources and inter-hour operational constraints. For decades, studies have been performed that assess the total installed capacity (or a capacity adjusted for outage rates) to serve peak load.

Commented [PJM40]: First paragraph – This should address NERC energy assessments only – The first sentence insults many organizations…WECC, Hydro Quebec, ISO-NE, PJM and anyone else that currently performs energy analysis.

Commented [DM41]: Added clarification on what we mean by inconstant rather than no entities do energy assessments.

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Commented [CC42]: To avoid confusion between Reliability Standard 'requirements" changed to necessary as I think it's intended to convey the same thing.

Commented [PJM43]: Load forecast is a variable but not something to address in these studies, recommend removing from this bullet, the rest of this bullet is OK

Commented [DM44]: Removed forecast

Commented [JF45]: I would add renewable resource generation forecast uncertainty.

Commented [DM46]: added

Commented [WP47]: These proposed edits tie to the bullet on page vi regarding DERs and load mgmt. programs.

Commented [DM48]: Added his comments as separate bullet to not lose resource depletion but also include load management.

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Commented [WP49]: These proposed edits tie to the bullet on page vi regarding DERs and load mgmt. programs.

Commented [DM50]: Added his comments as separate bullet to not lose resource depletion but also include load management.

Commented [IESO51]: The sentence beginning, " There are two types of fuel…" More accurate would be that the availability of fuel leads to the classification of the fuels. I suggest the following: "The availability of fuel may be classified into two broad categories, viz. Stored and accessible on site and Delivered just-in-time"

Commented [DM52]: Moved earlier in the paper.

Commented [IESO53]: While this paragraph has offered examples of fuels that fall into the two different categories, it may be beneficial to include in an appendix, a more comprehensive (not exhaustive) list of fuels along with there classification, with comments on some of the considerations that should be examined when performing energy reliability assessments.
Creat appendix listing examples of typical fuels and their classification. Some other examples are geo-thermal, tidal and wave energy.

Commented [DM54]: This classifiction does not support understanding key concepts in vol 1 of this paper. Potentially, it should be considered in vol 2.

Commented [TMK55]: Remove from here

Commented [CC56]: Another "should" change.

Commented [CC57]: A "require" change

Commented [JF58]: Capacity reliability should also be assessed for each hour of the year because the hour of greatest capacity need is not necessarily the hour with the highest load, as seems to be the case in California.

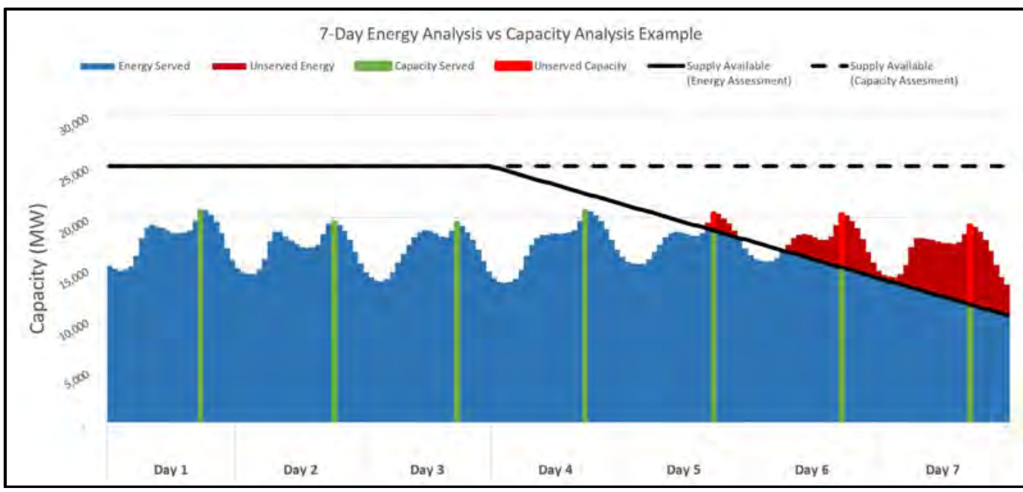
Commented [DM59]: Added sentence related to clarify what we mean by independent snapshots.

Some regions have included higher levels of details in their capacity assessments that factor in concepts of energy availability; for example, some capacity assessments already consider the detailed modeling of hourly loads, intermittent generation profiles, storage charging/discharging and fuel constraints.~~Usually, these studies implicitly assume that fuel will always be available for every resource on the system. Some capacity analyses include assumptions that allow them to account for the *instantaneous* unavailability of a generator due to having no fuel.~~

In contrast, an energy reliability assessment considers the unavailability of a generator whether the outage is caused by the depletion of stored fuel over time, disruption of upstream delivery of fuels (both stored fuels and just-in-time fuels), or the *prolonged* unavailability of a generator due to unavailability of just-in-time fuel. An energy reliability assessment deals with the entire duration of a given time period~~includes all hours~~ (hourly or at some other time resolution)~~or all periods for another time resolution analysis) for a specified period~~~~f~~2 period and accounts for the impact of changes in conditions over time on different aspects of generator operation and demand behavior.

A series of sequential capacity assessments is not equivalent to an energy reliability assessment. Since energy reliability assessments consider the ability to deliver energy over the study duration over a specific time period, an energy reliability assessment needs to include the constraints on different types of resources throughout the time-period.

An assessment that looks only at instantaneous fuel availability may show the system to have adequate fuel and fail to identify overall fuel depletion caused by dispatching the resources to provide the energy needed to match morning, evening, and intra-hour ~~ramps~~ ramping~~associated with variable generation~~ throughout the entire study period.



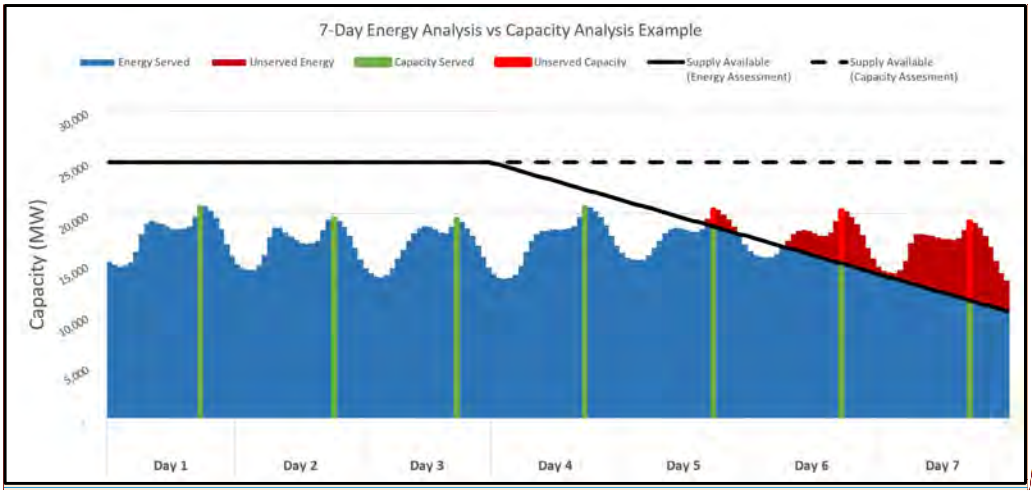
Commented [IESO60]: This section should include a statement acknowledging the dependencies on upstream delivery processes, of fuels that are stored and accessible on site.
It should be borne in mind that even fuels that are stored or accessible on site may have upstream delivery processes which, if disrupted for sufficient time, could render unavailable, the resource that depends on them.

Commented [DM61]: Added additional version

Commented [ISO-NE62]: Differenciating between Unserved Energy and Unserved Capacity is very difficult. Consider using a different color to provide better contrast to "peak capacity served".

Commented [PJM63]: Capacity is not unserved – demand would be unserved.

Commented [EP64]: Add peak demand served instead of peak demand unserved. David will email the updated graph.



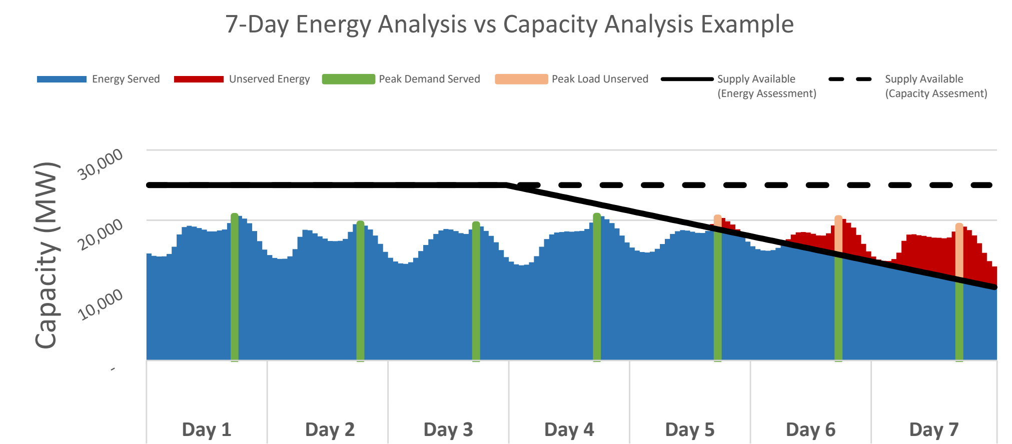


Figure 1.1: An Energy Reliability Assessment versus a Capacity Assessment

A capacity assessment looking at snapshots in time would fail to account for the impact of limited energy supply on the ability to serve demand. Figure 1.1 illustrates an operational example of the difference between energy and capacity assessments for a 7-day horizon. The example assumes 7 cold days of operation during which a stored fuel such as oil may be ~~required~~ necessary to serve load and is depleted during earlier days. For a capacity assessment, a snapshot of the highest demand (green line in Figure 1.1) determines if there is sufficient capacity; the available capacity (dotted line) would be 25 GW throughout the week regardless of fuel depletion required from operation of the system over a seven-day period. The capacity assessment would indicate sufficient capacity available to meet demand. Even if the capacity assessment included some inputs related to fuel supply risk, the lack of fuel available in later days would not ~~include the reduction of~~ capture the impacts on available capacity that is dependent on fuel oil consumption and/or replenishment earlier in the week.

An energy reliability assessment would include the effect of all time periods throughout the horizon. As oil is consumed to meet energy needs earlier in the week, the available capacity is dependent on how fuel reserves are conserved, replenished and/or depleted. The energy reliability assessment identifies the risk of unserved energy (red area in Figure 1.1) and unserved capacity (red line in Figure 1.1) in later days due to limited energy. These risks cannot be adequately observed in a capacity assessment which does not consider the chronology of the declining energy availability and resulting generator constraints over a longer period. By the last two days, even the demand at the low points in the load cycle are unable to be served due to depleted energy supply.

Both types of assessments have value and must be understood and treated differently to evaluate both energy and capacity impacts to the BPS. **Table 1.1** provides a summary of differences between capacity and energy reliability assessments.

Table 1.1: Capacity Assessment versus Energy Reliability Assessment

	Capacity Assessment	Energy Reliability Assessment
Demand Representation	Uses forecasted load scenario(s) that represent a snapshot in time (e.g., 50:50 load, 90:10 load, peak hour load).	Uses time-series demand to incorporate the load changes throughout each day, hour, or year.
	Uses individual snapshots of fixed loads and operating reserves, typically peak demand.	Includes flexible load and net-load variability.
Supply Representation	Uses statistical representation of generator availability to calculate capacity contributions (e.g., UCAP[12], ELCC[13]) resulting in a single value that represents the outage potential at a single point in time.	Represents generator outages based on separate outage modes (e.g., equipment failure, fuel unavailability, network issues), each with a different probability of occurrence, impact, and duration.

Commented [ISO-NE65]: Unless purposefuly positioned in this section of the paper, consider repositioning to earlier in the Section within the document. This section reads more as an intro.

Commented [DM66]: I propose that we keep this as is. This works as a summary of details above.

Commented [PJM67]: Are you really expecting to get information to model load during an hour? Hour and year should be eliminated. Modeling load by hour should be sufficient.

Commented [DM68]: Potentially, yes. I don't see a reason to limit that here.

[12] UCAP: Unforced Capacity is a value that is assigned to a supply resource (e.g., generator) that represents the amount of power generation not subject to forced outages. UCAP is a function of EFORd, the equivalent demand forced outage rate, and ICAP, installed capacity.
[13] ELCC: Effective Load Carrying Capability is a representation of a supply resource's contribution to serving demand in reference to a theoretical resource that is not subject to outages

Table 1.1: Capacity Assessment versus Energy Reliability Assessment

	Capacity Assessment	Energy Reliability Assessment
Transmission Representation	The transmission model is likely to be similar for a capacity and energy reliability assessment. It is possible to use the exact same model for both types of analysis.	The added complexity of an energy reliability assessment may necessitate ~~require~~ a different, potentially simpler, transmission model.
Risk and Reliability Evaluation	Evaluates reliability by simulating snapshots of BPS operation.	Evaluates time-series of BPS operation with fuel stock and other finite resources to be considered.
	Uses clearly defined industry standard capacity or reserve margins to determine the system's level of reliability in terms of magnitude of insufficient supply.	Measures energy-based metrics to evaluate magnitude, duration, and frequency of energy insufficiency over the study period. Though some are maturing, these metrics can be in their infancy and may not be well developed or standardized.~~These metrics are still in their infancy and have not yet been well developed or standardized.~~

Commented [ISO-NE69]: We understand that Transmission Representation entry for both Capacity Assessment and Energy Reliability Assessment will have, at a minumum, transmission rating differences based upon seasonal limits. ERAWG may want to cosndier if this should be reflected in this table or description.

Commented [DM70]: I think this is too much detail for this table and not a distinct between the two assessment types.

Commented [CC71]: Another instance of changing require to necessary/necessitate

Probabilistic vs. Deterministic

Both energy and capacity assessments can be performed using deterministic or probabilistic methods. Both methods have advantages and disadvantages.

Commented [ISO-NE72]: consider minor change to keep the same assessment order throughout the document.

A deterministic approach uses one set of events that will occur for a given scenario. The results of those events have a single outcome for each modeled scenario. An array of assumptions can be made such that there are different outcomes, but the outcome is coupled with the fixed inputs. While the deterministic method may not model a large number of scenarios compared to probabilistic method, if the modeled scenarios are well chosen, these scenarios allow for a clear design basis that ensure a larger number of potential events have sufficient reliability. Deterministic studies can make it easier to make a decision and communicate the decision and its rationale. ~~The decisions have a clear rationale; the decision remediates an issue found in an individual scenario or small set of scenarios (e.g., a transmission planning scenario with a large generator contingency will not be able to supply all load but can with a transmission upgrade).~~

Commented [ISO-NE73]: We did not find the last sentence supportive to the point made in the paragraph. Consider deleting

Commented [DM74]: deleted

A simple example of a deterministic study would be the contingency dispatch of generation to replace the largest generation source loss that would challenge fuel adequacy. The source loss is selected, the initial conditions are fixed, the energy necessary~~required~~ to replace the contingency is selected and dispatched. By looking at the largest generation loss, if all other conditions stay the same, there is a reasonable confidence that any mitigation action is sufficient to respond to unstudied smaller resources that also experience outages.~~While unstudied resources may experience outages, ensuring that the system can maintain reliability with the largest generation loss provides assurance that the loss of smaller resources could be handled as well.~~

Commented [JF75]: This is true only if all other conditions remain the same. This type of study does not provide a comprehensive assessment of system reliability.

A probabilistic study uses a range of inputs, often sampled from a distribution of inputs or historical data, to produce a distribution of results instead of the single result in the deterministic case. The results of a probabilistic study have both a magnitude of impact, duration of events, and a likelihood of occurrence. These distributions of results can be represented by an expected value or risk metric. These risk metrics can assess adequate BPS reliability and resilience by setting limits for these metrics.

~~A simple example of an equivalent value would be the classic lottery ticket equivalent value calculation. If the probability of winning $1,000 is 10%, then the equivalent value is $100 per entry. Similarly f~~In a~~or an example~~ probabilistic ~~capacity~~ assessment, a loss of load expectation (LOLE) can be calculated. If you simulate 1,000 annual operations of a power system which are equally likely to occur and ~~calculate~~ count the number of ~~hours~~ days with insufficient energy for any duration, you will have a distribution of the ~~magnitude~~ number of ~~shortfall hours~~days with energy shortfalls ~~lost~~ per ~~scenario~~simulation. If this distribution of outcomes has a total of ~~30~~ 25 ~~events~~days~~hours~~ with a loss of load, the loss of load expectation ~~of~~ is 0.025~~03~~ ~~04~~ ~~hour~~~~sevents~~ days/year.

Table 1.2 contains a summary of the comparison between deterministic and probabilistic assessment methods that can be used in an energy reliability assessment.

Table 1.2: Deterministic Versus Probabilistic Assessments

	Deterministic	**Probabilistic**
Demand Representation	Considers a single demand forecast or set of discrete forecasts with a separate case for each	Considers multiple demand forecasts and considers uncertainties such as: weather impacts on demand, weather impacts on net-load/behind-the-meter generation, economic drivers. Input data may be based on distributions of data.
Supply Representation	Considers a singular supply shape per case – e.g., extreme weather, one 'hydro year'. Can include operational constraints (e.g., ramp rates)	Considers multiple supply scenarios and factors uncertainties such as: temperature, water availability, multiple outage scenarios, fuel risks. May consider a distribution of events or multiple weather years for wind/solar/hydro. Input data may be based on distributions of data.

Commented [PJM76]: Check calculation. I get 0.003 hours per year for thirty hours.

Commented [DM77]: @Anna, the calculation has changed based on everyone's comments but can you double check this calculation too.

Commented [LA78]: I think it's correct now.

Commented [JF79]: By NERC's own definition, I believe what you are calculating here is loss of load hours (LOLH) and not LOLE, which is the expected number of event periods per time span. An event period is defined as a specified time span during which one or more shortfalls occur. LOLH is the expected number of shortfall hours/year. If the event period is 1 hour, then the LOLE would be 0.03 event-hours/year. However, if the event period is 1 day, then you cannot convert the 30 shortfall hours into an equivalent and unique LOLE value for event days/year. Also, the distribution of the number of shortfall hours per simulation is irrelevant here. To calculate LOLH only the total number of shortfall hours and the total number of simulations is needed.

Commented [DM80]: Corrected to be consistent with LOLE calculation because our version wasn't quite LOLH either.

Commented [WP81]: The descriptions should cite elements of probabilistic analysis such as probability distributions, stochastic modeling (e.g., Monte Carlo simulation), etc.

Commented [DM82]: Added references.

Table 1.2: Deterministic Versus Probabilistic Assessments

	Deterministic	Probabilistic
Transmission Representation	Uses a single transmission model with transmission availability of each element considered, independently.	Considers correlation of transmission topology/availability – temperature, multiple outage scenarios
Risk and Reliability Evaluation	Determines unserved energy for a single run[14]	Uses multiple metrics (e.g., LOLE, LOLEV, EUE, LOLH, VaR) based on to evaluate expected magnitude, duration, and frequency of energy insufficiency. Theses metrics are based on the results of stochastic modeling methods.
	Determines sufficient reliability by evaluating sufficient power in each scenario, separately.	Determines sufficient reliability using risk metrics, which includes probability of scenarios while individual simulations may not have sufficient reliability.

~~Deterministic and probabilistic methods can be used together to better understand risk and make decisions to mitigate risksdevelop mitigation strategies. One method to incorporate the deterministic and probabilistic methods is to use a range of inputs in a probabilistic analysis and evaluate the results of the most impactful scenarios in a deterministic analysis.~~ One of the challenges of probabilistic assessments is developing and understanding the impact of discrete mitigation activities. Deterministic assessments can be used in conjunction with probabilistic assessments to explore a scenario in greater depth and confirm whether a selected mitigation strategy can effectively address that scenario. ~~In this case, the identified scenarios allow for a design basis that will meet an adequate level of reliability;~~ R~~this r~~isk-informed scenario development can be used to ensure that reliable operation is maintained during low probability (albeit, not necessarily rare) and likely events (e.g., multiple cloudy/rainy days). ~~This is a~~ H~~h~~ybrid ~~between~~ probabilistic and deterministic modeling approaches can be effective to develop a resource mix and transmission systems that meet the desired reliability and resilience goals.

Table 1.3: Summary of Assessments

	Deterministic	Probabilistic

[14] Unserved energy and expected unserved energy (EUE) are related concepts but differ in their calculation and interpretation. Unserved energy is a metric calculated for individual scenarios. EUE is a probabilistic risk metric calculated based on average unserved energy ~~calculated~~ from many scenarios and combined based on the probability of those scenarios occurring to produce a single metric. EUE includes the likelihood of modeled events to calculate the value in terms of unserved energy per a time period (often unserved energy per year).

Commented [WP81]: The descriptions should cite elements of probabilistic analysis such as probability distributions, stochastic modeling (e.g., Monte Carlo simulation), etc.

Commented [DM82]: Added references.

Commented [JF83]: Technically, LOLE is the frequency of event-periods (e.g., 0.01 event-days/year) and does not represent the frequency of events, where an event is defined as a contiguous set of shortfall hours. That metric is the loss of load events or LOLEV.

Commented [DM84]: Added LOLEV as an additional metric in list.

Formatted: Comment Text

Commented [JF85]: As written, this does not make sense to me. If you first run a probabilistic analysis with a number of random variables, then what does one gain from taking one of the simulations with a bad combination of random variables and analyzing it again deterministically? The only reason this might be done is if the probability distribution for a random variable is not known. In that case, probabilistic analyses can be run for multiple scenarios with different chosen values for the variable with an unknown probability distribution.

Deterministic and probabilistic methods can be used together when the probability distribution for a random variable is not known. In that case, probabilistic analyses can be run for multiple scenarios with different chosen values for the variable with an unknown probability distribution.

Commented [DM86]: I see his point but this is an example rather than the method to use. Is the described idea in paper wrong or unclear?

Commented [LA87]: How about something like this: One of the challenges of probabilistic assessments is developing and understanding the impact of discrete mitigation activities. Deterministic assessments can be used in conjunction with probabilistic assessments to explore a scenario in greater depth and confirm whether a selected mitigation strategy can effectively address that scenario.

Commented [JF88]: Probabilistic analyses provide a number of metrics that can be used to assess both adequacy and resiliency. To assess adequacy, for example, a limit can be set for the expected frequency of shortfall events (LOLEV). The system is inadequate if events are occurring too often. To assess resiliency, a limit can be set for the magnitude or duration of a low probability but potentially high impact event. The value at risk (VaR) metric can be used for this. For example, setting the 95th percentile VaR limit for event duration to 8 hours means that the system is deemed to be resilient as long as the 5th percentile longest shortfall does not exceed 8 hours. See my earlier reference to the Power and Conservation Council's 2027 adequacy assessment for more detail.

Commented [DM89]: Added comment above about comparing risk metrics to limits for adequate reliability. Further discussion seems more appropriate for vol 2.

Capacity Assessment	A single or few sets of discrete inputs for supply and demand looking at a single snapshot in time	Numerous sets of dependent and independent input variables representing supply and demand looking at various possibilities ~~looking at~~for a single snapshot in time
Energy Reliability Assessment	A single or few sets of discrete, dependent and independent inputs for supply and demand looking at a long duration of interrelated steps in a multi-interval case resulting in specific final conditions describing the state of a system in operational terms	Numerous sets of dependent and independent input variables representing supply and demand looking at a long duration of interrelated steps in a multi-interval case resulting in a distribution of risks with associated probability and impact

Study Frequency, Horizon, and Duration

The design of a process to conduct energy reliability assessments includes consideration of the study frequency, horizon, and duration.

Table 1.4: Definitions of Study Frequency, Horizon and Duration		
	Definition	**Example**
Study Frequency	How often a study is performed	Performed once per year
Study Horizon	How far in advance the study analyzes	Analyzed year one through year five
Study Duration	The length of time of the study period	Studied a 90-day period

An energy reliability assessment consists of multiple consecutive hours/days/months, in contrast to a single-hour capacity study or multiple hourly capacity studies with dependencies between hours not being considered.

Several factors, depending on how far in advance the study is being performed, will limit the level of detail provided by the energy analysis. Short study periods that are near-term horizon (e.g., performed today for the next 7 days) have forecasts available and can be very precise. Longer horizon studies have a wide range of input variables. High precision is not necessarily available, or even desired, and a wider array of input assumptions is necessary to properly account for realistic possibilities. The study frequency, horizon, and duration are highly dependent on the challenges faced and are regionally specific.

Study frequency considerations should include how fast input data changes, how much time and effort ~~is~~are needed to complete a study, and how long it takes to determine and execute mitigating actions. If assumptions change enough on an annual basis to repeat a study, then the frequency would be annual. Shorter horizon studies will generally have a study frequency that updates as the time that was studied in the prior iteration expires.

The study horizon will generally be defined by what actions can be taken in the time between when the study is performed and when ~~the study starts~~period of interest occurs. Short horizon actions such as outage coordination of existing resources would drive the need for a short study horizon. Long lead time actions such as expanding resource portfolios (i.e., building new generators) would lead to a long-term study horizon. Long-term horizon studies necessitate ~~require~~ more assumed inputs than a near-term horizon study, reducing the importance of precision.

The study duration of an energy study is likely more difficult to define until work has been done to better understand what is being studied. It could be arbitrarily defined as a 90-day period or a full year. Once that study is complete, subsets could be brought into focus for producing more precise studies.

The study frequency and study duration must be determined by the desired outcome and align with the logistics related to the timeframe. For example, performing short-term horizon studies with assumptions that transmission facilities will be built are unrealistic. Performing long-term horizon studies with single weather forecasts will fail to evaluate the equally likely conditions.

Considerations for determining the optimal study duration and study horizon should include elements such as fuel replenishment and other logistical constraints, storage capabilities and expected inventory, accuracy and timeliness of weather/climate forecasts, and the expected duration of long-term events (e.g., cold spells and heat waves). ~~Replenishment~~ Fuel replenishment timelines relate to study horizon and study duration in that there ~~is~~ may be sufficient time to complete mitigation efforts. An example in the operations planning time frame could be:

~~1.~~
- If the process of refilling an oil tank takes two weeks to complete, from the time the need to refill the tank is recognized to the time the tank inventory has been replenished, the study should be performed using at least a horizon that allows sufficient time for refueling to occur. On the other side of the

Formatted: Bulleted + Level: 1 + Aligned at: 0.5" + Indent at: 0.75", Tab stops: Not at 0.5" spectrum, weather forecasts begin to lose accuracy beyond a week. Attempting to forecast weather too far beyond that period would likely lead to less accurate results.

~~2.~~ • Alternatively, when performing longer duration and longer horizon studies, seasonality should factor into the decision. It would be prudent to study a winter season, with similar risks and conditions for a three-month period. It could be confusing ~~or non-productive~~ to study combined winter and spring seasons in a single study.

As stated before, all of these study horizons have ~~are~~ regionally specific considerations for selection based on realistic, though potentially extreme, conditions.

Commented [WP90]: While this is generally true, late winter weather events can impact spring unit availability to the extent that there is plant damage or modified maintenance schedules.

Commented [LA91]: Just deleted the non-productive statement

Chapter 2: Elements of an Energy Reliability Assessment

Chapter 2 explores the different elements of an energy reliability assessment. There are considerations to be made for supply and demand as well as other variables that could impact both. This chapter discusses some of the elements to consider for an energy reliability assessment related to demand, supply, with a separate discussion on DERs that can blur the lines between supply and demand.

Energy Demand Considerations

Instantaneous (Peak) Demand vs. Prolonged Demand

Energy reliability assessments take into consideration prolonged energy demand (power demand over time) to assess the availability of supply across a pre-determined study period. Meeting peak demand requires supply to reach a single high point at an instant in time before ramping down into the off-peak hours of the day. Off-peak demand still consumes energy, albeit at a lower rate. Modeling time-sequenced demand gives an analyst the ability to measure the impact of all demand and the effect it has on supply that would be ~~required~~ necessary to serve that demand at each individual point in time. Hourly integrated demand is given as one example, but time periods may vary, depending on the scope of the assessment.

In the operations time frame energy reliability assessments should include a demand forecast across an appropriate study period to effectively study the impact of resource depletion while allowing time to react, with at least hourly granularity, but could ~~require~~ necessitate higher precision when intra-hour constraints present a risk to reliable operations.

In the operations-planning horizon (1 day to 1 year), an energy reliability assessment includes a demand forecast across a time horizon that is tailored to the system being studied, with at least hourly granularity.

In the long-term planning horizon (> 1 year), an energy reliability assessment includes an hourly demand forecast for a longer study period, e.g., ~~an entire season~~the entire study period.

Commented [TMK92]: Recommend rejecting change. Point is to illustrate a longer study period (season)

Commented [LA93]: agree

Behavior of Demand

In the operations and operations planning time frames, demand behavior is primarily influenced by weather. Weather forecasts are incorporated into the energy reliability assessment, where it impacts demand.

In the long-term planning time frame, changes in demand will be influenced by many variables such as: economic growth, changes in the penetration of behind-the-meter resources, climate trends, market mechanisms involving demand response and other demand response behaviors, such as vehicle-to-grid energy supply, new types of loads (e.g., hydrogen production, crypto-mining), heating electrification, electrification of other commercial and industrial processes, and energy efficiency advancements.

Behind-the-meter generation can obscure the line between supply and demand. Some behind-the-meter locations are comprised of solar PV, energy storage, and electric vehicles at the same location making it difficult to predict the net flow at these distribution level locations. Behavior may also be potentially shaped by market mechanisms or other programs that incentivize voluntary curtailments of specific demands at certain times, declared events, or via real-time dispatch. Because demand response programs are usually designed for peak load management, voluntary curtailments frequently result in increased ~~consumption~~energy demand during subsequent time periods.

Commented [TMK94]: Accepted and slightly altered

While the current capability of these programs may be limited for now, advances in smarter devices can provide better capability for external control in the future. A potential benefit of increased external control and dispatchability is that it reduces the burden to serve that demand using grid-connected resources.

Technological advancements may provide better capability for external control in the future.

Usage ~~of~~ and Controllability of Demand

An important consideration in the demand forecast is whether the demand can be controlled or whether it is fixed. For example, controllable demand includes programs that exist to target the conservation of energy at specific times to reduce the real-time demand on the BPS for a variety of reasons. Opportunity exists to expand the capability of controllable demand as appliances become more sophisticated and interconnected on the Internet of Things[15]. Controllable demand can be used to shape and shift demand in a day or week to help balance supply and demand but still requires energy. Response fatigue can potentially limit the amount of response that would be seen after enough calls for conservation are made. Eventually, the consumers of electricity may elect to disregard conservation requests if they are over-used. Consideration for the controllability of demand allows for more accurate modeling of how the system would operate and also gives options for determining solutions when supply resources may not be available to produce power.

Distributed Energy Resources

Distributed Energy Resources (DERs) are becoming a more integral part of the power system and must be included in studies. This is true today, and studies that look beyond the next year or two should make reasonable assumptions of the growth of such resources. In some cases, DERs can account for over 30% of a BA's supply. ~~and s~~Some BAs are experiencing operational challenges due to the variability of DERs, whether it be predictable or volatile. DERs do not have to be of any specific class of generation but are more likely to be comprised of solar and solar coupled with energy storage, especially if those resources are new and built as part of plans to meet decarbonization policy goals[16]. Modeling DERs refines the precision of an energy assessment and gives the analyst more insight into the behavior and risks of bulk power supply versus distributed power supply (DER).

Commented [PJM95]: Break this sentence into two and explain the second part a bit more: In some cases, DERs can account for over 30% of a BA's supply and some BAs are experiencing operational challenges.

Commented [TMK96]: updated

Energy Supply Considerations

Fuel Assurance and Logistics

Generating electricity is a complicated process. There are numerous steps in supply chains that depend on each other to provide the necessary fuel and materials, to a highly complex set of machines that ultimately generate electricity. Each supply chain is critical to the operation of each individual facility, have some intersection along the way, and are often controlled by entities outside the organization of the grid operator or generator that depend on them. Failure of any of several chains can result in reduced capability or full outages. Studies should consider the supply chains of fuel, consumable emissions control supplies, repair parts for routine maintenance and/or unplanned repairs including those for electronic control equipment, transmission facilities, and even personnel.

Some supply chains remain relatively unconstrained and can be assumed to be available at all times. These will not ~~require~~ necessitate detailed modeling as other fuels may, but a thorough evaluation should be used to justify the exclusion of detailed modeling.

Supply chain demand outside of the electric sector that competes for the same resources should also be considered. Supplies that depend on trucking or rail transportation (for example) are competing with a variety of unrelated goods that share the same transportation and associated resources. Demand on gas pipelines for heating, hot water, and other residential/commercial/industrial use can stress natural gas supply and transportation networks and reduce the amount of fuel available for power generation. Each region of the country may have its own specific (and

[15] https://en.wikipedia.org/wiki/Internet_of_things

[16] For example, as of January 2020, California has building codes mandating new single-family homes and multi-family dwellings up to 3 stories high must install solar panels.

seasonal) constraint points on regional fuel supply chains. Competing demand is not limited to natural gas. Fuel oil for home heating and generation is a shared commodity. Increased demand for home heating oil depletes stocks and potentially stresses supply chains for fuel oil for generators as well. The United States Census Bureau provides information on the types of fuels used to heat homes, broken down by region[17].

To go one step further, fuel supply chains are linked through the demand for those fuels. When coal is depleted for power generation, it must be replaced, likely with either gas- or oil-fired generation. That replacement stresses the supply chain for those fuels. Additionally, replenishment is not instantaneous in most situations. Even natural gas, which flows through high-throughput pipelines from the production source to the demand location ~~requires~~ necessitates advance scheduling to keep the transportation network in balance. Stored fuels ~~require~~ need additional time to arrange delivery in the amount and timeline that is ~~required~~ necessary to ensure continued operation. Not all resources can replenish faster than they can use stored fuels. The method of replenishment (barge, truck, pipeline, etc.) is important when attempting to model energy. Replenishment strategies also play a role in energy modeling. Knowing what decisions will be made to maintain inventory should be considered for energy analysis modeling.

Some stored fuels are sourced overseas and ~~require~~ need days, or even weeks, to deliver. The logistics of these actions is where energy analyses can ~~really~~ provide the necessary situational awareness needed for power generators to make timely decisions to ~~attempt to purchase fuel~~signal the need to schedule and deliver fuel. Beyond logistics is the impact of worldwide events on supply chains. This concept is referenced in *Reliability Guideline: Fuel Assurance and Fuel-Related Reliability Risk Analysis*[18].

Commented [TMK97]: Recommend rejecting.

The decisions we talk about are being made by the people who buy fuel, not the entity doing the study. The entity doing the study is signaling the need, but the decision is to buy.

Loosely related in terms of fuel supply chain are the supplies of fuel to variable energy resources, primarily solar, wind, and run-of-river hydroelectric generation. The nature of the generator is to produce electricity at nearly 100% of the capability of the incoming fuel supply. Since the fuel supply is heavily dependent on factors outside of human control, efforts must be made to forecast the availability, or at least make reasonable assumptions, such that the reaction can be measured. The reaction, in this case, is to balance supply and demand with other types of resources, such as oil, natural gas-fired generators, and energy storage.

Modeling fuel supply constraints to generators gives an analyst the ability to better understand the profile of electric output as it pertains to using other dispatchable supply resources to balance the power system.

In the Long-term Planning horizon, fuel assurance can be assessed using scenarios or probabilistic analyses that consider:

- Multiple water years (e.g., high, medium, low drought conditions).
- Storage capability and inventory level of fuel, including natural gas, and time for stored fuel to be delivered to generators.
- Multiple wind and solar profiles (e.g., multiple years of data or scenarios with reduced availability of wind/solar).
- Multiple generation installation and retirement scenarios which have the potential to reduce available fuel diversity and amplify dependence on other fuel inventories.
- Project future bulk electric and fuel transmission capability and topology.

Commented [TMK98]: Accepted change with one alteration

[17] https://data.census.gov/cedsci/table?q=heat&tid=ACSDT1Y2019.B25040
[18] https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Fuel_Assurance_and_Fuel-Related_Reliability_Risk_Analysis_for_the_Bulk_Power_System.pdf

Outages and Failure Modes

For many capacity studies, forced outage rates serve as a proxy to generator outages caused by various failure methods including fuel insecurity, and work well for a given set of conditions. When a fleet of similar generators perform with high capacity factors, or at least with the ability to perform at high capacity factors, average outages can be applied as de-rates to the generation fleet to assume an average outage amount (in MW) for a capacity study. Changing the type of study from capacity to energy or the generation fleet to be less consistent or predictable ~~requires~~ necessitates additional inputs to be considered, or the existing inputs to be used differently. In the case of a fleet of widely variable generators (wind and solar), forward-looking studies must consider a wide array of outcomes in a probabilistic study. Usually, the forced outage rates are treated as independent events. However, correlated factors such as weather, hydro conditions, and generator outages should be linked as such and not treated independently. Weather drives demand and impacts the probability of outages. A prime example is the case with extreme cold or hot weather which directly correlates with higher loads and indirectly correlates to higher forced outage rates (FOR). To capture this temperature/availability relationship, the modeling of a monthly or seasonal FOR of a generating unit is more accurate that using and annual average FOR. If these events are studied independently, the likelihood of this event will be overestimated and will skew the results of the study to be more favorable. This masks the true expectation of failure and can be worse than not knowing the actual risk.

An additional consideration to be included in energy reliability assessments is the likelihood of increased forced outages of natural gas-fired generation ~~when~~as more variable generation is added to the grid. ~~G~~Natural gas-fired units may cycle and remain offline more often ~~and experience~~raising the likelihood of ~~more~~ start-up and operational failures due to a higher off-line frequency.

Using the generation forced outage rates to represent outages to occur at the single specific hour of the study is adequate until the study becomes more complex. Simple analyses may reduce the output of each generator by an assumed amount to approximate outage impacts on the overall energy picture. Giving generators a “haircut” better approximates energy capability over a long period of time but may obscure specific problems when performing complex, time-dependent studies.

There are many failure mechanisms for generators, each with different probabilities of failure and different impacts for each failure mode. There is a higher probability that a generator will be reduced by a small percentage for a few hours, but still a non-zero chance that the same generator will be out of service for months or longer, all depending on how it fails.

In a probabilistic study, each failure mode can be modeled with its probability of occurrence, the associated impact, and study period. The probability of occurrence is some fractional value that the outage would occur. The impact of a failure will be dependent on the failure mode as well. For example, a natural gas-fired, combined cycle generator with supplemental heat recovery steam generator (HRSG) firing may continue to operate but will suffer a capacity reduction due to failure of the supplemental firing system. Other failure modes will result in different impacts and must be accounted for accordingly. Finally, the study period must be accounted for. Every failure mode should also have an expected duration of impact. This is important for an energy reliability assessment in that MWhs will be replaced by other resources and could have cascading effects.

Each generator will have a different set of assumed failure modes. Classes of generators can have a similar set of assumptions, but a holistic system study could benefit from more specifics based on the generator or generator type. Another consideration for failure modes is associated conditions. Some failure modes can only occur, or have a higher probability of occurrence, during specific conditions. Wet coal problems can only occur under rainy or snowy conditions. Generator freezing can only occur during cold weather, increasingly so as temperature drops.

As an example of the changes needed to improve outage characterization, IEEE Standard 762 “Standard Definitions for Use in Reporting Electric Generating Unit Reliability, Availability, and Productivity”, which provides guidance on

Commented [Dom99]: System Operators frequently have to balance economy and relaibility when making dispatch decisions. It should be made clear that reliability is prioritized over economy during an emergency.

Commented [LA100]: I think this doesn’t add to the discussion and could be potentially confusing for volume 1

Commented [TMK101]: Accepted change with alterations calculating outage rates, is currently being updated. Prior editions of IEEE Standard 762 did not distinguish the reasons a unit failed to produce electrical energy, other than distinguishing between planned and unplanned outages and reserve shutdowns. Without this distinction, at times, the standard has been used to enumerate only equipment failures. The draft revision to the standard[19] acknowledges the broader range of failure modes by introducing a new term “resource unavailability.**”** This is the unavailability that is normal to the generation technology employed and captures full and partial outages as a result of such drivers as:

- ~~1.~~ Regular (hour-to hour, diurnal, and seasonal) energy unavailability for both variable energy resources (e.g., sunlight and wind), and conventional resources. For conventional resources, this can include low water for a hydro plant or inadequate fuel supply (including diversion of the resource to other users by the supplier) or transportation infrastructure disruption for a thermal plant; and
- ~~2.~~ Circumstances where the energy resources exceed a limit for safe operation, such as when wind speed exceeds a wind turbine’s cut-out speed.

Such characterization of outages, and the additional information that it can provide, will be useful for performing a more rigorous energy reliability assessment.

Transmission and Reliance on Inter-area Interchange (External Assistance)

The supply of electricity is only as good as its ability to reach the load. If power cannot move from the supply to the demand, the production capacity is irrelevant. That concept applies to intra- and inter-regional transmission systems. Electric transmission is part of the supply chain to deliver electricity to end users. Transmission constraints that limit the flow of electricity are one of the better understood parts of this problem as they have been studied for decades. Transmission system constraints are usually separated into constraints that are contained within an area (intra) and the constraints between areas (inter).

Even an unconstrained transmission system can present obstacles to be studied. Areas that serve demand with supply from outside their region make assumptions about the availability of energy in the outside region. Available Transfer Capability for imports does not necessarily mean that energy from imports is available and these limitations should be included in an energy reliability assessment. The availability of imports is dependent on energy issues or demand requirements in external regions. Coordinated studies would show the assumptions of imports and exports at adjoining interfaces, ensuring that energy is available to support exports to an area that is depending on the corresponding imports, and is not counted in multiple energy reliability assessments. Conflicting assumptions could leave operators unexpectedly energy deficient.

Traditionally, peak demand is the point at which the BPS experiences its highest usage and potentially highest stress level while transferring the most power from generators to load centers and loading transmission lines most heavily. With the influx of DERs usually being smaller and (as the name implies) more distributed, the riskiest period of the BPS operation may no longer coincide with peak power demand. Off-peak hours in this case could be at any other period of the day, based on the variable nature of modern generators. Examples include peak photovoltaic or wind production, when generation could go beyond a simple offset of demand to the point where a change in load and generation patterns would cause transfers across the transmission system to operate closer to limits, potentially causing congestion mitigation measures to be implemented, at a time when studies would not normally be performed. There are potential constraints on the BPS that would be made apparent using studies that go beyond the snapshot of peak demand.

Modeling or making assumptions of transmission capability and availability of imports provides more accuracy for an assessment while giving potential insight into stress on the system beyond peak demand periods.

Formatted: Bulleted + Level: 1 + Aligned at: 0.25" + Indent at: 0.5", Tab stops: Not at 0.5"

Commented [LGE102]: Suggest mentioning that energy storage can help with firming variable generators. "Pairing energy storage with variable generators like wind and solar PV can help with firming overall system generation."

Commented [LA103]: We discuss storage at length in the next section. I don’t think we need to talk about storage in a discussion of external assistance.

[19] Please refer to IEEE P762[TM] (Draft 41, October 3, 2022), Standard Definitions for Use in Reporting Electric Generating Unit Reliability, Availability, and Productivity has been approved in balloting and is undergoing final editing

Energy Storage

Until recently, pumped storage hydro-electric was the main type of energy storage on the BPS and is typically used to provide fast-start balancing of supply and demand or contingency recovery (via the triggering of operating reserves). Pumped-storage hydro can also be used to provide additional demand on the BPS, typically when light load conditions exists and the BPS is operating in a "minimum-generation" state. Depending on the configuration, pumped-storage hydro can be used on a daily or weekly cycle. Today, with more variable supply resources, the role of storage has trended more towards balancing, with the objective of stabilizing the supply for what may now consider a relatively consistent demand curve.

The operation of a specific facility, including the duration of time that energy storage can discharge to the grid, varies by the design of the site and technology type. Long duration storage such as pumped storage hydroelectric and newer storage technologies have the potential to inject energy at various times when conditions may otherwise not support adequate supply for several days. This would be the case when there is unfavorable weather to produce solar and wind power (i.e., cloudy and calm) for multiple days. Energy assessments may provide insight into the amount of storage needed for a specific scenario. Storage is quantified in both capacity (MW) and energy (MWh) and must be modeled as such.

Stand-alone storage is a device that takes power from the system, saves it as some form of potential energy, and uses it to provide electricity later. The efficiency of storage should be considered in an energy analysis. Furthermore, the fact that stand-alone storage resources are overall consumers of energy means that they should be considered for exclusion from operation when facing a risk of fully depleting energy constrained resources. However, if storage is co-located with a supply resource, then the storage can provide capacity and energy at times when the supply resource is not operating.

Co-located or hybrid storage includes storage coupled with a supply resource like solar, wind, or other energy supply. These storage types can be modeled as a single facility or broken down into its individual components, so long as the capabilities are accurately included in the assessment.

Modeling storage is key to future studies when each instance in time could be dependent on storage just to meet the energy ~~requirements~~needs.

Operational Characteristics and Balance of Supply and Demand

To effectively simulate the multi-hour interdependencies between supply and demand, considering the impacts of operational characteristics of resources on energy availability is important. Such operational characteristics include startup and shutdown profiles of generators and intertemporal constraints such as minimum down times, minimum and maximum run times, and number of startups allowed, which may depend upon the generator's technology type or emissions restrictions. The operational profile can also impact the duration of energy availability should limited energy resources be depleted to support ramping or other ancillary services or BPS needs. Models that simulate chronological unit commitment and dispatch are integral to the assessment of multi-hour energy availability.

In a power system with generation that can change output at a rate faster than the rate of change in power demand, ramping is not a concern. Traditionally, generators are dispatchable from a minimum output to a maximum output at the discretion of a system operator whose goal is to maintain supply balanced with demand. Simply, this is a two part equation with supply on one side and demand on the other. Supply is either set to a fixed output that does not usually change over time (e.g., nuclear power plant), variable output that can be accurately predicted and/or does not represent a large portion of the generation fleet (e.g., run-of-river hydro or low-penetration of wind generation), or dispatchable that follows dispatch instructions and assumed fuel availability. A new addition to this equation can be described as generation with variable output that cannot be accurately predicted and can be far less certain. Even in a situation where predictability is perfect, potentially high ramp rates from non-dispatchable resources ~~require~~

Commented [Dom104]: Storage resources should be better utilized and their capabilities understood when the system is stressed. Storage resources have unique characteristics and appear to be underutilized, especially during stressed system conditions. Understanding charging/discharging characteristics and optimizing their use would significantly enhance system reliability.

Commented [EP105]: Team: We will add the charging/discharging characteristics to Vol 2 document. Add to Vol 2 – assess for long term storage and long duration storage (longer than 10 hours) (Clyde L, John B)

Commented [PJM106]: Should mention that one installation may be operated very differently from the next, will be very difficult to make operations assumptions

Commented [TMK107]: Language added to next sentence (first in next paragraph)

Commented [ISO-NE108]: Replace with "capacity or energy deficiencies are forecast and when they unexpectedly occur."

Commented [TMK109]: Recommend rejecting. Emphasizing several days instead.

Commented [TMK110]: Accepted this change as well as the discussion on stand-alone storage differences. The reality of it is that people need to think of the two components separately. Co-located storage puts out less overall energy than direct PV to grid. Not operating the storage component still results in more energy available

Commented [CC111]: Does this change to needs fit? I don't want to change content only tone.

Commented [Dom112]: As electrification continues, the demand on the system continues to become more variable. As EVs, price responsive loads, large customer loads, demand response, and time of use customers continue to proliferate, electric demand will continue to increase and become more inconsistent. Baseload resources will continue to be critical to stabilize the system where intermittent resources cannot perform.

Commented [LA113]: Agreed – no change recommended since this is discussed below and in the demand section.

need analysis, and potential mitigating actions, when the offsetting, or replacement ramping capability may be insufficient. As the penetration of resources that rely on just-in-time fuel, and/or variable energy resources that rely on weather conditions increases, the overall variability of the supply increases, leading to higher levels of uncertainty in energy supply.

Demand on the system is also becoming more variable as a result of changes to the demand composition including electric vehicles, price responsive loads, demand response, and combined heat and power plants. All these demand elements may on short notice either self-supply on-site demand or increase system demand on the grid. As a result, supply and demand intra- and inter-hour ramps are increasing and are expected to increase in the future, placing a greater burden on existing dispatchable resources. For this whitepaper, flexible resources refer to any system resource that is available or can be called upon in a short time to respond to changing system conditions.

Commented [ISO-NE114]: The paragraph appeared to be more supportive of "Section 2; Energy Demand Consideraitons" rather than the "Operational Characteristics and Balance of Supply and Demand". Consider relocating the paragraph into Section 2; Energy Demand Consideraitons

Commented [TMK115]: It could be moved, but once it refers to ramping, it should stay here.

Conclusion

Energy reliability assessments are moving into the spotlight as a critical tool to fully understand the operation and planning of the BPS. The evolving grid will rely heavily on increased levels of variable and flexible resources ~~and natural gas-fired generators~~ to meet future energy needs. Consequently, the behavior of all resources must be understood and accurately modelled. Performing energy reliability assessments and ensuring the validity of assumptions used in those assessments are important foundational activities for maintaining BPS reliability and resiliency.

Commented [LGE116]: Suggest adding energy storage since it is now often incorporated with intermittent resources, like solar PV.

Appendix A: Contributions

ERATF Tiger Team	
Peter Brandien	ISO-New England
Layne Brown	Western Electricity Coordinating Council
Candice Castaneda	North American Electric Reliability Corporation
Julie Jin	Electric Reliability Council of Texas, Inc.
Soo Jin Kim	North American Electric Reliability Corporation
Mike Knowland	ISO-New England
Anna Lafoyiannis	EPRI International Inc.
William Lamanna	North American Electric Reliability Corporation
Mark Lauby	North American Electric Reliability Corporation
Clyde Loutan	California ISO
Al McMeekin	North American Electric Reliability Corporation
David Mulcahy	Illuminate Power Analytics
Levetra Pitts	North American Electric Reliability Corporation
Elsa Prince	North American Electric Reliability Corporation
Valerie Carter-Ridley	North American Electric Reliability Corporation
Aidan Tuohy	Electric Power Research Institute
Jack Armstrong	
John Brewer	

Commented [EP117]: NERC staff will rearrange alphabetically

Energy Reliability Assessments Working Group

Action
Approve the conversion of the Task Force into a Working Group.
Approve the Scope Document.

Summary
In January 2021, the Energy Reliability Assessment Task Force (ERATF) was created and was tasked with assessing risks associated with unassured energy supplies stemming from the variability and uncertainty from renewable energy resources, limitations of the natural gas system and transportation procurement agreements, and other energy-limitations that inherently exist in the future resource mix.

During the past three years, the scope of the task force has identified additional work required, since the changing resource mix, resource adequacy, critical infrastructure interdependencies, extreme natural events are on-going issues challenging our industry.

The energy reliability assessment team is a forum designed to help foster solutions. The team will continue to monitor industry issues and create technical documents that provide solutions to the on-going industry issues.

NERC
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Energy Reliability Assessment Working Group

Scope Document
Updated May 2023

Purpose

Electricity is fundamental to the quality of life for nearly 400 million citizens in North America. Electrification and the advancement of renewable energy resources continues as new technology and policies are contributing towards greater electrification of transportation and heating. The Bulk Power System (BPS) is undergoing unprecedented changes that require a rethinking of generating capacity, energy supply, and load serving needs.

Layered into this environment, there is evidence that industry is facing fuel uncertainty in certain instances. For example, natural gas fueled resources may, depending on the contract for fuel acquisition,[1] be subject to fuel curtailment or interruption during peak fuel demands in some areas. Additionally, natural gas pipeline designs and how generators interconnect with these pipelines can vary, resulting in significantly different impacts on generators and the BPS under natural gas pipeline disruption scenarios. Furthermore, variable energy resources require that there are sufficient flexible energy resources available to quickly respond to off-set ramping requirements in some areas. To some extent, the impacts can be mitigated with the supply and geographical diversity from renewable and smaller distributed resources. However, these uncertainties are already causing many system operators to consider scheduling, optimization, and commitment of resources over a multi-day time frame. Replacing the existing generation fleet with energy-limited resources requires industry to consider capacity requirements, energy resources, and fuel availability by extension. Even if sufficient capacity is available, a level of certainty in the delivery of fuel is required to ensure that energy is available to support demand. These circumstances are anticipated to continue as the BPS continues to evolve.

The Energy Reliability Assessment Working Group (ERAWG) is assigned the responsibility to (i) facilitate ongoing assessment of risks and (ii) identify potential responsive measures associated with unassured energy supplies.[2] Such considerations include the timing and inconsistent output from variable renewable energy resources, fuel location, and volatility in forecasted load that can result in insufficient amounts of energy on the system to serve electrical demand. The ultimate goal of the ERAWG is to make recommendations to ensure the reliable operation of the BPS throughout the year.

[1] Contracts here should be considered in the broadest sense. Namely, beyond just firm/interruptible natural gas, there is the need for logistics of natural gas and fuel oil acquisition, transportation, and delivery in a timely fashion to address emerging and projected energy requirements.
[2] Some examples: lack of firm natural gas transportation, pipeline maintenance or disruption, compressor station failures, and/or emission limitations on fossil fuels. All resources have some degree of fuel uncertainty due to unavailability, including coal (onsite stock-piles can be frozen) and nuclear (during some tidal conditions affecting cooling intake).

Roles and Activities

The *Ensuring Energy Adequacy with Energy-Constrained Resources*[3] white paper that was reviewed by the Reliability and Security Technical Committee (RSTC) identified energy availability concerns related to the operations, the operations planning, and the mid- to long-term planning time frame. This has also been a source of discussion within the industry. Future considerations related to the reliability of energy are more complex and consider use of utility and non-utility assets in different manners as compared to a historical view. In order to effectively accommodate that type of conversation, the industry needs to assess the current processes and expectations to ensure the "basics" are covered. The RSTC assigned responsibility to the ERAWG to carry out the following continuing activities in its role of obtaining stakeholder engagement and feedback:

- For the planning, operational planning, and operations time horizons, support the performance and coordination of assessments and identify the need for improvement of tools and methods that can identify the right mix of resources to ensure sufficient amounts of energy are available for the following:
  - To serve demand
  - To meet ramping requirements at all times
  - To ensure the required energy can be delivered from the source to the end user
- Provide information to industry on energy reliability issues
- Support industry readiness and success on this topic
- Foster, coordinate, and facilitate activities of industry and RSTC sub-groups around the issues, risk, and potential mitigations or course corrections
- Gather industry feedback around recommended solutions that are actionable by either registered entities or industry groups (membership forums, trade associations, and technical committees, etc.)
- Evaluate options for industry outreach
- Develop suggested recommendations related to the issues
- Present work outcomes to the RSTC for awareness
- Determine appropriate path for recommendations to be considered and action taken

The ERAWG will report its work and deliverables to the RSTC, and the RSTC maintains ultimate responsibility for decisions and recommendations to NERC.

Advancing the above concepts with industry requires discussions with appropriate NERC technical committees. In addition, the following actions may be initiated:

[3] https://www.nerc.com/comm/RSTC/AgendaHighlightsandMinutes/RSTC_Meeting_Agenda_Package_Sept_15_2020_ATTENDEE_PUBLIC.pdf

- Coordinate developments of energy reliability assessment activities with industry working groups.
- Subject matter experts may be assembled (e.g. task forces or working groups) to develop the following:
  - The technical foundation for energy assurance and assessment in each of the three time horizons.
  - Ways to identify the levels of energy that are required to meet the operational needs.
  - The tool specifications needed to incorporate energy considerations into planning, operational planning, and operations assessments.
- Engage industry research and development organizations (e.g. Electric Power Research Institute, United States Department of Energy, Natural Resources Canada, and national laboratories, etc.) to validate the technical foundation(s) and development of the tool(s), metrics, and methods.
- Coordinate studies and plans with adjacent Balancing Authorities to identify enhanced collaborative regional support.
- Evaluate the NERC standards for omissions to address fuel assurance and resulting energy limitations for the planning timeframe.

Deliverables

The ERAWG may develop the following deliverables based on the aforementioned activities:

- Reliability guidelines, technical reference documents, or white papers related to risks associated with unassured energy supplies.
- Analysis of current or developing tools and metrics being performed across North America that are related to energy reliability assessments.
- Revise or update technical documents previously developed by the group, as deemed necessary.

Membership

- The ERAWG membership will include members who have technical or policy level expertise in the following areas: Resource Adequacy
- Fuel procurement for electric generation
- Electric and fuel infrastructure operations
- Fuel supply and delivery chains
- NERC staff coordinator(s)
- Liaison to RSTC
- Leadership
  - The ERAWG will have a chair and a vice chair appointed by the RSTC chair.

- Observers
  - The ERAWG chair may invite observers to participate in meetings. Observers may actively participate in the discussion and ERAWG deliverables.

Meetings

The ERAWG meetings will be scheduled based on workload as determined by the members. Meetings may also occur in conjunction with the regular RSTC meetings. The ERAWG meetings will be open to other participants.

Reliability Guideline Review:
Integrating Reporting ACE with the NERC Reliability Standards

Action
Approve

Summary
The Guideline "Integrating Reporting ACE with the NERC Reliability Standards" is up for review by the Resources Subcommittee (RS). This guideline is intended to provide recommended practices for calculating and using Reporting Area Control Error (RACE) with the NERC Reliability Standards.

Reference Document:
The RS reviewed the Integrating Reporting ACE with the NERC Reliability Standards to insure continued relevance. Changes to the guideline include:

- Transferred document to the current NERC guideline template and re-organized by chapter.
- Added in component for Imbalance Market Transactions
- Added metrics for analysis

Background
Historically, ACE has been used to describe many terms involved in Tie Line Bias control. Within a Balancing Authority Area's (BAA's) Automatic Generation Control (AGC) algorithm there may be more than one ACE value in use. The term "Reporting ACE" was developed and is used in place of the term ACE to provide a consistent performance measurement using Reporting ACE and to remove any unnecessary restrictions on the specification of ACE within the Load-Frequency Control system.

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Reliability Guideline

Integrating Reporting ACE with the NERC Reliability Standards

Date: February 6, 2023

RELIABILITY | RESILIENCE | SECURITY




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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 NERC and the six Regional Entities, is a highly reliable, resilient, 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 made up of six Regional Entity boundaries as shown in the map and corresponding table below. The multicolored area denotes overlap as some L~~l~~oad-S~~s~~erving E~~e~~ntities participate in one Regional Entity 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 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 nor are they Reliability Standards; 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

Historically, ~~ACE~~ Area Control Error (ACE) has been used to describe many terms involved in ~~Tie Line~~Tie-line Bias control. Within a Balancing Authority Area's (BAA's) Automatic Generation Control (AGC) algorithm there may be more than one ACE value in use. The term "Reporting ACE" was developed and is used in place of the term ACE to provide a consistent performance measurement using Reporting ACE and to remove any unnecessary restrictions on the specification of ACE within the Load-Frequency Control system.

Introduction

Purpose

This reliability guideline is intended to provide recommended practices for calculating and using Reporting ACE ~~Area Control Error (ACE)~~ in a ~~Tie Line~~Tie-line Bias (TLB) control program integrated with the NERC Reliability Standards. The effective use of Reporting ACE within a TLB control program should address the following components:

1. Management Roles and Expectations.
2. Information Technology Roles.
3. Manual Source Data Entry.
4. Automatically Collected Source Data.
5. Uses of Reporting ACE.
6. Historic Data Management.
7. Special Conditions and Calculations.

Each individual component should address processes and procedures, evaluation of any issues or problems along with solutions, testing, training, and communications. These provisions and activities together will be referred to as the TLB control program.

Applicability

This reliability guideline is applicable to: Balancing Authorities (BAs).

Background

TLB[1] control has been used as the preferred control method in North America since the early 1950s. The term ACE was developed for the specific implementation of coordinated TLB control now in use throughout the world. This document provides responsible entities guidelines for using both required specifics and the best practices for calculating and using Reporting ACE in coordination with other measures to provide reliable frequency control. While the incorporation of these best practices is strictly voluntary, reviewing, revising, or developing a process using these practices is highly encouraged to promote and achieve reliability for the BES.

The Control Performance Standard 1 (CPS1)[2] measure was among the first of the results-based measures developed by NERC. It defined not how to perform control but rather the target control results that were to be achieved and a method to measure whether ~~-~~or ~~-~~not that defined control target had been met. As a result, when CPS1 was implemented, the ACE Equation used in that measure was also specified within that standard.

Historically, ACE has been used to describe many terms involved in TLB control. Within a Balancing Authority Area's (BAA's) Automatic Generation Control (AGC) algorithm there may be more than one ACE value in use. In some systems, the ACE is filtered prior to determining control actions ~~in order to~~to smooth the control signals, or there may be additional "feed- forward" terms added to ACE in anticipation of future changes (~~e.g.~~e.g., anticipated ramps, changes in ambient light at sunrise or sunset). There may be gain terms that modify certain variables such as the Frequency Bias Setting (FBS) to improve the quality of control for the specific characteristics of that particular BAA, or

[1] Capitalized terms hold the same definition as in the NERC glossary throughout this document.
[2] Standard BAL-001-2 – Real Power Balancing Control Performance.pdf ~~A (nerc.com) http://www.nerc.com/files/BAL-001-2.pdf~~

manual offsets. ~~The NERC Glossary of Terms defines Reporting ACE and allows modifications such as those described above. This will be described as Control ACE for the purpose of the metrics section.~~

Some auditors have raised compliance issues related to the use of such modifications to the ACE used within the Load-Frequency Control (LFC) system (also referred to as AGC) and required changes in the AGC system to conform to the definition of ACE in the BAL-001 NERC Reliability Standard. The term “Reporting ACE” was developed and is used in place of the term ACE to provide a consistent performance measurement using Reporting ACE and to remove any unnecessary restrictions on the specification of ACE within the LFC system.

Chapter 1: Applicable Roles

Applicable Roles

Management, Information Technology (IT), and Balancing Authorities (BAs) should evaluate all their uses for Reporting ACE in operations and reliability measurements. Reporting ACE is one of the most important single measurements available to indicate the current state of the responsible entity's contribution to Interconnection reliability. Reporting ACE is also used as an integral part of the measurements used in the BAL-001 and BAL-002 NERC Reliability Standards. Technical requirements associated with the parameters used in the calculation of Reporting ACE are specified in the BAL-003 and BAL-005 NERC Reliability Standards.

Management Roles and Expectations

Management plays an important role in maintaining an effective TLB control program. The management role and expectations below provide a high-level overview of the core management responsibilities related to each ~~Tie Line Bias~~TLB control program. The management of each responsible entity should tailor these roles and expectations to fit within its own structure.

i. Set expectations for safety, reliability, and operational performance.

ii. Assure that a TLB control program exists for each responsible entity and is current.

iii. Ensure the proper expectation of TLB control program performance.

iv. Share insights and good practices with other BAs.

Information Technology (IT) Roles

b. Participate in appropriate TLB control related training.

c. Ensure the Reporting ACE and source information are always current and correct.

d. Implement the TLB control program in Real-time.

e. Ensure that the Energy Management System (EMS) supports the manual data entry of all source data required to be entered by IT staff, system operations staff, and System Operators and properly manages that data once entered.

f. Ensure that the EMS supports and manages the automatic collection of all source data that is required to be measured in real-time through telemetry and data exchange including data quality information to indicate data validity.

g. Ensure that the programs that manage data used to calculate components of Reporting ACE, Reporting ACE itself, and subsequent measures based on Reporting ACE are up to date and correct as identified by, but not limited to the calculations and equations in section 7.~~:~~

Balancing Authorities (BAs)

The role of the Balancing Authority is to monitor ACE with respect to the Control Performance Standard and Disturbance Control Standard. The BA evaluates dispatch options and coordinates their actions with other BAs, Marketing Entities, Transmission Operators, and the Reliability Coordinator.

Chapter 2: Data Collection

The Area Control Area (ACE) uses two sources of data when calculating a value. Manual source data that can be entered ~~real time~~in Real-time or after the fact by BA or IT personal and automatically collected source data that is pulled from equipment in the field.

Manual Source Data Entry

Reporting ACE is calculated in Real-time, at least every six seconds[3], by the responsible entity's Energy Management System (EMS~~), and~~) and may be partially based on source data manually entered into that system. The following source data may be manually entered:

NI_S (Scheduled Net Interchange): The power transfer schedules, including Dynamic Schedules and the schedule ramps where applicable, are processed by the EMS. Dynamic Schedules are estimated before the delivery ~~period, and~~period and corrected in R~~r~~eal-time. If telemetry failures occur during such delivery periods, they are manually corrected after the delivery. If scheduled flow estimates are equal and have opposite signs for the Adjacent BAAs, the effect of any errors will be confined to the two Adjacent BAAs responsible for the manual entries. Failure to match scheduled flow estimates will result in errors that affect other BAAs.

NI_A (Actual Net Interchange): The telemetry values of actual tie flows, including pseudo-ties, between Adjacent BAAs may not be available from an automatic collection source due to telemetry failures, requiring manual entry of estimated flows. These manual entries should be performed in a manner that reasonably assures equal magnitude and opposite sign values are used by the Adjacent BAAs entering the manual data. If the actual flow estimates are the same for the Adjacent BAAs, the effect of any errors will be confined to the two Adjacent BAAs responsible for the manual entries. Failure to match actual flow estimates will result in errors that affect other BAAs on the Interconnection.

B (Frequency Bias Setting): The FBS, or minimum required value, for the BAA is specified by calculations performed as part of compliance with BAL-003-2~~1.1~~ - Frequency Response and FBS;

"R2. Each Balancing Authority Area that is a member of a multiple Balancing Authority Area Interconnection and is not receiving Overlap Regulation Service and uses a fixed Frequency Bias Setting shall implement the Frequency Bias Setting determined in accordance with Attachment A, as validated by the ERO, into its Area Control Error (ACE) calculation during the implementation period specified by the ERO and shall use this Frequency Bias Setting until directed to change by the ERO."[4]

[3] BAL-005-1 Balancing Authority Control – "R1~~2~~. The Balancing Authority Area shall use no greater than a six-second scan rate in acquiring data necessary to calculate Reporting ACE."

[4] As a note of interest, the new procedures put forth with BAL-003-~~1.1~~2 will result in the reduction of minimum FBS values on the multiple BA Interconnections to bring them closer to the natural measured Frequency Response of the Interconnection. The rule requiring a minimum FBS of 0.9% of peak load in the NERC ~~–~~standards ~~dates~~date back to 1962 when NAPSIC, the precursor to the NERC Operating Committee, codified the recommendations of the Interconnected Systems Group made in 1956 to set a minimum of 50% of the natural measured response, which was 2% of peak load at that time. The 1% figure was more than 200% of the natural measured response for the Eastern Interconnection and in some cases is approaching a value that could result in instability by being too high. The logic justifying a minimum of the natural response is still valid. When configured with a FBS equal to the actual Frequency Response of the BAA, Reporting ACE will reflect the BAA's obligation to match

10 is the factor (10 0.1Hz/Hz) that converts the FBS units to MW/Hz.

F_S (Scheduled Frequency): Scheduled Frequency, normally 60 Hz, is manually adjusted on a coordinated basis when directed to do so by the Interconnection Time Monitor ~~as specified in BAL-004-WECC-30~~.[5] ~~It is important for all BAAs on an interconnection to make these adjustments on a coordinated basis so that all BAAs are controlling to the same Scheduled Frequency at all timesalways controlling to the same Scheduled Frequency.~~

I_{ME} (Interchange Meter Error): This term, normally zero, is available for use by the s~~S~~ystem o~~O~~perator or operations staff to add a correction term in the Reporting ACE calculation to compensate for data or equipment errors affecting any other components identified by analysis of historic data demonstrating the existence of errors, usually errors between integrated hourly scan-rate data and hourly agreed to accumulated meter data. (See the Special Conditions and Calculations section of this document for additional information)

L_{max} is the maximum value allowed for I_{ATEC} set by each BA between 0.2*|B| and L_{10}, $0.2*|B| \leq L_{max} \leq L_{10}$.

Y is normally calculated by the ATEC program in the EMS for BAAs on the Western Interconnection.

H is set to 3 and used by the ATEC program in the EMS for BAs on the Western Interconnection. It represents the number of hours over which the primary inadvertent interchange is paid back.

B_S is used by the ATEC program in the EMS for BAAs on the Western Interconnection. It represents the sum of the minimum FBSs for all BAAs on the Interconnection.

ΔTE is used by the ATEC program in the EMS for BAAs on the Western Interconnection. In some cases, it may be calculated by the EMS based on the factors in the ΔTE equation. ΔTE is the hourly change in system Time Error as distributed by the Interconnection time monitor.

TD_{adj} is an adjustment for the differences between the local clock in the local time standard and the Interconnection time monitor control center clocks so that the local EMS can calculate the correct ΔTE for the BAAs and used by the ATEC program in the EMS for BAAs on the Western Interconnection.

TE_{offset} is entered as instructed by the Interconnection time monitor.

ε_1 is the RMS Limit for the 1-minute average frequency error for the Interconnection.

Automatically Collected Source Data

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.

In addition, data quality information (usually in the form of data quality flags associated with each data value) must be retained and presented in real-time to the s~~S~~ystem o~~O~~perators. This data quality information is presented to the s~~S~~ystem o~~O~~perator to have situational awareness with respect to the

its actual interchange, less the impact ~~from its current Frequency Response offset,~~from its current Frequency Response offset to its scheduled interchange.

[5] This is consistent with condition 3 in the Reporting ACE Definition: "The use of a common Scheduled Frequency F_S for all areas at all times."

quality of the data inputs and final calculated result. It is later used to determine which data is valid for use in performance calculations such as Control Performance Standard 1 (CPS1), Balancing Authority Ace Limit (BAAL), Disturbance Control Standard (DCS), and ~~f~~Frequency ~~r~~Response ~~o~~Obligation (FRO~~M~~).

NI_S (Scheduled Net Interchange): Most interchange schedules and some Dynamic Schedules are entered into the EMS in a summary format either as individual schedules, schedule nets with each Adjacent BAA, or a final Scheduled Net Interchange. These schedules are converted into scan-rate schedules by the EMS. The EMS calculates the Scheduled Net Interchange, where applicable, by summing all individual schedule values or nets with each Adjacent BAA for all regular and Dynamic Schedules and includes the result as NI_S in the ACE equation. Ramping is not accounted for, these schedules represent the contracted transactions or the expected transactions (for dynamic schedules).

NI_A (Actual Net Interchange): The tie-line value representing each tie-line flow and pseudo-tie quantity is collected at the required scan rate of six seconds or less.[6] [7] [8] [9] Data that is of questionable accuracy or timeliness is flagged with an appropriate data quality flag. This information is presented to the s~~S~~ystem o~~O~~perator to support situational awareness.[10] The EMS sums the individual flow values on all ~~tie-line~~tie-lines and ~~pseudo-ties~~pseudo-ties with all adjacent BAAs at the scan rate and includes this value as NI_A in the Reporting ACE equation calculation. The result is a series of NI_A values at the EMS scan rate and associated data quality flags. The associated data quality of the telemetry is also assigned to the result of appropriate calculations.

F_A (Actual Frequency): Actual frequency is provided by a frequency measuring device at the accuracy specified in BAL-005-1[11] at the EMS scan rate. If a frequency value is not available, the value for that scan is marked invalid.

II_{actual} (Inadvertent Interchange): This term is only used in the Western Interconnection ACE calculation. Inadvertent Interchange "Actual" for the previous hour is calculated by the EMS from the previous hour's data as the difference between the integrated hourly average Scheduled Net Interchange and the integrated hourly average Actual Net Interchange.

t (Manual Time Error correction minutes in the hour): The number of minutes of manual Time Error correction in the hour.

[6] Data transmitted at a rate slower than the scan rate of the remote sensing equipment may require the inclusion of anti-aliasing filtering at the source of the measurement to eliminate the risk of aliasing in the data transmitted to the EMS.

[7] It is acceptable to collect tie-line flow data from RTUs that use report by exception ~~as long as~~if those RTUs can support the scan rate of six seconds or less when data is changing rapidly and both adjacent BAAs are receiving comparable data to keep the measured flows equivalent.

[8] The six-second scan rate not only assures that data collected is close to Real-time, ~~it~~but it also limits the latency (time skew) associated with the data collection.

[9] The accuracy of the flow data is set by those using the flow data for transmission flow management. As with all ACE data, as long as both adjoining BAAs are using the same values for tie-line flow, the effects of any error in flow measurement will be confined to the two adjacent BAAs.

[10] Indications of suspect data are usually indicated with color changes and/or alarms

[11] BAL-005-1 – ~~Automatic Generation Control~~R3 specifies an accuracy of ≤0.001 Hz (equivalent to ≤ +/- 0.0005 Hz) for the ~~Digital Frequency Transducer~~frequency metering equipment.

Chapter 3: ACE Management

Uses of Reporting ACE

Reporting ACE is currently used to measure balancing performance within TLB control on ~~all of~~all the Interconnections.[12] Consequently, Reporting ACE is one of the primary measurement parameters in many of the NERC Balancing ~~Reliability~~ Standards. The following Reliability ~~s~~Standards require the use of Reporting ACE as part of the performance metrics or set requirements associated with the calculation of Reporting ACE.

h. BAL-001-2 – Real Power Balancing Control Performance.

i. BAL-002-3~~2~~ – Disturbance Control Standard – Contingency Reserve from a Balancing Contingency Event (when approved by FERC).

j. BAL-005-1~~0.2b~~ – Automatic Generation Control and BAL-005-1 – Balancing Authority Control (when approved by FERC).

Historic Data Management

The industry currently requires the retention of data supporting the calculation of Reporting ACE and compliance measurements based in part on Reporting ACE to support the NERC compliance audit process. This data retention must be considered as an integral part of the Reporting ACE and “TLB control program”.

Special Conditions and Calculations

I_{ME} (Interchange Meter Error): This term, normally zero, is available for use by the s~~S~~ystem o~~O~~perator or operations staff to add a correction term in Reporting ACE. It compensates for data or equipment errors affecting any other components of Reporting ACE identified by analysis of historic data. These errors are usually between integrated hourly scan-rate data and hourly agreed to accumulated meter data. The process used for including adjustments in the I_{ME} term should be based on good quality control methods.[13]

These error correction adjustments can be used to correct errors in NI_A, NI_S,[14] Reporting ACE, and other measurements that depend upon an accurate Actual Net Interchange and/or an accurate Scheduled Net Interchange. The same logic and evaluation processes that are valid for inclusion in the I_{ME} term of the Reporting ACE equation should also be valid as adjustments to the scan rate tie-line flows used for the measurement of Frequency Response as part of the BAL-003-2~~1~~ Reliability Standard.

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[12] On single BAA Interconnections, the ACE equation reduces to a single term, **$-10B\ (F_A - F_S)$**, because there are no ~~tie-line~~tie-lines or schedules to include in the first term, **$(NI_A - NI_S)$**, and there is no **I_{ME}** term to correct for ~~tie-line~~tie-line or dynamic schedule measurement errors in the first term.

[13] Adjustments to the **I_{ME}** term should follow good quality control methods and exclude tampering as demonstrated by the Deming’s Funnel Experiment.

[14] As long as the actual ~~tie-line~~tie-line flows and scheduled flows match for adjacent Balancing Authority Areas, any problems with the measurement of balancing on the Interconnection will be confined to within the boundaries of those adjacent Balancing Authority Areas. Errors in the **NI_S** would only occur and only support correction in cases where there is a measurement error associated with a dynamic schedule.

ACE Diversity Interchange (ADI): This is a frequency neutral form of ACE exchange that uses real-time, sub-minute adjustments to the unadjusted ACE values of participating BAs that always net to zero and are non-zero individually only when at least one participating BAs unadjusted ACE value differs in algebraic sign from at least one other participating BAs unadjusted ACE. Participating BAs 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.

Imbalance Market (IM) Transactions: The Energy Transfer System Resources (ETSRs) are defined as aggregate resources at the IM BAA Default Generation Aggregation Point (DGAP), which is an aggregation of all supply resources in the BAA. Each ETSR is defined as either an import or an export resource, and it is associated with an Energy Imbalance Market (EIM) intertie with another EIM BAA.

Use of Source-Sink Pairs for Asynchronous DC ~~Tie Line~~Tie-lines to Another Interconnection: One of the primary rules for ~~insuring~~ensuring the validity of the Reporting ACE equation is, "All portions of the Interconnection are included in exactly one BAA so that the sum of all BAAs generation, load, and loss is the same as total Interconnection generation, load, and loss." This is accomplished by requiring the inclusion in Reporting ACE of all tie-~~–~~lines, pseudo-~~–~~ties, interchange schedules and Dynamic Schedules to Adjacent BAAs and only Adjacent BAAs on the same ~~Interconnection, and~~Interconnection and requiring the exclusion of all asynchronous DC ~~tie line~~tie-lines and associated scheduled interchange with BAAs on a different Interconnection from Reporting ACE. Following this simple rule ~~insures~~ensures that all loads, ~~losses~~losses, and generation are properly included with each Interconnection.

Instead of including the power transfers from an asynchronous DC tie-~~–~~line between two Interconnections as a normal interchange transfer between two BAAs, this form of power transfer should be included as though it is a linked source-sink pair for the purposes of managing frequency control within a tie-line bias control program. One terminal of an asynchronous DC ~~tie line~~tie-line will appear to the receiving Interconnection and receiving BAA as an energy resource similar to a generator. This is the source end of the source-sink pair. The other terminal of the same asynchronous DC tie-line will appear to the supplying Interconnection and supplying BAA as an energy sink similar to a load. This is the sink end of the source-sink pair.

Interchange transactions linked to either the source or sink from other BAAs on the same Interconnection as the source or sink will schedule those transactions, include those transactions in Reporting ACE, and manage those transactions in a similar manner to any other energy transaction. Only the BAA acting as the source or the sink for the DC tie-line will exclude the asynchronous tie-line from its Reporting ACE while including all transactions with Adjacent BAAs on the same Interconnection associated with that source or sink power transfer in their Reporting ACE.

ACE Component and CPS1 Calculations:

i. Actual Net Interchange[15] (NI_A):

All BAAs involved account for the power exchange and associated transmission losses as actual Interchange between the BAAs, both in their ACE and Reporting ACE equations and throughout ~~all of~~all their energy accounting processes.

(1) Calculate for each scan[16].

(2) Integrated hourly average calculated for each hour as an integration of the scan rate values.

ii. Scheduled Net Interchange[17] (NI_S):

(1) Calculate for each scan.

(2) Integrated hourly average calculated for each hour as an integration of the scan rate values. (This value differs from the block accounting value.)

Note: Dynamic Schedules are to be accounted for as Interchange Schedules by the source, sink, and contract intermediary BAA(s), both in their respective ACE and Reporting ACE equations, and throughout ~~all of~~all their energy accounting processes.

iii. Frequency Error ($\Delta F = (F_A - F_S)$):

(1) Calculate for each scan.
(2) Calculate clock-minute average from valid samples available within each clock-minute[18] where at least half of the scan-rate samples are valid.

iv. Frequency Trigger Limit – Low (FTL_{Low}):

Calculate the Frequency Trigger Limit – Low for each clock-minute where at least half of the scan rate samples are valid by subtracting three times Epsilon1 from the Scheduled Frequency (F_S).

v. Frequency Trigger Limit – High (FTL_{High}):

Calculate the Frequency Trigger Limit – High for each clock-minute where at least half of the scan rate samples are valid by adding three times Epsilon1 to the Scheduled Frequency (F_S).

vi. Accumulated Primary Inadvertent Interchange (PII):

Calculated each hour for WECC BAAs only.

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[15] By definition "Actual megawatt transfers on asynchronous DC ~~tie line~~tie-lines directly connected to another Interconnection are excluded from Actual Net Interchange." Additional information on asynchronously connected DC ~~tie line~~tie-lines connected to another interconnection is provided in "Special Conditions and Calculations" section of this document.

[16] Actual Net Interchange scan-rate values are also used as one of the primary inputs to the calculation of Frequency Response Measure (FRM) on FRS Form 1 and FRS Form 2.

[17] By definition "Scheduled megawatt transfers on asynchronous DC ~~tie line~~tie-lines directly connected to another interconnection are excluded from Scheduled Net Interchange." Additional information on asynchronously connected DC ~~tie line~~tie-lines connected to another interconnection is provided in the "Special Conditions and Calculations" section of this document.

[18] Clock-minute averages are used for the calculation of ACE and Frequency Error in CPS1 and BAAL to eliminate the transient variations of tie-line flows and frequency error used in the calculation of performance measures. The one-minute period was chosen because it is evenly divisible by all whole-second scan rates less than the maximum specified scan rate of six seconds. This assures greater comparability of performance data among BAs with different scan rates.

$\mathbf{PII}_{\mathbf{accum}}^{\mathbf{on/off}\text{peak}} = \text{last period's } \mathbf{PII}_{\mathbf{accum}}^{\mathbf{on/offpeak}} + \mathbf{PII}_{\mathbf{hourly}}$

vii. Automatic Time Error Correction ($\mathbf{I}_{\mathbf{ATEC}}$):

Calculate for each hour for WECC BAAs only for inclusion in the ACE and Reporting ACE Equation for the next hour.

$\mathbf{I}_{\mathbf{ATEC}} = \frac{\mathbf{PII}_{\mathbf{accum}}^{\mathbf{on/off\ peak}}}{(\mathbf{1-Y})*\mathbf{H}}$ when operating in ATEC mode.

The absolute value of $\mathbf{I}_{\mathbf{ATEC}}$ shall not exceed $L_{\mathbf{max}}$.

$\mathbf{I}_{\mathbf{ATEC}}$ shall be zero when operating in any other AGC mode.

$\mathbf{PII}_{\mathbf{hourly}} = (1\text{-}Y) * (\text{IIactual} - \text{B delta TE}/6)$

viii. Reporting ACE:

(1) Calculate for each scan.

(2) Calculated average for each clock-minute for BAAs using a fixed FBS when at least half of the values are valid.[19]

ix. Compliance Factor:[20]

(1) Calculate for each scan where both Reporting ACE and Frequency Error are valid.

(2) Calculate for each clock-minute where both the average clock-minute Frequency Error and the average clock-minute Reporting ACE are valid.[21]

x. Clock-hour compliance factor:[21]

Calculate for each hour by summing the valid clock-minute compliance factors for the hour and dividing by the number of valid clock-minute compliance factors in the hour.

xi. Month compliance factor:[21]

Calculate by summing the valid clock-minute compliance factors in the month and dividing by the number of valid compliance factors in the month.

xii. 12-month compliance factor:[21]

Calculate by summing the valid clock-minute compliance factors in the 12-month period and dividing by the number of valid clock-minute compliance factors in the 12-month period.

xiii. CPS1 compliance factor.

Calculate the CPS1 compliance factor by dividing the 12-month compliance factor by the square of the Epsilon1 value for the Interconnection.

xiv. CPS1:

[19] The average of the value of the ratio of the scan rate value of Reporting ACE divided by the scan rate value of -10 times the FBS times the Actual Frequency for those BAs using a variable FBS, where at least half of the ratio values are valid.

[20] Used for CPS1.

[21] The compliance factor is calculated when the average of the value of the ratio of the scan rate value of Reporting ACE divided by the scan rate value of -10 times the FBS for those BAs using a variable FBS, where at least half of the ratio values are ~~valid~~valid, and the average clock-minute Frequency Error is valid.

(1) Calculate the CPS1 scan rate performance by dividing the scan rate compliance factor by the square of the Epsilon1 value for the interconnection and subtracting that value from 2 and multiplying the result by 100 to convert to a percentage performance for each scan with a valid compliance factor.

(2) Calculate the CPS1 clock-minute performance by dividing the clock-minute compliance factor by the square of the Epsilon 1 value for the interconnection and subtracting that value from 2 and multiplying the result by 100 to convert to a percentage performance for each clock-minute with a valid compliance factor.

(3) Calculate the CPS1 clock-hour performance by dividing the clock-hour compliance factor by the square of the Epsilon1 value for the interconnection and subtracting that value from 2 and multiplying the result by 100 to convert to a percentage performance for each clock-minute with a valid compliance factor.

(4) Calculate the CPS1 monthly performance by dividing the month compliance factor by the square of the Epsilon 1 value for the interconnection and subtracting that value from 2 and multiplying the result by 100 to convert to a percentage performance for each clock-minute with a valid compliance factor.

(5) Calculate the CPS1 12-month performance by dividing the 12-month compliance factor by the square of the Epsilon 1 value for the interconnection and subtracting that value from 2 and multiplying the result by 100 to convert to a percentage performance for each clock-minute with a valid compliance factor.

Contributors

NERC gratefully acknowledges the contributions and assistance of the following industry experts in the preparation of this guideline.

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Guideline Information and Revision History

Guideline Information	
Category/Topic: [NERC use only]	**Reliability Guideline/Security Guideline/Hybrid:** Reliability Guideline
Identification Number: [NERC use only]	**Subgroup:** [NERC use only]

Revision History		
Version	**Comments**	**Approval Date**
0	Initial Version – Calculating and Using Reporting ACE in TLB Control Program	5/18/2015
1	Resources Subcommittee Review	11/4/2019
2	Resources Subcommittee Review; reformat and addition of metrics	2/6/2023

Metrics

Pursuant to the Commission's Order on January 19, 2021, *North American Electric Reliability Corporation*, 174 FERC ¶ 61,030 (2021), reliability guidelines shall now include metrics to support evaluation during triennial review consistent with the RSTC Charter.

Baseline Metrics

All NERC reliability guidelines include the following baseline metrics:

- BPS performance prior to and after a reliability guideline as reflected in NERC's State of Reliability Report and ~~Long Term~~Long-Term Reliability Assessments (e.g., Long Term Reliability Assessment and seasonal assessments).
- Use and effectiveness of a reliability guideline as reported by industry via survey.
- Industry assessment of the extent to which a reliability guideline is addressing risk as reported via survey.

Specific Metrics

The RSTC or any of its subcommittees can modify and propose metrics specific to the guideline ~~in order to~~to measure and evaluate its effectiveness, listed as follows:

Compare monthly or quarterly CPS1 ~~exceedances derived from control ACE~~ and BAAL exceedance values submitted in the voluntary quarterly data filing submitted by each BA to the NERC Balancing Authority Submittal Site (BASS) ~~website~~ to the CPS1 ~~exceedances derived from~~and BAAL exceedance values calculated from raw RACE~~.~~ data submitted to NERC for the M6 Disturbance Control Standards Failures metric.

- Using ~~Control~~Reporting ACE (~~CACE~~RACE) from the ~~EMS or a~~ M6 data historian, calculate ~~Control~~ Compliance Factor clock minute averages: (~~C~~*CF*clock-minute~~):~~). ~~C~~*CF*clock-minute= [(~~CACE~~RACE~~c~~/-10*B*) * 10 dFclock-minute]
- Calculate ~~Control~~ Clock-Minute CPS1 values: ~~C~~CPS1= (2 – ~~C~~*CF*) * 100%
    - Develop counters to compile exceedances of CCPS1 clock-minute <= -700%
- Compare the monthly ~~CCPS1 (CACE~~CPS1 and BAAL exceedance minutes submitted by the BA to the CPS1 and BAAL (RACE derived) exceedances ~~to the CPS1 (RACEderived) exceedances for review and analysis~~from M6 historian data.

Observations:

- ~~If CCPS1 exceedances are approximately equal to the CPS1 exceedances, then CACE and RACE may be the same.~~
- ~~By evaluation of the number of CCPS1 exceedances and in which minute block (0-9, 10-14, 15-19, >20), an analysis may be made as to the governing parameters for specific performance characteristics vs a compliance measure.~~

- The CPS1 and BAAL Exceedance values submitted by the BA should be approximately the same as those calculated from the M6 raw RACE data. While ~~the~~ performance scores will not match exactly, if a BA~~s~~ calculates a difference that is materially greater ~~who~~ than the differences ~~materially~~calculated by the majority of BAs, it could indicate a potential error in that ~~Bas~~BA's RACE, ~~exceed those of those of the majority of BAs could potentially have an error in theire RACE,~~ CPS1, or BAAL calculations.

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- The BAs reported CPS1 ~~>~~<= -700% exceedance minutes should exactly match the BAs reported BAAL exceedance minutes. If ~~those~~the numbers are different, it could ~~indicated~~indicate an~~d~~ error in the RACE, CPS1 or BAAL calculations.

Agenda Item 17b
Reliability and Security Technical
Committee Meeting
June 21, 2023

Reliability Guideline Review: Operating Reserve Management

Action

Approve

Summary

The Guideline "Operating Reserve Management" has had its triennial review by the NERC Resources Subcommittee. 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. 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. It also provides guidance with respect to the management of Operating Reserve required to meet the NERC Reliability Standards.

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 Reference Document:

The NERC Resources Sub-Committee reviewed the Operating Reserve Management to insure continued relevance. Changes to the guideline include:

- Addition of metrics to support evaluation during triennial review, consistent with the RSTC Charter. Additionally, clarifications were made in response to some comments. Finally, several errata changes were made to correct grammar and typographical errors.
- Clarifications in response to some comments.
- Errata changes to correct grammar and typographical errors

This guideline has been posted for 45-day industry comment and includes the response to those comments.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Reliability Guideline

Operating Reserve Management: Version 4~~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 NERC Reliability 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.

[1] See the RSTC Charter link on the NERC Reliability and Security Technical Committee (RSTC) landing page - https://www.nerc.com/comm/RSTC/Pages/default.aspx. ~~https://www.nerc.com/comm/RSTC/RelatedFiles/RSTC_Charter_approved20191105.pdf~~

Metrics

Pursuant to the Commission's Order on January 19,2021, *North American Electric Reliability Corporation*, 174 FERC Section 61,030 (2021), reliability guidelines shall now include metrics to support evaluation during triennial review, consistent with the RSTC Charter.

Baseline Metrics

- Performance of the BPS prior to and after a reliability guideline, as reflected in NERC's State of reliability Report and Long-Term Reliability Assessments (e.g., Long-term Reliability Assessment and seasonal assessments);
- Use and effectiveness of a reliability guideline as reported by industry via survey; and
- Industry assessment of the extent to which a reliability guideline is addressing risk as reported via survey.

Specific Metrics

The RSTC or any of its subcommittees can modify and propose metrics specific to the guideline in order to measure and evaluate its effectiveness

Evaluated quarterly:

- Voluntary submittal of CPS1 and BAAL performance
    - Outreach to BAs which show performance degradation
- Voluntary submittal of DCS event performance
    - Outreach to BAs which show performance degradation
- Frequency Working Group review of frequency events, including Interconnection Frequency Response Measure of each event and M4 evaluation
    - Results of these evaluations feed directly into the annual SoR and FRAA
- ERS M6 review of performance
    - Outreach to BAs which show performance degradation

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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.
- NERC, as the FERC certified ERO, 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 NERC Reliability Standards to maintain the reliability of the BES.
- This guideline is not intended to supersede any NERC Reliability Standards or Regional Specific Reliability Standards. Its intent is to provide a general overview to its readers of the concepts of Operating Reserve Management.
- 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 auxiliary unit/plant loads such as adding ~~mills~~coal pulverizers or boiler draft 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

Definitions

When reading this Reliability Guideline, the reader should note that all terms contained in the NERC Glossary of Terms and used in this Guideline are capitalized. In addition to those terms some additional terms have been defined and provided below to assist the reader. Terms defined in Italics below distinguish them from those defined and approved by NERC.

Bottoming Out Condition: A situation experienced by a BA where the Balancing Authority Area load is at or below the minimum unit capabilities of online units. This situation results in the BA having no regulation down to support operations and further load reductions. Also known as a min gen condition.

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.*[2] Variable load that mirrors governor droop and dead-band may also be considered FRR.

Interruptible Load/Demand: 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).

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2 ~~https://www.nerc.com/comm/OC_Reliability_Guidelines_DL/PFC_Reliability_Guideline_rev20190501_v2_final.pdf~~https://www.nerc.com/comm/RSTC_Reliability_Guidelines/PFC_Reliability_Guideline_rev20190501_v2_final.pdf

Field Code Changed

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 following the contingency event deployable in 10 minutes.

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* (e.g., on four hours' notice, generation~~s~~ that cannot be started within 90 minutes, preplanned demand response resources).

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 Contingency Event 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 e~~a~~ffect a transfer of electricity between purchasing and selling entities and is effectively FERC's equivalent to NERC's Operating Reserve.

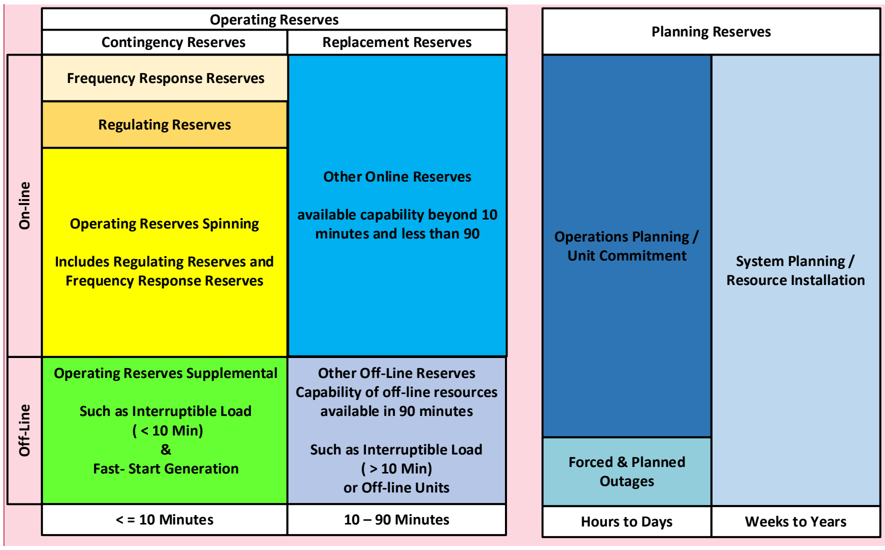

Figure 1~~-1~~: Operating Reserves

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Commented [A4R3]: Joseph provided editable version, but so far there is no need to edit this.

The various terms associated with this guideline document represent distinct conditions pertaining to reserve management and assessment. Figure 1 clearly shows the differing types of reserves between the operating and planning environment and potential availability based on time or generating unit operational status.

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
- Variable e~~E~~nergy r~~R~~esource~~(VER)~~ forecast error

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[3]
- Events associated with EEA ~~3~~[4]3[3]
- A large loss-of-load event

Commented [A5]: Footnote 3 Link is bad and footnote 4 is not on this page. Shouldn't they both be #3?

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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 periodic 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

[3] See the currently enforceable version of EOP-011 on the NERC Reliability Standards page at https://www.nerc.com/pa/Stand/Pages/ReliabilityStandards.aspx.
~~https://www.nerc.com/EOP-011-1.pdfhttps://www.nerc.com/pa/Stand/Reliability%20Standards/EOP-011-1.pdf~~

- Conduct periodic evaluations of the effectiveness of the Operating Reserve program considering feedback from participants and incorporating lessons learned

System Operator Roles

BA Operator

It is important for the system operator to know the specifics of their BA reserve strategy and maintain situation awareness through the following:

- Participate in appropriate system operator training that includes BA reserves management
- 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, variable energy resource~~VER~~ f~~F~~orecast, ~~-~~ 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
  - Ensure 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.
- Direct r~~R~~edistribution of~~e~~ reserves by requesting BA to redispatch units to hold reserves in different areas of the BA footprint

- Direct s~~S~~hedding of 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. The responsible entity's process should include the following at a minimum:

- **~~A~~ M~~m~~ethod(s) 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).
- **Knowledge of~~ing~~ 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 i~~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 NERC Reliability Standards.
For a responsible entity to meet the requirements of the NERC Reliability Standards BAL-002, 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 unit governor responses are independent of control center control. A unit may or may not be able to provide frequency reserves or contingency reserves if operating at maximum output. 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 frequency reserves 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 instead be loaded to maximum output and, if so, unavailable to participate in frequency response and contingency reserves.

Additionally, the responsible entity should consider an appropriate mix and coordination of frequency-responsive reserves (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 reliability 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
- Hybrid Facilities – (e.g. Solar/Battery)

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~~consider 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.~~i.e., operations planning, same ~~day~~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.
Responsible entities should consider leveraging their Replacement Reserves to meet the Contingency Reserve Restoration Period, preplanning, and training of system operators may be required. Actions like the following should 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
- 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., inverter based resources, 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. The process should include at least the following:

- The BAL-003 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 standard cover these calculations in more detail. To determine an initial target

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[4] See the currently enforceable version of BAL-003 on the NERC Reliability Standards page at https://www.nerc.com/pa/Stand/Pages/ReliabilityStandards.aspx ~~http://www.nerc.com/pa/Stand/Reliability%20Standards/BAL-003-2.pdfhttps://www.nerc.com/pa/Stand/Reliability%20Standards/BAL-001-2.pdf~~

(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~~For example, if the key Eastern Interconnection parameters ~~from~~ are: IFRO = 1015 MW/0.1 Hz and MDF = 0.420 Hz, then ~~. T~~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.
- 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.

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[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

- 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 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 NERC 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, BAL-002, and BAL-003. 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~~consider 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 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 BAs 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 NERC 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~~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 (e.g., losing an entire generating station due to a fault that clears the bus) as defined in the Balancing Contingency Event glossary Term.~~ 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, 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 one or more of the following:

- New unit commitment processes
- New operating guidelines
- Additional tools for operators
- 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 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

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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 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

[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

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
- 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 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 operational year. Partial BAL-003 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 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 FRSG's 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.

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. 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.

[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. This document can be found at https://www.nerc.com/comm/OC/ReferenceDocumentsDL/Dynamic_Transfer_Reference_Document_v4.pdf

Operating Reserve Interaction

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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

Once resources are identified, a second review should consider fuel constraints to determine if any limitations generation exist. 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)
- Energy Storage Resources
  - Energy Storage Duration
  - State of Charge

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. 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 reliably 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
  - Weather Conditions (Temperatures, cloud coverage, wind speeds, precipitation, and humidity)
- Hydrothermal limitations
- Battery Management
- Fuel Supply
- Renewable Forecast Error

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 governs the timeliness of the aggregate of such recoveries. The timeliness of the recovery from larger imbalances is governed by BAL-002 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, Interconnection reliability will be supported to arrest frequency deviations.

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 is 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:

$$FRR + RRO \geq FRRO \qquad \textit{Inequality (1)}$$
$$FRR + RR + CR \geq FRR + RRO \qquad \textit{Inequality (2)}$$

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 Contingency Reserves when nothing is substituted for Contingency Reserves.

Both inequalities represent the total required reserve on both sides of the inequality.

These inequalities are used to determine the FRO in BAL-003 as adjusted by the base frequency error profile that results from reserve substitution. In addition, the contingency reserve requirement in R2 of BAL-002 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. 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 Documents~~Charter~~ (accessible from the RSTC landing page – Reliability and Security Technical Committee (RSTC) (nerc.com)) NERC Reliability and Technical Committee Charter

NERC Operating Manual (from the Operating Committee link)

~~Use of Frequency Response Metrics to Assess the Planning and Operating Requirements for Reliable Integration of Variable Renewable Generation, Key Findings~~

~~[Note: add links for Form 1 and Form 2]~~

~~Add Gen Loss of Comm Guideline?~~ Reliability Guideline: Generating Unit Operations During Complete Loss of Communications (from the RSTC Approved Documents Page link)

Primary Frequency Control Reliability Guideline (from the RSTC Approved Documents Page link)

Cited NERC Documents

NERC Alerts Landing Page – Alerts (nerc.com)

NERC Alert A-2015-02-05-01 Generator Governor Frequency Response

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Commented [A13R12]: Updated/verified links

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~~Primary Frequency Control Reliability Guideline~~

NERC Reliability Standards Landing Page – Reliability Standards (nerc.com)

NERC Standard BAL-003

Other Cited Documents

Lawrence Berkeley National Laboratory - Use of Frequency Response Metrics to Assess the Planning and Operating Requirements for Reliable Integration of Variable Renewable Generation, Key Findings

Federal Energy Reliability Commission - 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
4/15/2021	3.0	Industry Comments addressed
~~9~~10/13~~0~~/2022	4.0	~~Begin~~ 3-year review and revisions, added metrics, errata changes

SAR MOD-031

Action
Endorse

Background
This SAR has been through the RAS coordination prior to RSTC engagement. Their comments are included in this SAR. The RSTC has reviewed this SAR and the comments have been incorporated in the materials. Responses to comments have also been drafted and included. This work is a follow-up after the approval of the SPIDERWG review of NERC Reliability Standards white paper.

Summary
MOD-031-3 seeks to "provide authority for applicable entities to collect Demand, energy and related data to support reliability studies and assessments and to enumerate the responsibilities and obligations of requestors and respondents of that data." The SPIDERWG has recently recommended in the *White Paper: SPIDERWG NERC Reliability Standards Review*[1] that MOD-031-3 should be revised to allow for the PC to obtain existing and forecasted DER information from DPs or TPs. The TP should have the ability to act as an intermediary to provide data from DPs to the PC.

[1] Available here: https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Whitepaper_SPIDERWG_Standards_Review.pdf

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Standard Authorization Request (SAR)

Complete and submit this form, with attachment(s) to the [NERC Help Desk](). Upon entering the Captcha, please type in your contact information, and attach the SAR to your ticket. Once submitted, you will receive a confirmation number which you can use to track your request.

The North American Electric Reliability Corporation (NERC) welcomes suggestions to improve the reliability of the bulk power system through improved Reliability Standards.

Requested information			
SAR Title:	MOD-031-3 — Demand and Energy Data		
Date Submitted:	~~_/_/2022~~06/XX/2023		
SAR Requester			
Name:	Shayan Rizvi, NPCC (NERC SPIDERWG Chair) John Schmall , ERCOT (NERC SPIDERWG Vice-Chair)		
Organization:	The NERC System Planning Impacts of DER Working Group (SPIDERWG)		
Telephone:	Shayan – 212-840-1070 John – 512-248-4243~~Shayan – John –~~	Email:	Shayan – srizvi@nppc.org John – john.schmall@ercot.com~~Shayan – John –~~
SAR Type (Check as many as apply)			
☐ New Standard ☒ Revision to Existing Standard ☒ Add, Modify or Retire a Glossary Term ☐ Withdraw/retire an Existing Standard		☐ Imminent Action/ Confidential Issue (SPM Section 10) ☐ Variance development or revision ☐ Other (Please specify)	
Justification for this proposed standard development project (Check all that apply to help NERC prioritize development)			
☐ Regulatory Initiation ☐ Emerging Risk (Reliability Issues Steering Committee) Identified ☐ Reliability Standard Development Plan		☒ NERC Standing Committee Identified ☐ Enhanced Periodic Review Initiated ☒ Industry Stakeholder Identified	
Industry Need (What Bulk Electric System (BES) reliability benefit does the proposed project provide?):			
MOD-031-3 seeks to "provide authority for applicable entities to collect Demand, energy and related data to support reliability studies and assessments and to enumerate the responsibilities and obligations of requestors and respondents of that data." The SPIDERWG has recently recommended in the *White Paper: SPIDERWG NERC Reliability Standards Review*[1] that MOD-031-3 should be revised to allow for the PC to obtain existing and forecasted DER information from DPs or TPs. The TP should have the ability to act as an intermediary to provide data from DPs to the PC.			

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[1] Available here: https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Whitepaper_SPIDERWG_Standards_Review.pdf ~~[Link]~~

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Requested information
Purpose or Goal (How does this proposed project provide the reliability-related benefit described above?):
The purpose of this SAR is to revise and modify MOD-031-3 in the "Requirements and Measurements" section so that PC are allowed to obtain existing and forecasted DER information from DPs or TPs. This project's goal is to ensure that various forms of historical and forecast Demand and energy data and information is available to the parties that perform reliability studies and assessments, and provide the authority needed to collect the applicable data.
Project Scope (Define the parameters of the proposed project):
SPIDERWG recommends that a Standard Drafting Team (SDT) review and modify MOD-031-3, as necessary, such that the Standard requires DPs and TPs to provide existing and forecasted DER data when the PC determines the need as it is becoming critical to know how much actual demand is on the system given the amount being served by embedded generation. ~~As Project 2022-02[2] is currently defining the term "DER", the SDT should define the term "DER" in the NERC Glossary of Terms if that project does not produce a term in the NERC Glossary of Terms as part of its final project.~~
Detailed Description (Describe the proposed deliverable(s) with sufficient detail for a drafting team to execute the project. If you propose a new or substantially revised Reliability Standard or definition, provide: (1) a technical justification[3] which includes a discussion of the reliability-related benefits of developing a new or revised Reliability Standard or definition, and (2) a technical foundation document (*e.g.*, research paper) to guide development of the Standard or definition):
SPIDERWG identified that standards revisions be made to MOD-031 to have specific language reflecting DERs[4] and how to address them. ~~Further, while Project 2022-02 is currently defining DERs, should their project be unable to add the definition to the NERC Glossary of Terms[5] due to the term not being in more than one standard, this SDT should use and add their term to the Glossary of Terms as part of their project.~~ TPs should be an intermediary to provide this data from DPs to the PC as the DER from the DP affects the existing and forecasted demand amount of the TP's planning area ~~and~~ as well as ~~affect~~ the TP's projected DER capacity for their planning area. This process continues up for each TP in a PC's planning area. Thus, to minimize double counting, the TPs should be the intermediary of DER forecast information between DPs and PCs. Because of how each entity's ~~output~~ forecast is dependent on the results of another, the

~~[2] Project Page available here: https://www.nerc.com/pa/Stand/Pages/Project2022-02ModificationstoTPL-001-5-1andMOD-032-1.aspx~~
[3] The NERC Rules of Procedure require a technical justification for new or substantially revised Reliability Standards. Please attach pertinent information to this form before submittal to NERC.
[4] MOD-031 calls out "Demand-side Management" whose definition is "All activities or programs undertaken by any applicable entity to achieve a reduction in Demand." A reading of this definition includes generation sources as they offset Demand, or "the rate at which electric energy is delivered to or by a system or part of a system." The SPIDERWG review of this standard calls for greater specificity to be added to this standard.
~~[5] Latest Glossary of Terms is available here: https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf~~

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Requested information
standard should be both clear on DER and revised to ensure the PC's need to obtain existing and forecasted gross demand is met. This process is currently not found in MOD-031-3 language and would add a separate pathway of data transfer specific to DER data. The current structure of MOD-031 has a PC request information of entities, and this change would have the TP act as an intermediary to the DP for PC requests for existing and forecasted DER ~~information.~~capacity information. As no reporting mechanism currently exists for DER resource owners to identify their future year interconnection date to the DP, the SDT should ensure provisions are available to DPs to share narrative and data projections appropriate to the data they have available. This existing and future projections is separate from the details for steady-state and stability data specifications per MOD-032-1, which is currently in update by Project 2022-02. For instance, the "monthly peak hour forecast" for DER will have a maximum active power value for the entity's footprint, but this does not equate to the equipment active power settings covered by Project 2022-02.
Cost Impact Assessment, if known (Provide a paragraph describing the potential cost impacts associated with the proposed project):
The costs are unknown. Potentially, there will be a staffing increase to perform the forecasting; however, that cost can be on the transmission entity side of this SAR.
Please describe any unique characteristics of the BES facilities that may be impacted by this proposed standard development project (*e.g.*, Dispersed Generation Resources):
None. This SAR specifies the addition of requirements to data exchange between PCs, TPs and DPs in addition to TPs being the intermediary between DPs and the PC. This should not have a negative impact BES facilities.
To assist the NERC Standards Committee in appointing a drafting team with the appropriate members, please indicate to which Functional Entities the proposed standard(s) should apply (*e.g.*, Transmission Operator, Reliability Coordinator, etc. See the most recent version of the NERC Functional Model for definitions):
Impacted: Planning Coordinator (PC), Transmission Planner (TP), Balancing Authority (BA), Resource Planner, ~~Load-Serving Entity~~ and Distribution Providers (DP)
Do you know of any consensus building activities[6] in connection with this SAR? If so, please provide any recommendations or findings resulting from the consensus building activity.

Commented [A2]: Clarity edits to address EEI comment 3

Commented [A3]: Added per EEI comment 4

[6] Consensus building activities are occasionally conducted by NERC and/or project review teams. They typically are conducted to obtain industry inputs prior to proposing any standard development project to revise, or develop a standard or definition.

Requested information
This SAR has been submitted through the RSTC and has been vetted by the SPIDERWG membership. The SPIDERWG also coordinated with the Reliability Assessment Subcommittee under the RSTC as MOD-031 impacts their ability to perform assessments. Their review is incorporated in the scoping sections of this SAR. The SPIDERWG membership includes BAs, RCs, TOs, TPs, TOPs, PCs, and DPs. The SPIDERWG recommended this standard be revised in *White Paper: SPIDERWG NERC Reliability Standards Review*.
Are there any related standards or SARs that should be assessed for impact as a result of this proposed project? If so, which standard(s) or project number(s)?
Project 2022-02 is currently defining DER, which can be used in this standard for current and projected capacity information under MOD-031. As Project 2022-02[7] is currently defining the term "DER", the SDT should define the term "DER" in the NERC Glossary of Terms if Project 2022-02 does not produce a term in the NERC Glossary of Terms as part of its final project Project 2022-02 covers the steady-state and dynamics data requirements pertaining to DERs, while this SAR is proposing a project to cover current and forecasted capacity projections for DERs. This SAR does not propose to link the two outside of using common definitions in the NERC Glossary of Terms for DERs.~~None.~~
Are there alternatives (e.g., guidelines, white paper, alerts, etc.) that have been considered or could meet the objectives? If so, please list the alternatives.
The SPIDERWG considered Standards revisions alongside compliance implementation guidance and reliability guidelines. Neither compliance implementation guidance nor reliability guidelines were determined to be sufficient by SPIDERWG in their consensus-based white paper above.

Formatted: Justified

Commented [A4]: Added per EEI comment 1,2, and 7

Reliability Principles	
Does this proposed standard development project support at least one of the following Reliability Principles (Reliability Interface Principles)? Please check all those that apply.	
☒	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☐	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.

[7] Project Page available here: https://www.nerc.com/pa/Stand/Pages/Project2022-02ModificationstoTPL-001-5-1andMOD-032-1.aspx

Reliability Principles	
☒	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
☐	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.
☐	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.
☐	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☐	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.
☐	8. Bulk power systems shall be protected from malicious physical or cyber attacks.

Market Interface Principles	
Does the proposed standard development project comply with all of the following Market Interface Principles?	Enter (yes/no)
1. A reliability standard shall not give any market participant an unfair competitive advantage.	Yes
2. A reliability standard shall neither mandate nor prohibit any specific market structure.	Yes
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard.	Yes
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards.	Yes

Identified Existing or Potential Regional or Interconnection Variances	
Region(s)/ Interconnection	Explanation
None	N/A

For Use by NERC Only

SAR Status Tracking (Check off as appropriate).	
☐ Draft SAR reviewed by NERC Staff ☐ Draft SAR presented to SC for acceptance ☐ DRAFT SAR approved for posting by the SC	☐ Final SAR endorsed by the SC ☐ SAR assigned a Standards Project by NERC ☐ SAR denied or proposed as Guidance document

Version History

Version	Date	Owner	Change Tracking
1	June 3, 2013		Revised
1	August 29, 2014	Standards Information Staff	Updated template
2	January 18, 2017	Standards Information Staff	Revised
2	June 28, 2017	Standards Information Staff	Updated template
3	February 22, 2019	Standards Information Staff	Added instructions to submit via Help Desk
4	February 25, 2020	Standards Information Staff	Updated template footer

EEI Draft SAR Comments
SAR Title: MOD-031-3 Current & Future DER Projections

Comments:

1. Recommend updating the SAR to allow for the ability to **Add, Modify or Retire Glossary Term**.
2. Suggest that the SAR include direction to define DERs.
3. **Detailed Scope Section –** It is unclear the level of detailed data that DPs will be required to obtain from DER Resource Owners. It would be helpful for the SAR to include a baseline or reference the Reliability Guideline titled "DER Data Collection for Modeling in Transmission Studies" if the data from the Reliability guideline is the expectation data (see below).
    a. Location, both electrical and geographic
    b. Type of DER (or aggregate type)
    c. Historical or expected DER output profiles
    d. Status
    e. Maximum and minimum DER active power capacity (Pmax and Pmin)
    f. Maximum and minimum DER reactive power capability (Qmax, producing vars; Qmin, consuming VARs); alternatively, a reactive power capability curve for the overall
    g. U-DER facility (this is specific to U-DERs)
    h. Distribution system equivalent feeder impedance (particularly for R-DERs and load modeling) (U-DER) Reactive power-voltage control operating mode
    i. *If one or more DERs are represented as a U-DER with a generator record in the power flow, the TP and PC may also need the following specific information to accurately represent this element (based on their specific modeling practices):*
        i. Facility step-up transformer impedances
        ii. Equivalent feeder or generator tie line impedance (for large U-DER facilities) if applicable
        iii. Facility or transmission-distribution transformer tap changer statuses and settings where applicable.
        iv. Shunt compensation within the facility
    j. Data collection for Parameterizing the DER_A Dynamic Model (See chapter 3)
    k. And Short Circuit Studies (See Chapter 4)
4. The SAR should recognize that there are currently no regulatory obligations for DER resource owners to provide certain data and the SDT should consider provisions for this when developing the requirements.
5. **Proposed Drafting Team** – Suggest LSEs be removed from the list of SDT members. LSE is no longer a registered entity.
6. **TPs as Intermediaries between DPs and PCs** – It would be helpful to include rational for why the TPs are needed as intermediaries.
7. There is an approved project (Project 2022-02/Modifications to TPL-001 and MOD-032) that was developed by the SPIDER WG and approved by the SC on September 21, 2022 that adds DER data collection requirements on DPs and as directed by the PC and TP. The MOD-032-1 (Data for Power System Modeling and Analysis) SAR seems to address the same issues as this MOD-031 SAR. The MOD-031 SAR should be clear how it is different from the MOD-032 project.

Commented [JS1]: Added text to include this portion into the related projects section such that Project 2022-02's efforts are not duplicated and further emphasized while still allowing for the potential addition of DER or other terms in the check boxes.

Commented [JS2]: As the data is different, the SPIDERWG did not include this comment in the revisions. Rather this is in support of why the two SARs are needed for these standards. Clarity edits also added in related Projects section of the SAR.

Commented [JS3]: Changes made to Detailed Scope section of SAR

Commented [JS4]: Change made as proposed

Commented [JS5]: Clarity added to highlight how these entity's forecast areas overlap.

Commented [JS6]: Added language to the related standards and SARs section to address this comment.

8. EIA is proposing to collect information on energy storage and other types of DERs and presently collects data on certain types of DERs. Add consideration for the SDT to harmonize the NERC data collection with EIA.

Commented [JS7]: Thank you for your comment. Due to the review periods and variability with how and what EIA data collects, the harmonization of collection between EIA and MOD-031 can break should EIA modify their collection. SPIDERWG does not agree with adding requirement language that requires EIA data collection harmonization. No changes made to the SAR.

NERC
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RELIABILITY CORPORATION

MOD-031 Standard Authorization Request

Request for Endorsement

Shayan Rizvi, NPCC – SPIDERWG Chair
Wayne Guttormson, SaskPower - RSTC Sponsor

NERC Reliability and Security Technical Committee
June 21, 2023

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MOD-031 SAR

- Sought RSTC Reviewers in March 2023.
  - Previously included RAS review and revisions
- 1 comment set received from reviewers
  - Generally supportive of direction, sought clarity
  - Revisions included in SAR document, focused on related projects/SARs
  - Responses included in separate Word file
- Project focuses on clarity to MOD-031 w.r.t DER and implements a process to send data for existing and forecasted DER capacity information.
- **Seeking endorsement by RSTC**

Questions and Answers

Reliability Guideline: DER Data Collection and Model Verification for Aggregate DER

Action
Approve

Background
This reliability guideline merges two others from SPIDERWG as part of the tranche process. This reliability guideline has been posted for a 52-week comment period from industry, with comments, redlines, and responses included as part of the materials.

Summary
The primary objective of this reliability guideline is to provide recommended practices for TPs and PCs to establish effective modeling data and model verification requirements regarding aggregate DER data for the purposes of performing reliability studies. This includes TPs and PCs working with DPs, RPs, and other applicable data reporting entities to facilitate the transfer of data needed to represent aggregate DER in BPS reliability studies. TPs and PCs should review their requirements and consider incorporating the recommendations presented in this guideline into those requirements. DPs are encouraged to review the recommendations and reference materials to better understand the types of modeling data needed by the TP and PC and to help facilitate this data and information transfer. In many cases, the aggregate data needed for the purposes of modeling may not require detailed information from individual DERs; rather, aggregate data related to location, type of DERs, vintage of IEEE 1547, interconnection time line and projections, and other key data points can help develop aggregate DER models. The detailed guidance provided in this guideline follows the required data transfer established in NERC Reliability Standard MOD-032-1 and speaks to the system level verification in MOD-033.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Reliability Guideline

DER Data Collection and Model Verification of Aggregate DER

December 2022

RELIABILITY | RESILIENCE | SECURITY

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Suite 600, North Tower
Atlanta, GA 30326
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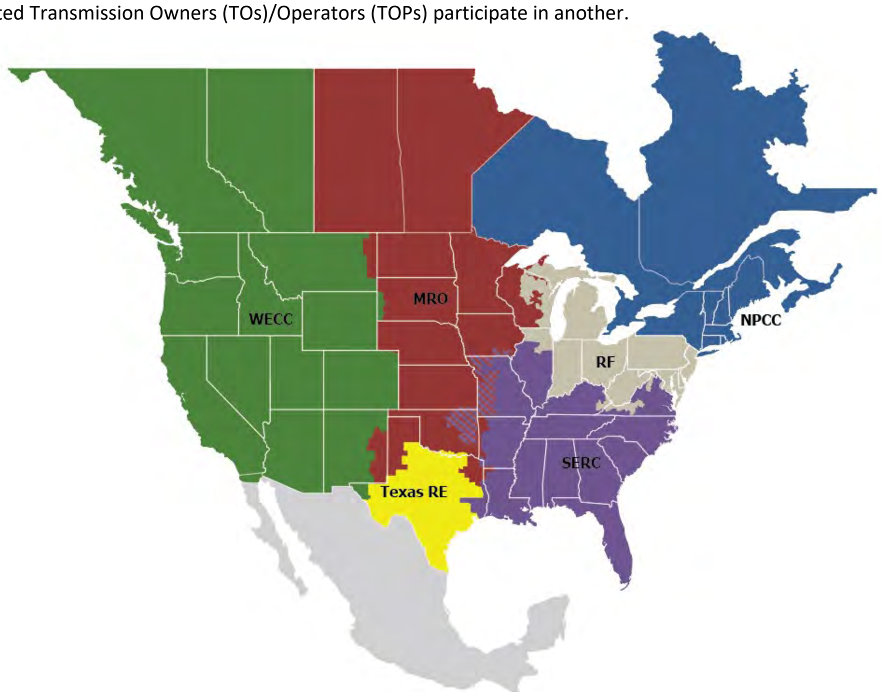
Preface

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, 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 made up of six Regional Entity boundaries as shown in the map and corresponding table below. The multicolored area denotes overlap as some load-serving entities participate in one Regional Entity while associated Transmission Owners (TOs)/Operators (TOPs) 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 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 nor are they Reliability Standards; 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.

Metrics

Pursuant to the Commission's Order on January 19, 2021, *North American Electric Reliability Corporation*, 174 FERC ¶ 61,030 (2021), reliability guidelines shall now include metrics to support evaluation during triennial review consistent with the RSTC Charter.

Baseline Metrics
All NERC reliability guidelines include the following baseline metrics:

- BPS performance prior to and after a reliability guideline as reflected in NERC's State of Reliability Report and Long Term Reliability Assessments (e.g., Long Term Reliability Assessment and seasonal assessments)
- Use and effectiveness of a reliability guideline as reported by industry via survey
- Industry assessment of the extent to which a reliability guideline is addressing risk as reported via survey

Specific Metrics
The RSTC or any of its subcommittees can modify and propose metrics specific to the guideline in order to measure and evaluate its effectiveness, listed as follows:

- Established TP and PC criteria for metering and monitoring of DER behind a T-D Interface
  - ~~Count of electronic relays and digital fault recorders used for model verification associated with a single T-D Interface~~
  - Percentage[1] of DER MW that has been validated through ~~covered by~~ electronic relays ~~and~~ or digital fault recorders
  - Percentage of DER MW that has been validated through non-measurement methods~~used for model verification per TP region~~
- Percentage of MW of DER ~~explicitly~~ modeled[2] in a transmission base case compared to the total capacity[3] of DER reported in the NERC Long Term Reliability Assessments for a given year, adjusted for resource categorization shifts.
- Count of ~~entities~~ TPs and PCs that have identified specific modeling requirements for DER in transmission level studies
  - Count of entities that have used identified specific modeling requirements to develop DER models
  - Percentage of TPs and PCs of the above representing DER by total of NERC Compliance Registry
- For grid disturbances that have identified a DER response, the DER model representing that equipment matches the grid disturbance. [4]

[1] Percentage is calculated by the ratio of verified DER models towards all DER models in a planning case.
[2] This includes both explicitly modeled DER as generators or DER modeled using the dg fields in the load model.
[3] Calculated using best available capacity factors and engineering judgement to align the generation in the base case to nameplate capacity.
[4] This metric will require careful engineering judgement by NERC's Event Analysis department as well as the NERC RSTC.

Executive Summary

Modeling the BPS for performing BPS reliability studies hinges on the availability of data needed to represent the various elements of the grid. While many individual BPS elements are modeled explicitly,[5] some components are represented in aggregate. These aggregate representations include end-use loads[6] as well as a growing amount of distributed energy resources (DERs).[7] As the penetration of DERs continues to grow, representing DERs in planning assessments becomes increasingly important. Steady-state power flow, dynamics, short-circuit, electromagnetic transient (EMT), and other types of planning studies may need information and data that enable Transmission Planners (TPs) and Planning Coordinators (PCs) to develop models of aggregate amounts of DERs for planning purposes. Further, these models used to represent DER aggregations should be verified to some degree. Verification of these models, at a high level, entails developing confidence that the models reasonably represent the general behavior of the installed equipment in the field (in aggregate). Since DER models used in planning studies often represent an aggregate behavior of hundreds or even thousands of individual devices, guidance is needed for TPs and PCs to effectively perform an appropriate level of model verification to ensure that planning assessments are capturing the key impacts that DERs can have on BPS reliability.

TPs and PCs establish modeling data requirements and reporting procedures per the requirements of NERC Reliability Standard MOD-032-1.[8] The data requirements should include specifications for collecting DER data for the purposes of aggregate DER modeling, particularly as DER penetration levels continue to increase. Clear and consistent requirements developed by the TPs and PCs will help facilitate the transfer of information between the Distribution Providers (DPs), Resource Planners (RPs), and any other external parties (e.g., state regulatory entities or other entities performing DER forecasting to the TP and PC for modeling purposes). The modeling data requirements established by TPs and PCs may differentiate utility-scale DERs (U-DERs) and retail-scale DERs (R-DERs) based on their size, impact, or location on the distribution system.[9] U-DERs may require detailed information regarding the facility while smaller-scale R-DER data will typically represent aggregate amounts of DERs. Both individual and aggregate information pertaining to DER levels can be useful to TPs and PCs as they develop DER models for their footprint. MOD-032 designees that develop Interconnection-wide planning cases should also ensure clear and consistent ~~requirements~~ internal processes for TPs and PCs to accurately account for aggregate amounts of DERs in the planning cases. TPs and PCs should also establish clear requirements and any applicable thresholds regarding DER modeling practices; however, DERs should be accounted and reported to the TP and PC for modeling purposes.[10] Any thresholds established for aggregate DER modeling should be based on engineering judgment and experience from studying DER impacts on the BPS; data regarding aggregate amounts of DERs will need to be collected by TPs and PCs to facilitate these studies.

This guideline provides TPs and PCs with tools and techniques that can be adapted for their specific systems to verify that the created aggregate DER models are a suitable representation of these resources in planning assessments. The first step in DER model verification is collecting data and information regarding actual DER performance (through measurements) to BPS disturbances or other operating conditions. Measurements of DERs (individual or aggregate) are currently sparse, and this guideline recommends practices for ensuring adequate data are collected for larger

[5] Such as BPS transformers, generators, circuits, and other elements

[6] Typically loads are aggregated to each distribution transformer. Therefore, all loads connected to that distribution transformer are represented as one load in the steady-state base case, and then an aggregate representation of the dynamic performance of those loads are developed using engineering judgment combined with available data.

[7] For the purpose of this guideline, SPIDERWG refers to a DER as "Any source of electric power located on the distribution system."

[8] https://www.nerc.com/_layouts/15/PrintStandard.aspx?standardnumber=MOD-032-1&title=Data%20for%20Power%20System%20Modeling%20and%20Analysis&jurisdiction=United%20States

[9] U-DER and R-DER are terms used for modeling aggregate amounts of DER. Refer to the flexible framework established in previous NERC reliability guidelines: https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability_Guideline_DER_A_Parameterization.pdf.

[10] This aligns with the guidance provided in NERC *Technical Report Distributed Energy Resource Connection Modeling and Reliability Considerations*: https://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/Distributed_Energy_Resources_Report.pdf.

utility-scale DERs as well as capturing the general behavior of the T-D Interface. This guideline discusses when model verification is triggered as well as how to understand the mix of different DER characteristics and describes differences between verifying the model response for aggregate R-DERs and larger U-DERs. Describing the recommended DER model verification practices can also help TOs, TPs, PCs, and DPs understand the types of data needed for analyzing DER performance for verification purposes both now and into the future as DER penetrations continue to rise. As has been observed in past large-scale disturbances, the response of DERs to BPS disturbances can significantly impact overall reliability of the BPS.[11]

Modeling and Verification for Future Study Conditions

TPs and PCs should see future and other guidance from the SPIDERWG that details the study concerns with DER and how to change the model to reflect those study conditions. It is likely that not all the same parameters changed in the models to obtain a verified model will be adjusted for study conditions. For example, a study sensitivity may try and determine the impact of updating all legacy DER models on a distribution system. For such a study, tripping parameters will likely change; however, the penetration will not for that specific study. These type of considerations are not applicable when verifying the DER model; however, they are to be considered when performing a study with a verified DER model.

Key Findings

During the development of this guideline, the NERC SPIDERWG identified the following key findings:

- **Model Development:** TPs and PCs require coordination and data from Transmission Owners (TOs) and DPs when developing their set of transmission models. DER model development is no exception, and with key data[12] provided to the TP and PC, the transmission entities can populate a model that represents the aggregate behavior of DER behind a T-D Interface. Modeling practices will differ[13] between each TP and PC; however, all DER should be accounted for in the model in such a way that facilitates easy identification of DER in the planning model.
- **Visibility and Measurement:** Verification of DER models requires measurement data to capture the general behavior of these resources. For R-DERs, data is most useful from the high-side of the transmission–distribution (T–D) interface, most commonly the T–D transformers. For U-DERs, this may be at the point of interconnection of each U-DER.[14]
- **Aggregation of U-DER and R-DER Behavior:** Verification of aggregate DER models becomes more complex when both U-DERs and R-DERs are modeled on the distribution system with different performance capabilities and operational settings, and verification practices will need to adapt to each specific scenario.
- **Data Requirements:** Data requirements for DER modeling follow the MOD-032 practices set by TPs and PCs. These practices typically include steady-state, dynamic, and short-circuit representations. Some data requirements may include GMD or EMT specifications in specific areas. DER model verification practices should ensure that both steady-state and dynamic modeling are supported.
- **Event Selection for Model Verification:** A relatively large disturbance on the BPS (e.g., a nearby fault or other event) is the most effective means of dynamic model verification; however, these events are not necessarily the only trigger of model verification. It should be noted that aggregate model verification is not a one-time exercise. Since system loads and DER output levels keep changing when more events happen and the

[11] https://www.ofgem.gov.uk/publications-and-updates/ofgem-has-published-national-grid-electricity-system-operator-s-technical-report
[12] The data here is related to the building of the aggregate representation of DER in transmission cases. TOs and DPs likely do not have all data available. All data available is not a prerequisite for sending data to develop transmission models.
[13] For example, two entities will likely differ in their practices for when to model a larger DER installation as a stand-alone generator record behind the T-D Interface rather than using automated load models that lump the large DER installation as a component of the aggregate.
[14] For more discussion on placement of measurement devices, see Chapter 1

measurement data becomes available, the verified models should be checked to ensure that other events that have happened in the system can be replicated.

- **Concept of Verified Models:** Developing an aggregate DER model is not equivalent to having a verified model.[15] A verified model should not be expected to be usable for all types of planning studies. A developed aggregate DER model for the positive sequence simulation tools is a mathematical representation at a given location while verification of this model is an exercise that entails comparing the model performance to the actual equipment performance during staged or grid events and tuning relevant parameters to match the model behavior with actual field response. Developing a model useful for study, based on information attained through model verification, requires engineering judgement.[16]

Key Recommendations for DER Data Collection

From the key findings previously listed, the following recommendations are intended to help guide TPs and PCs in performing aggregate DER model verification in their planning studies:

- TPs, TOs, and PCs should encourage DPs and other applicable entities that may govern DER interconnection requirements to revise interconnection requirements to ensure both high and low time-resolution data collection.[17]
- TPs, PCs, TOs, and other applicable entities that may need DER information should coordinate with DPs for facilities connected to distribution systems to determine the necessary measurement information that would be of use for DER modeling and model verification and jointly develop requirements[18] or practices that will ensure this data is available. ~~As the TPs, PCs, and TOs are dependent on the DP to have the data made available, this will likely require actions from state regulatory bodies[19] and DPs to establish requirements to gather this information:~~
  - This collaboration should include a minimum set of necessary data for performing model verification.
  - This collaboration should include a procedure where newer DER models,[20] rather than the existing DER models, can be verified with additional data should a more accurate representation be required.
- TPs and PCs should review their modeling practices and determine if verification of both the load and DER components of their models should be done together or separately. It is recommended to verify both components simultaneously for enhanced efficiency and improved model accuracy.

- TPs and PCs should coordinate with their TOs, TOPs, and DPs to gather measurement data to verify the general behavior of aggregate DER.[21] Relevant T–D interfaces should be reviewed using data from the supervisory control and data acquisition (SCADA) system or other available data points and locations.

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[15] This is true for all sets of models and is not exclusive to aggregate DER models.

[16] A verified model may not be enough for a particular study as study conditions may be different than verified conditions (e.g., future years, different time of day).

[17] SPIDERWG recognizes that this recommendation may take some time depending on the group of entities to be involved due to the inclusion of distribution, which is not the case with BPS-connected resources.

[18] As the TPs, PCs, and TOs are dependent on the DP to have the data, this will likely require actions from state regulatory bodies and DPs to establish requirements to gather this information for the highest degree of success. However, actions taken on the high side of the T-D Interface can improve model and model verification.

~~[19] SPIDERWG has published guidance on this. Available: https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Guideline_IEEE_1547-2018_BPS_Perspectives.pdf Found here.~~

[20] For example, root-mean-squared (RMS) three-phase models.

[21] SPIDERWG is actively developing guidance on how this coordination should take place to ensure reliability of the BPS.

Key Recommendations for DER Model Verification

With the purpose of taking a correctly parameterized aggregate DER model and tuning it to match real performance, TPs and PCs should consider the following:

- Location of measured voltage, frequency, power, or other quantity with respect to the electrical terminals of the DER devices
- Correlation of output to end-use demand and the aggregate response of DER devices at the T-D interface[22]
- Accurate and robust metering equipment should be installed on the high or low side of the T–D transformer as well as equipment near the large DER terminals. These measurements should be made available to the TP and PC on request and stored for a reasonable amount of time after an event triggers the recording.

With the above three bullets in mind, TPs and PCs should use measurement-based or non-measurement based approaches for steady-state or dynamic model verification of their DER models. Like BPS device models, operational considerations and adjustments are required to perform the study conditions. In order to change a verified model to the study conditions, the following items should be considered:

- Time of day, month, or year[23]
- Electrical changes between verified model and study model[24]
- Study sensitivity assumptions and conditions[25]

[22] This is particularly true of BESS DERs

[23] Irradiance and other meteorological quantities are affected by time, and some DER types are dependent upon this weather data

[24] For example, distribution system reconfiguration due to lost transformer affected the verified model, but a study model has a normal configuration

[25] For example, if studying cloud cover over a wide area, Solar PV DER will be affected and should be adjusted accordingly

Introduction

The ability to develop accurate models for BPS reliability studies hinges on the availability of data and information needed to represent the various elements of the grid. While many individual BPS elements are modeled explicitly (e.g., transformers, large BPS generators, transmission lines), some components of the grid are represented in aggregate for the purposes of BPS studies. Such models include the representation of end-use loads[26] as well as a growing focus on the representation of aggregate amounts of DERs. TPs and PCs establish modeling data requirements for DER data for the purposes of transmission planning assessments, and reasonable representation of DERs in the models used to execute these studies will be increasingly important. As this guideline highlights, DPs likely account for the aggregate amount of DERs connected to their system with varying degrees of detail and information available. In some instances, RPs may have information pertaining to future projections of DERs.

The case for a high quality model is even further emphasized by the rapidly growing DER penetrations across North America. Such models should be "trusted" to a suitable degree to incorporate into BPS planning studies, much like how TPs and PCs currently account for aggregated load. This guideline further identifies areas where a TPs and PCs level of "trust" can be validated or verified for use in bulk system studies. Other SPIDERWG guidance materials provide TPs and PCs with recommendations for modeling aggregate amounts of DERs and their parameterization in transient dynamic studies[27]. However, some degree of uncertainty is involved when applying assumptions or engineering judgement in the development of the model. Therefore, this guideline tackles the need for verification practices, after aggregate DER models are developed, to ensure that the models used to represent DERs are, in fact, representative of the actual or expected behavior. TPs and PCs gain more confidence in their aggregate DER models after verifying their accuracy and trust BPS planning studies results from this interaction.

Purpose

The primary objective of this reliability guideline is to provide recommended practices for TPs and PCs to establish effective modeling data and model verification requirements regarding aggregate DER data for the purposes of performing reliability studies ~~and model verification~~. This includes TPs and PCs working with DPs, RPs, and other applicable data reporting entities to facilitate the transfer of data needed to represent aggregate DER in BPS reliability studies. TPs and PCs should review their requirements and consider incorporating the recommendations presented in this guideline into those requirements. DPs are encouraged to review the recommendations and reference materials to better understand the types of modeling data needed by the TP and PC and to help facilitate this data and information transfer. In many cases, the aggregate data needed for the purposes of modeling may not require detailed information from individual DERs; rather, aggregate data related to location, type of DERs, vintage of IEEE 1547, interconnection time line and projections, and other key data points can help develop aggregate DER models. The detailed guidance provided in this guideline follows the required data transfer established in NERC Reliability Standard MOD-032-1 and speaks to the system level verification in MOD-033.

Applicability

This reliability guideline is applicable to TPs, PCs, TOs, and other users of DER modeling for representing aggregate DER in their set of models as well as those entities performing model verification or validation checks for the same models.

[26] Typically loads are aggregated to each distribution transformer. Therefore, all loads connected to that distribution transformer are represented as one load in the steady-state base case, and then an aggregate representation of the dynamic performance of those loads are developed using engineering judgment combined with available data.

[27] SPIDERWG has published a guideline on the modeling and parameterization of aggregate DER models here: https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Reliability_Guideline_ModelingMerge_Responses_clean.pdf ~~[INSERT LINK WHEN FINISHED]~~

Related Standards

The topics covered in this guideline are intended as useful guidance and reference materials as TPs and PCs create and verify DER models in studies. While this guidance does not provide compliance guidance of any sort, the concepts apply generally to the following standards:

- MOD-032
- MOD-033
- TPL-001
- PRC-002

Background

The NERC *Reliability Guideline: Modeling DER in Dynamic Load Models*,[28] published December 2016, established a foundation for classifying DERs as either U-DERs or R-DERs for the purpose of modeling. That guideline also provided a flexible framework for modeling U-DERs and R-DERs in steady-state power flow base cases as well as options for modeling DER in the dynamic models. This included options for representing DERs with a stand-alone DER dynamic model or integrating DERs as part of the composite load model. The NERC *Reliability Guideline: Distributed Energy Resource Modeling*,[29] published September 2017, provided further guidance on establishing reasonable parameter values for DER dynamic models. That guideline reviewed the available dynamic models and recommended default parameter values that could be used as a starting point for modeling DERs. The NERC *Reliability Guideline: Parameterization of the DER_A Model*[30] recommended use of the DER_A dynamic model to represent either U-DERs or R-DERs in dynamic simulations. This model was in the process of being developed during the publication of the previous two guidelines. Therefore, that guideline demonstrated the benchmarking and testing of the DER_A model and also provided recommended default parameter values for the DER_A model for different scenarios of DER installations in various systems. Again, the recommendations presented in that guideline are intended to be a starting point for planning engineers to further determine representative DER dynamic model parameter values. In 2021, the NERC RSTC initiated a review of all approved reliability guidelines, and the content in the above three documents is now housed completely in a new reliability guideline titled *Reliability Guideline: Parameterization of the DER_A Model for Aggregate DER*[31]*.*

The NERC Distributed Energy Resources Task Force (DERTF) also published a technical report on *Distributed Energy Resources: Connection Modeling and Reliability Considerations,*[32] published December 2016, and a technical brief on *Data Collection Recommendations for Distributed Energy Resources,* published March 2018.[33] Both of these reports provided industry with a high-level overview of the information that may need to be collected and shared among entities for the purposes of modeling and studying DER impacts as well as monitoring DERs in real-time. Furthermore, these reports emphasized that netting of DERs with load should be avoided since it can mask the impacts that either may have on BPS reliability, particularly for dynamic simulations.

The NERC SPIDERWG has developed this reliability guideline to build upon past efforts and specifically focus on gathering the data and modeling information needed to effectively execute transmission planning modeling and study activities. Effectively gathering data regarding the aggregate levels of DERs is critical for TPs and PCs to execute planning assessments and ensure reliable operation of the BPS in the long-term planning horizon.

[28] https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability_Guideline_-_Modeling_DER_in_Dynamic_Load_Models_-_FINAL.pdf
[29] https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability_Guideline_-_DER_Modeling_Parameters_-_2017-08-18_-_FINAL.pdf
[30] https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability_Guideline_DER_A_Parameterization.pdf
[31] Available here: [link]
[32] https://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/Distributed_Energy_Resources_Report.pdf
[33] https://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/DER_Data_Collection_Tech_Brief_03292018_Final.pdf

Recommended DER Modeling Framework

The recommendations regarding DER data collection for the purposes of modeling and transmission planning studies use the recommended DER modeling framework proposed in previous NERC reliability guidelines (see **Figure I.1**).[34] For the purposes of modeling, the framework characterizes DERs as either U-DERs or R-DERs. These definitions are intended to be adapted to specific TP and PC planning practices and specific DER installations as needed. As a reference from previous DER modeling recommendations, these definitions include the following:

- **U-DER:** DERs directly connected to, or closely connected to, the distribution bus or connected to the distribution bus through a dedicated, non-load serving feeder.[35] These resources are typically three-phase interconnections and can range in capacity (e.g., 0.5 to 20 MW).
- **R-DER:** DERs that offset customer load, including residential,[36] commercial, and industrial customers. Typically, the residential units are single-phase while the commercial and industrial units can be single- or three-phase facilities.

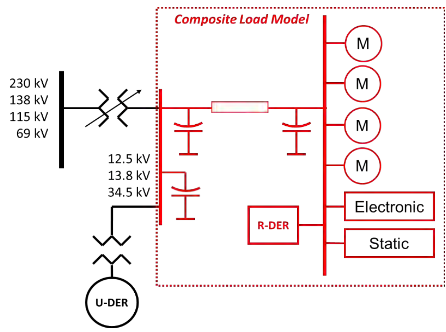

Figure I.1: DER Modeling Framework

Both U-DERs and R-DERs can be differentiated and modeled in power flow base cases and dynamic simulations. TPs and PCs have successfully adapted these general definitions for their system and often refer to U-DERs and R-DERs for the purposes of modeling aggregate DERs. Aggregate amounts of all DERs should be accounted for in either U-DER or R-DER models in the base case, and TPs and PCs may establish requirements for modeling any U-DERs as well as aggregate amounts of the remaining DERs as R-DERs. The aggregate impact of DERs, such as the sudden loss of a large amount of DERs, has been observed[37] to be a contributor to BPS performance during disturbances.

There will inherently be lag between the time when DER steady-state and dynamic models are created and when verification of these models with system disturbances and engineering judgement can take place. However, this should not preclude the use of these models in BPS reliability studies. Engineering judgment can be used in the interim to develop reasonable and representative DER models that capture the key functional DER behaviors. Explicit modeling of aggregate DER amounts is strongly recommended[38] versus netting these resources with load as the key functional behaviors are different.

[34] https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability_Guideline_DER_A_Parameterization.pdf

[35] Some entities have chosen to model larger (i.e., multi-MW) U-DERs that are connected further down on load-serving feeders as U-DERs explicitly in the base case. This has been demonstrated as an effective means of representing U-DERs and is a reasonable adaptation of the above definition. TPs and PCs should use engineering judgment to determine the most effective modeling approach.

[36] This also applies to community DERs that do not serve any load directly but are interconnected directly to a single-phase or three-phase distribution load serving feeder.

[37] https://www.ofgem.gov.uk/publications-and-updates/ofgem-has-published-national-grid-electricity-system-operator-s-technical-report

[38] https://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/Distributed_Energy_Resources_Report.pdf

Types of Reliability Studies

Data of BPS elements as well as other necessary aspects[39] of the interconnected BPS are used in a wide array of reliability studies performed by TPs and PCs. In particular, studies considered by SPIDERWG include the following:

- **Steady-State Studies:[40]** Steady-state reliability studies include both power flow analysis and steady-state contingency analysis of future operating conditions.[41] In addition, steady-state stability studies typically include voltage stability[42] as well as small signal eigenvalue analysis. These studies all require information regarding the end-use load as well as the DER penetration to accurately model the behavior of these resources in future normal and abnormal operating conditions.
- **Dynamic Studies:[43]** Dynamic studies typically refer to phasor-based, time-domain simulations of the interconnected BPS. These studies include performing contingencies and identifying any potential instabilities, uncontrolled separation, or cascading events that may occur due to BPS dynamic behavior and all the elements connected to it. The data used in these simulations also represents the aggregate[44] effects of end-use loads as well as aggregate DERs. DERs, particularly in dynamic simulations, can have a relatively significant impact on BPS performance for voltage stability due to redispatched dynamic reactive devices on the BPS, rotor angle stability due to changes in BPS-connected generation dispatch, and frequency stability due to changes in rate of change of frequency and frequency response performance.[45] Furthermore, the dynamic behavior (e.g., momentary cessation, tripping, voltage and frequency support) of aggregate amounts of DERs can have a significant impact on the BPS, and the expected performance of aggregate DERs should be represented in dynamic models.[46] In many cases, the details of individual DERs are not relevant unless their individual size is deemed impactful[47] to BPS performance. A reasonable understanding of the aggregate behavior of DERs is more suitable for most dynamic simulations.[48] Regardless, TPs and PCs need access to DER data to determine potential impacts of aggregate amounts of DER on the BPS.
- **Short-Circuit Studies:** Short-circuit studies are used for a wide range of analyses, such as assessing breaker duty and setting protective relays. As DERs continue to offset BPS-connected generation, particularly during high DER output levels, short-circuit conditions may need to be assessed more regularly, or close attention may be needed in certain areas of low short-circuit strength. This is particularly a concern for systems with high penetrations of DERs as well as BPS-connected inverter-based resources. As described in **Chapter 4**, some DER data related to short-circuit performance may be needed as DER penetrations increase. It is important for TOs and TPs to establish data collection practices early to help ensure sufficient data is available for modeling purposes. TOs, TPs, and PCs will need to determine an appropriate time to begin modeling DERs for short-circuit studies; however, gathering the necessary data will help facilitate improved modeling practices in the future.

[39] Such as aggregate demand (steady-state) and the dynamic nature of end-use loads (dynamics)
[40] Fundamental-frequency, positive sequence, phasor simulations
[41] For example, high penetrations of DERs may have an impact on BPS voltage control and voltage stability due to reduced or limited dynamic reactive resources on the BPS.
[42] Active power-voltage (P-V) and reactive power-voltage (Q-V) analysis
[43] Fundamental-frequency, positive sequence, phasor simulations
[44] Or possible individual large loads or resources connected to the distribution system if they can potential have an impact to the BPS
[45] NERC SPIDERWG is working on more comprehensive reliability guidelines that will cover these topics in more detail (e.g., impacts of DERs to underfrequency load shedding (UFLS) programs).
[46] https://www.ofgem.gov.uk/publications-and-updates/ofgem-has-published-national-grid-electricity-system-operator-s-technical-report
[47] Again, this is based on TP and PC engineering judgment and experience studying DER impacts. For TPs and PCs to execute these studies, they will likely need to gather relevant data to create aggregate or large individual DER models.
[48] This is for at least most instances of R-DER. U-DER may need additional or more accurate data collection in some cases.

- **Geomagnetic Disturbance (GMD) Studies:** GMD studies are performed for applicable facilities per NERC TPL-007-3,[49] which analyzes the risk to BPS reliability that could be caused by quasi-dc geomagnetically induced currents (GICs) that result in transformer hot-spot heating or damage, loss of reactive power sources, increased reactive power demand, and misoperation of system elements due to GMD events. TPL-007-3 GIC vulnerability assessments typically do not model the distribution system for various reasons because the transmission-distribution (T-D) transformers include a delta-wye transformation with GICs not propagating through delta windings and distribution circuits being relatively short in length with high impedance. Therefore, GICs on the distribution system are minimal and are not likely to impact the distribution system. Based on this finding, DER modeling for the purposes of GMD vulnerability assessments per NERC TPL-007-3 is likely not needed at this time.[50]
- **EMT Studies:** Given the higher fidelity models, EMT analysis for DER interconnections can be useful in finding low short-circuit strength issues, such as controls instabilities, voltage control coordination issues, inability to ride through BPS disturbances, and benchmarking positive sequence fundamental-frequency phasor models. Items such as ride-through and voltage response can be better represented in EMT studies than traditional positive sequence studies. This is important when large groups of DERs (relative to the size of the system) are interconnected. Most industry experience to-date is based on studies conducted of BPS-connected inverter-based resources. However, EMT studies may be useful when large[51] amounts of aggregate DERs are connecting to areas where system strength is of concern. More industry research and experience is needed in this area; however, EMT studies are becoming increasingly used to ensure reliable operation of the BPS and should be considered in the context of increasing DER penetrations.

For all types of reliability studies, each TP and PC will need to determine the relative impact to the BPS as DER penetrations increase. To determine such impacts, information is needed to be able to model aggregate amounts of DERs. Therefore, this guideline stresses the importance of TOs, TPs, and PCs establishing data collection requirements (per the latest effective version of MOD-032) that are specifically related to collecting aggregate DER data sufficiently early such that the data is available for modeling purposes either now or in the future.

Case Assumptions

Similar to end-use load models, the assumptions used for modeling DERs will dictate how the resource(s) should be represented in planning base cases. NERC TPL-001-4 requires that planning assessments use steady-state, stability, and short-circuit studies to determine whether the BES meets performance requirements for system peak and off-peak conditions. TPs and PCs need to determine and specify these conditions to ensure clarity in data submittals from DPs and RPs in conjunction with other applicable data sources. MOD-032 designees that create the Interconnection-wide power flow and dynamics base cases should also ensure that clear and consistent modeling requirements are developed for TPs and PCs to reasonably account for and model aggregate DERs in the planning cases. For example, solar photovoltaic (PV) DERs are highly dependent on the time of day that is closely linked to the assumptions used in creating the base cases. TPs and PCs will need to consider the coincidence of DER output with demand levels to ensure cases are set up appropriately. In some areas, system peak loading may occur during late afternoon when active power output from solar PV is minimal (as illustrated in **Figure I.2** and discussed below); however, light loading conditions may occur when DER output is near its maximum. Regardless, setting up DER levels in planning studies hinges on sufficient data being collected by the TP and PC regarding the aggregate levels and behavior of DERs in their footprint.

[49] https://www.nerc.com/_layouts/15/PrintStandard.aspx?standardnumber=TPL-007-3&title=Transmission%20System%20Planned%20Performance%20for%20Geomagnetic%20Disturbance%20Events&jurisdiction=United%20States

[50] Note that GICs on the BPS can create high levels of harmonic voltage distortion that can propagate to the distribution system. Situations where harmonic voltage distortion is identified may warrant closer investigation by affected entities.

[51] The term “large” is relative to each specific system and will need to be considered by each TP and PC. However, in order to execute these types of studies some degree of data will need to be collected by TPs and PCs.

PCs and TPs should clearly identify the assumptions used in planning cases as part of their data requirements so that DPs can effectively provide this information for the purposes of modeling aggregate DERs in planning base cases. Note that these studies are generally used to determine whether the BPS is robust enough to handle expected or impending operating conditions and credible contingencies based on the study results obtained. The following assumptions should be clearly defined for each base case in the TP and PC data requirements:

- **Year:** Each base case represents a specific year being studied. TPs are responsible for creating base cases of future, expected system conditions in the long-term planning horizon that include forecasted demand levels and should also include forecasted aggregate amount of DERs for each year being modeled. This data is based on local or regional DER growth trends and can come from multiple data sources.[52]
- **Season:** Each base case typically has a specified season (e.g., summer, spring, winter) or type of season (e.g., shoulder season), which is already defined in the planning process.
- **Time of Day:** Each TP and PC should identify the critical times of day that should be studied; this is often dependent on the time when gross demand peaks (or hits its minimum), when aggregate DER output peaks, and when net demand peaks (or hits its minimum). The assumed hour of day for each base case should be clearly defined by TPs and PCs to facilitate data collection from DPs and base case creation.
- **Load (Peak vs. Off-Peak):** The NERC TPL-001 standard uses terms such as "System peak Load" and "System Off-Peak Load"; however, it is not clear if these terms refer to gross or net load (demand) conditions. Therefore, it is recommended that TPs and PCs clearly articulate which load is being referred to in the case creation process. As the penetration of DERs continues to grow, it is likely that both peak and off-peak gross load and net load conditions should both be studied for potential reliability issues. This is particularly applicable to systems where the gross load and net load peak and off-peak conditions are significantly different. In all cases, TPs and PCs should ensure that gross load data is explicitly provided such that net loading can effectively be simulated by DER dispatch.
- **DER Dispatch Assumptions:** The TP and PC likely have established assumptions around how the DER will be dispatched in the planning base cases. While this may not directly affect the information flow from the DP to the TP and PC, these assumptions may help the DP in gathering the necessary data and information needed. These dispatch assumptions may include both active power output levels and reactive power capability. Additional planning base cases should reflect expected stressed system conditions that depend on the geospatial and temporal patterns (e.g., weather patterns) of demand and DERs, and their impact on BPS-connected generation dispatch. These conditions might include heavy transmission flows that have a very different pattern than during peak-load conditions.

[52] Such as state incentive policy forecasts or other relevant regional DER forecasting tools

To illustrate this concept, consider an example of the development of the Interconnection-wide "System Peak" base case. The TP in this example assumes that the "System Peak" case represents the hour of peak net demand (i.e., gross demand less DER output). Refer to **Figure I.2** for a visualization of this example. Assume that this is a summer peak case, so the season has been defined. The gross demand peaks around 4:00 p.m., and net demand peaks around 5:00 p.m. local time, respectively, defining the time of day. Based on this, DER output assumptions are established, DERs in this area are predominantly distributed solar PV, and their output is assumed to be roughly 50–60% of its maximum capability at 4:00 p.m. and much closer to 0% of its maximum capability at 6:00 p.m. Assume in this example that DERs are compliant with IEEE Standard 1547-2003 based on time of installation of the DERs.[53] Furthermore, assume the DP has not required volt-var functionality by DERs, so the DERs are not expected to provide voltage support; rather, they are assumed to operate at unity power factor (defining active and reactive power output assumptions to be modeled). This concept applies to off-peak loading conditions as well as system peaking in winter as well.

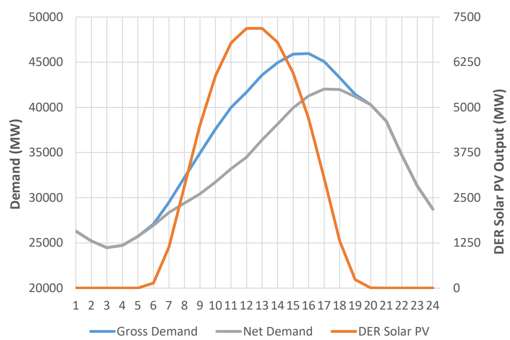

Figure I.2: DER and Demand Profiles for Summer Peak Condition [Source: CAISO]

By using the established case creation assumptions and DER modeling requirements specified by the TP and PC (described in the following sub-section), the DP can provide the necessary DER data needed to represent the aggregate DER in planning cases.

Considerations for Distributed Energy Storage

Recent discussions regarding the expected growth of energy storage, particularly battery energy storage systems (BESS), relate to both BPS-connected and distribution-connected resources. Many of the recommendations regarding data collection and model verification of aggregate DERs also applies for distribution-connected BESS. This guideline covers this in more detail throughout where distinctions on distribution-connected BESS can be more informative; however, SPIDERWG has found that aggregate modeling of distributed storage relates more to case dispatch assumptions rather than building of a transmission planning model.

Time Line and Projections of DER Interconnections

The TP and PC are focused on developing planning base cases with reasonable assumptions of future BPS scenarios, including BPS generation, demand, and aggregate DERs. Accounting for the currently installed penetration of DERs helps the TP and PC understand what the existing system contains regarding DERs. This information, in most cases, should be provided by the DP to support data sharing across the transmission-distribution interface. Furthermore, the TP and PC should develop forecasts for DER growth into future years. This information may or may not be available to the DP; however, if the DP or state-level agency or regulatory body is performing DER forecasting for the purposes of distribution planning, this information may be available. In many cases, regional forecasts may be available from other data sources that could be useful for the DP, TP, and PC. If external sources (e.g., DER forecasts through state-level forecasts) are used by the DP, the DP should share that information with the TP and PC so they can incorporate those forecasts into their planning practices. Therefore, development of planning base cases uses a combination of data for existing DERs and projections of DERs.

[53] https://standards.ieee.org/standard/1547-2003.html

Visualization of DER penetration, both existing and forecasted values, can be useful to the TP for the purposes of modeling DER in steady-state power flow base cases as well as dynamic simulations. **Chapter 2** and **Chapter 3** describe why understanding and estimating the vintage and deployed settings of DERs installed can be of significant value for the purposes of DER modeling.[54]

Example of Applying DER Interconnection Time Lines

This section provides an illustrative example of applying DER interconnection times; it is intended solely as an example that could be adapted by TPs and PCs and is not intended to establish expected dates of standards implementation. **Figure I.3** shows an example system with installed DER capacity from early 2010 to the end of 2019 as illustrated by the solid blue curve. The TP and PC are in the process of developing a five-year out 2025 base case, and they have pulled in forecasted DER growth (dotted blue curve) from either the RP, DP, or other external source (e.g., state-level agency or regulator body) that projects DER out to the end of 2025.

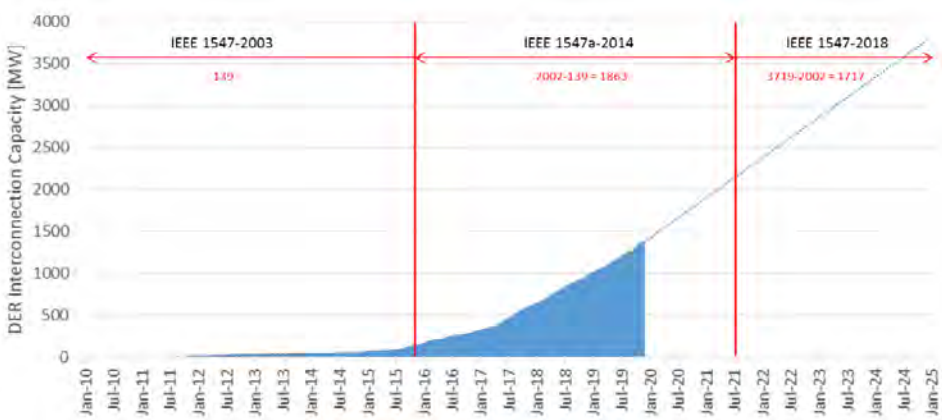

Figure I.3: Example DER Interconnection Capacity Growth

Assume all DERs connected to this example system are inverter-based and that the DERs comply with the various versions of IEEE 1547. For example, up to November 2015, due to interconnection requirements at the time, assume DERs were installed with settings compliant with IEEE 1547-2003. After November 2015 up to an assumed July 2021, assume[55] that DERs were installed with settings compliant with IEEE 1547a-2014.[56] Finally, after July 2021, assume that DERs will be installed with settings compliant with IEEE 1547-2018[57] once interconnection requirements are updated and compliant equipment becomes available. The red numbers show the amount of aggregate DER capacity that meet each standard implementation. It is clear that a small amount of resources are compliant with IEEE 1547-2003 while the remaining majority are mixed between IEEE 1547a-2014 and IEEE 1547-2018. The revised IEEE 1547-2018 includes much more robust ride-through performance and the capability for active power-frequency control on overfrequency conditions. In this example, no resources are required to maintain headroom to respond to underfrequency conditions. Interconnection requirements will presumably be updated in July 2021 to require local

[54] The Electric Power Research Institute (EPRI) is launching a public, web-based DER Performance Capability and Functional Settings Database: https://dersettings.epri.com.

[55] This is an assumption used here for illustrative purposes. However, while IEEE 1547a-2014 widened the ride-through settings, actual installed settings may not have been modified unless relevant interconnection requirements were adopted by DPs.

[56] https://standards.ieee.org/standard/1547a-2014.html

[57] https://standards.ieee.org/standard/1547-2018.html

DER voltage control capability (volt-var capability). However, application of volt-var functionality is subject to DP practices and requirement, so wide-area implementation of this functionality should not be assumed unless confirmed as an established practice by the relevant DPs.

Based on the estimation of DER vintages as well as estimated deployed settings, the TP and PC can make reasonable assumptions regarding the following modeling considerations:

- Overall capacity of DERs connected to the system
- Expected locations of DER growth, if location-specific information is available
- The percentage of DERs responding to overfrequency disturbances
- The assumption that no DERs will respond to underfrequency disturbances
- The assumed DER ride-through capability, and frequency and voltage trip settings
- The assumed DER ride-through performance in terms of active and reactive current injection
- The percentage of DERs controlling voltage (steady-state)

The ability of TPs and PCs to understand when DERs were installed will greatly improve their ability to use engineering judgment to assume modeling parameters. This is particularly important for modeling aggregate amounts of R-DERs where minimal information is available. After building a representative model for DER, a planner can, typically at a later time, verify the model against recordings from the equipment or validate the parameters with as-built information.

Difference between Event Analysis and Model Verification

While some of the same data may be used between event analysis and model verification, especially dynamic model verification, the two procedures are not necessarily the same. Event analysis is intended to comprehensively review the disturbance and to identify the root cause of the event. The data needed to execute event analysis typically includes a vast array of event logs, dynamic disturbance recordings, pre-contingency operating conditions, and other forms of documentation. The pre-contingency system operating condition and the dynamic disturbance recordings captured during these events can be used for steady-state and dynamic model verification and not just for use in event analysis. Model verification's purpose is to add fidelity to models, which this document covers. While some recorders can be used in the same process as event analysis, the processes are quite different.

Guide to Model Verification

Model verification first requires an adequate model be developed and then for an entity to gather event data to match the model performance with that information. Model verification of the models used in planning studies occurs when TPs and PCs utilize supplemental information to verify parameters in their transmission model used in their high fidelity studies. The process begins with a perturbation on the system, resulting in a visible performance characteristic from devices. Such data is stored and sent[58] to the TP/PC for use in validating their set of representative models of those devices. The process continues with the PC perturbing their model and storing the outputs.[59] Those model outputs and the measured outputs are compared and the verification procedure stops if there is a sufficient match based on the TP/PC procedures. If not, small tuning adjustments are made to verify the set of models as it relates to the measured data. It is anticipated that verification of planning models incorporating aggregate DER take more than one of these perturbations. An example of model verification can be found in Appendix E:~~Appendix B~~ that details an example that uses the playback models to verify a set of DER models. As some of the Interconnection-wide

[58] Generally, this is done by RCs, TOPs, and TOs; however, this can also be done by DPs in reference to monitoring equipment on their system
[59] Practices may change related to the software changes, which is similar to the current load model verification practices. SPIDERWG is reviewing and recommending simulation practice changes regarding to DERs in other work products.

base cases predict a future condition for resources not yet built, measurement data and forecasted conditions are not available;[60] while high fidelity conditions are expected of these cases, many of the practices contained here are not practical. In brief, it is not practical to exhaustively verify a future model's behaviors; however, it is highly important that near-term cases have verified, high fidelity models.

Three Phase versus Positive Sequence Model Verification

The majority of planning studies performed by TPs and PCs use RMS[61] fundamental frequency, positive sequence simulation tools.[62] Hence, steady-state powerflow and dynamic simulations assume[63] a balanced three-phase network that has conventionally been a reasonable assumption for BPS planning (particularly for steady-state analysis). Therefore, this guideline focuses on verification of the models used for these types of simulations. However, other simulation methods may be used by TPs and PCs based on localized reliability issues or other planning considerations. These studies, using more advanced or detailed simulation models, may require more detailed three-phase simulation methods, such as a three-phase root-mean-squared (RMS) dynamic simulation, an electromagnetic transient (EMT), or a co-simulation; these methods require more detailed modeling data and verification activities. However, DER model verification using these methods is outside the scope of this guideline as the majority of the planning studies are based on the RMS fundamental frequency and positive sequence quantities.

[60] SPIDERWG is developing separate guidance to verify aspects of these base cases.

[61] Root-mean-square

[62] This is different from three-phase simulation tools used by DPs to capture things like phase imbalance, harmonics, or other unbalanced effects on the distribution system.

[63] This assumption is inherently built into the power flow and dynamic solutions used by the simulation tools.

Chapter 1: Data Collection for DER Modeling and Verification

The data and information needed to create a steady-state and dynamic model for individual or aggregate DERs is different than the data and information used to verify those models. TOs, TPs, and PCs should work with their DPs and other applicable entities to collect information pertaining to existing DERs and to forecast future DER levels for planning studies of expected future operating conditions. In contrast, data used for DER model verification focuses more on the actual performance of aggregate or individual DERs that can used to compare against model performance. Data collection requirements and reporting procedures established by each TP and PC are expected to vary slightly based on the types of studies being performed. However, there are a common set of information needed to model DERs and common ways that data can be collected. This chapter also speaks to placement of recording devices and measurement quantities recommend to gather for model verification. This chapter first describes the data and information used for verifying the DER model(s) created.

MOD-032-1 Data Collection and DER

The purpose of NERC Reliability Standard MOD-032-1 is to "establish consistent modeling data requirements and reporting procedures for development of planning horizon cases necessary to support analysis of the reliability of the interconnected transmission system." MOD-032-1 serves as the foundation for the development of the Interconnection-wide planning base cases that are used as a starting point by TPs and PCs to perform their reliability assessment per the NERC Reliability Standard TPL-001. The requirements and overall flow of data is shown in **Figure 1.1**, specifically related to DER modeling information. The process is described briefly with the following requirements:

- Requirement R1 of MOD-032-1 requires that each PC and each of its TPs jointly develop data requirements and reporting procedures for steady-state, dynamics, and short circuit modeling data collection:
  - These requirements should include the data listed in Attachment 1 as well as any additional data deemed necessary for the purposes of modeling.
  - The data requirements should address data format,[64] level of detail, assumptions needed for the various types of planning cases or scenarios, a data submittal time line, and posting the data requirements and reporting procedures.

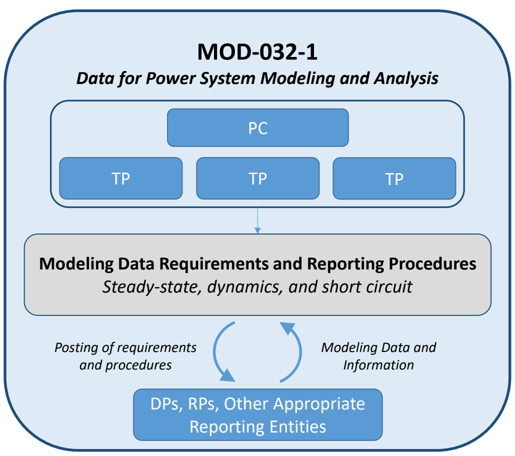

Figure 1.1: MOD-032-1 Flowchart for DER Data

[64] This generally includes any model-related formats, possible software versioning, or other relevant data submittal formatting issues. Practices for collecting data differ from each TP and PC to integrate with their planning practices.

- Requirement R2 of MOD-032-1 requires each of the applicable entities[65] to provide the modeling data to the TPs and PCs according to the requirements specified.
- Requirement R3 requires each of the applicable entities to provide either updated data or an explanation with a technical basis for maintaining the current data if a written notification is provided to them by the PC or TP with technical concerns regarding the data submitted.
- Requirement R4 requires each PC to make the models for its footprint available to the ERO or its designee[66] to support the creation of Interconnection-wide base cases.

Attachment 1 of MOD-032-1 "indicates information that is required to effectively model the interconnected transmission system for the Near-Term Transmission Planning Horizon and Long-Term Transmission Planning Horizon…A [PC] may specify additional information that includes specific information required for each item in the table below." **Figure 1.2** shows an excerpt from the MOD-032-1 Attachment 1 table.

steady-state *(Items marked with an asterisk indicate data that vary with system operating state or conditions. Those items may have different data provided for different modeling scenarios)*	**dynamics** *(If a user-written model(s) is submitted in place of a generic or library model, it must include the characteristics of the model, including block diagrams, values and names for all model parameters, and a list of all state variables)*	**short circuit**
1. Each bus [TO] a. nominal voltage b. area, zone and owner 2. Aggregate Demand[2] [LSE] a. real and reactive power* b. in-service status* 3. Generating Units[3] [GO, RP (for future planned resources only)] a. real power capabilities - gross maximum and minimum values b. reactive power capabilities - maximum and minimum values at	1. Generator [GO, RP (for future planned resources only)] 2. Excitation System [GO, RP(for future planned resources only)] 3. Governor [GO, RP(for future planned resources only)] 4. Power System Stabilizer [GO, RP(for future planned resources only)] 5. Demand [LSE]	1. Provide for all applicable elements in column "steady-state" [GO, RP, TO] a. Positive Sequence Data b. Negative Sequence Data c. Zero Sequence Data 2. Mutual Line Impedance Data [TO] 3. Other information requested by the Planning Coordinator or Transmission Planner necessary for modeling

Figure 1.2: Excerpt of MOD-032-1 Attachment 1 Table

> **Key Takeaway:**
> TPs and PCs should update their data reporting requirements required under Requirement R1 of MOD-032-1 to include specific requirements for aggregate DER data from the appropriate entities who have access to this data.

Currently, the table in Attachment 1 does not provide a line item for aggregate DER data. Rather, the table includes a statement[67] in each of the columns that states "other information requested by the [PC] or [TP] necessary for modeling purposes" should be collected. This item should be used by the TPs and PCs as technical justification for collecting aggregate DER data necessary for modeling purposes as an interim solution until revisions to MOD-032-1 can occur. DPs should work with their respective TPs and PCs to understand expectations for gathering available DER data and making reasonable assumptions

[65] Including each Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, TO, and Transmission Service Provider. Note that, at the time of writing this guideline, the Load Serving Entity has been deregistered, and SPIDERWG recommends that DPs are the best suited to provide DER information to TPs and PCs for modelling purposes. Therefore, DP is used as the applicable entity throughout this document. Project 2022-02 is currently altering MOD-032-1 to adjust Attachment 1. Among which is the transfer of the Load Serving Entity to Distribution Provider for Item #2. These proposed edits are currently not approved and as such are not reflected in this document. See Project 2022-02 webpage for latest documents here: https://www.nerc.com/pa/Stand/Pages/Project2022-02ModificationstoTPL-001-5-1andMOD-032-1.aspx

[66] In each Interconnection of the NERC footprint, a "MOD-032 Designee" has been designated to create the Interconnection-wide base cases. Each designee has a signed agreement with NERC to develop base cases of sufficient data quality, fidelity, and time lines for industry to perform its planning assessments.

[67] Refer to items #9 and #10 in the steady-state and dynamics columns in NERC MOD-032-1, respectively.

for any data that may not be available. TPs and PCs should also develop necessary processes for aggregating DER data and performing some degree of verification of the data received.[68]
Regardless of the elements explicitly defined in MOD-032-1 Attachment 1, each TP and PC should jointly develop data requirements and reporting procedures for the purpose of developing the Interconnection-wide base cases used for transmission planning assessments. These requirements are often very detailed and specific to each PC and TP planning practices, tools, and study techniques. Therefore, TPs and PCs should update their data reporting requirements for Requirement R1 of MOD-032-1 to explicitly describe the requirements for aggregate DER data in a manner that is clear and consistent with their modeling practices. Coordination with their DPs in developing these requirements should result in the most effective outcome for gathering DER information for modeling.[69] **Chapter 2** provides a foundation and starting point for establishing the specific information that should be gathered for modeling purposes in coordination with the DP.

Data Collection and the Distribution Provider

Key Takeaway:
The "source" of the DER data may come from other entities than a DP, such as a DER developer. It is intended that clear coordination between DPs, TPs, and PCs highlight the needs required to collect the data from the "source."

DPs are the most suitable entity[70] to provide data and information pertaining to DERs within their footprint since DPs conduct their interconnection processes for resources that interconnect to their system and may have access to the measurements necessary to perform DER model verification. Applicable entities that may govern DER interconnection requirements (e.g., states) are encouraged to ensure DPs are capable of collecting data for model verification purposes as unverified models have an impact on BPS studies. This impact compounds on itself as the DER penetration in a local area grows; however, access to measurements for verifying model performance alleviates those study impacts. Sometimes the actual "source" of the data is a DER developer[71] or other distribution entity that is not a functional NERC entity. TPs, PCs, and TOs are encouraged to coordinate with DPs and respective DER developers, generators, owners, or other distribution entities related to DERs in order to develop a mutual understanding of the types of data needed for the purposes of DER modeling and model verification. Coordination between these entities can also help develop processes and procedures for transmitting the necessary data in an effective manner.

DPs, TPs, PCs, and TOs should understand the types of data needed to verify DER models and to provide recommended practices for gathering this data and applying it for verification purposes. It is intended that the best "source" of this data will become apparent with clear coordination on the needs for the data. DER model verification starts with applicable entities having suitable DER modeling data available to make reasonable engineering judgments regarding how to model the aggregate behavior of DERs. There is no one-size-fits-all method to this effort; entities should coordinate with each other to develop solutions most applicable for their specific systems and situations. However, common modeling practices and similar data needs will exist and are discussed in this chapter in more detail.

[68] NERC SPIDERWG is working on a separate reliability guideline to support industry in performing verification of DER data and creating DER models.
[69] EPRI (2019): *Transmission and Distribution Operations and Planning Coordination*. TSO/DSO and Tx/Dx Planning Interaction, Processes, and Data Exchange. 3002016712. Electric Power Research Institute (EPRI). Palo Alto, CA: https://www.epri.com/#/pages/product/000000003002016712/.
[70] There are instances where a DP registration does not exist on the other side of the T-D Interface. In these settings, there is no NERC standard requirement to obligate the distribution planner or provider for data. However, the distribution planner or provider, regardless of NERC registration status, is the most suited entity to provide information due to their ability to set interconnection requirements on their system. It falls then to the TO in order to initiate and gather the DER information in a collaborative process among these unregistered entities using best available practices.
[71] A DER developer is an entity that procures, sites, installs, and manages the construction of a DER.

Monitoring Requirements in IEEE 1547

The IEEE 1547 standard represents a series of standards that provide requirements, recommended practices, and guidance for addressing standardized DER interconnections. IEEE 1547 was first published in 2003 and later updated in 2018 to address the proliferation of DER interconnections. Both IEEE 1547-2003[72] and IEEE 1547-2018[73] standards are technology neutral. The monitoring requirements for both standards are presented here:

- **IEEE 1547-2003:** The IEEE 1547-2003 standard is applicable for DER installations installed prior to the full adoption and implementation of IEEE 1547-2018,[74] including provisions for DERs with a single unit above 250 kVA or aggregated more than 250 kVA at a single point of common coupling to have monitoring for active power, reactive power, and voltage. However, the standard did not specify any requirements for sampling rate, communications interface, duration, or any other critical elements of gathering this information. Further, DER monitoring under this requirement was typically through mutual agreement between the DER owner and the distribution system operator. Therefore, it is expected that data and information for these legacy DERs is likely very limited (at least from the DER itself); this may pose challenges in the future for DER model verification and BPS operations.
- **IEEE 1547-2018:** The IEEE 1547-2018 standard places a higher emphasis on monitoring requirements and states that "the DER shall be capable of providing monitoring information through a local DER communication interface at the reference point of applicability… The information shall be the latest value that has been measured within the required response time." Active power, reactive power, voltage, current, and frequency are the minimum requirement for analog measurements. The standard also specifies monitoring parameters, such as maximum response time and the DER communications interface. Therefore, larger U-DER installations will have the capability to capture this information and DPs are encouraged to establish interconnection requirements that make this data available to the DP that will be applicable to distribution and BPS planning and operations.

Information and data can be collected for the purposes of DER model verification from locations other than at the DER point of common coupling, assuming that the needed portions of the distribution system are represented within the transmission system model. This is particularly true for capturing the behavior of aggregate amounts of R-DERs. However, particularly for larger U-DER installations, this type of information can be extremely valuable for model verification purposes.

Recording Device Considerations

This section specifies considerations for applicable entities that may govern DER interconnection requirements regarding recording devices. In addition to the information that the IEEE 1547-2018 standard requires to monitor, event-driven capture of high-resolution voltage and current waveforms are useful for DER dynamic model verification. These allow the key responses of fault ride-through, instability, tripping, and restart to be verified. It is recommended that the built-in monitoring capabilities of smart inverter controllers or modern revenue meters are fully explored by relevant entities since they may provide similar data as a standalone monitor. These meters may also be able to monitor power quality indices.

Key Takeaway:
Recording capabilities will vary on IEEE 1547-2003 and IEEE 1547-2018 compliant DERs. It is critical to understand these capabilities when considering additional recording devices.

[72] https://standards.ieee.org/standard/1547-2003.html
[73] https://standards.ieee.org/standard/1547-2018.html
[74] It is expected that DERs compliant with IEEE 1547-2018 will become widely available around the 2021 time frame based on the progress and approval of IEEE 1547.1: http://grouper.ieee.org/groups/scc21/1547.1/1547.1_index.html

Entities may receive nominal nameplate information for the resource, but factors like the resource's age and weather conditions will influence the actual output characteristics. Recording devices should be capable of collecting, archiving, and managing disturbance fault information and normal operation conditions identified by protection equipment (e.g., relays) and significant changes observed during normal operating conditions (e.g., phasor measurement unit (PMU) reading).

An example of a recording device is a power quality meter (PQ meters), a type of measurement device used in a multitude of applications, including compliance, customer complaint troubleshooting, and incipient fault detection. These devices are programmable to record voltage and current waveforms during steady-state conditions and during system events. These types of measurement devices record both RMS and sinusoidal waveforms at many different sample rates and are International Electrotechnical Commission code compliant on their RMS and sinusoidal samplings. These types of meters are viable when capturing aggregate DER performance on the BPS depending on the placement of the device and can function as a standalone meter or as part of a revenue meter. TPs and PCs should collaborate with applicable entities that may govern DER interconnection requirements and the DP regarding recording devices so that these recording devices accomplish each entity's objectives. Entities are encouraged to begin with selecting PQ Meters to start this collaboration and to determine the full equipment needed for steady-state or transient dynamic data capture. The improved model quality and fidelity will benefit all the stakeholders.

Placement of Measurement Devices

Selecting measurement locations for DER steady-state and dynamic model verification depends on whether TPs and PCs are verifying U-DER models, R-DER models, or a combination of both. TPs, PCs, and DPs should consider the following recommendations when selecting suitable measurements for DER model verification:

- **R-DER:** An R-DER model is an aggregate representation of many individual DERs. Therefore, the aggregate response of DERs can be used for R-DER model verification. This is suitably captured by taking measurements of steady-state active power, reactive power, and voltage at T–D interface.[75] This may be acquired by measurements at the distribution substation for each T–D transformer bank or along a different distribution connected location.[76]
- **U-DER:** U-DER models represent a single or group of DERs, so the measurements needed to verify this dynamic model must be placed at a location where the response of the U-DERs or group of DERs can be differentiated from other DERs and load response. For U-DERs connecting directly to the distribution substation (even through a dedicated feeder), the measurements for active power, reactive power, and voltage can be placed either at the facility or at the distribution substation. For verifying groups of DERs with similar performance, measurements capturing one of these facilities may be extrapolated for verification purposes with engineering judgment. Applicable entities that may govern DER interconnection requirements should consider establishing capacity thresholds (e.g., 250 kVA in 1547-2003) in which U-DERs should have monitoring equipment at their point of connection[77] to the DP's distribution system.

Key Takeaway:
Measurement locations of DER performance depend on the type of DER model (U-DERs vs. R-DERs) being verified. Aggregate R-DER response can be captured at the T–D interface whereas explicit model verification of U-DER models may require data at specific larger DER installations.

[75] Note that such a measurement, expectedly, could include the combined response from the load and the DER; however, this will not undermine the accuracy of the model verification since the model framework also includes both load and resource components as described in the DER model framework sections.
[76] While uncommon, measurement data along a distribution feeder can replace data at a T–D interface. Entities are encouraged to pursue the location that is easiest to accommodate the needs of all entities involved.
[77] This point is chosen to provide information on the plant's response. It is anticipated that this will measure the flows across the transformer that connects the DER facility to the DP's system.

- **Combined R-DER and U-DER:** Situations where both U-DER and R-DER exist at the distribution system may be quite common in the future. Where possible, the response of U-DERs (based on DER modeling practices) should be separated from the response of R-DERs and end-use loads. Measurement locations at the T–D interface are recommended in all cases, and additional measurements for capturing and differentiating U-DERs may also be warranted.

As described, the DER type and how it is modeled will dictate the placement of measurement devices for verifying DER models. Figure 1.3~~Figure 1.1~~ illustrates the concepts described above regarding placement of measurement locations for capturing the response of R-DERs, U-DERs, or both. In the current composite load model framework, specific feeder parameters are automatically calculated at initialization to ensure voltage at the terminal end of the composite load model stays within American National Standards Institute (ANSI) acceptable continuous service voltage. These parameters represent the aggregated impact of individual feeders, as indicated by the dashed box in Figure 1.3~~Figure 1.1~~. Each of the highlighted points in Figure 1.3~~Figure 1.1~~ pose a different electrical connection that this guideline calls out. At a minimum, placement at the high or low side of the transformer provides enough information for both steady-state and dynamic model verification. For U-DERs, it is suggested that monitoring devices are placed at their terminal as shown in Figure 1.3~~Figure 1.1~~. While other locations are highlighted, they are not necessary for performing model verification when the two aforementioned locations are available; however, they may be able to replace or supplement the data and have value when performing model verification.

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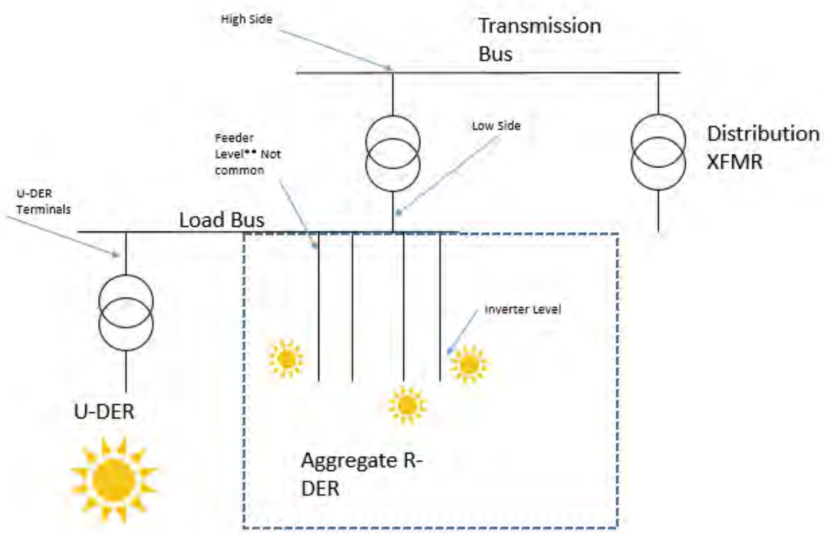

Figure 1.3: Illustration of Measurement Locations for DER Model Verification

Measurement Quantities used for DER Model Verification

Measurement devices used for DER steady-state model verification for both U-DERs and R-DERs should be capable of collecting the following bolded data at their nominal frequency, and should make available, if possible, the non-bolded data:

- **Steady state RMS voltage (Vrms)**
- **Active power (W)**

- **Steady state RMS current (Irms)**
- Reactive power (Vars)

Measurement devices used for DER dynamic model verification for both U-DERs and R-DERs should be capable of collecting the following bolded data, and should make available, if possible, the non-bolded data:

- **RMS[78] voltage and current (Vrms, Irms)**
- **Frequency (Hz)**
- **Active power (W)**
- **Reactive power (Vars)**
- Harmonics[79]
- Protection Element Status
- Inverter Fault Code[80]

In addition to the measurements described above, DER monitoring equipment systems[81] should be able to calculate or report the following quantities:

- Power factor
- Apparent power (magnitude and angle)
- Positive, negative, and zero sequence voltages and currents
- Instantaneous voltage and current waveforms as seen by the measurement device

Table 1.1 provides useful locations a summary between the steady-state and dynamic recording devices. Each of the measurements above is categorized in **Table 1.1** as necessary, preferred, or helpful to assist in device selection. For dynamic data capture, digital fault recorders (DFRs) and distribution PMUs are two high-resolution devices that are useful in capturing transient events, but they are not the only devices available to record these quantities. In some instances, already installed revenue meters may provide this RMS information.[82]

Table 1.1: Recording Device Summary

Topic	Steady-State	Dynamic
R-DER		

[78] References to RMS here are fundamental frequency RMS.
[79] These measurements should collect the Total Harmonic Distortion (THD) and Total Demand Distortion (TDD) at the T–D interface. These levels should be consistent with IEEE standards (e.g., IEEE std. 519) and such standards refer to the upper harmonic boundary for measurement.
[80] Inverter fault code for individual R-DER is not practical to obtain in comparison to other recommendations to improve model quality. However, the aggregate or most prominent fault code for DER (both R-DER and U-DER) is beneficial when performing wide area system validation after large disturbances. It may be more practical to infer the Inverter Fault Code of modeled R-DER from the U-DER nearby, if the Inverter Fault Code is available.
[81] This does not mean that every measuring device must calculate the quantities listed; however, the system used to collect, store, and transmit the measurements should perform the calculations. These calculations can be done on the sending, receiving, or archival end of the monitoring equipment system.
[82] These devices can also offer different measurement quantities as well. See Chapter 6 of NERC's Reliability Guideline on BPS connected inverter devices here. While DERs are different in treatment of performance, the measurement devices discussed there can be used on the high side of the T–D transformer for similar data recording

Table 1.1: Recording Device Summary		
Topic	**Steady-State**	**Dynamic**
Useful Location(s) of Recording Devices	High-side or low-side of T–D transformer(s); individual distribution circuits[83] (see **Figure 1.1**)	
Examples of Recording Devices	Resource side (SCADA) or demand side (Advanced Metering Infrastructure (AMI)) devices.	DFR, distribution PMU, or other dynamic recording devices.
Minimum Set of Measurements	Active Power, Reactive Power	Frequency, RMS Voltage, Active Power, Reactive Power
Additional Preferred Measurements	RMS Voltage	RMS Current
Measurements Helpful if Available	Frequency, Apparent Power, Steady-State Current	Harmonics, Protection Element Status, Inverter Fault Code
U-DER		
Useful Location(s) of Recording Devices	Point of interconnection of U-DERs; distribution substation feeder to U-DER location; aggregation point of multiple U-DER locations if applicable (see **Figure 1.1**)	
Examples of Recording Devices	DP SCADA or AMI; DER owner SCADA	DFR, distribution PMU, modern digital relay, or other dynamic recording devices[84]
Minimum Set of Measurements	Active Power, Reactive Power	Frequency, RMS Voltage, Active Power, Reactive Power
Additional Preferred Measurements	RMS Voltage	RMS Currents
Measurements Helpful if Available	Frequency, Apparent Power, Steady-State Current	Protection Element Status, Harmonics, Disturbance Characteristics,[85] Sinusoidal Voltage and Currents, Inverter Fault Codes.

[83] individual distribution circuit data is not necessary but can be useful either in addition to or in replacement of T-D transformer data

[84] For wide-area model validation, the outputs from these devices should be time synchronized, such as by GPS.

[85] This can be a log record from a U-DER characteristic or a record of how certain types of inverters reacted to the BPS fault. This is different from event codes that are applied from the BPS perspective and the inclusion of this information can assist with both root cause analysis as well as verification of aggregate DER settings.

In regards to protection quantities, the identified U-DER protection device informational flags, coupled with an inverter log from a large U-DER device, helps in determining what protective function impacted the T–D interface and to verify that such performance is similar in the TP's set of models. This type of information becomes more important to understand as penetration of large DER increases in a local area, especially if such protection functions begin to impact the T–D interface.

Management of Large Quantities of DER Information

Management of the increasing diversity of DER functional settings from the various inverter vendors can become a challenge. Even once DPs, RCs, and TPs successfully coordinated DER functional settings, the reliable application of these settings to DERs in the field may not be ensured. Many DER manufacturers currently use "manufacturer-automated profiles" that preset certain functional parameters to the values specified in applicable rules (i.e., CA Rule 21, HI Rule 14H, or the default values of a certain IEEE 1547-2018 performance category). To date, these "manufacturer-automated profiles" are not validated by any third party, and verification by utility engineers is often limited to the review of a photo taken by a DER installer of the selected manufacturer-automated profile on the DER's general user interface at the time of commissioning. Given the criticality of DER trip and other settings for the BPS, more sophisticated verification methods are desired.

One solution is a "common file format" for DER functional settings that has been developed through a broad stakeholder effort by organizations like EPRI, IEEE, IREC, and SunSpec Alliance and is now available for the public.[86] This effort defines a CSV file format that contains DER settings by specifying unique labels, units, data types, and possible values of standard parameters, leveraging the IEEE 1547.1-2020 standard's "results reporting" format. The report enumerates the rules to create such CSV files that will be used to exchange and store DER settings. Potential use cases of such common file format include the following:

- How utilities provide required settings (utility required profile, URP) to the marketplace
- How developers take, map, and apply specified settings into the DER
- How DER developers provide the required proof of applied settings for new plants as part of the interconnection process
- How utilities internally store and apply their system wide records of DER settings for planning and operational purposes, including exchange of DER voltage and frequency trip settings as well as settings for DER frequency-droop across between DPs and TPs

One way to exchange these common DER settings files could be a central database (e.g., one hosted by EPRI). Authorized users can upload settings files, and all other users can download settings files to help exchange information among all applicable entities.[87] This central storage is recommended to reduce the information management and storage for verifying the DER models in bulk system studies.

[86] EPRI (2020): Common File Format for Distributed Energy Resources Settings Exchange and Storage. 3002020201. With assistance of Interstate Renewable Energy Council (IREC), SunSpec Alliance (SunSpec), Institute Electrical and Electronic Engineers (IEEE). Electric Power Research Institute (EPRI). Palo Alto, CA. Available online at https://www.epri.com/research/products/000000003002020201.

[87] EPRI has launched a public, web-based DER Performance Capability and Functional Settings Database in 2020: https://dersettings.epri.com

Chapter 2: DER Steady-State Data Collection and Model Verification

This chapter describes the recommended data reporting requirements for collecting sufficient data to model aggregate DERs in Interconnection-wide power flow base cases. Each PC, in coordination with their TPs, should consider integrating these recommendations into their requirements per MOD-032-1 Requirement R1. After collecting the data for steady-state model verification for aggregate DERs, the first set of models to verify is generally this steady-state DER model. Due to how it feeds into many different studies and that it is the starting point for dynamic studies, it will generally be the first stage of verifying the DER model.

DER Modeling Needs for TPs and PCs

Modeling data requirements for steady-state aggregate DER data should be explicitly defined in the modeling data requirements established by each PC and TP per MOD-032-1. This section describes the recommended data and modeling practices ~~necessary~~ for consistently representing the aggregate DERs in steady-state power flow base cases. TPs and PCs generally model gross load and aggregate DERs at specific BPS buses or at distribution buses at the low-side of the T-D transformers depending on their modeling practices. To accomplish modeling aggregate DER at the distribution bus, TPs and PCs need T-D transformer modeling data for explicit representation in the power flow model and can then assign the gross load and aggregate DERs connected to the low-side bus accordingly. The TP and PC should establish DER data collection requirements for aggregate DER data at each T-D transformer so this can be modeled correctly.[88] DPs should have some accounting of DERs at the bus-level or T-D transformer level in coordination with TP and PC data reporting needs. The DP may need to use engineering judgment to support the TP and PC in gathering the necessary data needed for suitable developing models.

DER models in the steady-state power flow base case, whether represented as a generator record or as a component of the load record, have specific data points that must be accurately populated in order to represent aggregate DERs.[89] These data points, on a bus-level or T-D transformer level, may include the following:

- Location, both electrical and geographic
- Type of DER (or aggregate type)[90]
- Historical or expected DER output profiles[91]
- Status
- Maximum and minimum DER active power capacity (Pmax[92] and Pmin)
- Maximum and minimum DER reactive power capability (Qmax, producing vars; Qmin, consuming VARs); alternatively, a reactive power capability curve for the overall U-DER facility (this is specific to U-DERs)

[88] Modeling on a T-D transformer basis is the most common approach for DER modeling where the T-D transformer is explicitly modeled and the aggregate load and aggregate DERs from the connected distribution feeders are represented. However, some TPs and PCs may have different modeling practices (e.g., by feeder-level basis), and therefore their requirements for data collection of DER may be slightly different.

[89] Since the BPS models use aggregate or equivalent representations of the distribution system and DERs, these models are not expected to accurately represent the steady-state reactive capability of a DER at the T-D interface. The models provide a reasonable representation of aggregate equipment capability that may have some effect on BPS performance during contingency events. Modeling of this capability is important for contingency analysis and dynamic simulations.

[90] This may be defined as part of the generator name, generator ID, or load record ID, and may be useful as the DER penetration continues to increase and different types of DER may need to be tracked.

[91] If meter-level data is available, profiles of DER output help TPs and PCs understand how the DER should be dispatched in the power flow base case. This is essential for developing reasonable base cases that represent expected operating conditions of the BPS, including the operation of aggregate DERs. If metering data is not available in the area, default profiles are helpful for TP and PC base case creation.

[92] The preferred approach for variable (inverter-based) DERs is for the DP to provide total aggregate DER capacity and the TP and PC can set active power output (Pgen) of the DER in the power flow to an output level based on assumptions specified for each case. For large synchronous DERs, similar data collection requirements for steady-state modeling data can be used as would be used for BPS-connected resources.

- Distribution system equivalent feeder impedance[93]
- (U-DER) Reactive power-voltage control operating mode[94]

If one or more DERs are represented as a stand-alone generator record in the power flow, the TP and PC may need the following specific information to accurately represent this element (based on their specific modeling practices):

- Facility step-up transformer impedances
- Equivalent feeder or generator tie line[95] impedance (for large U-DER facilities) if applicable
- Facility or transmission-distribution transformer tap changer statuses and settings where applicable
- Shunt compensation within the facility[96]

The majority of newly interconnecting DERs across North America are either utility-scale solar PV (i.e., U-DERs) or rooftop solar PV (i.e., R-DERs) facilities. To reasonably represent these resources in the base case, the TP and PC may request that the DP or applicable DER Aggregator[97] to provide a reasonable estimate or differentiation between U-DERs and R-DERs. This may simply be a percentage value of the estimate of U-DERs versus R-DERs and possibly the number and size of U-DERs. While individual accounting of R-DERs is very unlikely and inefficient, typically the accounting of U-DERs is much more straightforward since these resources are typically relatively large (e.g., 0.5 to 20 MW).[98]

On the other hand, DERs other than solar PV should be noted by the DP since these resources (e.g., battery energy storage, wind, small synchronous generation, combined heat and power facilities) may have different operational characteristics. For example, these resources may operate at different hours of the day, which would change the dispatch pattern when studying different hourly system conditions. DPs should have the capability to account for these different types of DERs to aid in the development of the base case models for the TP and PC; engineering judgment may be needed to estimate the expected operational characteristics and performance of the different DER technologies, particularly for forecasted DER levels.

Mapping TP and PC Modeling Needs to DER Data Collection Requests

The information described above defines the necessary information that will be needed by TPs and PCs to model aggregate DERs as either U-DERs or R-DERs. However, this information will likely not need to be provided or collected by the TP and PC for each individual DER; rather, these entities will need a reasonable understanding of the aggregate DER information. This section provides a mapping between the TP and PC needs and the information that should be requested from DPs by TPs and PCs as part of MOD-032. **Table 2.1** shows how the DER modeling needs are mapped to data requests. Also, refer to **Appendix B:**~~Appendix B~~ for considerations for distributed energy storage systems.

Example of DER Information Mapping for Steady-State Power Flow Modeling

To apply the concepts described in **Table 2.1**, consider an example where aggregate DER data is being provided by the DP (possibly in coordination with external parties, such as a state regulatory body or other entity performing

[93] This is useful for modeling both DER and load if there is a need to explicitly represent the recommended modeling framework in the simulation opposed to the automatic tuning of this parameter by the composite load model.

[94] TPs and PCs should consider local DER interconnection requirements regarding power factor and reactive power-voltage control operating modes, where applicable. These modes may include operation at a set power factor (e.g., unity power factor or some of static power factor level) or operation in automatic voltage control. TPs and PCs can configure the power flow models by adjusting Qmax, Qmin, and the mode of operation to appropriately model aggregate DERs.

[95] In some cases, for generator tie line modeling, the MVA rating and length may be needed by the TP and PC.

[96] This is based on DER modeling practices established by the TP and PC.

[97] DER Aggregators were introduced in FERC Oder 2222 as an entity that can aggregate control over multiple resources, including DER and Demand Response. Order text available here: https://www.ferc.gov/sites/default/files/2020-09/E-1_0.pdf

[98] These values are used as a guideline in the DER modeling framework; however, they can be adapted based on specific modeling needs.

state-level DER forecasts) to the TP and PC. Following the structure of **Table 2.1**, the TP and PC would receive useful data for steady-state power flow modeling:

- 50 MW total aggregate DERs are allocated to T-D Interface[99] (per TP and PC modeling requirements)
- 35 MW are considered U-DERs and 15 MW are considered R-DERs (based on TP and PC modeling practices)
- Of the U-DERs, 20 MW are solar PV and 15 MW are BESS (i.e., ± 15 MW)
- Of the R-DERs, all 15 MW are solar PV
- About 75% of DER are likely IEEE 1547-2003 vintage and the remaining are most likely compliant with newer vintages of IEEE 1547 based on updated DP interconnection requirements
- Of all DERs, only 10 MW of the BESS U-DERs are electrically close to the feeder head and the remainder are interspersed with load.
- All DER operates at unity power factor

Table 2.1: Steady-State Power Flow Modeling Data Collection

Aggregate DER Modeling Information Needed[100]	Information Necessary for Suitable Modeling of Aggregate DERs
Location	The DER interconnection location will need to be assigned to a specific T-D transformer or associated BPS or distribution bus based on the TP and PC modeling practices. Further specifying the colocation of DER to load also determines if the DER should be modeled closer to the head of the feeder or interspersed with load at the modeled load bus. Geographic location should also be given so that proper DER (e.g., solar) profiles and estimated impedance can be applied.
Type of DER (or aggregate type)	Specify the percentage of DERs considered U-DER and R-DER.[101] Provide an aggregate breakdown (percentage) of the types of DERs per T-D transformer. Preferably, this is specified as a percentage of aggregate DERs that are solar PV, synchronous generation, energy storage, hybrid[102] power plants, and any other types of DERs.
Historical or expected DER output profiles	For each type of aggregate DER (e.g., solar PV, combined heat and power, energy storage, etc.), specify a general historical DER output profile occurring during the studied conditions. What output are these resources dispatched to during peak and off-peak conditions? The TP and PC should define peak and off-peak conditions.
Status	Based on the DER output profile provided, TPs and PCs will know whether to set the aggregate DER model to in-service or out-of-service based on assumed normal operating conditions for the case.
Maximum DER active power capacity (Pmax)	Maximum active power capacity of aggregate DERs should be provided to the TP and PC. This, again, should be aggregated to the T-D transformer (i.e., each T-D transformer should generally have an amount of aggregated U-DER and R-DER, as necessary), depending on the TP and PC requirements.

[99] A T-D Interface is a fictitious point where the transmission system ends and the distribution system ends, demarcated by one or multiple transformers at the distribution substation.
[100] The granularity of information submitted to the TP and PC by the DP should be defined in the data reporting requirements established by the TP and PC. This is most commonly on a T-D transformer basis.
[101] Consult with your TP and PC for more information on specific modeling requirements for U-DERs and R-DERs. Refer to NERC reliability guidelines: https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability_Guideline_DER_A_Parameterization.pdf.
[102] Hybrid plants combine generation and energy storage and have different operational characteristics than either individual type of DERs.

Table 2.1: Steady-State Power Flow Modeling Data Collection	
Aggregate DER Modeling Information Needed[100]	**Information Necessary for Suitable Modeling of Aggregate DERs**
Minimum DER active power capacity (Pmin)	Minimum active power capacity of aggregate DERs should also be provided, similar to maximum capacity. Systems with energy storage may have a Pmin value for aggregate DER modeling less than zero since the storage resources may be able to charge when generation DERs are at 0 MW output.
Reactive power-voltage control operating mode	Are the DERs controlling local voltage? Or are they set to operate at a fixed power factor? If some are operating in one mode while others are operating in a different mode, estimate the percentage in each mode using engineering judgment based on time of interconnection.
Maximum DER reactive power capability (Qmax and Qmin)[103]	If DERs are controlling voltage (i.e., volt-var control), some aggregate reactive capability may need to be modeled. Otherwise, information pertaining to the expected power factor for DERs should be provided so that Qmax and Qmin can be configured in the model. For some U-DERs, a capability curve of reactive capability at different active power levels may be needed (at least at Pmax and Pmin levels).[104] Reactive devices required at the distribution bus to assist with voltage regulation and not otherwise aggregated in the DER model may also need to be represented.

Steady-State DER Data Characteristics

As **Table 1.1** summarizes the measurement quantities necessary , preferred, and helpful if available, entities that are placing recording devices will need to decide upon the sample rate and other settings prior to installing the device. **Table 1.2** summarizes the many aspects related to utilizing steady-state data for use in model verification. As the steady-state initial conditions feed into dynamic transient simulations, the steady-state verification process feeds into the dynamic parameter verification process. With the focus on BPS events, the pre-contingency operating condition and the dynamic disturbance recordings captured during these events can be used for steady-state and dynamic model verification. This is a unique process different from steady-state verification of seasonal cases in the base case development process. The considerations in **Table 1.2** can be applied to both seasonal case verification as well as pre-contingency operating condition verification. Additionally, for steady-state verification, it is important to gather what mode other types of devices, such as Automatic Voltage Regulators, are in as they impact the voltage response.

Table 1.2: Steady State DER Model Verification Data Considerations	
Topic	**Key Considerations**
Resolution	High sample rate data is not needed for steady-state model verification. For example, one sample every 10 minutes can be sufficient.[105] SCADA data streams come in at typically 2–4 seconds per sample; however, these speeds are not always realizable.

[103] Qmax refers to producing vars, and Qmin refers to consuming vars.

[104] If this information is not known, the vintage of IEEE 1547-2018 standard could be useful to apply engineering judgment to develop a conservative capability curve.

[105] The resolution needs to be able to reasonably capture large variations in power output over the measurement period.

Table 1.2: Steady State DER Model Verification Data Considerations	
Topic	**Key Considerations**
Duration	Generally, a handful of instantaneous samples over a day will verify the dispatch of the DER and load for each Interconnection-wide base case. Durations nearing days or weeks of specific samples may be needed to verify DER control schemes, such as power factor operation, load following schemes, or other site-specific parameters. For these, TPs and PCs are encouraged to find an appropriate duration of data depending on their needs for verification of their steady-state models.
Accuracy	At low sample rate, accuracy is typically not an issue. Data should be high accuracy regardless, however.
Time Synchronization	Time synchronization of measurement data may be needed when comparing data from different sources across a distribution system or even across feeder measurements taken with different devices at the same distribution substation. Many measurement devices have the capability for time synchronization, and this likely will become increasingly available at the transmission-distribution substations. In cases where time synchronization is needed, the timing clock at each measurement should be synchronized with a common time reference (e.g., global positioning system)[106] to align measurements from across the system.
Aggregation	Based on the modeling practices for U-DERs and R-DERs established by the TP and PC,[107] it may be necessary to differentiate DERs for the purposes of accounting in the power flow model. This includes separating out the MW values for U-DERs and R-DERs and having sufficient measurement data to capture each type in aggregate. Based on modeling practices by the TP and PC, this same process can be used to separate “fuel types” of the DER; for instance, separating out battery DERs from solar photovoltaic (PV) DERs if desired.[108]
Dispatch Patterns and Data Sampling	Different types of DERs are often driven by external factors that will dictate when these resources are producing electric power. For example solar PV DERs provide energy during times of solar irradiance, wind resources provide output during times of increased wind, and BESS may inject or consume energy based on market signals or other factors. In general, these recommendations can apply to sampling measurements for these resources: • Solar PV: Capture sufficient data to understand dispatch patterns during light load daytime and peak load daytime operations; nighttime hours can be disregarded since solar PV is not producing energy during this time. • Wind: Capture output patterns during coincident times of high solar PV output (if applicable) as well as high average wind speeds. • BESS: BESS should be sampled during times when the resource is injecting in addition to when the resource is consuming power.

[106] https://www.gps.gov/
[107] https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability_Guideline_DER_A_Parameterization.pdf
[108] SPIDERWG has published a white paper specifically on BESS modeling available here: [Link when available]

Table 1.2: Steady State DER Model Verification Data Considerations	
Topic	**Key Considerations**
Post-Processing	Depending on where the measurement is taken, some post-processing will need to be done to determine if the DER is connected to point on transmission that is not the normal delivery point. These same mappings apply to the dynamic model verification process. In terms of data set completeness, data dropouts or other gaps in data collection should be eliminated by using hole filling or other interpolation techniques. A different set of data that does not have significant data gaps could alternatively be used.
Data Format	Microsoft Excel and other delimited data formats are most common for sending or receiving steady-state measurement data. Other forms may exist but are generally also delimited file formats.

Verifying the operation mode for DERs may require coordination with distribution entities, and it is best to work with the applicable entities that may govern DER interconnection requirements and the DP to determine the best placements of devices purposed for model verification. It is beneficial to include steady-state current and voltage waveforms to determine the operation mode, especially for inverter-based DERs.

Steady-State DER Model Verification

Steady state verification procedures can use lower time resolution data nor does the data require a tie to a particular event. An entity in SPIDERWG provided an example of performing steady-state verification outside of an event on their system; when conducting short circuit studies, an entity found that an aggregation of DERs was incorrectly modeled. In this scenario, the aggregation in question were DERs modeled as an aggregation of R-DERs. The R-DER aggregation was modeled on the nearest BPS bus at the incorrect voltage level. This was affecting the powerflow solution at the modeled BPS transformer and cause increased LTC activity in the powerflow model. The entity solved the issue in their studies by verifying the location of the resource and the connection voltage as well as analyzing the BPS bus path to get the appropriate impedances between the R-DERs and the BPS transformer. SPIDERWG recommends entities proactively verify their steady-state DER model based on steady-state conditions that are not related directly to an event.[109]

The TP should systematically verify their models as data is made available.[110] This is to ensure their set of models is of high fidelity for their study's conditions. Important scenario conditions to verify include the following:[111]

- DER output at a (gross or net) peak demand condition
- DER output at some off-peak demand condition
- When the percentage of DERs is significantly high[112]

At each of these scenarios, measuring the active and reactive power will help verify the steady-state parameters entered into the DER records. Voltage measurements will also help inform how the devices operate based on the inverter control logic, voltage control set points, and how these aggregate to the T–D interface. Engineering

[109] For example, this can include voltage reduction tests, overnight low load conditions, or other operational conditions based on engineering judgement.
[110] This may require coordination among both transmission and distribution entities such as PCs, RCs, and DPs.
[111] These examples are used to be in alignment with the conditions in TPL-001-4 (link: here).
[112] This is typically decided based on engineering judgement and does not necessarily coincide with developed peak or off-peak Interconnection-wide base cases.

judgement should be used to correlate the captured measurements into parameter adjustments (e.g., T-D Transformer impedance or Pmax of U-DERs) for the steady-state model where individual metering is not available.[113]

Temporal Limitations on DER Performance

Due to a multitude of reasons, time dependent DER operational characteristics can inhibit the DER performance. As an example, solar irradiance inherently limits the output of solar PV DERs. If the irradiance is insufficient to reach the maximum output of the resource, such conditions need to be accounted for in the model verification activity or a different period chosen such that the limit is not applicable. Dispatch of DER off of maximum power should be carefully aligned with steady-state and dynamic parameterization[114] of limits and functions. The unavailability of such data should not stop the process as verification of other parameters can be performed.

Key Takeaway:
Time dependent variables impact the dynamic capability of the DERs in the aggregation. TPs should separate maximum nameplate capacity and maximum dynamic capability during the event during dynamic model verification of their models.

Steady-State Model Verification for an Individual DER Model

The objective of steady state verification of DER installations is to verify the correlations between active power, reactive power, and voltage trends. The responses below in **Figure 2.1** demonstrate how DER device characteristics may change in the day-to-day responses. This figure shows a sample seven-day week for a U-DER device that is set up to follow the local station load. Each valley in the figure corresponds to one day. Compare the response in **Figure 2.1** with the total load response in **Figure 2.2**. While the data contained here demonstrates the controllability aspects of the DER resource over a long period of days, much of this data can be inferenced based off irradiance data taken close to the facilities; however, the TP for this particular site could verify the load following nature by gathering this week of information and aligning it gross load.[115]

Key Takeaway:
The large majority of DER facilities are solar PV, and behave generally like other BPS solar PV IBR resources. This predictable performance should be included when gathering data for model verification purposes.

[113] This is likely the case for R-DERs; however individual metering on U-DERs will reduce the amount of error in model verification.
[114] See NERC Modeling Notification that
[115] In the steady state, the DER MW and MVAR output could be verified based on day four only. However, as this installation followed the nearby station load, a wider variety of samples were needed. To verify the load following setting, day five provides valuable information regarding the load following settings as the day was characterized by low load on the feeder with the DER dropping its output to follow that lower load to prevent back feeding.

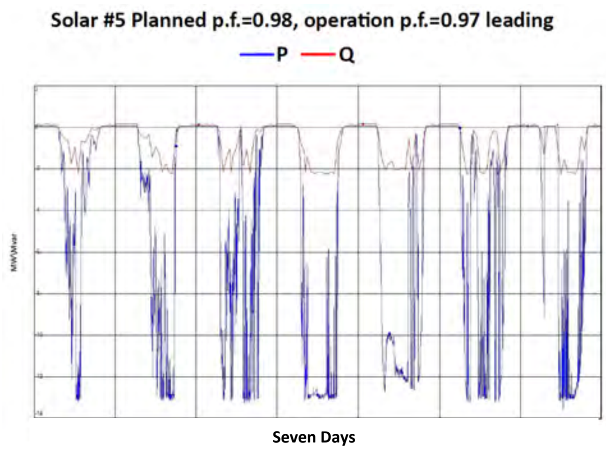

Figure 2.1: Load Following U-DER Response

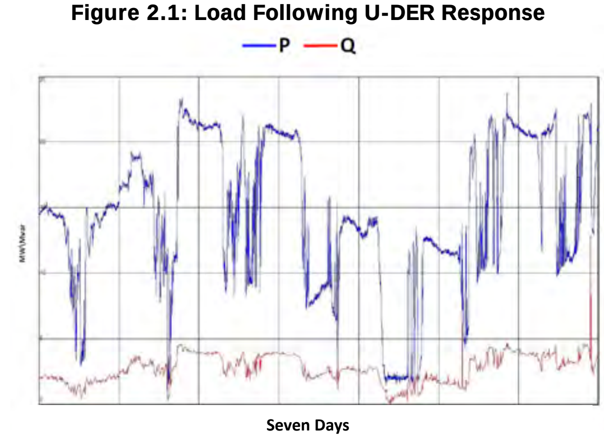

Figure 2.2: Load Response near the U-DER

In addition, it is important to know that these measurements came from two different electrical locations (at the terminals of the U-DER device and at the T–D interface for the load). Such separation and multiple measurement locations allow for the steady-state verification process to be easier. Each TP/PC should consult with the DP is able to submit the data required to the modeled aggregation as well as identify critical measurement locations. If there is not data measurements like **Figure 2.1** and **Figure 2.2** available, the TP is able to adjust their set of planning models to account for changes to the DER aggregation from the existing model by asking questions of the DP and applicable entities. **Table 2.1** highlights some of these important questions.

Table 2.3: Sample DER Steady-State Questions and Anticipated Parameters

Data Collected[116]	Anticipated Parameters
What is the aggregated operational characteristics of DERs at the T-D interface within a specified time domain?	The collected data from this question will help set the maximum power output of all DER represented in the verification process. This accounts for the aggregated coincident capacity of the resources.
What is the point of interconnection (i.e. transmission substation) where the aggregate DER connects to?	This will identify which load/generator record in the powerflow set of data to attribute the aggregate DER capacity and generation in the set of BPS models.
What is the magnitude and type of aggregated coincident load connected to the transmission substation?	The collected data from this question will assist in determining capacities of various loads (e.g., motor load or electronic load) to determine how the overall model for the T-D interface will perform when adjusting both the DER model and load model.
What reactive capability is supplied at the DER installations?	The collected data from this question will assist in determining the maximum reactive output of all DER represented in the verification process. This question can also be asked of the aggregate load response to identify the power factor of major loads.
What is the minimum power of DER at the T-D interface?	For non-solar related DER devices such as microturbines or BESS, this parameter provides the minimum required output of the DER resource.

Battery Energy Storage System Performance Characteristics

With regard to BESS, the performance of the DER is highly dependent upon the control of the device. Understanding the operational characteristics of the BESS DER will allow the TP and PC to associate the steady-state interactions of load and the modeled BESS DERs. If the model verified consists of one or more BESS installations that cannot provide measurements per the TP and PC verification processes, DPs and other entities may need to contact the original equipment manufacturer or DER developer for answers to some of the questions in **Table 2.1**. It is recommended that DPs and other entities establish good relationships with the BESS original equipment manufacturers in order to obtain useful type testing reports and other information that may answer the question in **Table 2.1.** Regardless of how the DER is modeled, current practices include surveys or other written means to obtain an operational profile of BESS DER and help validate the parameters used in steady-state analysis.

It is recommended to utilize a single DER model for multiple DER types, but differing control design (e.g., IEEE 1547-2018 vs. IEEE 1547-2003) or modeling practices may dictate otherwise. Examples for moving to separate aggregations is related to the frequency or voltage regulation settings. The TP and PC should use engineering judgement and readily available information to determine if these considerations are necessary for their models and alter their verification practices to account for dual aggregation modeling accordingly.[117]

Steady-State Model Verification for Aggregate DERs

The verification of multiple facilities is a more complex process than modeling a single U-DER facility due to the variety of different controls and interactions at the T–D interface. When modeling many U-DERs and R-DERs at the T–D interface, some assumptions help the verification process. Most legacy DERs (i.e., IEEE 1547-2003) may operate at

[116] These questions are useful for BESS DERs as well as other technology types of DERs. These questions are not to be used in lieu of more detailed modeling requests to develop the initial set of models but rather implemented as a way to check the parameterization of already established models.

[117] SPIDERWG has developed a white paper outlining these modeling practices here: [LINK]

constant power factor mode only and typically are typically set at unity power factor, making this a safe assumption to not adjust those modes for the models representing legacy DERs. The IEEE 1547-2018 standard has introduced more DER operating modes (e.g., volt-var, watt-var, or volt-watt), and this may require reaching out to the DP to verify as the settings could be represented in a piecewise function or the functionality may not even be used. More complex control schemes will require more than a cursory review of settings. Additionally, if there are any load following behaviors, it is preferable to collect each day in a week to capture load variation. It is preferable to monitor each individual U-DER location while leaving the monitoring of R-DER at the high side of the T–D interface as per **Figure 1.1.**

Figure 2.3 shows example measurements from a 44 kV feeder. The four solar plants in the figure, each rated 10 MW, and one major industrial load are connected to the feeder at different electrical locations. All solar plants were planned to operate at constant power factors at either unity or leading. The leading power factor requirement was to manage voltage rise under high DER MW outputs that travel through a long feeder with a low X/R ratio. The data show that the third solar plant's reactive power output was opposite to the planned direction (i.e., lagging vs. leading). The second solar plant also could not maintain unity power factor as planned. **Figure 2.3** also plots the industrial load profile and the total feeder flow measured at terminal station. Based on this, the steady state verification of the DER should reflect the aggregation of all four of those facilities as it is reflected at the T–D interface. Here, the TP is able to verify the aggregate of the U-DER solar facilities as the MW and MVAR flows from these facilities were recorded. Additional confirmation of steady-state voltage settings would require the voltages at these locations and such measurements are recommended to supplement these graphs. From the graphs, the following steady-state DER values (assuming DER is at maximum output) would be compared against the modeled representation and corrected:

- Aggregate U-DER at 40 MW production from Solar 1, 2, 3, and 4
- Aggregate R-DER at ~6 MW from the difference in one day on the Load graph
- Gross load at ~14 MW

The R-DER steady-state component and the gross load component would be difficult to gather from the single load measurement alone. However, careful engineering judgement can help separate the DER from the load in those measurements. Additionally, it is important to calculate the power factor of the aggregate U-DER. While the largest discrepancy between the 0.995 leading planned and in operation 0.994 lagging power factor, correcting that representation isn't as important as correcting the representation of the aggregation. In the aggregation, at maximum power production the aggregate of U-DER modeled DER produces two (0+1.5+1.5-1) MVAR. This equates to the aggregate operating at 0.999 leading power factor and would be used to check the performance of the aggregation of U-DER in the modeled representation in the modeling framework.

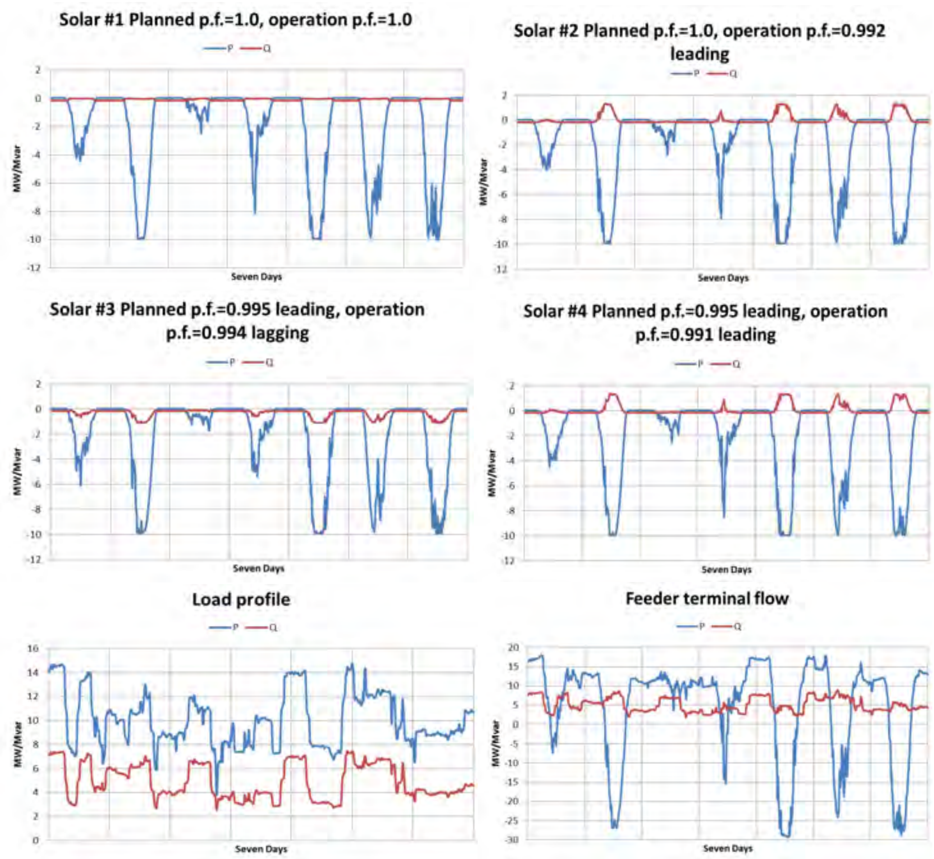

Figure 2.3: Active and Reactive Power Measurements from U-DERs, Load, and Substation

Figure 2.4 shows another example taken from a 230 kV load serving substation. Power trends from eight monitored[118] DERs connected to 44kV feeders supplied from the station are plotted in the figure.. Note that the sixth solar DER is a behind-the-meter (BTM) installation, the seventh is a biomass DER and the eighth is aggregation of three solar DERs and load.[119] The last two plots in **Figure 2.4** are measured from two paralleled 230kV-44kV step-down terminals. It can be seen that nearly zero MW transferred across the transformers under high DER outputs. The Mvar flow steps were a result of shunt capacitor switching at the 44kV bus of the station. Based on each of these monitored elements, the powerflow representation should capture the active power, reactive, power, and voltage characteristics as seen across the modeled T–D transformer. This process may require baseline measurements to determine gross load values in addition to coordination of substation level device outputs in relationship to the load and DER as evident in this example with the capacitor bank switching, DER, and load output affecting the T–D transformer.

[118] The meter at Solar #2 was out of service in the week due to failed current transformer.
[119] This would represent the contributions of R-DER in the aggregate DER model

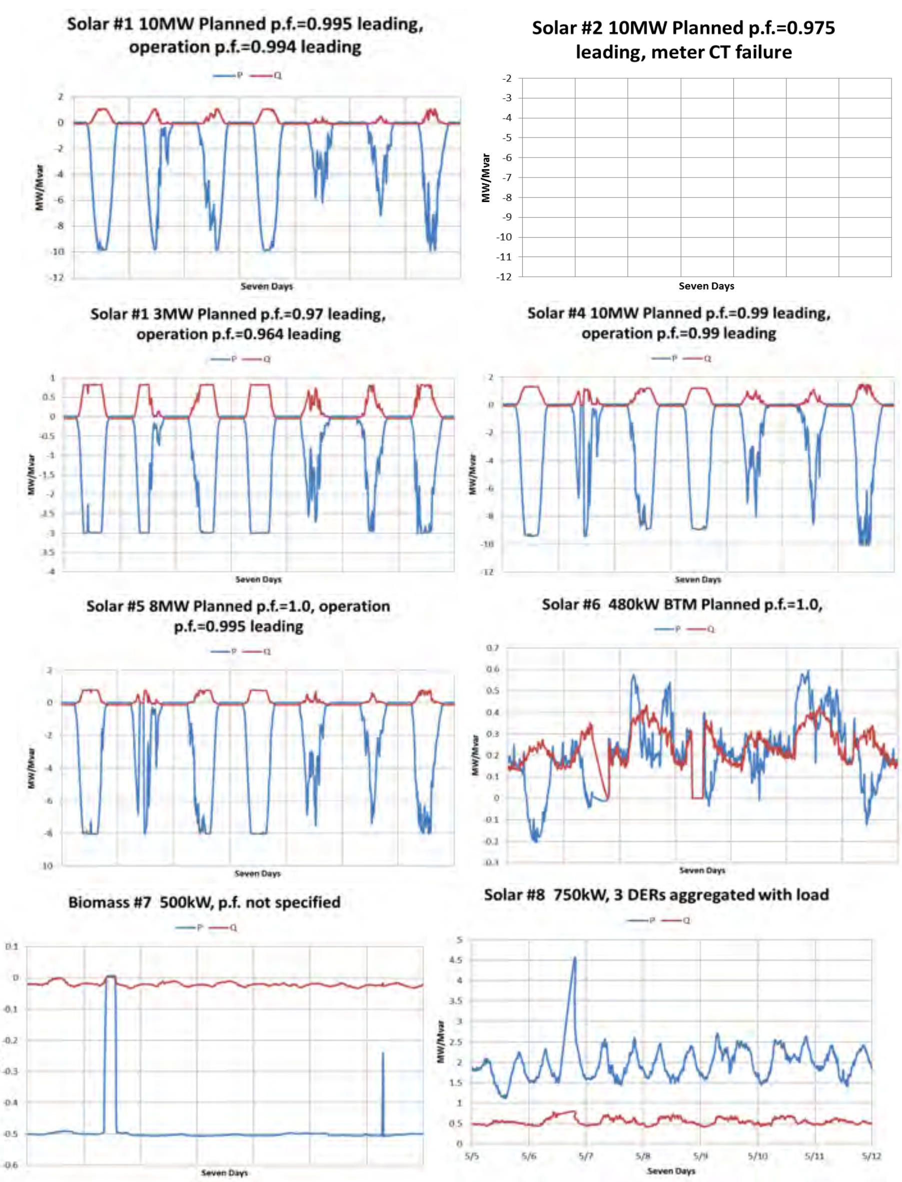

Figure 2.4: **Active and Reactive Powers Measured from Various DERs and Substation Transformers**

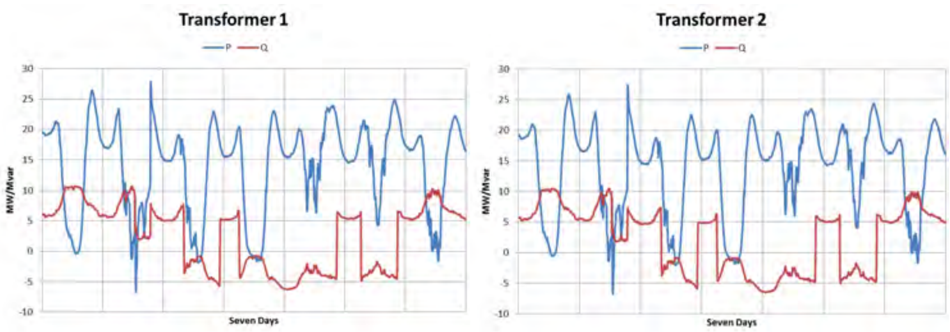

Figure 2.5: Active and Reactive Powers Measured from Various DERs and Substation Transformers

As with the aggregations in **Figure 2.3**, the TP or PC can use the active and reactive output measurements from the substation transformers and the DERs to account for the steady-state representation of the DER and load for cases that are to represent conditions during this time. Even with failures to send data from specific U-DER facilities, the verification procedure can occur so long as assumptions are made. The following points can be deduced from **Figure 2.4** assuming that the 10 MW U-DER solar facility also acts similarly to the others fed off the parallel transformers:

- Aggregate U-DER production of 40.5 MW from the solar and biomass graphs except for the ones BTM
- Aggregate R-DER production of about 1.5 MW from the daily changes in the BTM solar load
- Gross load of about 40–42 MW taken from both transformer graphs and backing out the aggregate DER (both U-DER and R-DER) production.

In **Figure 2.4**, since one of the U-DER-modeled DERs did not have measurements, the TP and PC can assume either it operated with the planned power factor or wait on the metering to be restored. However, it should be clear from both **Figure 2.3** and **Figure 2.4** that such measurements allow the TP and PC to verify their models such that DER behavior is adequately modeled in their simulations. For instance, if these T–D interfaces simply modeled a net load during peak conditions, they would be ignoring nearly 55 MW of gross load. Doing so will impact the simulated performance of the transmission substation.

Steady-State Model Verification Changes with Increasing Generator Records

Key Takeaway:
Increasing the number of generator records for representing DER in the simulation increases the importance of having on-site measurements available for model verification.

Once the model contains significant amounts of U-DERs and R-DERs, the dispatch of the modeled DER becomes difficult to verify in the steady state records with only one measurement at the T–D interface. With measured outputs of all U-DER served from the substation, a TP is able to verify the MW and MVAR output between the two aggregations so long as the gross load of the feeder is known. **Figure 2.5** reiterates the recommended SPIDERWG modeling framework that demonstrates the two points of the record where DER connect to. That is, DER connected near the substation or DER further out on the feeder and closer to load. Additionally, with voltage measurements pertaining to the U-DER, the whole set of active power, reactive power, and voltage parameters can be verified to perform as according to the steady state operational modes. Note that this process will inherently vary across the industry as performance and configuration on the distribution system varies. In general, the verification of the steady state MW, MVAR, and V characteristics will need measurements of those quantities and which of the DER model inputs those measurements pertains to (i.e. the U-DER or R-DER representation). Additionally, some modeling practices have more than one generator record for different aggregations of DER technology types. The increase of generator records when modeling DER increases the importance of monitoring individual large U-DER facilities in order to attribute the correct steady state measurements to the planning models. In the case of large amounts of U-DER and R-DER at the T-D interface, assumptions will be required to categorize the metered DER response in relationship to the non-metered DER response. SPIDERWG recommends measurement equipment be required for the U-DER behind a T-D interface in order to reduce the impact these assumptions have on model quality improvements.

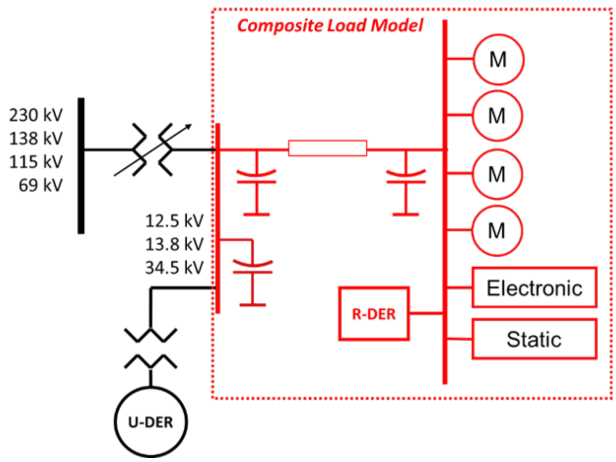

Figure 2.6: **Aggregate U-DER and R-DER Steady-State High Level Representation**

Chapter 3: DER Dynamic Data Collection and Model Verification

This chapter describes the recommended data reporting requirements for collecting sufficient data to model aggregate DER in interconnection-wide dynamics cases. Each PC should consider integrating these recommendations into their requirements per MOD-032-1 Requirement R1 in coordination with their TPs. Further, this chapter discusses the verification of aggregate DER models for use in dynamic simulations. Generally speaking, the primary initiating mechanism for verification of dynamic models are BPS-level events. Historic events may be used to verify the performance of equipment online during the event. The majority of dynamic model verification occurs when using recorded BPS level events as a benchmark to align the model performance

DER Modeling Needs for TPs and PCs

Transient dynamic modeling data requirements for aggregate DERs should be explicitly defined in each PC and TP's modeling data requirements per MOD-032-1. This section describes the recommended data and modeling practices ~~necessary~~ for consistently representing the aggregate DER in dynamic simulations performed by TPs and PCs to ensure BPS reliability. Refer to the existing NERC reliability guidelines[120] regarding DER modeling for more information about recommended dynamic modeling approaches for DERs. While synchronous DERs exist and some new synchronous DERs are being interconnected in varying degrees,[121] inverter-based DERs (e.g., solar PV and battery energy storage) are rapidly being interconnected to the system in many areas across North America. Therefore, this section will use the DER_A dynamic model as an example for describing necessary information for the purposes of developing DER dynamic models.

The DER_A dynamic model is the recommended model for representing inverter-based DERs (i.e., wind, solar PV, and BESSs).[122] The DER_A model is appropriate for representing U-DERs and R-DERs as a standalone generator record or as a component of the load model (e.g., using the composite load model). The TP and PC will need to specify what their modeling practices are regarding U-DERs and R-DERs, including but not limited to the following:

- How are U-DER and R-DER differentiated in the planning base cases?
- Is a size threshold used to differentiate resources, or is this based on location along the distribution feeder(s)?
- Are the details of DER data different in any way between U-DERs and R-DERs?
- Are there specific interconnection requirements applicable to U-DERs, R-DERs, or both?
- Are U-DERs expected to have higher performance requirements for participating in energy markets?
- Are DERs combining generation and energy storage (i.e., hybrid plants), are these technologies ac-coupled or dc-coupled, and what are the operational characteristics of the facility (i.e., how is charging and discharging of the energy storage portion modifying total plant output)?
- What are the specific distribution-level tripping schemes or return to service requirements that would apply during the dynamics time frame for different vintages of DER installation dates?
- Are DERs generally located near the distribution substation or closer to the end-use loads?
- Are there any BPS protection schemes (e.g., direct transfer trip) that could result in the disconnection of DERs under certain BPS configurations?

[120] Reliability Guidelines are available here: https://www.nerc.com/comm/Pages/Reliability-and-Security-Guidelines.aspx

[121] DERs that are synchronously connected to the grid exist across North America; in some areas, these are the predominant type of DER. The DER modeling guidelines mentioned above can be referenced and adapted for gathering DER data for the purposes of modeling these resources.

[122] The New Aggregated Distributed Energy Resources (der_a) Model for Transmission Planning Studies: 2019 Update, EPRI, Palo Alto, CA: 2019, 3002015320 https://www.epri.com/#/pages/product/000000003002015320/?lang=en-US

- Are U-DERs or R-DERs expected to employ momentary cessation for large voltage excursions?

The DER_A dynamic model consists of many different parameter values that represent different control philosophies and performance capabilities for aggregate or individual inverter-based DERs; however, most of the parameter values remain fixed when representing different DER vintages or specific distribution-level interconnection requirements.[123] Therefore, it is important to focus on the control modes of operation and parameter values that change based on what types and vintages of DERs are connected to the distribution system. The following section will describe how gathering this data can be a fairly straightforward task and provide adequate information for the TP and PC to be able to use engineering judgment to model aggregate DERs in their footprint.

Mapping TP and PC Modeling Needs to DER Data Collection Requests

As mentioned, the complexity and number of parameter values of the DER_A dynamic model should not prohibit or preclude entities from developing relatively straightforward information gathering to supply the needed data for TPs and PCs to be able to model these resources. **Table 3.1** shows how parameterization of the DER_A dynamic model can be mapped to questions that should be asked by the TP and PC and to information that should be provided by the DP or other external entity to help facilitate DER model development. Note that **Table 3.1** shows default DER_A parameters to capture the general behavior of DERs compliant with IEEE 1547-2018 Category II, which is taken from NERC *Reliability Guideline: Parameterization of the DER_A Model for Aggregate DER*.[124] The table describes IEEE 1547 and its various versions; however, the concepts would also apply to other local or regional rules, such as California Rule 21 or Hawaii Rule 14H. Values listed in red are those that are likely subject to change across different vintages of the IEEE 1547 standard and would likely need to be modified to account for systems with DERS with varying vintages of IEEE 1547. The questions posed in this guideline are intended to help TPs and PCs reasonably parameterize the DER_A dynamic model based on the information received. Refer to **Appendix B:**~~Appendix B~~ for considerations for distributed energy storage systems.

Table 3.1 is intended as an example to help illustrate how the TP and PC could map questions related to DER information for the purposes of developing an aggregate DER dynamic model. The order of parameters and exact names of parameters may be slightly different across software platforms. Refer to a specific software vendor model library for exact parameter names and order of parameters. However, the concepts can be applied across software platforms.

Table 3.1: Data Collection for Parameterizing the DER_A Dynamic Model

Param	Default	Information Necessary for Suitable Modeling of Aggregate DERs
trv	0.02	Parameter values do not generally change between vintages of IEEE 1547. For the purposes of modeling, these default parameters are appropriate. Any dynamic voltage support requirements set by the DP should be communicated to the TP and PC so they can determine an appropriate modeling practice. Note that these parameters can be used to represent either dynamic voltage support or steady-state volt-var functionality; TPs and PCs will need to determine which approach is being used and specify any data collection requirements accordingly.
dbd1	-99	
dbd2	99	
kqv	0	
vref0	0	
tp	0.02	
tiq	0.02	

[123] For example, representing DERs compliant with different versions of IEEE 1547 (e.g., -2003, -2018, etc.) or DP-specific interconnection requirements. For those settings that can be remotely managed and written per Clause 10 of IEEE 1547-2018, the TP and PC should specify how a management system can send information to update their models when such changes alter the control of the aggregate DER model and thus impact the T-D Interface.

[124] Available here: https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Reliability_Guideline_ModelingMerge_Responses_clean.pdf ~~[Insert published link]~~

Table 3.1: Data Collection for Parameterizing the DER_A Dynamic Model		
Param	**Default**	**Information Necessary for Suitable Modeling of Aggregate DERs**
ddn	20	Are DERs required to have frequency response capability enabled and operational for overfrequency conditions? As in, do DERs respond to overfrequency conditions by automatically reducing active power output based on this type of active power-frequency control system? If so, what are the required droop characteristics for these resources (e.g., 5% droop would equal a *ddn* gain of 20)?[125] What is the estimated fraction of resources installed on your system that are required to have this capability (based on interconnection date and requirements)?
dup	0	Are DERs required to have frequency response capability enabled and operational for underfrequency conditions? As in, if there is available energy, do DERs respond to underfrequency conditions by automatically increasing active power output based on this type of active power-frequency control system? Are there any requirements for DERs to have headroom to provide underfrequency response? If so, what are the required droop characteristics for these resources? What is the estimated fraction of resources installed on your system that are required to have this capability (based on interconnection date and requirements)?
fdbd1	-0.0006	If frequency response capability is enabled and operational, the deadband should be set to match any interconnection requirements governing this capability and performance. Consider the different types of interconnection requirements and what the correct assumption would be for this parameter, where applicable.
fdbd2	0.0006	If frequency response capability is enabled and operational, the deadband should be set to match any interconnection requirements governing this capability and performance. Consider the different types of interconnection requirements and what the correct assumption would be for this parameter, where applicable.
femax	99	Values vary based on what vintage of IEEE 1547 the DERs are, so a time line of interconnection capacity estimating the amount and timing of DER interconnection will support modeling.
femin	-99	Values vary based on what vintage of IEEE 1547 the DERs are; so a time line of interconnection capacity estimating the amount and timing of DER interconnection will support modeling.
pmax	1	Parameter values do not generally change between vintages of IEEE 1547. No information needed from DP for the purposes of modeling, assuming that these default parameters are appropriate. In cases where the TP or PC has determined that these default parameters are not appropriate, the TP or PC may request additional information of the DP for this purpose.
pmin	0	
dpmax	99	
dpmin	-99	
tpord[126]	5	
Imax	1.2	
vl0	0.44	
vl1	0.49	
vh0	1.2	
vh1	1.15	
tvl0	0.16	
tvl1	0.16	
tvh0	0.16	
tvh1	0.16	
Vrfrac	1.0	Values vary based on what vintage of IEEE 1547 the DERs are, so a time line of interconnection capacity estimating the amount and timing of DER interconnection will support modeling.

[125] Note that TPs and PCs will need to consider the fraction of DERs providing frequency response, if applicable. The values of *ddn* and *dup* will need to be scaled appropriate to account for this fraction. The gain value can be determined by scaling (1/droop) by the fraction of DERs contributing to frequency response. This concept applies to *dup* as well.

[126] The active power-frequency response from DERs, if utilized in studies, should be tuned to achieve and ensure a closed-loop stable control. This parameter may need to be adapted based on this tuning.

Table 3.1: Data Collection for Parameterizing the DER_A Dynamic Model

Param	Default	Information Necessary for Suitable Modeling of Aggregate DERs
fltrp	56.5	Values vary based on what vintage of IEEE 1547 the DERs are, so a time line of interconnection capacity estimating the amount and timing of DER interconnection will support modeling.
fhtrp	62.0	Values vary based on what vintage of IEEE 1547 the DERs are, so a time line of interconnection capacity estimating the amount and timing of DER interconnection will support modeling.
tfl	0.16	Parameter values do not generally change between vintages of IEEE 1547. No information needed from DP for the purposes of modeling, assuming that these default parameters are appropriate. In cases where the TP or PC has determined that these default parameters are not appropriate, the TP or PC may request additional information of the DP for this purpose.
tfh	0.16	
tg	0.02	
rrpwr	2.0	Values vary based on what vintage of IEEE 1547 the DERs are, so a time line of interconnection capacity estimating the amount and timing of DER interconnection will support modeling.
tv	0.02	Parameter values do not generally change between vintages of IEEE 1547. No information needed from DP for the purposes of modeling, assuming that these default parameters are appropriate. In cases where the TP or PC has determined that these default parameters are not appropriate, the TP or PC may request additional information of the DP for this purpose.
Kpg	0.1	Values vary based on what vintage of IEEE 1547 the DERs are, so a time line of interconnection capacity estimating the amount and timing of DER interconnection will support modeling.
Kig	10.0	Values vary based on what vintage of IEEE 1547 the DERs are, so a time line of interconnection capacity estimating the amount and timing of DER interconnection will support modeling.
xe	0.25–0.8[127]	Parameter values do not generally change between vintages of IEEE 1547. No information needed from the DP for modeling purposes, assuming that these default parameters are appropriate. In cases where the TP or PC has determined that these default parameters are not appropriate, the TP or PC may request additional information of the DP for this purpose.
vfth	0.3	TP and PC engineering judgment can be used to set this parameter value. May be subject to change across vintages of IEEE 1547 for the purposes of modeling.
iqh1	1.0	Parameter values do not generally change between vintages of IEEE 1547. No information needed from DP for the purposes of modeling, assuming that these default parameters are appropriate. In cases where the TP or PC has determined that these default parameters are not appropriate, the TP or PC may request additional information of the DP for this purpose.
iql1	-1.0	
pfflag	1	
frqflag	1	
pqflag	Q priority	Values vary based on what vintage of IEEE 1547 the DERs are, so a time line of interconnection capacity estimating the amount and timing of DER interconnection will support modeling.
typeflag	1	What penetration of energy storage resources are connected to the distribution system? What percentage of DERs are energy storage? Are these larger utility-scale energy storage DERs, or more distributed (e.g., residential) energy storage DERs? Any values or estimates as the interconnection of energy storage DERs will help determine whether to and how to separate out energy storage DERs in the models.

Table 3.1 highlights the concept that interconnection time line is critical for the purposes of creating dynamic models of aggregate DERs because the capabilities and performance of DERs is dominated by the interconnection requirements set forth on those DERs. TPs and PCs may have additional data points that provide useful information for capturing more information relevant to developing reasonable DER models, and may have other data points needed for modeling larger U-DER installations if such additional requirements or data are needed. For DER model parameter values that vary with the vintage of IEEE 1547, a time line of interconnection capacity can be shared to estimate the amount and time in which resources were interconnected, which can be used to estimate the makeup of various IEEE 1547 vintages. TPs and PCs will also need to consider what the expected settings of the actual installed equipment[128] may be; this can be informed by any interconnection requirements or expected default settings used.

[127] Studies performed by EPRI have shown that *Xe* may need to be a greater value in certain systems or for certain simulated faults to aid in simulation numerical stability. These studies have shown that the increased *Xe* value does not reduce the reasonability of the DER response.
[128] Opposed to the estimation that is made from using the time of interconnection for the general capacity of DER.

To recap the relevant information needed for aggregate DER dynamic modeling, the following data points should be considered by TPs, PCs, DPs, and other external entities in the development of requirements and when providing this information for modeling purposes:[129]

- What is the vintage of IEEE 1547 (or equivalent standard) that is applicable to the DERs and were there any applicable updates to DP interconnection requirements regarding DERs? If it is a mixed collection of vintages, based on the interconnection date, engineering judgment should be used by the DP, TP, and PC to assign percentages to different vintages, as applicable.
- Do the installed or projected future installations of DERs have the capability to provide frequency response in the upward or downward direction? If so, are there any relevant requirements or markets in which DERs may be dispatched below maximum available active power?
- Are DERs providing dynamic voltage support or any fault current contribution or are they entering momentary cessation?
- What are the expected trip settings (both voltage and frequency) associated with the vintages of IEEE 1547 or other local or regional requirements that may dictate the performance of DERs?
- Are DERs installed on feeders that are part of UFLS programs? If so, more detailed information regarding the expected penetration of DERs on these feeders may be needed. As stated previously, hybrid U-DER facilities likely need specific, more detailed modeling considerations by the TP and PC, and therefore should be differentiated accordingly.

Dynamic DER Data Characteristics

Dynamic recorders capture the transient conditions of an event have differing data considerations than the steady-state recording equipment. The data characteristics and considerations for recording measurements used in transient dynamic model verification are found in **Table 1.3.** In comparison to steady-state measurements, dynamic data measurements require a faster sampling rate with the trade-off that the higher fidelity sampling is only for a shorter period of time. The data captured from dynamic disturbance recorders can be used for dynamic model verification.

Table 1.2: Dynamic DER Model Verification Data Considerations

Topic	Key Considerations
Resolution	Typically, the BPS planning models look at responses of less than 10 Hz, so the sampling rate of the measuring devices should be adequate to capture these effect. Therefore, a resolution on the order of 1–4 milliseconds is recommended to be above the Nyquist Rate for these effects. For reference, typical sampling rates recording devices can report at 30–60 samples per second continuously, with some newer technologies sampling up to 512 samples per cycle for specific triggers.

[129] The TP and PC will need to consider these points when developing aggregate DER dynamic models, and, therefore, will need information from the DP and any other external entities that may be able to help provide information in these areas.

Table 1.2: Dynamic DER Model Verification Data Considerations	
Topic	**Key Considerations**
Triggering	Dynamic recording devices will need to have their triggers set in order to record and store their information. Some important triggers to have are those that detect a BPS fault or accept nearby protection relays that assert a trigger to the device to record. This generally shows up as the following: • Positive sequence voltage is less than 88% of the nominal voltage[130] • Over-frequency events[131] • Under-frequency events Although more sensitive trigger values can be used to obtain more data, some of those triggering events may not be useful in verifying the large disturbance dynamic performance of BPS models. In the transmission system model, the DER terminals are expected to have the same electrical frequency. Additionally, for areas that are also concerned with verification of DER due to overvoltage conditions, a high voltage trigger should also be implemented.
Duration	An event duration requirement depends on the dynamic event to be studied. SPIDERWG recommends a recording window of at least 15 seconds for DER model verification.[132] For longer events, such as frequency response, the time window can range from a few seconds to minutes.
Accuracy	Dynamic measurements should have high accuracy and precision. Typically, the recording devices will use the same instrumentation as the protection system, which already has a high level of accuracy.
Time Synchronization	Dynamic measurements should be time synchronized to a common time reference (e.g., global positioning system) so that dynamic measurements from different locations can be compared against each other with high confidence that they are time aligned. This is essential for wide-area model verification purposes.[133]
Aggregation	Based on the modeling practices for U-DERs and R-DERs established by the TP and PC, it may be necessary to differentiate DERs for the purposes of accounting in the power flow model. This includes separating out the MW values for U-DERs and R-DERs and having sufficient measurement data to capture each type in aggregate. Similar to **Table 1.2**, it may also be necessary to separate the U-DERs or R-DERs by operational characteristics based on the TP's and PC's modeling practices.

[130] This value is presented as an example based on prior event analysis reports. Entities are encouraged to decide on trigger thresholds based on their experience of the local system.

[131] both over- and under-frequency events are typically at +/- 0.05 Hz around the 60 Hz nominal; however, this value should be altered for each interconnection appropriately based on the amount and types of events desired to be used for BPS model verification.

[132] Even if a 15-second window is not available for an event, TPs and PCs should use what is available and determine its worth for model verification.

[133] Per PRC-002-3, SER and FR data shall be time synchronized for all BES busses per R10 (available here: https://www.nerc.com/pa/Stand/Reliability%20Standards/PRC-002-3.pdf). This same concept should be true for these measurements that may not be taken from BES buses.

Table 1.2: Dynamic DER Model Verification Data Considerations	
Topic	**Key Considerations**
Data Format	Similar to the steady-state data, the dynamic data formats typically come in a delimited file type such that Microsoft Excel can readily read. If it does not come in a known Excel format, ASCII[134] files are typically used that would be converted into a file format readable in Excel. However, other files types, such as COMTRADE,[135] are also widely used by recording devices and can be expected when requesting dynamic data from these recording devices.
Post-Processing	In terms of data set completeness, data gaps should be minimized not through interpolation but through careful selection and archival of event recordings. This is in contrast to the steady-state data key consideration that would recommend interpolation.

Event Qualifiers when Using DER Data

Some qualifiers should be used when selecting the types of events used in model verification due to the varying nature of events. It should be noted that many of these events will not coincide with a defined "system peak" or "system off-peak" condition. Because of the many aspects of events, the following list should be considered when performing verification of the DER dynamic model:

- Utilization of measurement error in calculations regarding closeness of fit
- Separation of DER response from load response in events, both in steady state and dynamics performance
- Reduction strategies to simplify the system measurements to the models under verification

Because of event complexity, some events simply will not have any value in verifying the DER models and thus will have no impact to increasing model fidelity. Such considerations are as follows:

- Events that occur during DER nonoperational or disconnection periods
- Other events that do not contain a large signal response of DERs (e.g., events in areas with very low instantaneous penetration of DERs)

Selecting multiple events for validation will provide TPs additional assurance on the validity of the dynamic DER model rather than selecting the "perfect" event. This should be done even for already verified DER models. One of the most important aspects to add an event to play-back in simulation would be that the event cause code is different previously used events and the new event.[136] Based on the above factors, it is crucial to the model verification process that each recorded event have sufficient detail to illustrate the event cause and the DER response in order to link the two. Such documentation should be considered in order to ensure future procedures are beneficial to the verification of the wide-area and DER models.

DER Dynamic Model Verification for a Single Aggregation

If the transmission model contains DER models, those models should adequately represent dynamic performance of aggregate DERs. U-DERs and R-DERs differ in that dynamic performance characteristics of individual installations of U-DERs are likely accessible while the dynamic performance characteristics of individual installations of R-DERs are not. By having the individual performance readily available, the TP or PC is able to tune their transmission models

[134] ASCII stands for American Standard Code for Information Interchange as a standard for electronic communication.

[135] COMTRADE is an IEEE standard for communications (IEEE Std. C37.111) that stands for Common Format for Transient Data Exchange

[136] Additionally, events are not the only method by which dynamic changes of behavior may be impacted. For instance, voltage reduction tests may have portions of recordings that are useful to playback into the model in the same way an event recording would. These should also be explored by TPs and PCs to verify their models.

that represent those resources.[137] This indicates that if the DP/TP/PC has access to the commissioning tests of the individual U-DER, the availability of these results is also useful in DER model verification as some commissioning tests demonstrate the full dynamic capability of the installed devices.

~~Though this section focuses on the dynamic performance of U-DERs, many of the same performance characteristics may be inferred under engineering judgment to apply to R-DERs.[138]~~ With data made available, model verification can occur. See **Figure 3.1** for a high-level representation of the recommended modeling framework that will be used in this section to describe the topology with load and other modeled components. ~~The composite load model here contains a DER input; however, this section details assumes that input is not used and all DER is lumped into the one generation record at the head of the feeder.~~ In order to separate out the contributions from the DER and the load, engineering judgement will need to be used in reading net load jumps[139] from events coupled with a deep understanding of the nature of load in that particular area. The TP or PC can disaggregate the response using these points to start attributing the response. The measurement taken at the T–D interface will represent the responses of all the components of the equipment in **Figure 3.1**, and it is not the goal to separate the measurement to its respective parts and verify the components separately. Rather, verifying the cumulative (composite load + DER) response to the aggregate[140] models to a reasonable state for its representation in transmission models[141] is the goal. Examples of data collection for this guideline are in **Appendix F**.

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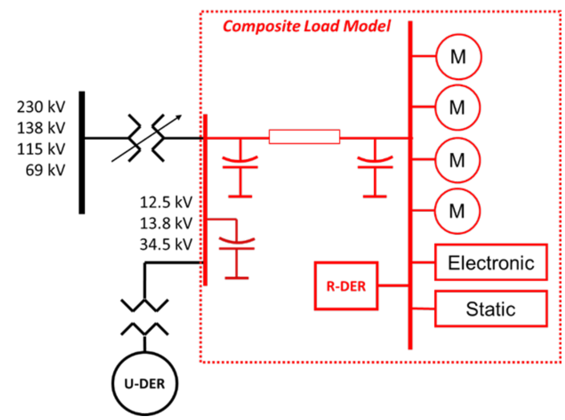

Figure 3.1: High Level Individual U-DER and Load Model Topology

[137] This is the case whether using an aggregate dynamic model (such as DER_A), an individual dynamic model set (such as the second generation renewable models) or a synchronous model. Because U-DERs generally will dominate the model performance, individual U-DER performance can verify a majority of T-D interfaces in the transmission model.

~~[138] In the model framework, the U-DER facilities are connected to the low side bus of the T–D transformer as they are generally close to the substation with a dedicated feeder. When this is not the case, the TP should consider moving that DER facility from the classification of U-DERs to R-DERs in the modeled parameters, if the facility is sufficiently far away from the substation that the feeder impedance affects the performance of the large DER facility.~~

[139] For net load recorded at the high side of the T-D transformer.

[140] Note that both the composite load model and the DER_A model are aggregate models that represent aggregate equipment.

[141] The Load Modeling Task Force has developed a reference document on the nature of load here. A NERC disturbance report located here has demonstrated the net load jumps and deals with this at a high level. EPRI has also published a public report that details this as well, available here.

Dynamic Parameter Verification without Measurement Data

> **Key Takeaway:**
> Ensuring correctly modeled IEEE 1547 vintage through data requests allows the TP to ensure their dynamic DER model is correctly parameterized

In the instances where measurement data is not made available to the TP for use in model verification, the TP is capable of verifying a portion of their dynamic models by requesting data from the DP or other entities that is not related to active and reactive power measurements, voltage measurements, or current measurements. A sample list of data collected and anticipated parameter changes is listed in **Table 3.1**. This list of parameters is not exhaustive in nature. This table should be altered to address the modeling practices the entity uses[142] in representing ~~U-DERs~~ aggregate DER in their set of BPS models and should be used to guide dynamic performance verification. These parameters can be used to help adjust the model in order to assist in performing the iterative verification process. As the DER_A model is one of the few current dynamic models provided for representing inverter-based DER, those parameters are listed to assist the process. These parameters can come from a previous model in addition to a data request. An important note is that requesting the vintage of IEEE 1547[143] inverter compliance will provide the TP information adequate to ensure their model was correctly parameterized to represent a generic aggregation of those inverters. This is especially true of higher MW DER installations as these are more likely to dominate the aggregation of DERs at the T–D interface. This method is not intended to replace measurement based model verification but rather supplement it where measurements are not currently available.

Table 3.3: DER Dynamic Model Data Points and Anticipated Parameters

Data Collected	Anticipated Parameters	Example DER_A parameters
What equipment standards are applicable to the inverters represented?	This will provide a set of voltage and frequency trip parameters. In general, this question can be answered by asking for the installation date, which correlates with the IEEE 1547 standard version date. This, however, will not be 100% accurate due to differences in jurisdictional approval of each version of the IEEE 1547 standard.	Voltage: vl0,vl1,vh0,vh1,tvl0,tvl1,tvh0,tvh1 Frequency: Fltrp,fhtrp,tfl,tfh Overall: Vrfrac
How much of DER trips during voltage or frequency events?	This data point, in combination with the data point above will help determine the total MW of capacity that trips with regard to voltage or frequency. The answer can take into account other known protection functions that trip out the distribution feeder or other equipment not related to the inverter specifications, or it can represent choices made inside the vintage.	Voltage: Vrfrac Frequency: Handled by the Ffrac block[144]

[142] Primarily this is due to interconnection requirements but can also be due to other external documents.
[143] Or other equivalent applicable equipment standard
[144] Unlike voltage trip there is no concept of "partial frequency trip" in the der_a model. What "partial voltage tripping" means is that after a voltage event depending on the voltage level, a fraction, Vrfrac, may recover. For frequency, if the frequency violates the Fltrp/tfl and Fhtrp/tfh, the entire DER_a trips. No external model is needed for this. This feature is already included in der_a.

What interruptible load is represented at the substation?	This data point will allow TPs and PCs to be able to coordinate the load response with the DER response. The information provided here can be used in other parts of the model verification process. If the DER model is part of a composite load model, this question becomes more important than if the DER has a standalone model.	If used as part of a composite load model: Vrfrac If standalone: N/A

Dynamic Parameter Verification with Measurement Data Available

The preferred method for dynamic parameter verification is the matching of model performance with field measurement data. Per FERC Order No. 828, the Small Generator Interconnection Agreement (SGIA) already requires frequency and voltage ride through capability and settings of small generating facilities to be coordinated with the transmission provider.[145] Per FERC Order No. 792, metering data is also provided to the transmission provider.[146] Thus, the TP/PC have access to data for verification of U-DER dynamic performance for units applicable to the SGIA. In utilities with DER larger penetrations, more prescriptive language may exist to supplement the SGIA. Data at the low side of the transformer provides the minimum amount of data to perform the process, but the measured data at the U-DER terminals also can provide a greater insight into the behavior of installed equipment, and the TP can perform a more accurate aggregation of such resources. If the DP has data that would help facilitate the verification process, the data[147] should be sent in order to verify the aggregated impact of the U-DER installations in the BPS Interconnection-wide base case set of models.

While the SGIA provides benefits for the TP/PC in obtaining data for SGIA applicable units, not all of the DER facilities will be under a SGIA. See **Table 3.2** to get an understanding of the amount of resources ISO-NE considers as DERs. For the representations here, the solar PV generation not participating in the wholesale market is 1,532 MW while 858 MW participates and is SGIA applicable. In this area, reliance on the SGIA alone will only apply to a third of the installed solar PV DER. In addition, generation from other sources totals 1,351 MW, which includes fossil fuel, steam, and other non-solar renewables as the fuel source for the DER. Based on this table, roughly 22% of all DERs applicable to the SPIDERWG Coordination Group's definitions would be verified if only those facilities under the SGIA would be verified. While the SGIA does play a role in the data collection, reliance on the SGIA alone could result in significant data gaps. The TP/PC should use measurement devices discussed in **Chapter 1** to gather measurements where feasible.

Table 3.4: New England Distributed energy Resources as of 01/01/2018

DER Category[148]	Settlement Only Resource Nameplate Capacity [MW]	Demand Resource (DR) Maximum Capacity [MW]	Total DER Capacity [MW]
Energy Efficiency	-	1,765	1,765
Demand Resources (excluding BTM DG capacity)*	-	99	99

[145] Order No. 828, 156 FERC ¶ 61,062.
[146] Order No. 792, 145 FERC ¶ 61,159.
[147] e.g., measurements from a fault recorder, PQ meter, recording device, or device log.
[148] Note that these categories are from ISO-NE and may not conform to the working definitions used by SPIDERWG related to DER (e.g., energy efficiency is not considered a component of DER under the SPIDERWG framework as it does not provide active power).

Table 3.4: New England Distributed energy Resources as of 01/01/2018			
DER Category[148]	**Settlement Only Resource Nameplate Capacity [MW]**	**Demand Resource (DR) Maximum Capacity [MW]**	**Total DER Capacity [MW]**
Natural Gas Generation	26	331	357
Generation using Other Fossil Fuels	75	268	344
Generation using Purchased Steam	-	19	19
Non-Solar Renewable Generation (e.g. hydro, biomass, wind)	523	126	649
Solar PV Generation participating in the wholesale market	810	48	858
Electricity Storage	1	-	1
Solar PV Generation not participating in the wholesale market	-	-	1,532
Total DER Capacity	1,436	2,656	5,625
Total DER Capacity/ Total Wholesale System Capability**	4.1%	7.5%	15.9%

* To avoid double counting, demand response capacity reported here excludes any BTM Distributed Generation (DG) capacity located at facilities providing demand response. Registered demand response capacity as of January 2018 is 684 MW.

** System operable capacity (seasonal claimed capability) plus SOR and DR capacity as of January 2018 is 35,406 MW.

Dynamic Model Verification for Multiple Generator Records at the T-D Interface

Similarly to verifying just one aggregate at the head of the feeder, the model consisting of an aggregation of DERs amidst load and at the head of the feeder will be conducted similarly with the same concerns discussed for steady-state verification.[149] Detailed in **Figure 3.2** and **Figure 3.3** is a complex set of graphs that represent R-DERs and U-DERs, along with load, connected to a 230/44/28 kV distribution substation to the response of an electrically close 115 kV three phase fault.[150]

Under the 115 kV system three-phase fault outside the station, the entire 230 kV station sees the voltage profile,[151] which details a roughly 15–20% voltage sag at the time of the fault. The station has one 230/44 kV step-down transformer (T3). The 44 kV feeders supplied by T3 connect four solar farms (Solar 1 to Solar 4 in **Figure 3.2**) and one major load customer at the end of the feeder (“Load” in **Figure 3.2**). The station also has two 230/28 kV step-down

[149] See an example in *Duke Energy Progress Distributed Energy Resources Case Study: Impact of Widespread Distribution Connected Inverter Sources on a Large Utility’s Transmission Footprint,* EPRI, Palo Alto, CA: 2019, 3002016689 for more information

[150] Note that it is only applicable to collect multiple U-DER locations when more than a single U-DER installation is modeled at the substation in the aggregation in order to ensure adequate measurements are available for the TP to verify their models.

[151] Left top corner of the figure

transformers (T1 and T2). Two solar farms (Solar 5 and Solar 6) and other loads with BTM generation are connected to the 28 kV feeders. The voltage of the 230 kV substation returns to normal after the fault; however, the current contributions across the distribution transformers changes from that of expected. At the 44 kV yard all four solar installations rode through the fault with increased current injection during fault. All load also rode through the event. Aggregated current at T3 shows total current unchanged after the fault but with a big increase during the fault. This is different from fault signatures in traditional load supply stations, which are characterized by reduced current during fault when the fault is outside of the station (i.e. upstream of the recording devices). This difference arises due to the fault current injected by the solar installations during the fault that passed through T3. Aggregated DER models should capture such increased current injection under external faults, and measurements like **Figure 3.3** assist in verifying those parameters.

At the 28 kV side, the two solar plants could not ride through and shut down. In addition, increased load current after fault clearing can be seen in T1/T2, which is impossible in the traditional station representation without DERs. This demonstrates that the pickup of the load was across the T1/T2 transformers. Based upon **Figure 3.2** and **Figure 3.3**, it can be determined that the dynamic model parameters should reflect the response of the aggregate, and that may look different depending on how the TP decides to model this complex distribution substation into the planning models. In summary, with metering at each U-DER,[152] large load, and station terminals, this example has enough information for verification of the complex models that represent these DERs. Primarily, the verification process would show a need to parameterize such that T1 and T2 reflect the reduction of DERs from Solar 5 and Solar 6, yet having T1's DER representation parameterized such that this reduction is not present.[153]

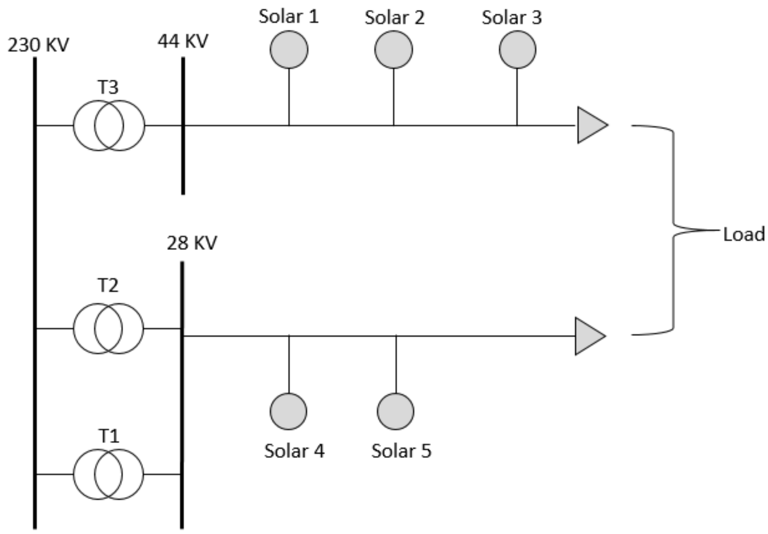

Figure 3.2: 230-44-28 kV Substation High Level Representation

[152] Note that some required monitoring at the end of the feeder

[153] Again, it is important to note that engineering judgement could also be used if the Load measurement was not there. Namely, if the TP or PC has a reasonable assumption that load would not trip out for this fault, any increase of transformer current can be associated with a trip or reduction of DER.

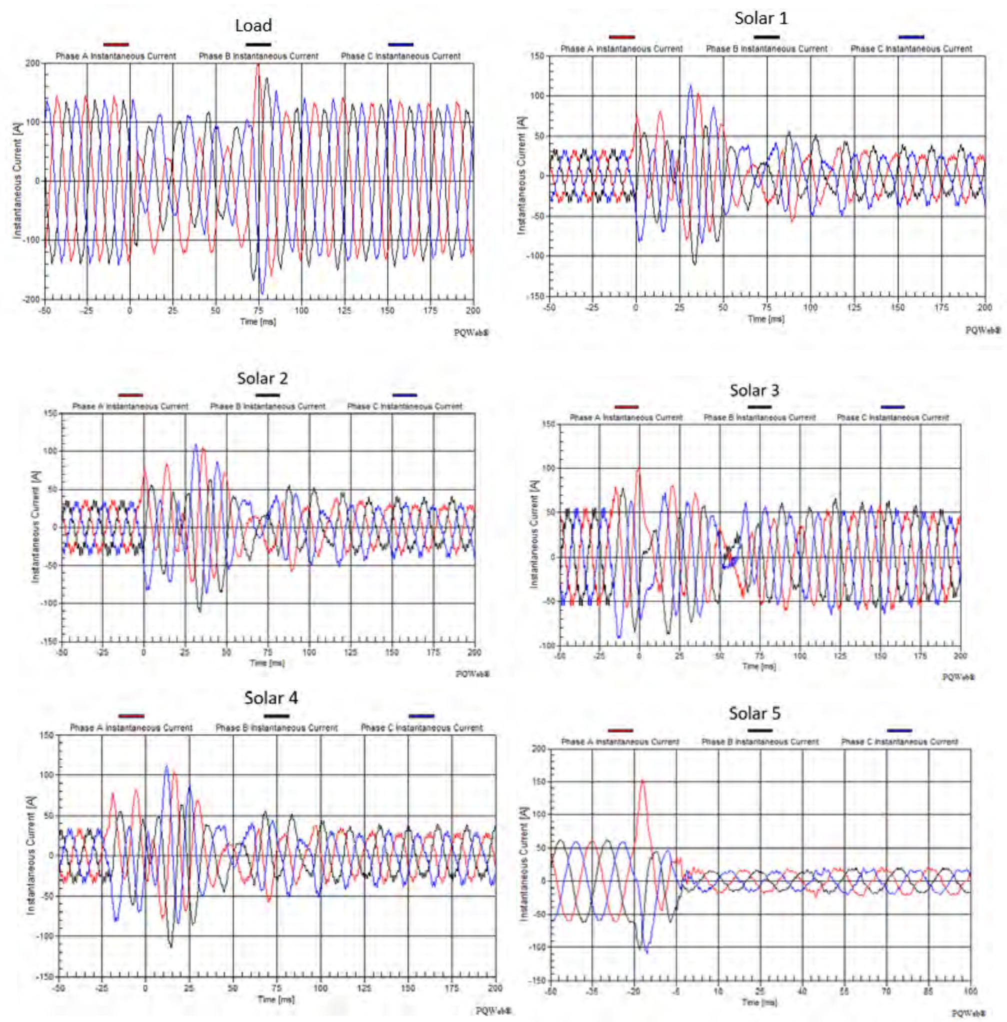

Figure 3.3: 230-44-28 kV Substation Response to a 115 kV Three Phase Fault

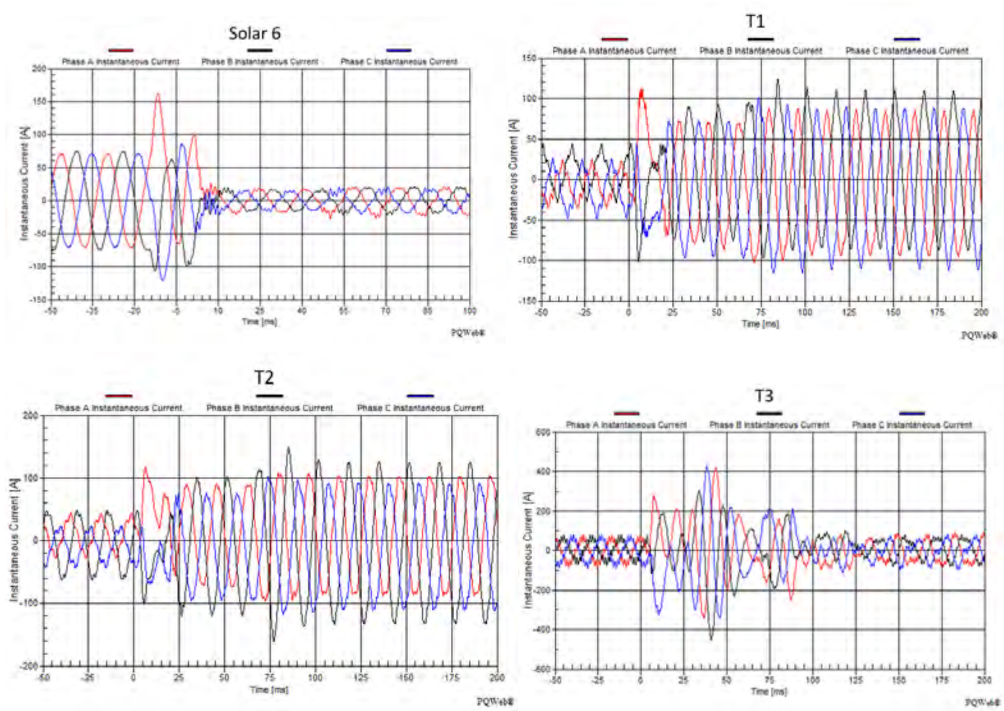

Figure 3.3: 230-44-28 kV Substation Response to a 115 kV Three Phase Fault

Dynamics of Aggregate DER Models

Similar to the process for individual DER models, the multiple generator models pose just a few more nuances in the procedure. As the **Recommended DER Modeling Framework** shows, the DER closer to the substation and the DER amidst load both will feed into the substation level measurement taken. This poses a challenge where the number of independent variables in the process are lower than the number of dependent outputs in the set with only one device at the T–D bank. As such, techniques that relate the two dependent portions of the model will be of utmost importance when verifying the model outputs. **Figure 3.4** describes the overall dynamic representation of U-DER-modeled DERs and R-DER-modeled DERs with respect to the T–D interface, and the same number of data points can help to verify the parameters in the DER model associated with the resource (similar to **Table 3.2)**. However, a few additional points help with attributing the total aggregation towards each model as seen in **Table 3.3**.

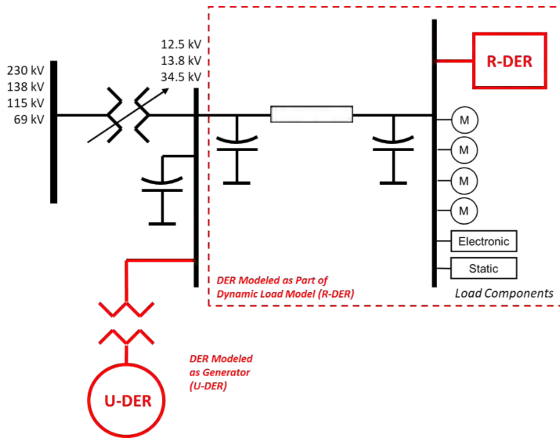

Figure 3.4: Aggregate DER Dynamic Representation Topology Overview

Table 3.5: DER Data Points and Anticipated Parameters

Data Collected	Data Measurement Location	Affected Representations	Anticipated Parameters
Ratio of U-DER and R-DER inverter output	Substation level	Relative Size of U-DER and R-DER Real Power output	Pmax in U-DER model, Pmax in R-DER model
Ratio of DER to Load	Substation Level	Relative size of Load model to U-DER and R-DER outputs	Pload in Load model, Pmax in DER models
Distance to U-DER installations	Substation Level to U-DER installation	Resistive loss and Voltage Drop	Voltage Drop / Rise parameters, Xe
Mean distance to DER amidst load.	Substation level to calculated mean	Resistive loss and Voltage Drop	Feeder, Voltage Drop / Rise Parameters.

Most notably, the last two rows of the table detail a way to help separate tripping parameters and voltage profiles seen at the terminals of U-DER and R-DER; however, these parameters may be the same for instances where U-DER installations are closer to the centroid of the feeder (i.e., more amidst load).. Should any of the above data be restricted or unavailable, following the engineering judgments in the *Reliability Guideline: DER_A Parameterization* *for Aggregate DER*[154] will assist in identifying the parameters to adjust based on inverter vintages. Further, the data answers in **Table 3.3** are not a substitution for measurement data taken at the U-DER terminals or at the high side of the T–D transformer. With the measurements available and the data in **Table 3.3**, the TP or PC can make informed tuning decisions when verifying their models. In terms of the DER_A model referenced in the reliability guideline above, there are some parameters that should not be tuned, and the guideline makes those explicit. In general, each model will have a set of parameters that are more appropriate to adjust to align with gathered measurements or answers to questions regarding installed equipment. Engineering judgement and the latest available guidance on specific models should be used to identify the parameters to tune in the model.

Initial Mix of U-DERs and R-DERs

> **Key Takeaway:**
> Relative sizes between load, U-DER, and R-DER can guide TPs and PCs on which portion of the aggregation to adjust during model verification.

In the model representation, the ratio of U-DERs and R-DERs is significant as the response of the two types of resources are expected to be different considering with relationship to specific voltage dependent parameters. As many entities do not track the difference in modeled DERs, if tracking DERs at all, it is expected that the initial verification of an aggregate U-DER and R-DER model requires more than the set of measurements at a location in order to attribute model changes. TPs and DPs are encouraged to coordinate/assist in getting a proper ratio of the devices in the initial Interconnection-wide base case. In the future, there exists a possibility that the interconnecting standard for U-DERs may be different than R-DERs. If such standards exist, the TP/PC should verify that the mix of U-DERs and R-DERs are representative of the equipment standards pertaining to the type of DER.

Parameter Sensitivity Analysis

As with most models, certain parameters in the DER_A model may impact the model output at the margins depending on the original parameterization. Trajectory sensitivity analysis (TSA), a type of sensitivity analysis varying the parameters of a model, quantifies the sensitivity of the dynamic response of a model to small changes in their parameters.[155] While TSA is commonly implemented differently across multiple organizations, certain software packages include a basic implementation. Among them are MATLAB Sensitivity Analysis Toolbox[156] and MATLAB Simulink. TSA analysis with respect to verifying DER_A dynamic model parameters can be found in **Appendix D** ~~**Appendix A**~~.

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TSA is one of many methods for TPs and PCs to gain understanding of the sensitivity of the dynamic model regarding small changes in model parameters; however, this is not a required step in model verification nor a required activity for tuning dynamic models. Furthermore, due to TSA linearizing the response of the dynamic model around the operating point, it may not account for changes in operating modes in the DER dynamic model and may not account for needed changes in flags or other control features in the model. Furthermore, some parameters in models may prove to be more sensitive than others but are not well suited for adjustments. One such example are transducer time delays that can greatly impact the response of the device, but other parameters are more likely to be changed first. Additionally, the numerical sensitivity of particular parameters is not needed for a TP to verify the aggregate DER dynamic model, but their impact on the dynamic response of the model is. It is encouraged that multiple set of parameters for DER models be tested against dynamic measurements when performing parameter analysis. Because of all these qualifications, use of TSA should be supervised by strong engineering judgment.

[154] ~~https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability_Guideline_DER_A_Parameterization.pdf~~ ~~[Link update on publish]~~Available here: https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Reliability_Guideline_ModelingMerge_Responses_clean.pdf

[155] Hiskens, Ian A. and M. A. Pai. "Trajectory Sensitivity Analysis of Hybrid Systems." (2000).

[156] https://www.mathworks.com/help/sldo/sensitivity-analysis.html

Chapter 4: Short-Circuit Data Collection Requirements

This chapter briefly describes considerations that should be made for gathering aggregate DER data for the purposes of short-circuit modeling and studies at the BPS level. Note that aggregate DER data collection for the purposes of distribution-level short-circuit studies is not considered.

Applications of Short-Circuit Studies

In general, short-circuit studies are used by transmission entities in two key ways: breaker duty assessment and setting protective relays. These are described below:

- **Breaker Duty Assessments:** In breaker duty assessments, all resources are on-line for the worst case assumption to ensure that BPS breakers will always be rated sufficiently to clear BPS fault events. This assumption has been used extensively in the past and will likely continue to be used in the future for these types of studies. In any system, the "significance"[157] of aggregate DER fault current will need to be considered by the engineer performing the studies. In areas where breakers are very close to their duty rating, aggregate DER contributions may be warranted (particularly of localized issues).
- **Setting Protective Relays:** Protective relay setting analyses study "all lines in-service" conditions as well as credible outage conditions that can affect the fault current characteristics of the local network. Alternate contingency events are selected and studied to ensure correct relay operation for a wide range of system configurations. In this case, the focus is not on equipment ratings; rather, it is on secure protection system operation. As the penetration of BPS-connected inverter-based resources as well as DERs continue to increase, their impact on BPS fault current impacts will become more significant and will need to be considered. This will likely be on a case-by-case basis in the near-term; however, this type of aggregate DER modeling data will likely be needed on a more regular basis in the future. Not fully modeling potential impacts to BPS fault current can have an adverse impact on setting protective relays.

In either type of study, it is important for TOs and TPs to establish data collection practices early to ensure sufficient data can be collected for performing accurate short-circuit studies. BPS equipment integrity and public safety are of utmost importance, and these studies rely on sufficient data to conduct them.

Potential Future Conditions for DER Data and Short-Circuit Studies

As the BPS continues to experience an increase in the penetration of BPS-connected inverter-based resources as well as DERs, short-circuit modeling and study practices may need to evolve. In some cases, aggregate DER data (along with possibly end-use load data) may become increasingly important for BPS short-circuit studies. In particular, each TP and PC should consider **Table 4.1**, which lays out potential future conditions where aggregate DER data may be needed for short-circuit modeling. **Table 4.1** is intended as a guide to help describe the considerations as they relate to specific system needs and therefore the need for aggregate DER short-circuit modeling data. In each scenario in **Table 4.1**, TPs, PCs, and TOs are recommended to establish short-circuit data collection requirements for existing and future DER additions to assure studies can be performed adequately.

> **Key Takeaway:**
> There is likely some cases where aggregate DER and load data can improve short-circuit studies. Particularly for local breaker-duty studies. TPs, PCs, and TOs should establish clear short-circuit data collection when DER become impactful to these studies.

[157] "Significance" is used loosely and generally in this discussion but becomes increasingly important under high penetration DER conditions.

Table 4.1: Potential Future Conditions for DER Data Collection for Short-Circuit Studies	
#	**Potential Future Conditions and Considerations**
1	**Condition:** BPS-connected synchronous generators dominate, and DERs are not prevalent.
	Consideration: This may be the status quo for some entities. BPS-connected synchronous generators provide significant fault current, and aggregate DERs and end-use loads are typically not modeled because the majority of fault current comes from synchronous machines.
2	**Condition:** Resource mix consists of both BPS-connected inverter-based and synchronous generators, and DERs are not prevalent.
	Consideration: This is likely the status quo for many entities with growing penetrations of BPS-connected wind and solar PV but fairly low penetrations of DERs. BPS fault currents are decreasing due to the BPS-connected inverter-based resources.[158] Aggregate DERs and end-use loads are generally not modeled in short-circuit studies because the majority of fault current still comes from the BPS (mainly synchronous generators).
3	**Condition:** BPS resource mix consists of both synchronous and inverter-based resources, and DERs are becoming increasingly prevalent.
	Consideration: Some areas are experiencing this condition today (e.g., CAISO, ISO-NE). The growth of DERs in conjunction with increasing BPS-connected inverter-based resources is leading to a high overall inverter-based system. Increased BPS-connected inverter-based resources is still affecting fault characteristics[159] on the BPS. Legacy DERs are likely not providing fault current due to the use of tripping and momentary cessation for large disturbances, and there likely has been a lack of interconnection requirements to specify behavior for DERs during fault events. Inverter-based DERs providing fault current, where applicable, may have an impact on localized breaker duty studies and may need to be considered for setting protective relays. On a broader scale, synchronous generators dominate BPS fault current; the impedance between DERs and the BPS fault is so large that DER fault current contribution to the BPS is relatively low. Therefore, TPs and PCs will need to explore this on a case-by-case basis but should ensure the ability to collect aggregate DER data.
4	**Condition:** DERs can provide the majority of energy to end-use customers during certain instances; these conditions are likely coupled with increasing BPS-connected inverter-based resources and limited on-line synchronous generators.
	Consideration: Few, if any, areas of the North American BPS experience situations like this today; however, this scenario may be more likely in the future (even within the planning horizon). Lack of on-line synchronous generators causes low fault current magnitudes. DER interconnection requirements for new-vintage DERs may allow for momentary cessation as a default setting (i.e., 1547-2018). Existing and future installations of DERs may not provide fault current unless momentary cessation is prohibited by local requirements.[160] Where DERs are providing fault current, inverter-based DERs can only provide a limited magnitude of current and their contribution will be primarily for nearby local faults; the impedance between the DERs and the BPS fault location cause their contribution to be low. BPS protective relaying could experience issues under these types of scenarios either due to very low fault current levels or unknown/unstudied fault current behavior (e.g., phase relationship).[161] Solutions may be needed to maintain acceptable levels of fault current (e.g., synchronous condensers). Some synchronous generation will likely remain on-line for the foreseeable future (i.e., hydro generators), providing a suitable amount of fault current in those areas. However, as the primary source of generation (and possibly fault current) in this scenario, aggregate DERs may need to be modeled in short-circuit studies. Aggregate representation of DERs is likely suitable so long as any significant differences in fault current contribution is differentiated. TPs and PCs will need to assess the potentiality of this scenario and determine whether they should proactively collect aggregate DER data for short-circuit modeling.

[158] The power electronics interface of inverter-based resources limits fault current contribution from these resources. Furthermore, some BPS-connected solar PV resources may employ momentary cessation, which is an operating state for inverters where no current is injected into the grid by the inverter during low or high voltage conditions outside the continuous operating range.

[159] Decreasing fault current magnitude and the uncertain phase angle relationship between voltages and currents from inverter-based resources

[160] This will need to be analyzed closely and coordinated between distribution and transmission planning and protection engineers.

[161] This would be caused both by BPS-connected inverter-based resources as well as the DERs.

Differentiating Inverter-Based DERs

It may be prudent for TPs and PCs to consider separating requirements for inverter-based and synchronous DERs due to their relatively different impacts on BPS fault characteristics. Synchronous DERs (e.g., low head hydro, run of river hydro, combined heat and power plants) likely should be modeled in short-circuit studies since they can be a significant source of fault current in that local area. However, the majority of newly interconnecting DERs in most regions are inverter-based (e.g., solar PV and BESSs). Inverter-based DERs may only provide a relatively small fault current (i.e., on the order of 1.1 pu maximum) if any. IEEE 1547-2018 allows for the use of momentary cessation during low voltages such as during fault events, and, therefore, fault current from DERs may very well be minimal or zero in the future. This type of information should be considered by the TP and PC performing short-circuit studies and verifying their short-circuit models.

Example Impact of Aggregate DERs on BPS Fault Characteristic

Whether or not a specific DER (i.e., U-DERs) or aggregate amount of DERs (i.e., R-DERs as well as U-DERs) have a significant[162] impact on the BPS will need to be determined by the TP and PC performing such studies. During SPIDERWG discussions, Southern California Edison provided a rough rule-of-thumb for DER impacts to be the following values:[163]

- At 500 kV, 1–2 A/MW
- At 230 kV, 4–5 A/MW
- At 115 kV, 7–8 A/MW
- At 66 kV, 10–15 A/MW

These values assume a three-phase fault is applied at the transmission or sub-transmission system bus where the DERs (and end-use loads) are directly being served out of and roughly account for typical impedance between the DERs and the T-D interface. These numbers will vary by system configuration but demonstrate a relative impact as DER penetrations continue to increase across large portions of the BPS.

Considering Short-Circuit Response from DERs and Loads

Inverter-based DERs configured to provide fault current are limited to around 1.1 pu maximum fault current due to the power electronics interface of the inverter. On the other hand, direct-connected motor loads will dynamically respond during and immediately after the fault and affect overall fault current contribution along the feeder. This is particularly true for R-DERs spread throughout the feeder; however, even fault current from U-DERs located at or near the head of the feeder may provide little fault current through the T-D interface. Therefore, short-circuit characteristics of end-use loads will need to be taken into account when considering DER short-circuit contributions.

Typically, load is not modeled in short-circuit analysis because its impact and significance to overall BPS fault current levels is very low. However, in localized areas or systems dominated by DERs, fault current from DERs may play a more significant role in overall fault current contributions. In these cases, it may be deemed necessary to model DERs for short-circuit analysis. It is important to note, however, that the response from end-use loads (particularly motor load) should also be considered in cases where DER contribution to BPS fault current is deemed necessary to model. This is analogous to short-circuit studies performed at large industrial facilities where the effects of motor loads on fault current cannot be overlooked since they have a significant impact on proper relay operation. The same concept applies to the BPS in a system where the fault current contribution from DERs and loads cannot be overlooked.

[162] The term “significant” is used loosely and generally in this discussion but becomes increasingly important under higher penetrations of DERs.
[163] This assumes a mix of R-DER and U-DER along the feeder and assumes a maximum fault current from DERs of 1.1-1.2 pu based on available inverter manufacturer data.

Verification of Short-Circuit Response from DERs and Loads

As the verification of short-circuit response from DERs and load require a fault to occur and sensitive equipment to measure the contributions across the distribution system, the SPIDERWG does not recommend a wide-spread initiative to verify short-circuit parameters.[164] Any testing in such a manner should be done on an ad hoc basis with solid engineering judgement and specialized equipment in place to ensure the testing of the system does not need to be repeated. SPIDERWG does recommend to ensure proper communication of known short-circuit parameters from distribution entities to transmission entities to identify portions of the bulk system that may have a short-circuit coordination concern. TPs, PCs, and DPs should also verify the instances where the distribution fuse-based protection would warrant the fault current contribution of DERs and load in transmission level models.

Aggregate DER Data for Short-Circuit Studies

In cases where DER data may be necessary for short-circuit studies, the TP and PC will need to establish requirements per MOD-032-1 Requirement R1 around what types of short-circuit modeling data need to be provided by the DP. These requirements should be as clear and concise as possible to help facilitate this data transfer. It is likely that many TPs and PCs fall into either Categories 2 or 3 of **Table 4.1** today. Where DER data may be needed for forward-looking short-circuit studies, the following information may be useful regarding aggregate[165] DERs:[166]

- Continuous MVA rating of aggregate DERs
- Estimated vintage of IEEE 1547-2018 and settings applicable for DER tripping and momentary cessation (i.e., would the DER trip or cease current injection for fault events)
- Assumed effective fault current contribution at a specific time frame(s)[167] during the fault
- Assumed phase angle relationship between voltages and currents

Example where DER Modeling Needed for Short-Circuit Studies

One example of where U-DER data may be needed is local breaker duty short-circuit analyses. Consider **Figure 4.1**, which shows a 230/69 kV network with a hypothetical yet possible situation where breaker underrating could happen. At the MK-69 bus, before the addition of DER #1 (20 MW) and DER #2 (20 MW), the breaker at MK-69 (shown in red) connecting the circuit to GY-69 is at 99.4% of interrupting duty when a fault is applied on the MK-69–GY-69 circuit (shown in **Figure 4.1** as well). If the DER fault current contribution were ignored, then short-circuit studies would remain unchanged since the contribution from DERs would not be modeled. However, if the 40 MW nameplate capacity of DERs is modeled to provide 1.1 pu fault current, the breaker could be underrated as the interrupting fault duty jumps to 101.1% and exceeds the 100% rating of the BPS element. These effects may be observed locally today across many parts of the BPS but may also become more prominent as the amount of DERs continues to increase (or if the fault current contribution is much higher from a synchronous DER).

[164] As such an initiative would entail a high cost to measurement equipment as well as require intentionally faulting the electric system, most likely creating disruptions and interruptions to load.

[165] Again, this is likely on a T-D transformer basis, per TP and PC data reporting requirements.

[166] Based on minimum requirements for modeling voltage-controlled current sources in short circuit programs

[167] These may include sub-transient, transient, and other applicable time frames based on TP and PC modeling and study techniques.

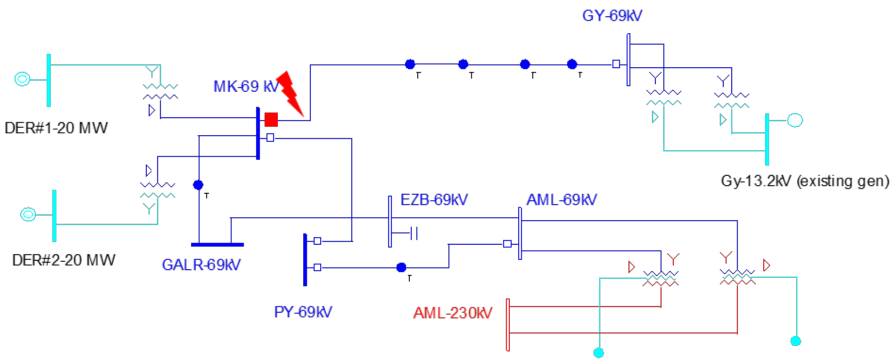

Figure 4.1: Example Network for Breaker Underrating Example

Chapter 5: GMD Data Collection Requirements

NERC TPL-007-3[168] requires TPs, PCs, TOs, and Generator Owners owning facilities that include power transformers with a high-side, wye-grounded winding with terminal voltage greater than 200 kV to perform GMD vulnerability analysis[169]. The GMD vulnerability assessment is a documented evaluation of potential susceptibility to voltage collapse, cascading, and localized damage to equipment due to GMD events.[170]

During a GMD event, quasi-dc GICs flow through transmission circuits and return through the Earth by grounded-wye transformers and series windings of autotransformers that provide a dc path between different voltage levels. DC current flow through transformers produces harmonic currents that can increase transformer reactive power consumption and may cause hot-spot heating that potentially leads to premature transformer loss of life or failure. Furthermore, harmonic currents propagate through the power system can cause BPS elements to trip and may be a potential susceptibility for aggregate DER tripping.[171]

In performing GMD vulnerability assessments, TPs and PCs use a dc-equivalent system model (GIC system model) for determining GIC levels and a steady-state power flow model for assessing voltage collapse risks. Current GMD vulnerability assessment techniques, per TPL-007-3, do not call for modeling the distribution system or including DER data.[172] Typically, only higher voltage BPS elements are represented in these simulations because long transmission circuits with low impedance generally produce the highest levels of GICs. Furthermore, delta transformer windings block GICs from flowing since they do not create a return path for GICs to flow. Many T-D transformers are delta-wye (grounded on the distribution side), so GICs could only flow on the distribution side. However, distribution circuits are relatively short and have high impedance, so GIC flow at the distribution level will be insignificant with respect to BPS impacts. Hence, distribution-level circuits are not included in the dc-equivalent system model (GIC system model).

Key Takeaway:
There is currently no need to model the distribution system, end-use loads, or aggregate DERs for the purposes of vulnerability assessments in TPL-007-3.

Based on these findings, there is currently no need to model the distribution system, end-use loads, or aggregate DERs for the purposes of vulnerability assessments in TPL-007-3. However, as the penetration of DERs continues to increase to higher levels, this assumption may need to be revisited in the future. The vulnerability of DERs to GMD-caused severe voltage distortion remains an issue for industry to explore in more detail.

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168 https://www.nerc.com/_layouts/15/PrintStandard.aspx?standardnumber=TPL-007-3&title=Transmission%20System%20Planned%20Performance%20for%20Geomagnetic%20Disturbance%20Events&jurisdiction=United%20States

169 The 200 kV and above threshold was compared to the impact of ignoring the 115 kV portion of the transmission system and found that the impact to GIC current was negligible. See here: https://www.nerc.com/pa/Stand/Project201303GeomagneticDisturbanceMitigation/ApplicableNetwork_clean.pdf

170 See NERC's *Glossary of Terms* used in Reliability Standards: https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf

171 While local distribution-related issues may arise, there is no evidence that widespread distribution issues could manifest and impact the BPS during GMD events. However, a large GMD event may cause severe harmonic distortion on the distribution system. The main concern related to DER would be potential tripping caused by harmonic distortion. However, further research is needed in this area to understand the extent to this risk. Refer to the EPRI report for more details: https://www.epri.com/#/pages/product/000000003002017707/?lang=en-US.

172 NERC *Application Guide for Computing Geomagnetically-Induced Current in the Bulk-Power System*, December 2013: http://www.nerc.com/comm/PC/Geomagnetic%20Disturbance%20Task%20Force%20GMDTF%202013/GIC%20Application
NERC *GMD Planning Guide*, December 2013: http://www.nerc.com/comm/PC/Geomagnetic%20Disturbance%20Task%20Force%20GMDTF%202013/GMD%20Planning

Chapter 6: EMT Data Collection Requirements

As the penetration of BPS-connected inverter-based resources continues to grow, EMT modeling and simulations are becoming increasingly critical for ensuring reliable operation of the BPS. Entities are developing interconnection requirements for BPS-connected inverter-based resources to ensure that modeling information is available to perform EMT simulations when needed.[173] As the DER penetration continues to grow, there may be situations where studying reliable operation of the BPS, including networked sub-transmission systems, will require modeling DERs.[174] If industry is moving towards performing EMT simulations for BPS-connected plants (for example, on the order of 50 MW) because of known reliability issues, it warrants similar EMT simulations to be performed for pockets of high penetrations of DERs as well (for example, a small geographic area of 50–100 MW of DERs). This chapter describes the situations where representing DERs in EMT models may be needed by the TP and PC and the steps that can be taken to help facilitate development of these models in coordination with the DP.

DER Modeling Needs for TPs and PCs

EMT simulations are used to study very detailed interactions between grid elements and controls and can capture potential reliability issues that may not be detected with fundamental-frequency, positive sequence, and phasor simulation tools. As the penetration of inverter-based resources grows, EMT simulations become increasingly important in many areas. In most cases, EMT simulations are needed in pockets of the BPS where the localized penetration of these resources is high. Examples of situations where these types of studies are needed include, but are not limited to, the following:

- High penetration pockets of inverter-based resources, particularly when DERs replace or displace synchronous generation in the local area. The lack of synchronous resources presents challenges related to synchronous inertia and low short circuit strength conditions. As these pockets experience increasing penetrations of DERs, potential reliability risks may arise that require EMT simulations to identify.
- Ride-through performance for DERs (and BPS-connected inverter-based resources) becomes critical during severe voltage excursions in pockets of low short circuit strength. This often requires EMT simulations that represent the specific phase-based protection aspects and inner control loops of inverter controls.
- Analysis of voltage control performance and coordination of voltage control settings across many DERs and the BPS. Areas with high penetration of DERs may need to rely on dynamic reactive support on the BPS and may see greater variability of voltages at the distribution level. This will need to be coordinated, and EMT simulations are more effective at identifying issues than fundamental-frequency, positive sequence, phasor simulations.
- Pockets of high penetrations of inverters are prone to control interactions between neighboring facilities or with the grid. In addition, these pockets may present control stability issues for inverter-based resources that require attention for aspects of large disturbance behavior, such as active and reactive power recovery and oscillations. When DERs represent a substantial amount of generation in a localized area, these issues may arise and could impact the BPS.
- Selection of control modes, such as momentary cessation and other ride-through performance, and reliable operation of the overall area or region (including parts of the BPS) may be necessary under high DER penetration conditions.

[173] https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Reliability_Guideline_-_Interconnection_Requirements-redline_June_16_2022.pdf
[174] https://www.nerc.com/comm/PC/System%20Planning%20Impacts%20from%20Distributed%20Energy%20Re/Studies%20-%20SPIDERWG%20Bulk%20DG%20penetration%20study%20-%20Marszalkowski,%20Isaacs.pdf

There is no clear threshold for when EMT simulations are needed in any of the situations described above.[175] TPs and PCs have developed various metrics to identify potential conditions, specifically for BPS-connected inverter-based resources, that warrant closer attention through EMT simulation techniques.[176]

Mapping TP and PC Modeling Needs to DER Data Collection Requests

EMT models are detailed representations of system elements used for identifying a wide range of potential issues, as mentioned above. However, representing end-use loads or aggregate DERs, in many cases, requires some assumptions and estimations be applied. While use of generic models for EMT simulations is typically discouraged for BPS-connected resources, the data for creating EMT models (or the EMT models themselves) may not be available for many types of DERs. However, for cases where the TP and PC have determined that an EMT study involving aggregate DERs may be needed to ensure reliability of the BPS,[177] the following recommendations are made:

- **R-DER:** Small, retail-scale DERs across the distribution system (e.g., rooftop solar PV) will most likely not have DER models or information available, and this level of detail is not needed for a BPS EMT simulation. Rather, generic EMT models can be used to represent the aggregate amount of DERs at locations similar to how steady-state power flow and fundamental-frequency positive sequence simulations are performed. For the most part, the information needed to formulate an EMT model of aggregate DERs will mirror the information needed for fundamental-frequency, positive sequence dynamic models (i.e., steady-state and dynamic transient models in **Chapter 1** and **Chapter 2**), including the following:
  - Type of DER and vintage of IEEE 1547
  - Disturbance ride-through behavior including use of momentary cessation
  - Voltage, frequency, phase angle, and ROCOF trip thresholds
  - Dynamic and steady-state voltage control performance expectations
  - Reasonably replicate, to the ability of the model, the per-phase nature of DER functions
- **U-DER:** Some entities have implemented the same modeling requirements for larger inverter-based U-DERs as for BPS-connected inverter-based resources; namely, that an EMT model may be requested from the TP or PC and will need to be supplied by the DER owner in coordination with the manufacturer, to the extent possible. This is typically applicable only for U-DER facilities greater than 1 MVA in capacity. For substations with multiple inverter manufacturers, the TP and PC may aggregate these models into distinct U-DERs for the more predominant inverter types. On the other hand, other entities may deem that generic models may be suitable for U-DERs as well, and the information described above could also apply for developing EMT models for U-DERs.
- **Load Models:** In situations where detailed DER models are being provided or created for the purposes of EMT studies, it is also important to accurately capture the expected behavior of aggregate amounts of end-use loads. The performance of the end-use loads in combination with DERs will have an impact on the distribution system and BPS performance, and these should be accounted for in some way. The TP and PC will need to coordinate with the DP and/or TO for providing this load information in addition to the DER information found in the above bullet points.

Industry is still grappling with the growing need for EMT simulations in many areas, and new findings and recommendations will continually be developed. It is clear, however, that EMT simulations may be needed to

[175] The NERC Inverter-Based Resource Performance Subcommittee is also working on a reliability guideline on EMT studies. It is slated to be released in 2023 and will be published under the RSTC here: https://www.nerc.com/comm/Pages/Reliability-and-Security-Guidelines.aspx
[176] https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Item_4a._Integrating%20_Inverter-Based_Resources_into_Low_Short_Circuit_Strength_Systems_-_2017-11-08-FINAL.pdf
[177] Independently of the BPS study, a DP that needs to perform EMT analysis on its distribution system may require similar, if not more detailed, information than provided in the list.

appropriately identify specific reliability issues in high DER penetration pockets; [178] therefore, the TP and PC should coordinate with the DP, equipment manufacturers, or other external entity to gather EMT modeling information to the extent possible, when needed. In areas where there is not a DP across the T-D interface, the TP may need to revise their interconnection agreements to begin this collaboration[179]. A transmission study to investigate high DER penetration pockets will require a distribution EMT study to ensure that the equivalent distribution systems in the pocket are representative. However, a transmission EMT study that incorporates the impact of the T-D Interface does not have the same limitations. The modeling practices and level of detail will differ between both studies as the reliability issue to be studied is different. In both cases, increasing coordination among the transmission and distribution entities will highlight the necessary information to capture the issue to be studied and determine the models developed that represent the DER and load behind the T-D Interface.

[178] SPIDERWG has provided a technical report that highlights the various aspects for these types of simulations. Available here: https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Beyond_Positive_Sequence_Technical_Report.pdf

[179] There may be other venues to start the collaboration than a revision to the interconnection agreements. This underscores a higher need of collaboration in this area.

Appendix A: References For Further Reading

- NERC, "Connection Modeling and Reliability Considerations," Atlanta, G, February 2017.
- NERC, "Technical Brief on Data Collection Recommendations for Distributed Energy Resources," Atlanta, G, March 2018.
- NERC, "Reliability Guideline: Modeling Distributed Energy Resources in Dynamic Load Models," Atlanta, GA, December 2016.
- NERC, "Reliability Guideline: Distributed Energy Resource Modeling," Atlanta, GA, September 2017.
- NERC, "Reliability Guideline: Parameterization of the DER_A Model," Atlanta, GA, September 2019.
- P. Pourbeik, "Proposal for DER_A Model," WECC Renewable Energy Modeling Task Force, Salt Lake City, UT, September 2018.
- NERC, "Reliability Guideline: Improvements to Interconnection Requirements for BPS-Connected Inverter-Based Resources," Atlanta, GA, September 2019.
- NERC, "MOD-032-1 – Data for Power System Modeling and Analysis," Atlanta, GA, May 2014.
- NERC, "TPL-001-4 – Transmission System Planning Performance Requirements," Atlanta, GA, October 2014.
- NERC, "TPL-007-3 – Transmission System Planned Performance for Geomagnetic Disturbance Events," Atlanta, GA, November 2018.
- NERC, "Reliability Guideline: Integrating Inverter-Based Resources into Low Short Circuit Strength Systems," Atlanta, GA, December 2017.
- EPRI, "Assessment Guide: Geomagnetic Disturbance Harmonic Impacts and Asset Withstand Capabilities," 3002017707, Palo Alto, CA, December 2019.
- IEEE, "1547-2018 – IEEE Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces," April 2018.
- IEEE, "1547a-2014 – IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems – Amendment 1," May 2014.
- IEEE, "1547-2003 – IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems," July 2003.
- Ofgem, "Technical Report on the events of 9 August 2019," London, United Kingdom, September 2019.

Appendix B: Data Collection for DER Energy Storage

Collecting data for DER energy storage is similar to collecting data for DER generating resources. However, it is worthwhile to highlight considerations that should be made when developing data reporting requirements for collecting DER data that ensure clarity for representing energy storage for planning assessments. This appendix describes some of the considerations at a high level that should be made and also describes specific data points that are unique to energy storage from a data collection standpoint. While there are many types of energy storage technologies available today, this appendix focuses mainly on inverter-based battery energy storage since it is the most prominent form of DER expected in the foreseeable future and widely observed in DER Interconnection queues today. Existing large, synchronous DERs may need to be modeled explicitly based on TP and PC modeling practices, and the TP and PC should have these considerations listed in any modeling requirements. Note that electric vehicles today are likely modeled as part of the load since most existing electric vehicles do not provide storage capability, and demand response actions (such as reduction of heat pump loads) are also not generally modeled as energy storage in planning models. Lastly, there are different ways to model energy storage DERs—as part of the composite load model, as a standalone resource, or lumped with other forms of DERs. This guideline focuses on data collection necessary for the TP and PC to be able to make appropriate modeling decisions based on their own practices.

Considerations for Steady-State Modeling

Energy storage DERs are likely modeled similarly to other DERs in planning base cases although modeling and study practices may vary based on whether the energy storage is assumed to be charging or discharging. Energy storage DERs will need to be accounted for to ensure appropriate modeling based on TP and PC modeling practices. The following considerations should be made by the TP and PC when developing data requirements for DER information with the DP (note that these considerations build off of **Table 2.1**):

- **Location:** TPs and PCs will need to know the general location (at least mapped to a T-D transformer) of energy storage batteries such that they can be modeled appropriately in planning base cases in conjunction with other DERs and end-use loads. Separating DER generation and energy storage for collecting accurate DER data from the DP in coordination with any other state-level agency or regulatory body is a prudent step for effectively developing base cases based on TP and PC practices.
- **DER Type (or aggregate type):** As stated, differentiating out DER generators, DER energy storage, and hybrid facilities will be needed for the purposes of aggregate modeling of DERs in the future.
- **Transformer Information:** If the energy storage DER is represented as a U-DER, a generator step-up transformer may be explicitly modeled by the TP and PC based on their modeling practices.[180] In this case, transformer information may be needed by the TP and PC for modeling the energy storage DER facility. Appropriate reactive capability at the U-DER point of interconnection should be modeled regardless of modeling practice.
- **Historical or expected DER output profiles:** The output profiles for energy storage DERs are likely much different than for DER generation, such as synchronous or solar PV DERs. As such, the TP and PC will need to determine a suitable assumption for output profiles for each to create planning base cases. Therefore, some information will be needed on energy storage DER output profiles. Some questions for consideration include, but are not limited to, the following:
  - What percentage of energy storage DERs are participating in wholesale markets, and can the markets in which those DERs are participating provide any useful information in terms of how the energy storage DERs may be dispatched?

[180] These practices may include explicit modeling of the plant main power transformer and equivalent representation of individual pad-mounted transformers within the U-DER facility, or it may be simplified to an equivalent representation of transformations. The TP and PC should have modeling requirements that clarify this point.

- What percentage of energy storage DERs are operating based on retail signals, such as time of use charges or other third-party signals that drive charging and discharging, at specific hours of the day? Most commonly, the assumption is made that energy storage DERs will charge during light load conditions and discharge during peak loading conditions; however, various entities have experienced energy storage charging patterns that do not conform to these basic assumptions. Therefore, the DP will need to coordinate with the TP, PC, and any other state-level agency or regulatory body to determine how these patterns could affect transmission planning processes and practices.

- **DER Status:** It is not likely that additional considerations will be needed for energy storage DERs related to status (on-line versus off-line). However, TPs and PCs will need to consider whether the aggregate amount of energy storage DER is charging or discharging.
- **Maximum DER active power capacity (Pmax):** As mentioned, differentiating the amount (capacity) of energy storage DERs will enable the TP and PC to model these resources, as needed. Therefore, it is not likely that additional information would be needed for energy storage DERs.
- **Minimum DER active power capacity (Pmin):** Energy storage resources have the ability to charge (unlike DER generators), so energy storage DERs will have a modeled negative Pmin value in the base case. Therefore, separating out energy storage DERs will enable reasonable representation of Pmin values in the base case.
- **Reactive power-voltage control operating mode:** Similar to DER generators, it is important to understand any interconnection requirements and operating practices for the DERs regarding their reactive power-voltage controls. Knowing this information, TPs and PCs will be able to model them accordingly.
- **Maximum DER reactive power capability (Qmax and Qmin):** If energy storage DERs are providing any voltage support, these resources will need an associated Qmax and Qmin value in the base case, and the DP will need to coordinate with the TP and PC to understand appropriate assumptions.

Considerations for Dynamics Modeling

Energy storage DERs represented in the planning base case should have some aggregate dynamic model that captures the general behavior of these resources during abnormal BPS conditions. The DER_A dynamic model is used to represent inverter-based DERs, which energy storage DERs fall under. However, the parameter values for the DER_A dynamic model that would need to be modified are fairly minimal. These include, but may not be limited to, the following (note that these considerations build off of **Table 3.1**):

- ***Typeflag*:** Explicit modeling of energy storage DER requires consideration of the *typeflag* parameter of the DER_A dynamic model. Refer to software model specifications for how to set *typeflag* to emulate an energy storage device.[181]
- ***Pmin*:** The *Pmin* will need to be modified to accommodate the capability to absorb active power (i.e., negative *Pmin*), based on the expected energy storage capacity being modeled. If the voltage-dependent current limits (absolute value, not sign) are different in charging versus discharging mode, the values of the voltage-dependent current logic (VDL) tables will need to be changed based on operating mode assumption.
- **Frequency Response Parameters:** If the energy storage DER is providing frequency response capability in either the upward or downward directions or both, these parameters will need to be configured accordingly. This could be different than the aggregate DER generation model. For example, R-DERs may not be providing underfrequency response; however, larger energy storage DERs may be providing this capability and service to a wholesale market.
- **Frequency and Voltage Ride-Through Capability:** TPs, PCs, and DPs should consider whether any different requirements are in place for DER energy storage versus DER generation; however, this is not likely in most

[181] Based on the specification for the DER_A dynamic model: https://www.wecc.org/Reliability/DER_A_Final_061919.pdf.

cases once the new IEEE 1547-2018 inverters become available. Consider whether the fractional reconnection (*vrfrac*) or active power ramp rate (*rrpwr*) may also be different for DER energy storage and generation.

- **Voltage Control Parameters:** TPs, PCs, and DPs should also consider whether any different requirements are in place for DER energy storage versus DER generation regarding voltage control. Voltage control settings that differ across DER energy storage and generation may require modeling details where additional data may be required by the TP and PC.

Considerations for Short-Circuit Modeling

As with DER generation, DER energy storage will most likely be inverter-based and therefore will only provide a small amount of fault current to BPS faults. Therefore, the TP and PC can consider whether DER energy storage would need to be differentiated in short-circuit studies based on the materials in **Chapter 4**. However, it is not likely that DER modeling for short-circuit studies is widely performed in the near-term.

Considerations for GMD Modeling

No additional considerations for DER energy storage are needed beyond the recommendations provided in **Chapter 5**.

Considerations for EMT Modeling

EMT modeling considerations for energy storage DERs are similar to those described above for dynamics modeling. If the TP or PC determine that DER data is needed for EMT simulations, differentiating DER energy storage and DER generation is recommended. Larger U-DERs (either DER generation or DER energy storage) may require more detailed models than aggregate amounts of R-DERs (again, either DER generation or DER energy storage).

Appendix C: DER Data Provision Considerations

DPs have some accounting of aggregate DER, in coordination with the TP and PC data requirements per MOD-032-1. A time line and projection of aggregate DER growth at each T-D transformer is of particular importance for steady-state, dynamics, short-circuit, and EMT modeling purposes. The transfer of aggregate DER data to the TP and PC for modeling is ultimately critical to the reliable operation of the BPS, particularly moving forward as the penetration of DERs continues to grow.

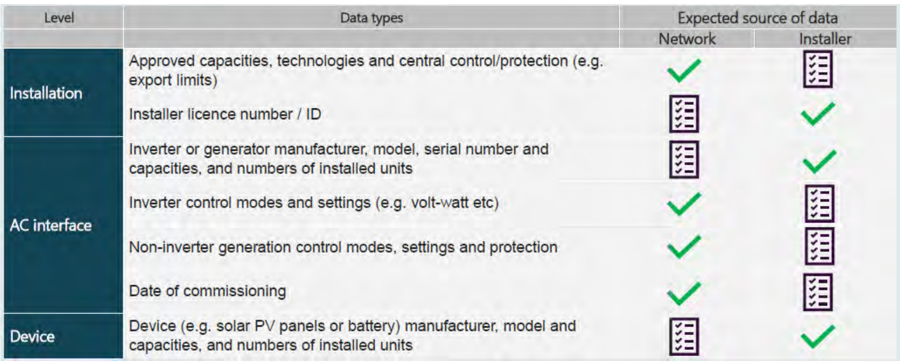
In some cases, however, the DP may not have aggregate DER information readily available to provide to the TP and PC for modeling purposes. This may be particularly true to future projections of DERs most relevant for TPs and PCs for planning purposes. External parties (e.g., state regulatory bodies like the California Energy Commission,[182] the Minnesota Public Utilities Commission,[183] and DER installers) may have more detailed information pertaining to wide-area DER projections. Thus, TPs and PCs will benefit from collaborating with DPs to determine if external parties can be engaged to help support the provision of DER data for modeling aggregate DER by the TP and PC.

TPs and PCs should consider developing an overall framework for the process of DER data collection. In particular, TPs and PCs will likely benefit by establishing data specifications that leverage the respective strengths of both DPs and DER installers for existing facilities as well as other sources for forward-looking projections. Furthermore, DPs could establish requirements that require DER installers to provide information to the DP, TP, and PC during DER interconnections. DPs may consider working with state regulators and other agencies to determine the most effective method for establishing these types of requirements. If alternative sources of DER data are readily available in higher quality forms for use by the TP and PC, these should be leveraged to the extent possible for use in planning BPS studies. Diagrammatic examples accompanying data specifications will likely reduce any confusion or misunderstanding between entities. Collaborative processes by which data specifications are determined and data collection frameworks are designed will likely result in higher quality information transferred from the DP and other applicable external entities to TPs and PCs. Higher quality information for the purposes of modeling will support reliable operation of BPS.

AEMO DER Registry Case Study

A recent example of external DER data that can be useful for modeling purposes comes from the Australian Electricity Market Operator (AEMO) DER Register.[184] Under the national electricity rules that govern Australia's major electricity market across the east and south eastern states, all network service providers (NSPs) provide or update "DER generation information," defined as "standing data in relation to a small generating unit" for any DER rated below 30 MW.[185] To facilitate the collection of DER generation information, AEMO worked with NSPs, DER installers, and other stakeholders for over a year to develop a secure online DER data submission process. AEMO requires submission of DER generation information at the national metering identifier level, simultaneously leveraging the relative strengths of NSPs and installers as DER data providers. **Figure C.1** illustrates AEMO's expectation for NSPs and installers to have different types of DER data, which AEMO determined are necessary to model and plan for the impacts of aggregate DER (options are allowed as to how the data is provided into AEMO's system).[186]

[182] https://ww2.energy.ca.gov/renewables/tracking_progress/documents/renewable.pdf
[183] https://mn.gov/puc/energy/distributed-energy/data/
[184] https://www.aemo.com.au/initiatives/major-programs/nem-distributed-energy-resources-der-program/der-register-implementation
[185] https://www.aemo.com.au/-/media/Files/Stakeholder_Consultation/Consultations/NEM-Consultations/2019/DER-register/Final/DER-Register-Final-Report.pdf
[186] https://www.aemo.com.au/-/media/Files/Electricity/NEM/DER/2019/DER-Register-Implementation/20191129---Introducing-DER-Register---NSW-Solar-Installer-Seminars_PDF.pdf



Level	Data types	Expected source of data: Network	Expected source of data: Installer
Installation	Approved capacities, technologies and central control/protection (e.g. export limits)	✓	📋
Installation	Installer licence number / ID	📋	✓
AC interface	Inverter or generator manufacturer, model, serial number and capacities, and numbers of installed units	📋	✓
AC interface	Inverter control modes and settings (e.g. volt-watt etc)	✓	📋
AC interface	Non-inverter generation control modes, settings and protection	✓	📋
AC interface	Date of commissioning	✓	📋
Device	Device (e.g. solar PV panels or battery) manufacturer, model and capacities, and numbers of installed units	📋	✓

Figure C.1: AEMO Expectations for Provision of DER Data [Source: AEMO]

The work flow for joint submission of DER generation data from the NSP and DER installers, ultimately resulting in a DER installation certificate, is shown in **Figure C.2**. The work flow diagram emphasizes the importance of a collaborative specification for attaining DER generation information. The distinction between "as-approved" and "as-installed" information is crucial; one subset of data is likely readily available to NSPs, whereas another subset of data is likely readily available to DER installers (see **Figure C.3**).

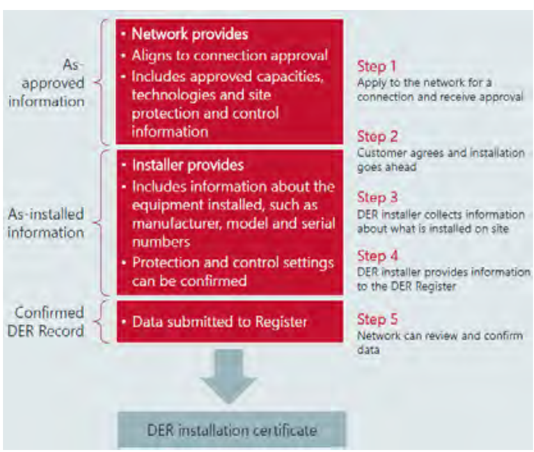


Figure C.2: Workflow of Joint Submission of DER Generation Data [Source: AEMO]

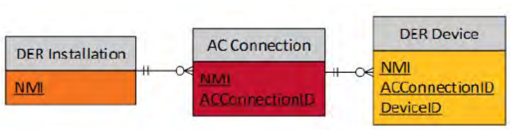


Figure C.3: Combination of DER Data as Defined by AEMO's Data Model [Source: AEMO]

To ensure quality of responses consistent with AEMO's data model structure, AEMO developed a series of scenarios to illustrate hypothetical DER configurations for NSPs and DER installers. Appendix E of AEMO's *DER Register Information Guidelines* shows the various considered scenarios.[187] The scenarios help ensure that the data requests are completed consistent with AEMO's specifications. The submission process is supported by an information collection framework that emphasizes four principals, listed below:

- Data collected should initially comprise the statically-configured physical DER system at the time of installation.
- Have regard to reasonable costs of efficient compliance compared to the likely benefits from the use of DER generation information.
- Best practice data collection should be implemented wherever possible to leverage existing data collection methods.
- Balancing information and transparency, the DER register should be accessible and easy to use while confidentiality and privacy are protected.

NSPs in the National Electricity Market have varying levels of sophistication when it comes connection approvals and data collection. As a result, AEMO's DER register system is designed with optionality to provide and validate DER data via API directly from the NSP, AEMO's web portal, or via smart-phone applications that many DER installers are already using to register an installation to access government subsidies. These options enable the minimum workflow change and cost for implementation for each NSP. The full design of the information collection framework and related implementation material is also publicly available.[188]

[187] https://www.aemo.com.au/-/media/Files/Stakeholder_Consultation/Consultations/NEM-Consultations/2019/DER-register/Final/DER-Register-Final-Report.pdf
[188] https://www.aemo.com.au/initiatives/major-programs/nem-distributed-energy-resources-der-program/der-register-implementation

Appendix D: Parameter Sensitivity Analysis on DER_A Model

Trajectory sensitivity analysis is one of the methods to correlate the linear sensitivity of dynamic model parameters to the dynamic response of a model. These types of calculations can help the TP understand these relationships during the tuning of dynamic model parameters. When verifying model performance, it is crucial to understand how the parameters affect the simulation output in order to match measured quantities.

If a parameter has significant influence on the trajectory of the dynamic model output, the corresponding trajectory sensitivity index will be large. It is common for certain parameters to have a significant influence on the trajectory of a particular disturbance or system condition and negligible influence in other disturbances or conditions. Before starting the parameter calibration procedure, it is critical to identify the candidate parameters in order to reduce the computational complexity of the problem. In this study, the measurement was the active and reactive power at the DER bus.

To quantify the sensitivity of parameters, a full parameter sensitivity analysis on DER_A model was carried out by performing the calculation on each of the parameters of DER_A, and the resulting parameter sensitivity indexes are summarized in **Table D.1**. Simulations were performed in PSS®E and utilize one of the sample cases (savnw) as a model basis. The DER-A model was added to the system, and each of the DER-A parameters were altered by +/- 10%; the simulated event was a three phase 500 kV fault on the line between bus number 201 and bus number 202. Parameters of the DER_A model not listed in **Table D.1** had a trajectory sensitivity of zero. It should be noted that the sensitivity calculation depends on the operating point in the simulation and that the DER_A model is an aggregated model. Both of these indicate that this calculation itself requires engineering judgement to determine if those parameters are justified to be changed. For instance, the Trv parameter is not a great candidate to change in the verification of the DER dynamic model even though it has a high sensitivity and impacts the simulation output greatly. The parameters that are good candidates to change are those that adjust the needed section of the dynamic performance (i.e., before, during, or after the fault) in the verification process, and the parameter chosen to tune makes sense to adjust (i.e., a controller gain). To help illustrate this, consider the Trv example in **Figure D.1**; while this constant has high sensitivity, it is less likely to be altered as other parts of the DER-A model that are likely to change between the initial model build and the installed equipment. Additionally, the graphical change for this calculation for Imax, Pmax, and Tiq are found in **Figure D.2** to **Figure D.4**, respectively.

Table D.1: Parameter Sensitivities for the DER_A model

Parameter	Value	Sensitivity	Description
Trv	0.02	High	Voltage measurement transducer time constant
Tiq	0.02	Low	Q-control time constant
Pmax	1.00	High	Maximum power limit
Imax	1.20	High	Maximum converter current
Vl	0.49	High*	Inverter voltage break-point for low voltage cut-out
Vl	0.54	High*	Inverter voltage break-point for low voltage cut-out
vh0	1.20	High*	Inverter voltage break-point for high voltage cut-out
vh1	1.15	High*	Inverter voltage break-point for high voltage cut-out
Tg	0.02	High	Current control time constant (to represent behavior of inner control loops
Rrpwr	2.00	High	Ramp rate for real power increase following a fault
Tv	0.02	High*	Time constant on the output of the multiplier

* indicates this variable is affected only when the voltage trip flag (VtripFlag) is enabled

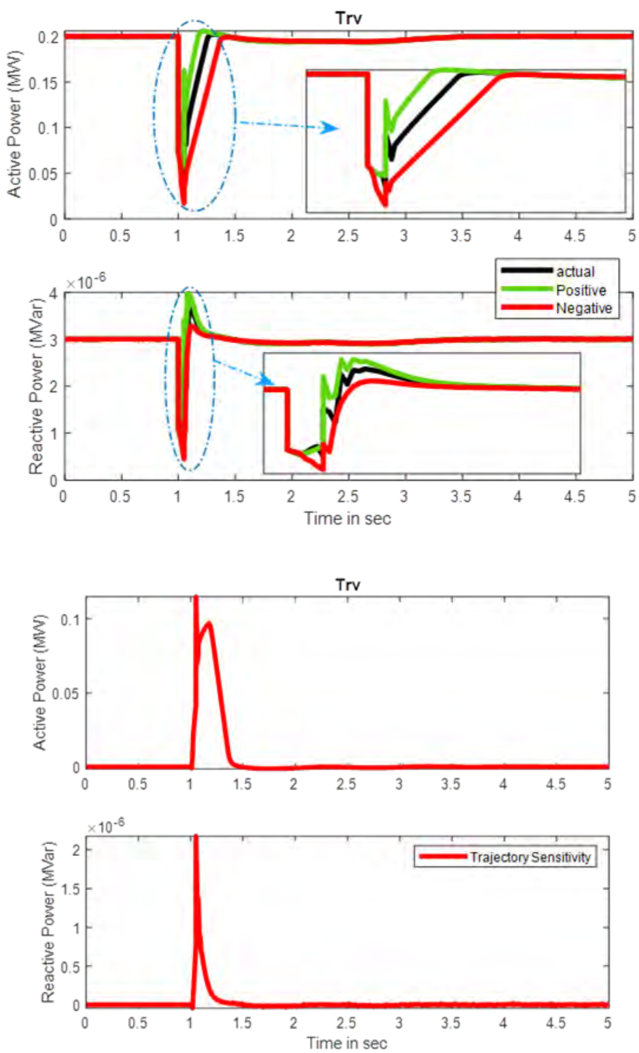


Figure D.1: Simulation Output and the Resulting TSA Calculation on Trv[189]

[189] The reader is cautioned that this graph and following graphs are not matching measurement data to simulation output; however, it is comparing a set parameter adjustment back to the original model output for the same contingency. As expected, as one increases the time constant for the inverter to react for a voltage dip due to a BPS fault, the inverter may not see the dip in time, and decreasing the time constant means the model will react quicker to voltage changes. See the block diagram in **Figure A.4** that shows the Trv constant, which demonstrates why this phenomenon exists.

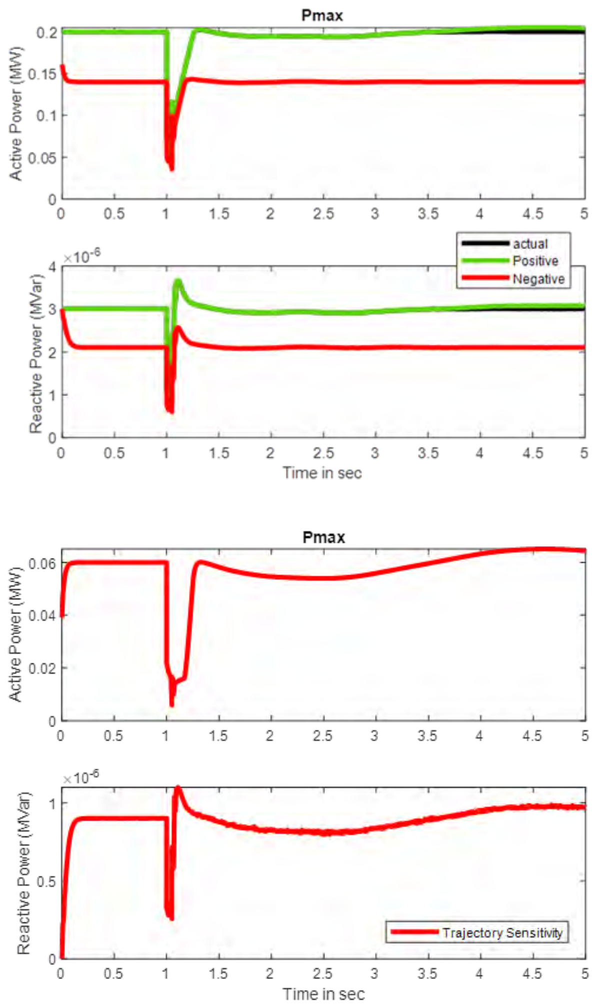


Figure D.2: Simulation Output and the Resulting TSA Calculation on Pmax.

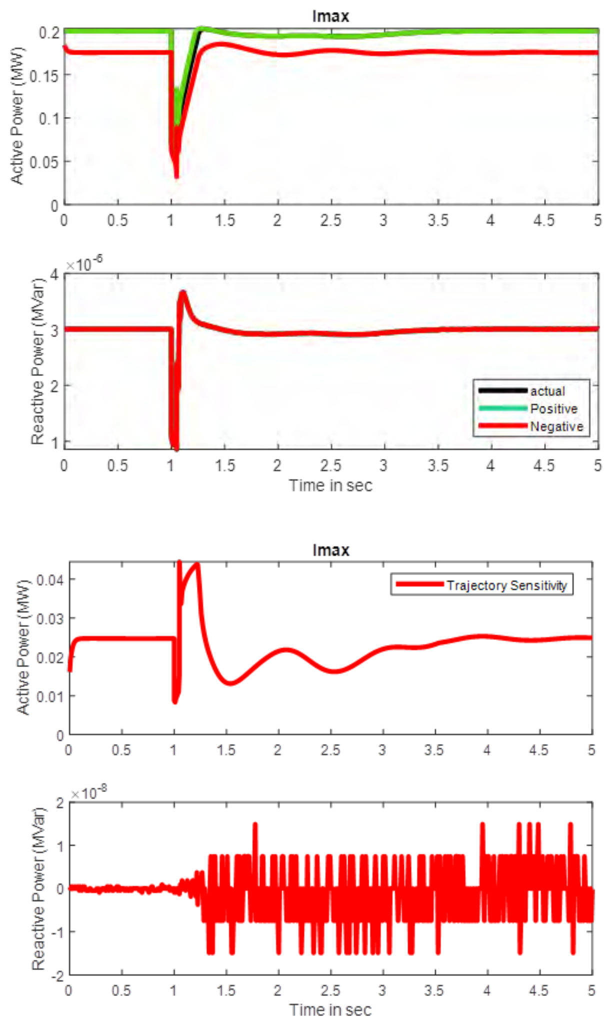


Figure D.3: Simulation Output and the Resulting TSA Calculation on Imax

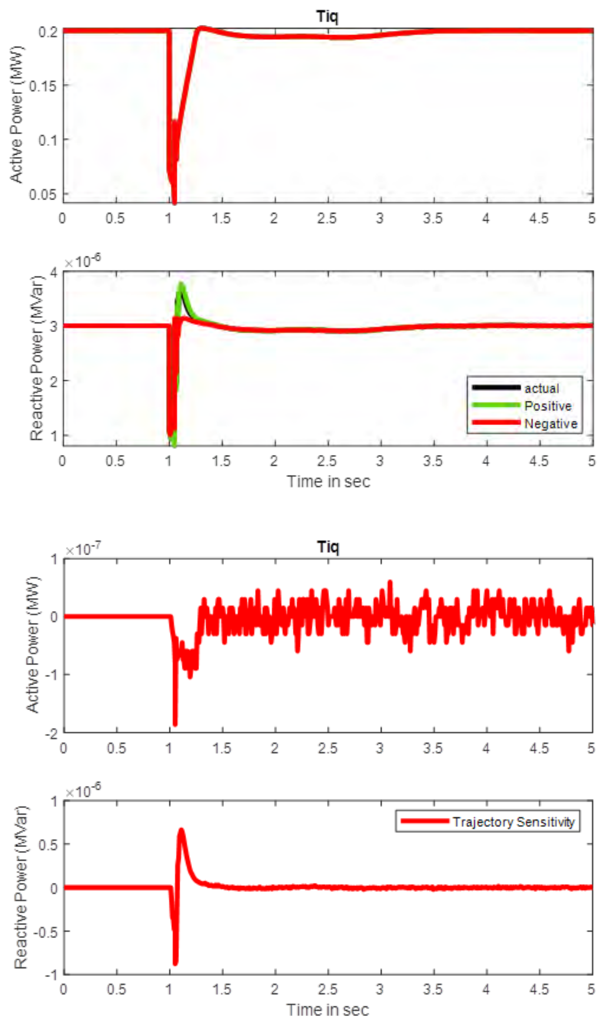


Figure D.4: Simulation Output and the Resulting TSA Calculation on Tiq.

Highly sensitive parameters have a relatively higher trajectory sensitivity and parameter values closer to zero are not as sensitive. Dynamic model control flags can affect the parameter sensitivity and therefore, need to be carefully selected (i.e., PfFlag, FreqFlag, PQFlag, GenFlag, VtripFlag, and FtripFlag). Figure D.5 shows where these flags are located with respect to the DER_A dynamic model.

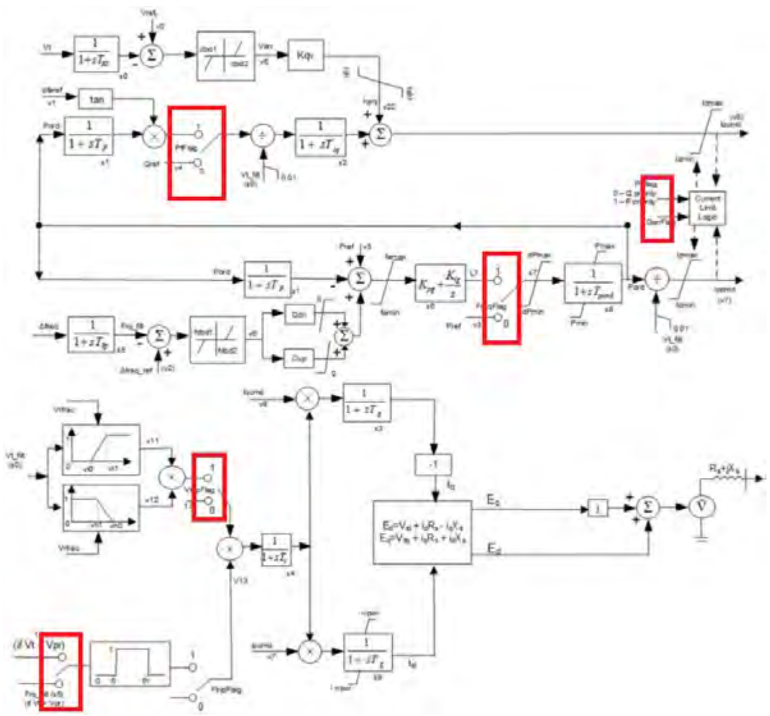


Figure D.5: DER_A Control Block Diagram in PSS®E [Source: Siemens PTI][190]

[190] PSSE model Documentation

Appendix E: Hypothetical Dynamic Model Verification Case

To assist in developing more complex verification cases and to demonstrate how certain aspects of the reliability guideline stated in **Chapter 3**, the SPIDERWG set up a sample case with hypothetical measurements and hypothetical parameters. This appendix demonstrates the model verification starting from a common load representation; this assumes that the load record that models the distribution bank, feeders, and end use customers is represented as a single load off the transmission bus and has already been expanded to the low side of the T–D bank for dynamic model verification. A generic load expansion for that single load record is used alongside the DER_A model. The example has the monitoring device at the high side of the T–D interface, and the verification monitoring records are set up with the monitoring at that location. If the monitoring devices were on the low side of the transformer, the model results would also need to reflect that.

Model Setup

In **Figure E.1**, a synchronous machine infinite bus representation that describes the modeled parameters is provided. The infinite bus is used to model the contributions from a strong transmission system and is used to vary both voltage and frequency at the high side of the transformer; however, the measurement location is assumed to be the high side of the transformer as per the recommendations in this reliability guideline. The TP/PC should determine the equivalent impedance in order to determine the system strength in that area. This example assumes a stiff transmission system at the load bus, so the transmission system is modeled as a jumper.

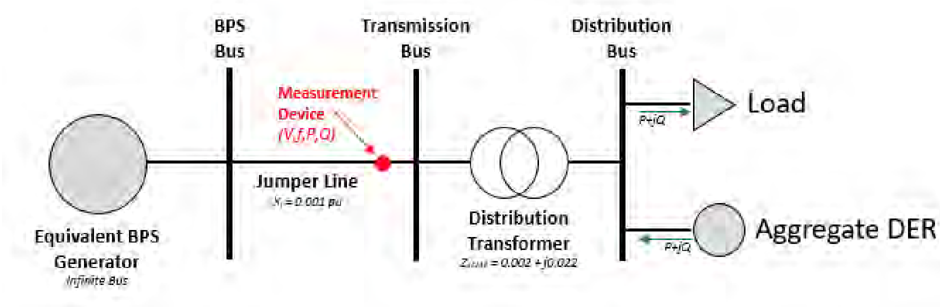


Figure E.1: Simulation Synchronous Machine Infinite Bus Representation for High Level Aggregate U-DERs

To populate the parameters in the representation, **Table B.1** provides the numerical parameters assumed in the setup of the powerflow, and **Table B.2** contains the default parameters utilized in the composite load representation at that bus. The transformer MVA rating is 80 MVA, and the study assumes that the transformer values have been tested upon manufacturing and is verified at the installation of the T–D bank.

Table E.1: Steady State Parameters for Study

Input Name	Value
Load	60+j30 MVA
Aggregate DER	10+j1 MVA

In order to parameterize the composite load model, the parameters in **Figure E.2** were used and are assumed to represent the induction motors and other load characteristics. This example is set to verify the dynamic parameters of the aggregate DER and assumes the impacts are separate from the load response and are fully attributed to the DER. The list of parameters that were provided in the original model is found in **Figure**

E.2 and lists the starting set of parameters in the simulation. The supplied measurements from the hypothetical DP to the hypothetical TP were taken at the high side of the distribution transformer as indicated in Figure E.1. In this example, the following models[191] were used to play in and record the buses at each system. Each model was chosen to assist in either retrieving simulation data from the files, inputting measurement data, or characterizing the dynamic transient response of the load or aggregate DER in Figure E.1. The following models were chosen for this simulation:

- Plnow: Used to input measurement data available for use in the dynamic simulation (time offset of zero for using all data in the file)
- Gthev: Used to adjust the voltage and frequency at the BPS bus in order to play-in the frequency and voltage signals
- Imetr: Used to monitor the flows at the high end of the T–D transformer where the measurement location is (this model records MW, MVAR, and amperage)
- Monit: Used to monitor convergence and other simulation level files when debugging software issues
- Vmeta: Used to tell the dynamic simulation to capture all bus voltages
- Fmeta: Used to tell the dynamic simulation to capture all bus frequencies
- Cmpldw: Used to characterize the load model
- Der_a: Used to characterize the aggregate DER model

[191] PSLF v21 was used to perform this example, and the PSLF model names are listed.

```
#
lodrep
cmpldw     102 "LOWSIDE"  13.8  "1"  :  #9   mva=-1 /
 "Bss"   0  "Rfdr"  0.01  "Xfdr"  0.01  "Fb"  0.75/
 "Xxf"   0.00  "TfixHS"  1  "TfixLS"  1  "LTC"  0  "Tmin"  0.9  "Tmax"  1.1  "step"  0.00625  /
 "Vmin"   1.025  "Vmax"  1.04  "Tdel"  30  "Ttap"  5  "Rcomp"  0  "Xcomp"  0  /
 "Fma"   0.167  "Fmb"  0.135  "Fmc"  0.061  "Fmd"  0.113  "Fel"  0.173  /
 "PFel"   1  "Vd1"  0.7  "Vd2"  0.5  "Frcel"  1  /
 "Pfs"   -0.998  "P1e"  2  "P1c"  0.566  "P2e"  1  "P2c"  0.434  "Pfreq"  0  /
  "Q1e"  2  "Q1c"  -0.5  "Q2e"  1  "Q2c"  1.5  "Qfreq"  -1  /
 "MtpA"   3  "MtpB"  3  "MtpC"  3  "MtpD"  1 /
 "LfmA"  0.75  "RsA"  0.04  "LsA"  1.8  "LpA"  0.12  "LppA"  0.104  /
 "TpoA"  0.095  "TppoA"  0.0021  "HA"  0.1  "etrqA"  0  /
 "Vtr1A"  0.7  "Ttr1A"  0.02  "Ftr1A"  0.2  "Vrc1A"  1  "Trc1A"  99999  /
 "Vtr2A"  0.5  "Ttr2A"  0.02  "Ftr2A"  0.7  "Vrc2A"  0.7  "Trc2A"  0.1 /
 "LfmB"  0.75  "RsB"  0.03  "LsB"  1.8  "LpB"  0.19  "LppB"  0.14  /
 "TpoB"  0.2  "TppoB"  0.0026  "HB"  0.5  "etrqB"  2  /
 "Vtr1B"  0.6  "Ttr1B"  0.02  "Ftr1B"  0.2  "Vrc1B"  0.75  "Trc1B"  0.05  /
 "Vtr2B"  0.5  "Ttr2B"  0.02  "Ftr2B"  0.3  "Vrc2B"  0.65  "Trc2B"  0.05 /
 "LfmC"  0.75  "RsC"  0.03  "LsC"  1.8  "LpC"  0.19  "LppC"  0.14  /
 "TpoC"  0.2  "TppoC"  0.0026  "HC"  0.1  "etrqC"  2  /
 "Vtr1C"  0.65  "Ttr1C"  0.02  "Ftr1C"  0.2  "Vrc1C"  1  "Trc1C"  9999  /
 "Vtr2C"  0.5  "Ttr2C"  0.02  "Ftr2C"  0.3  "Vrc2C"  0.65  "Trc2C"  0.1 /
 "LfmD"  1  "CompPF"  0.98  /
 "Vstall"  0  "Rstall"  0.1  "Xstall"  0.1  "Tstall"  9999  "Frst"  0.2  "Vrst"  0.95  "Trst"  0.3  /
 "fuvr"  0.1  "vtr1"  0.6  "ttr1"  0.02  "vtr2"  0  "ttr2"  9999  /
 "Vc1off"  0.5  "Vc2off"  0.4  "Vc1on"  0.6  "Vc2on"  0.5  /
 "Tth"  15  "Th1t"  0.7  "Th2t"  1.9  "tv"  0.025
#
models
#
monit        1 "INF    "  115.00 "1 " : #9  9999.00
vmeta        1 "INF    "  115.00 "1 " : #9  0.0 0.0
fmeta        1 "INF    "  115.00 "1 " : #9  0.0 0.0 0.050000
#
plnow       1 ! ! "1 " : #9 0.0
gthev       1 ! ! "1 " : #9 .0001  .001 1 2 10 10
#
imetr     101 ! ! "1 "        1 ! !  "1 "  1 : #9 "tf" 0.0
#
#

der_a   102 "LOWSIDE" 13.8 "U " : #9 mva=11 /
"trv" 0.02 "dbd1" -99 "dbd2" 99 "kqv" 0 "vref0" 0 "tp" 0.02 "pflag" 1 /
 "tiq" 0.02 "ddn" 0 "dup" 0 "fdbd1" -99 "fbdb2" 99 "femax" 0 "femin" 0 /
"pmax" 1 "pmin" 0 "frqflaq" 0 "dPmax" 99 "dPmin" -99 "tpord" 0.02 "imax" 1.2 /
"pqflag" 1 "vl0" 0.44 "vl1" 0.45 "vh0" 1.2 "vh1" 1.19 "tvl0" 0.16 "tvl1" 0.16 /
 "tvh0" 0.16 "tvh1" 0.16 "vrfrac" 0 "fltrp" 59.3 "fhtrp" 60.5 "tfl" 0.16 /
"tfh" 0.16 "tg" 0.02 "rrpwr" 0.1 "tv" 0.02 "kpg" 0 "kig" 0 "xe" 0.25 "typeflag" 1 /
| "vfth" 0.8" "iqh1" 0 "iql1" 0
#
#
```

Figure E.2: Starting Set of Dynamic Parameters

Model Comparison to Event Measurements

The event that was chosen to verify this set of models was a fault that occurred 50 miles away from the measurement location; the fault caused a synchronous generator to trip off-line. The measurements shown here are simulation outputs from a different set of parameters and are assumed to be the reference MW and MVAR measurements for verification purposes. For the purposes of illustration, the event is assumed to be a balanced fault.[192] The event is detailed in the first set of graphs in **Figure E.3**. The active power and reactive power measurements are taken at the high side of the T–D transformer corresponding to **Figure E.1**. In order to ensure that the load model was performing as anticipated during the event, the active powers from the load are recorded in **Figure E.4** and demonstrate two separate distinctions in the process:

- The load model responds similarly between the measurement values and the reported model.
- The changes and adjustments to the DER model do not impact the response in a way that would misalign the model with the measurements.

[192] TPs/PCs should be cognizant that unbalanced faults may not closely match the positive sequence simulation tools. This may be a source of mismatch that does not warrant modification in dynamic model parameters.

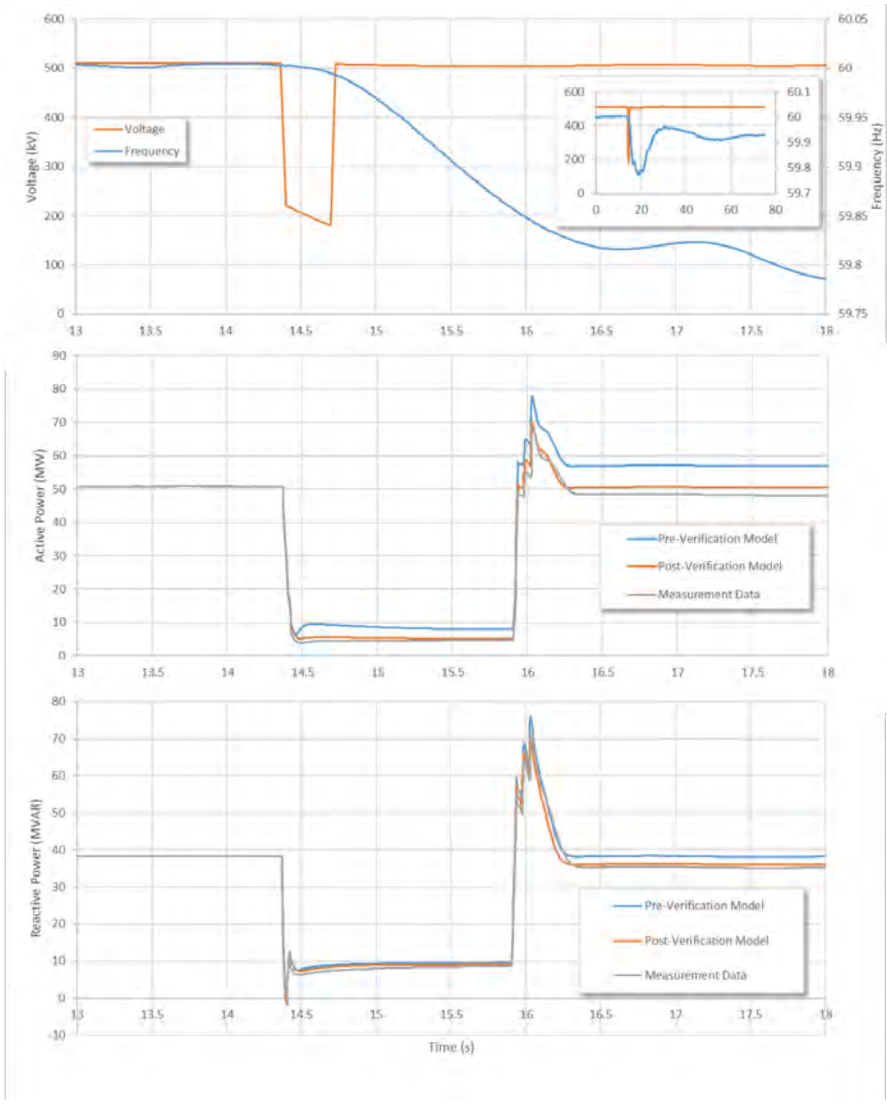


Figure E.3: Voltage, Frequency, Active, and Reactive Power Measurements

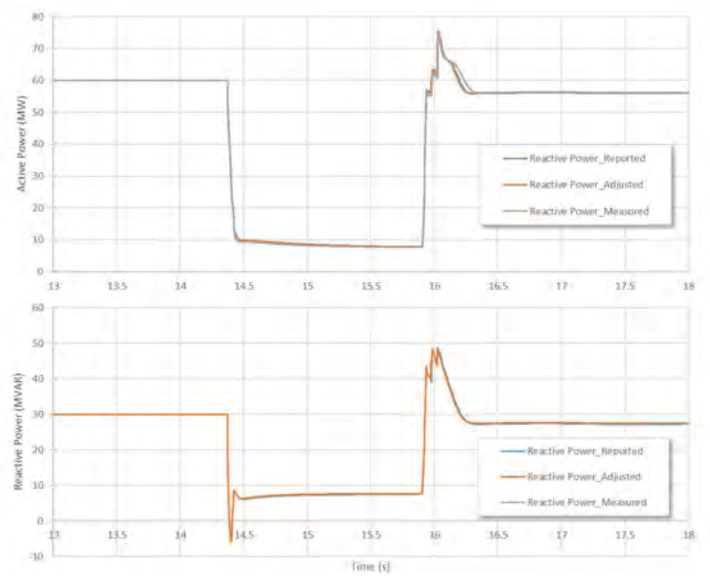


Figure E.4: Active and Reactive Power of Load Model

The model and measured power were very similar during the disturbance across the T–D transformer but differed during the post disturbance recovery. After demonstrating that the two active power measurements across the transformer were not equivalent, the study engineer identified candidate parameters for model verification. The low voltage ride through settings seemed to be too restrictive in the model, so the parameters were adjusted as detailed in **Table E.2**.

Table E.2: DER Parameter Changes

Parameter Name	Pre-Verification Value	Post-Verification Value
Vrfrac	0.00	0.20
Vfth	0.80	0.40
Vl0	0.44	0.35
Tvl0	0.16	0.75
Tvh0	0.16	0.75

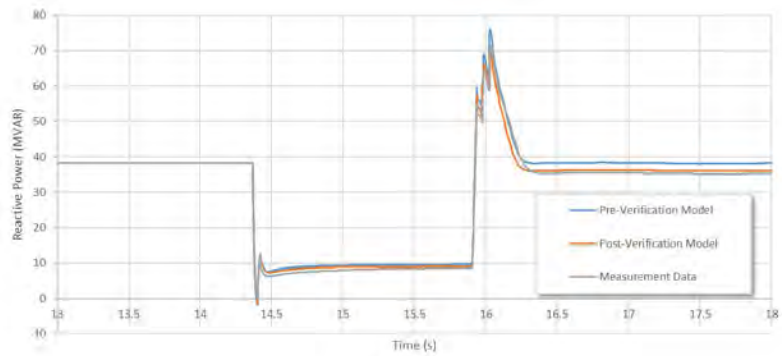


Figure E.5: Active Power of Model versus Measurements after Parameter Adjustment

After the adjustments were made in **Table E.2**, the simulation is performed once more and the active power is looked at again to determine the effect of the changes. This comparison is reproduced in **Figure E.5**. Based on the proximity of the orange and grey lines in **Figure E.5**, the verification process ends and the model is now verified against this particular event's performance. If the TP/PC determines that this verification is not adequate, the process would iterate again with more fine adjustments made until the entity has confidence in how the model behaves relative to the event measurements. As this process only used one event, it is highly recommended that the post-verification model be confirmed by playing back another event if available.

Appendix F: DER Measurement Collection Example

Specific types of BPS events have demonstrated a characteristic response in load meters that has been attributed to DER response;[193] however, a majority of TPs or PCs may not have seen the types of system level measurements and practices when looking to verify a set of aggregate DER models. This appendix provides TPs and PCs with an example of DER response to BPS events. It also suggest methods or ideas to consider when using the event data collected for verifying aggregate DER models in planning studies.

IESO DER Performance Under BPS Fault Conditions

DER responses to transmission grid disturbances are typically not in scope of DER commissioning tests; therefore, it is more practical to verify DER dynamic performance through naturally occurring events. An example of the performance expected can be found in **Figure F.1**, which shows an example of U-DERs responding to a 500 kV single-line-to-ground fault in Ontario. More than 30 DER meters recorded interruptions upon the fault and **Figure F.1** highlights seven locations as far as 300 km from the fault (voltage and current waveforms side by side, with nameplate MW indicated). The DERs were all installed under IEEE 1547-2003, so most of them tripped off-line following the voltage dips induced by the fault. At Site B and Site G, additional current waveforms from other solar plants connected to the same substations are included for comparison. The DER current outputs varied significantly due to different control strategies for the controllers, which experienced similar voltages at the point of connection.

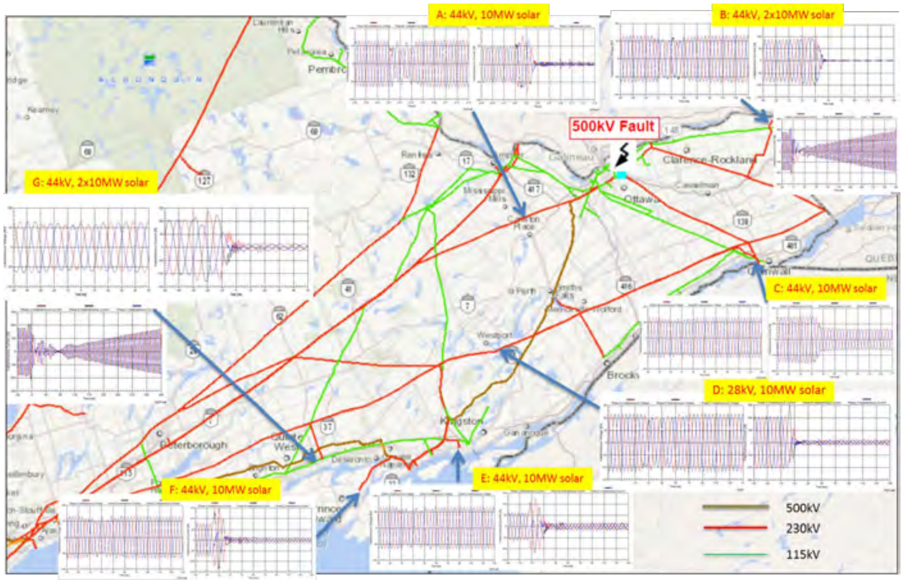


Figure F.1: Solar U-DER Voltage and Current Waveforms for a 500kV Fault

TPs can further verify the tripped loss of DERs by using aggregated measurements from revenue meters at substation. **Figure F.2** plots current waveforms from one out of two paralleled 230/44 kV step-down transformers at Site B, where multiple solar generators are connected through the substation to 44 kV feeders. The fault started near 0.0s in **Figure**

[193] https://www.nerc.com/pa/rrm/ea/April_May_2018_Fault_Induced_Solar_PV_Resource_Int/April_May_2018_Solar_PV_Disturbance_Report.pdf

F.2 and was cleared after three cycles (0.05 seconds). Increased net load current through the transformer can be seen after the fault cleared, suggesting most solar DERs could not recover immediately after fault clearing.

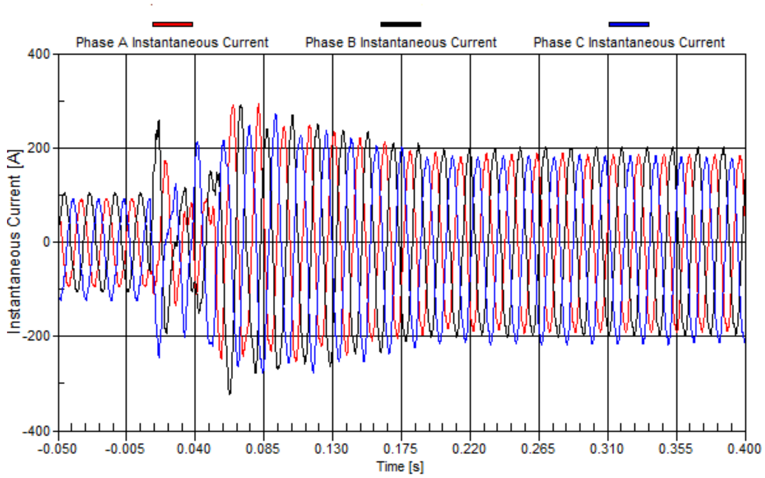


Figure F.2: Current Waveforms from 230/44kV Transformer at Site B

DER operating logs show various reasons that may initiate DER shutdown, such as under/over-voltage, frequency deviations or current/voltage unbalance. A common feature associated with such initiating causes is an arbitrarily short time delay, yet some designs employ instantaneous shutdown. The IEEE 1547-2003 standard allows for protection delay settings as short as zero seconds, but such small time delays have caused premature generation interruptions under remote BPS grid events. In most cases, the DERs would have been able to ride through the disturbances if the decision to trip off-line was delayed.

Figure F.3 compares performances of two 44 kV solar plants under a common 500 kV single-line-to-ground fault. The two plants connect to the same substation bus but have different control strategies. The inverter on left side (10 MW nameplate) stopped operating under voltage sag by design. In contrast, the one on right side (9 MW nameplate) was configured to inject reactive current under the same voltage sag. It can be verified from Figure F.3 that the current waveforms of the two plants were very similar between -25–0 ms. However, the controllers made different decisions based on the information from the 25 ms: the first solar plant stopped generating at t=0 ms while the second continued current injection during the BPS fault and beyond even though they were looking at almost identical voltages at the point of connection.

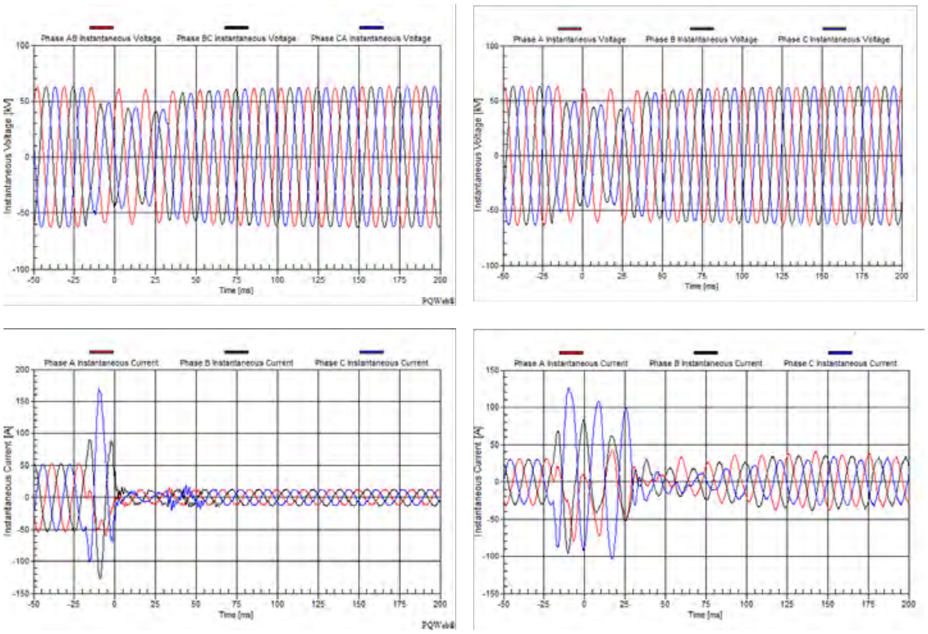


Figure F.3: Comparison of Two Adjacent Solar Plants' Responses to the Same 500kV Fault (top: voltage, bottom: current)

Installation data may suggest the overall majority of DERs are solar generators, but wind turbine connections in distribution system are also common in some utilities. Operation records show that wind DERs may experience similar interruptions as solar under BPS disturbances. **Figure F.4** and **Figure F.5** show Type IV and Type III wind plants responses to a common 500 kV bus fault, respectively. While the wind plants are connected at different locations and voltage levels (28 kV vs. 44 kV), both shut down under the BPS fault. **Figure F.6** shows a load current increase measured from one out of two paralleled 115 kV/44 kV step-down transformers as a result of wind generation loss in the 44 kV feeders. In this event, insufficient time delay (shorter than transmission fault clearing time) for voltage protection designed under 1547-2003 was confirmed to be the cause of shutdown. Such an issue is expected to diminish with the new 2018 standard revision, which requires at least 160 ms time delay to accommodate transmission fault clearing.

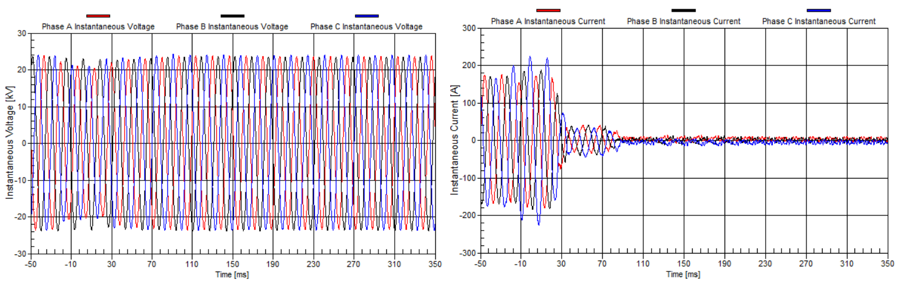


Figure F.4: Type IV Wind Plant (28kV/10MW) Response to 500kV Single-Line-to-Ground Fault

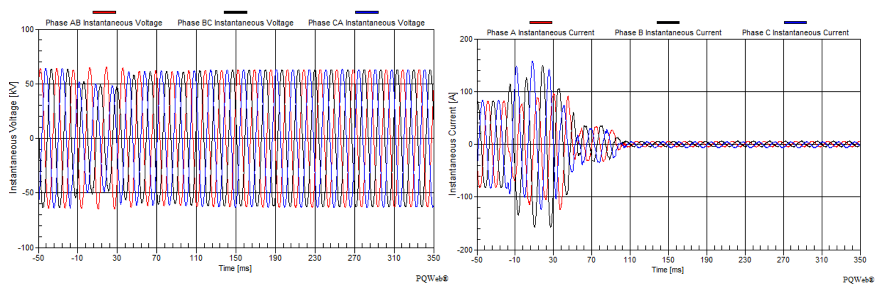


Figure F.5: Type III Wind Plant (44 kV/10 MW) Response to 500kV Single-Line-to-Ground Fault

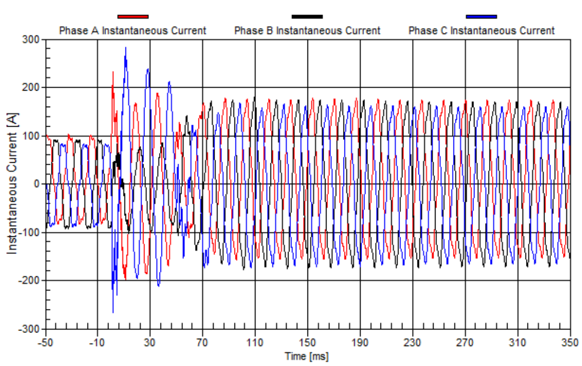


Figure F.6: Load Current Increase at a 115 kV/44 kV Transformer after Loss of Wind Generation

April–May 2018 Disturbances Findings

A noticeable amount of net load increase was observed during the Angeles Forest and Palmdale Roost disturbances.[194] DERs were verified to be involved in the disturbance using a residential rooftop solar PV unit captured in the Southern California Edison footprint about two BPS buses away from the fault through a 500/220/69/12.5 kV transformation. The increase in net load identified in both disturbances signified a response from BTM solar PV DERs; however, the availability, resolution, and accuracy of this information was fairly limited at the time of the event analysis. **Figure F.7** shows the California Independent System Operator (CAISO) net load for both disturbances. It is challenging to identify exactly[195] the amount of DERs that either momentarily ceased current injection or tripped off-line with BA-level net load quantities. Note that these measurements were taken at a system-wide level and represent many T–D interfaces while the IESO example in **Appendix F** is for specific T–D interfaces.

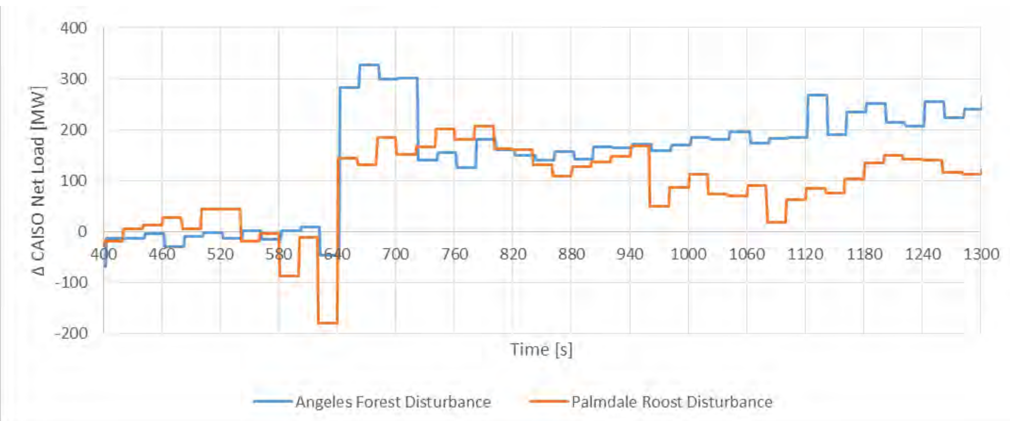


Figure F.7: CAISO Net Load during Angeles Forest and Palmdale Roost Disturbance [Source: CAISO]

SCE also gathered net load data for these disturbances (shown in **Figure F.8**). While an initial spike in net load was observed, this is attributed to using an area-wide net load SCADA point and a false interpretation of DER response during the events for the following reasons:

- The SCADA point used by SCE for area net load does not include sub-transmission generation or any metered[196] solar PV in their footprint. However, it does account for the unmetered DERs that are mostly composed of BTM solar PV.
- The SCADA point used by SCE for area net load is calculated as the sum of metered generation plus intertie imports, which includes area net load and losses.[197] Therefore, the SCADA point does not differentiate between changes in net load and changes in losses.
- Typically for energy management systems, the remote terminal units that report data to the EMS are not time-synchronized. Delays in the incoming data during the disturbance can result in temporary spikes. Fast changes in metered generation (e.g., generator tripping or active power reduction) before refreshed values

[194] https://www.nerc.com/pa/rrm/ea/Pages/April-May-2018-Fault-Induced-Solar-PV-Resource-Interruption-Disturbances-Report.aspx
[195] The ERO estimated that approximately 130 MW of DERs were involved in the Angeles Forest disturbance, and approximately 100 MW of DERs were involved in the Palmdale Roost disturbance; however, these are estimated values only.
[196] Generally, generation greater than 1 MW is metered by SCE on the distribution, subtransmission, and transmission system.
[197] Net Load + Losses = Metered Generation + Intertie Imports

of intertie flow can cause the calculated load point to change rapidly around fault events. Once the refreshed values are received, the spikes balance out.

For these reasons, the spikes in net load were noted as calculation errors, variations in system losses, and intertie flow changes. The temporary increase within the first tens of seconds after the fault event should not be completely attributed to DER tripping or active power reduction with area-wide net load SCADA points.[198] TPs and PCs, when gathering data for use in verification of DER models, should consider these bullets when using SCADA or other EMSs when utilizing these points for verification of DER models, especially when utilizing system-wide measurements.

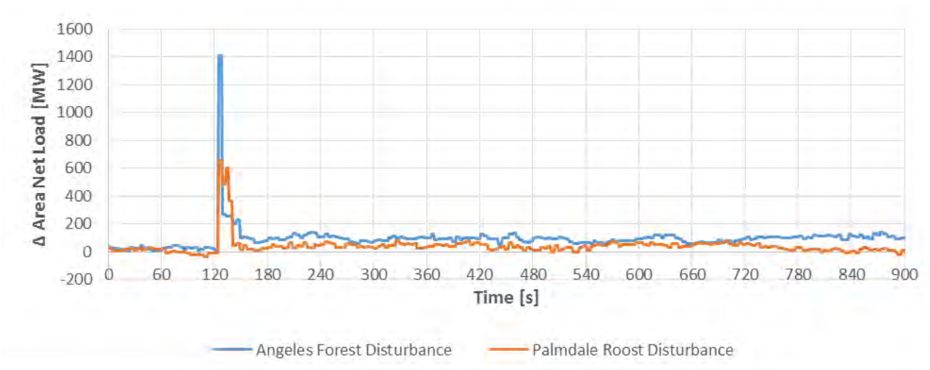


Figure F.8: SCE Area Net Load Response [Source: SCE]

Monitoring the T–D transformer bank flows with direct SCADA measurements (rather than calculated area net load values) is a more reliable method for identifying possible DER behavior during disturbances because it removes the time synchronization issues described in this section. Figure F.9 (left) shows direct measurements of T–D bank flows in the area around the fault. The significant upward spike does not occur in these measurements as it did in the area-wide calculation. However, it is clear that multiple T–D transformer banks did increase net loading immediately after the fault. These net load increases lasted on the order of five to seven minutes, correlating with the reset times for DER tripping as described in IEEE Std. 1547.[199] After that time, the net loading returned to its original load level in all cases. This method of accounting for DER response is much more accurate and provides a clearer picture of how DERs respond to BPS faults. However, this method is time intensive and difficult to aggregate all individual T–D transformer banks to ascertain a total DER reduction value. TPs and PCs are encouraged to use the SCE and PG&E examples as ways to improve their DER data collection and to identify or attribute responses in already collected data, especially for higher impact T–D interfaces.

[198] For that matter, SCADA scans are not recommended to determine the total tripping of any IBR resource, including DERs that are IBRs.

[199] IEEE Std. 1547-2003, "IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems": https://standards.ieee.org/standard/1547-2003.html.
IEEE Std. 1547a-2014, "IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems – Amendment 1": https://standards.ieee.org/standard/1547a-2014.html.
IEEE Std. 1547-2018, "IEEE Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces": https://standards.ieee.org/standard/1547-2018.html.

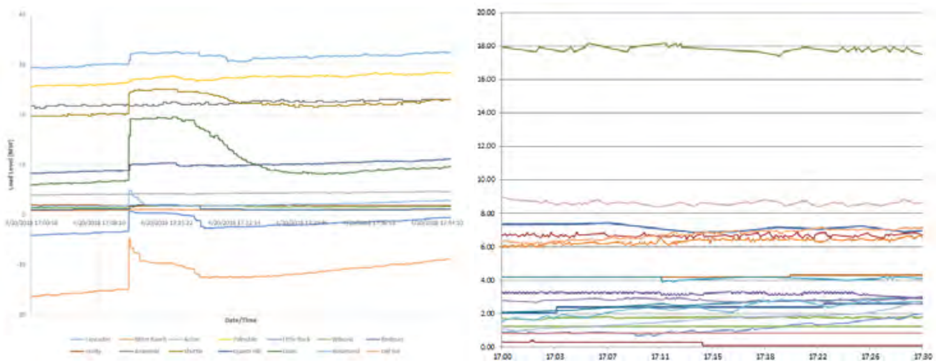


Figure F.9: SCE (left) and PG&E (right) Individual Load SCADA Points

Guideline Information and Revision History

Guideline Information	
Category/Topic: [NERC use only]	**Reliability Guideline/Security Guideline/Hybrid:** Reliability Guideline
Identification Number: [NERC use only]	**Subgroup:** [NERC use only]

Revision History		
Version	**Comments**	**Approval Date**

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Jorge Chacon	Southern California Edison
Nicolas Compas	Hydro Quebec
Ransome Egunjobi	Lower Colorado River Authority
Mohab Elnashar (Sub-Group Co-Lead)	Independent Electricity System Operator
Irina Green (Sub-Group Co-Lead)	California ISO
Evangelos Farantatos	Electric Power Research Institute
Lou Fonte	California ISO
Brian Hallett	ReliabilityFirst
James Helmberger	Omaha Public Power District
Andrew Isaacs	Electranix
Andrew Lopez	Southern California Edison
Brad Marszalkowski	ISO New England

Megan Miller	Electric Reliability Council of Texas
David Milner	CPS Energy
Amir Mohammednur	Southern California Edison
Nihal Mohan	Midcontinent ISO
Michael Odom	Southwest Power Pool
Jeff Palermo	PJP Consulting
Sunny Raheem	Southwest Power Pool
Jay Ramamurthy	Entergy
John Schmall	Electric Reliability Council of Texas
Clayton Stice	Electric Reliability Council of Texas
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Rich Bauer	North American Electric Reliability Corporation
Mark Olson	North American Electric Reliability Corporation
Ryan Quint ~~(SPIDERWG Coordinator)~~	North American Electric Reliability Corporation
John Skeath (SPIDERWG Coordinator)	North American Electric Reliability Corporation

Errata

Date: Example text here. Example text here. Example text here. Example text here. Example text here.

NERC

NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Reliability Guideline – DER Data Collection and Model Verification for Aggregate DER

Request for Approval

Shayan Rizvi, NPCC – SPIDERWG Chair

Wayne Guttormson, SaskPower - RSTC Sponsor

NERC Reliability and Security Technical Committee

June 21, 2023

RELIABILITY | RESILIENCE | SECURITY




Background

- Last of RGs in SPIDERWG’s assigned RGs in the Tranche reviews
  - Posted over December 2022 – Jan 2023, but received major comments on combined content interaction.
  - Incorporated all comments
  - Updates to data collection focused on language describing current EMT efforts, particularly inclusion of load + DER when modeling the T-D Interface in such simulations.
- **Combined two Reliability Guidelines into one**
  - Reliability Guideline: DER Data Collection for Modeling in Transmission Planning Studies
  - Reliability Guideline: DER Model Verification of Aggregate DER Modeling used in Planning Studies

Comments

- Ranges from clarity edits on figure assignment to holistic changes requested in sections of the document
  - SPIDERWG provided in-line responses to comments in supplemental documents
  - Metrics significantly altered based on comments
- SPIDERWG requesting approval of the RG to close out the Tranche reviews.

Questions and Answers

Privacy and Security Impacts of DER and DER Aggregators: Joint SPIDERWG/SITES White Paper

Action
Request RSTC Comments

Background
The Federal Energy Regulatory Commission (FERC) approved Order No. 2222, which enabled Distributed Energy Resources (DERs) to participate in wholesale electric markets[1] through a Distributed Energy Resource Aggregator (DER Aggregator) that interfaces with the Independent System Operators (ISOs) and Regional Transmission Operators (RTOs). These ISO/RTOs are generally registered as the Balancing Authorities (BAs) and Reliability Coordinators (RCs) in their respective Interconnections. The NERC System Planning Impacts from DER Working Group (SPIDERWG) and the Security Integration and Enablement Subcommittee (SITES) have both authored white papers[2] analyzing the bulk system reliability and security implications of the DER Aggregator; however, no NERC industry stakeholder group has explored the technical aspects of security controls for these grid functions and their systems. This paper focuses solely on the security controls available to DER and DER Aggregators and provides recommendations[3] in order to maintain the reliability of the bulk power system (BPS).

Summary
This paper explores the technical facets of security controls available to DER and DER Aggregators and provide an example of potential attacks that can be mitigated through the implementation of those security controls. It will also provide an overview on the security posture of distribution landscape (particularly for DER and DER Aggregators) and provide correlations to NERC Standards, should any exist. The Bulk Electric System (BES) Cyber Asset 15-minute impact test is compared to DER and DER Aggregators to understand their potential impact to the BPS. Further, privacy concerns are covered related to confidentiality of user data for DER owners in this electrical system as such data may be the target of a malicious actor. This paper will also provide high-level recommendations to DER and/or DER Aggregators on security controls or other risk mitigation measures.

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[1] FERC Order 2222 is available here: https://www.ferc.gov/sites/default/files/2020-09/E-1_0.pdf
[2] The SPIDERWG white paper *BPS Reliability Perspectives for Distributed Energy Resource Aggregators* is available at https://www.nerc.com/comm/RSTC_Reliability_Guidelines/SPIDERWG_White_Paper_-_BPS_Persepectives_on_DER_Aggregator_docx.pdf and the SITES white paper *Cyber Security for Distributed Energy Resources and DER Aggregators* is available at https://www.nerc.com/comm/RSTC_Reliability_Guidelines/White_Paper_Cybersecurity_for%20DERs_and_DER_Aggregators.pdf .
[3] This paper does not provide Compliance Implementation Guidance related to the CIP standards. Rather, security controls are presented at a high level and the functional interplay between DER, DER Aggregators, and other entities is considered in the context of security and security controls.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Privacy and Security Impacts of DER and DER Aggregators

Joint SPIDERWG/SITES White Paper

Background

The Federal Energy Regulatory Commission (FERC) approved Order No. 2222, which enabled Distributed Energy Resources (DERs) to participate in wholesale electric markets[1] through a Distributed Energy Resource Aggregator (DER Aggregator) that interfaces with the Independent System Operators (ISOs) and Regional Transmission Operators (RTOs). These ISO/RTOs are generally registered as the Balancing Authorities (BAs) and Reliability Coordinators (RCs) in their respective Interconnections. The NERC System Planning Impacts from DER Working Group (SPIDERWG) and the Security Integration and Enablement Subcommittee (SITES) have both authored white papers[2] analyzing the bulk system reliability and security implications of the DER Aggregator; however, no NERC industry stakeholder group has explored the technical aspects of security controls for these grid functions and their systems. This paper focuses solely on the security controls available to DER and DER Aggregators and provides recommendations[3] in order to maintain the reliability of the bulk power system (BPS)

This paper explores the technical facets of security controls available to DER and DER Aggregators and provide an example of potential attacks that can be mitigated through the implementation of those security controls. It will also provide an overview on the security posture of distribution landscape (particularly for DER and DER Aggregators) and provide correlations to NERC Standards, should any exist. The Bulk Electric System (BES) Cyber Asset 15-minute impact test is compared to DER and DER Aggregators to understand their potential impact to the BPS. Further, privacy concerns are covered related to confidentiality of user data for DER owners in this electrical system as such data may be the target of a malicious actor. This paper will also provide high-level recommendations to DER and/or DER Aggregators on security controls or other risk mitigation measures.

Intended Audience

This paper is intended for the following NERC Registered entities, external stakeholders, and broader groups:

- Planning Coordinator (PC)
- Transmission Planner (TP)

[1] FERC Order 2222 is available here: https://www.ferc.gov/sites/default/files/2020-09/E-1_0.pdf
[2] The SPIDERWG white paper *BPS Reliability Perspectives for Distributed Energy Resource Aggregators* is available at https://www.nerc.com/comm/RSTC_Reliability_Guidelines/SPIDERWG_White_Paper_-_BPS_Persepectives_on_DER_Aggregator_docx.pdf and the SITES white paper *Cyber Security for Distributed Energy Resources and DER Aggregators* is available at https://www.nerc.com/comm/RSTC_Reliability_Guidelines/White_Paper_Cybersecurity_for%20DERs_and_DER_Aggregators.pdf .
[3] This paper does not provide Compliance Implementation Guidance related to the CIP standards. Rather, security controls are presented at a high level and the functional interplay between DER, DER Aggregators, and other entities is considered in the context of security and security controls.

- Transmission Operator (TOP)
- Distribution Provider (DP)
- DER owners, aggregators, and developers
- ISO/RTOS (i.e., the BAs and RCs)

This paper includes recommendations to DER owners, DER Aggregators, and NERC registered entities as they assess or analyze their security posture. The complexity of securely managing these systems is further compounded by the increasing penetration of DER. This paper is not intended to alter the DP's interconnection requirements nor to alter the electrical specifications to produce DER equipment. Rather, this paper is seeking to recommend security measures or requirements that improve the electrical ecosystem's security posture.

Definitions

To clarify terms and definitions to accurately scope what constitutes resources in a DER Aggregator versus the SPIDERWG set of terms, the following main points should be noted:

1. The SPIDERWG definition[4] of **Distributed Energy Resource (DER)**, which is "any Source of Electric Power located on the Distribution system", is the preferred definition for discussing reliability concerns.
   a. This is different from the definition of DER in the FERC Order, which is "a source or sink of power that is located on the distribution system, any subsystem thereof, or behind a customer meter".[5] Namely, the reliability focused (i.e., SPIDERWG) definition focuses on generation only, while the FERC definition includes load.
   b. This is also slightly different from current discussions in Project 2022-02, which is attempting to consolidate definitions as to not add many new terms. The project definitions are not currently approved as of this paper.
2. FERC Order 2222 introduces the definition of **DER Aggregator**, which for this paper is the entity[6] that controls the aggregation of generation (i.e., DER) and load end-use devices.
   a. The **DER Aggregator** has control over both load and generation and it can control existing Demand Response programs
3. Both definitions include both **Inverter-Based Resources (IBR)** and non-IBR generation. For example, both a 1 MW Solar PV plant as well as a 500 kW steam cogeneration facility would both be DERs, assuming both are distribution connected.

[4] The SPIDERWG terms and definitions are available here: https://www.nerc.com/comm/RSTC/SPIDERWG/SPIDERWG%20Terms%20and%20Definitions%20Working%20Document.pdf
[5] Taken from FERC Order 2222 on page 85. Available here: https://www.ferc.gov/sites/default/files/2020-09/E-1_0.pdf
[6] Further, there are various names for the entity that controls and aggregates DER outside of the DER Aggregator. Examples include Virtual Power Plant (VPP) or emergency load reduction programs (excluded Demand Response). For this paper, DER Aggregator and these other entities are synonymous as they functionally aggregate DER (i.e., generation) on the distribution system.

4. DER Aggregators' **DER Management System (DERMS)** and **Virtual Power Plants' (VPP)** control schemes will likely have a different communications architecture.[7] For this paper, the architecture of DER Aggregators, VPPs, and utility systems that manage the control of DER are equivalent.

This paper uses the SPIDERWG set of definitions as this is a reliability focused technical discussion of the privacy and security impacts of DER and DER Aggregators. In instances where the load portion of a DER Aggregator is relevant, it will be called out as such (e.g., in terms like "DER and load").

IEEE 1547-2018

The recent update to IEEE 1547-2018[8] makes it possible for the utility, or any other entity, to deploy DER management systems (DERMS) and cohesively monitor and manage the diverse mix of DER technologies[9] and manufacturers being deployed today. Utilities and third-party aggregators are deploying DERMS, making them an integral part of system operations. However, the diverse mix of DERs, their evolving capabilities, as well as continuous interconnection and retirement, pose significant challenges to security and reliability of the DER ecosystem. Standardization efforts like IEEE 1547-2018 make DER integration practical by keeping DER operational functions simple and leaving more complex operational functions to the control and integration systems (i.e., DERMS or VPP).

Security Controls Available to DER and DER Aggregators

The *IEEE P1547.3 Guide for Cybersecurity of Distributed Energy Resources Interconnected with Electric Power Systems*[10], currently out for industry comments, provides guidance and recommendations for cybersecurity practices and controls to ensure secure communication of DER protocols (e.g., IEEE Std 1815, IEEE Std 2030.5, SunSpec Modbus, and IEC 61850) specified in the IEEE 1547-2018.

The 1547.3 guide includes considerations relating to the following cybersecurity topics:

- Risk assessment and management,
- Communication network engineering,
- Access control,
- Data security,
- Security management,
- Coping and recovering from security events,
- Testing and Commissioning for Cybersecurity and Conformance with the IEEE 1547.3

Though not exhaustive, the following sections provide a high level overview of security controls available to DER devices and installation sites, or to DER Aggregators and their control systems. Figure 1 graphically

[7] Primarily that utility implemented DERMS will likely have direct control and on-premises security controls while VPPs are more inclined to utilize cloud solutions for their security controls.
[8] IEEE 1547-2018 is available here: https://standards.ieee.org/standard/1547-2018.html
[9] E.g., Battery Energy Storage, Solar Photovoltaic, or synchronous DERs.
[10] IEEE P1547.3 website: https://sagroups.ieee.org/scc21/standards/ieee-std-1547-3-2007-revision-in-progress/

shows the new communication pathways (in red) introduced with the addition of the DER Aggregator to the electric ecosystem. The DER Aggregator sits at the T-D Interface and communicates its DER control capabilities to the ISOs and RTOs (i.e., the BAs and RCs), who then determine the utilization of those capabilities. Additionally, the DER Aggregator issues operating commands to the DERs it manages, as well as communicates necessary information with the additional key entities in the ecosystem. These new communication pathways necessitate a thorough understanding of associated security risks and the available mitigating controls essential to protecting data integrity, privacy, and grid reliability.

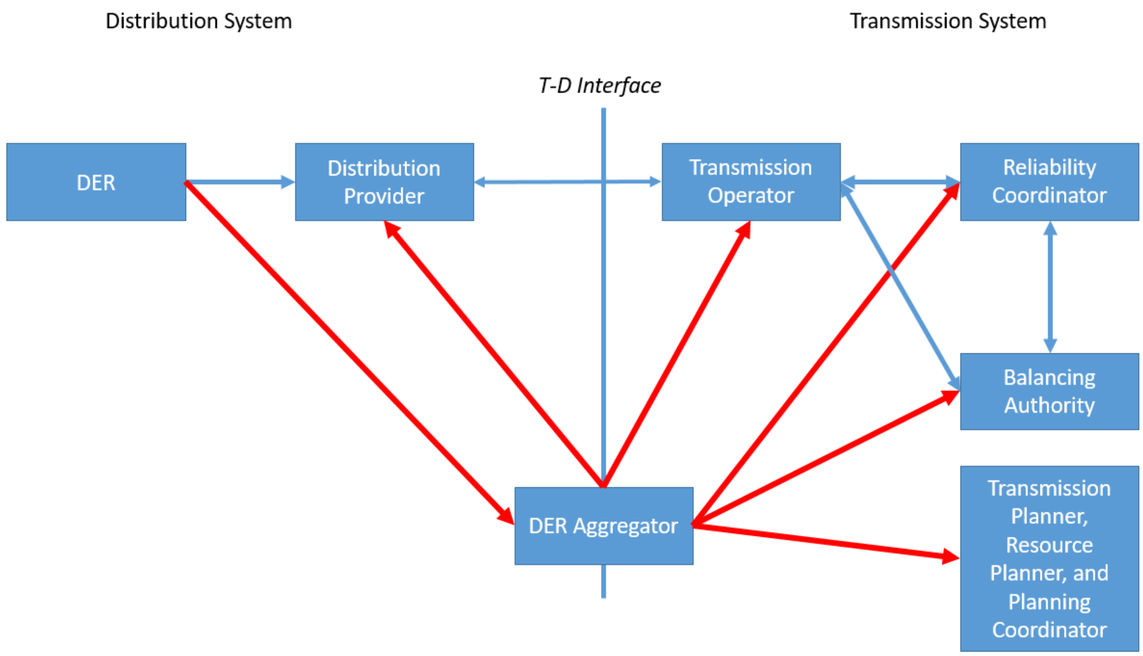

Figure 1: High-level Diagram of Added Communication for DER, DER Aggregators, and the BES[11]

Network and Protocol Security

DER, DER Aggregators, and utility networks should be separated based on ownership, control capabilities, and trust relationships within specific implementations. The increased attack surface stemming from the connection of numerous DERs demands network architectures that do not rely on implicit trust relationships. In the event of a single device or entire network segment compromise, proper network segmentation and additional security controls should ensure the continued operation of other segments.

Securely designed network architecture for DERs and DER Aggregators may include the following:

- **Demilitarized Zones (DMZ), subnets, and VLANs**: These logical network segments isolate sensitive or critical systems from other parts of the networks, establishing security zones by on criticality, and limiting unauthorized access and potential damage from cyberattacks.

[11] Note that attacks scenarios can target communications outside of those highlighted in the figure. For instance, Original Equipment Manufacturer to DER communication as well as DER directly to the RCs or BAs.

- **Intrusion Prevention Systems (IPS) and Intrusion Detection Systems (IDS):** These systems enable comprehensive visibility into network traffic, through the monitoring and detection of suspicious activity or potential threats. Actively scanning and analyzing network traffic for abnormal patterns identifies and prevents potential cyber threats, enhancing overall network security. This type of technology can be deployed at the perimeter of the network for border protection or internal to the network for “East-West” protection.
- **Absence of implicit trust relationships:** Network architectures should be designed without assumptions of trust between connected devices or systems, minimizing the potential for unauthorized access and lateral movement of attackers within the network.
- **Secure network boundaries:** Firewalls control incoming and outgoing network traffic based on predetermined rules, while data diodes ensure one-way data flow, adding layers of protection to network boundaries.
- **Strong encryption:** Implementing advanced encryption algorithms, such as Advanced Encryption Standard (AES) and Rivest-Shamir-Adleman (RSA), ensures the confidentiality and integrity of sensitive data transmitted across networks.
- **Secure Protocols:** Utilize communication protocols with built-in security features to ensure the safe and reliable exchange of information between DER devices and control systems, such as DNP3-SA, which incorporates robust authentication, encryption, and non-repudiation, providing a strong foundation for secure DER communication.
- **Authentication:** Robust authentication mechanisms, such as digital certificates, Public Key Infrastructure (PKI), and Multi-Factor Authentication (MFA), validate the identities of devices and users, reducing unauthorized access.
- **Authorization:** Implementing access control policies based on the 'least privilege' principle ensures that users and devices have the minimum necessary access rights, limiting the potential impact of compromised credentials.
- **Virtual Private Networks (VPN):** VPNs create secure, encrypted connections over public networks (i.e., the internet), protecting data transmission from eavesdropping and tampering.
- **Efficient logging and alerting:** Security Information and Event Management (SIEM) systems collect, analyze, and correlate log data from various network devices, generating alerts for potential security incidents and facilitating timely response.
- **Hardened networking equipment:** Applying Security Technical Implementation Guides (STIGs) or Original Equipment Manufacturer (OEM) recommendations ensures that networking equipment adheres to industry-standard security practices, reducing vulnerabilities and attack surfaces.

Besides isolating networks based on trust relationships and ownership, DER Aggregator and utility networks should also be segregated within their internal networks (e.g., isolating corporate networks from industrial control systems). Actual architectural implementations and specific security controls will depend on the use cases for a given DERMS. These can range from decentralized VPP architectures, centralized distribution utility DERMS, or hybrid implementations. In addition, these industrial control system (ICS) networks should be securely segmented from other networks including corporate networks. Insufficiently segmented networks with weak or lax security controls could enable cyberattacks to spread across multiple systems and network segments. DER endpoints, being the most vulnerable links in these networked systems, are likely to account for the majority of attack vectors. Figure 2 shows an example network architecture of a DER managing entity controlling both small scale DER and utility level DER. The figure highlights the effective use of network segmentation and firewalls to establish security zones, providing network boundaries to deploy further security controls.

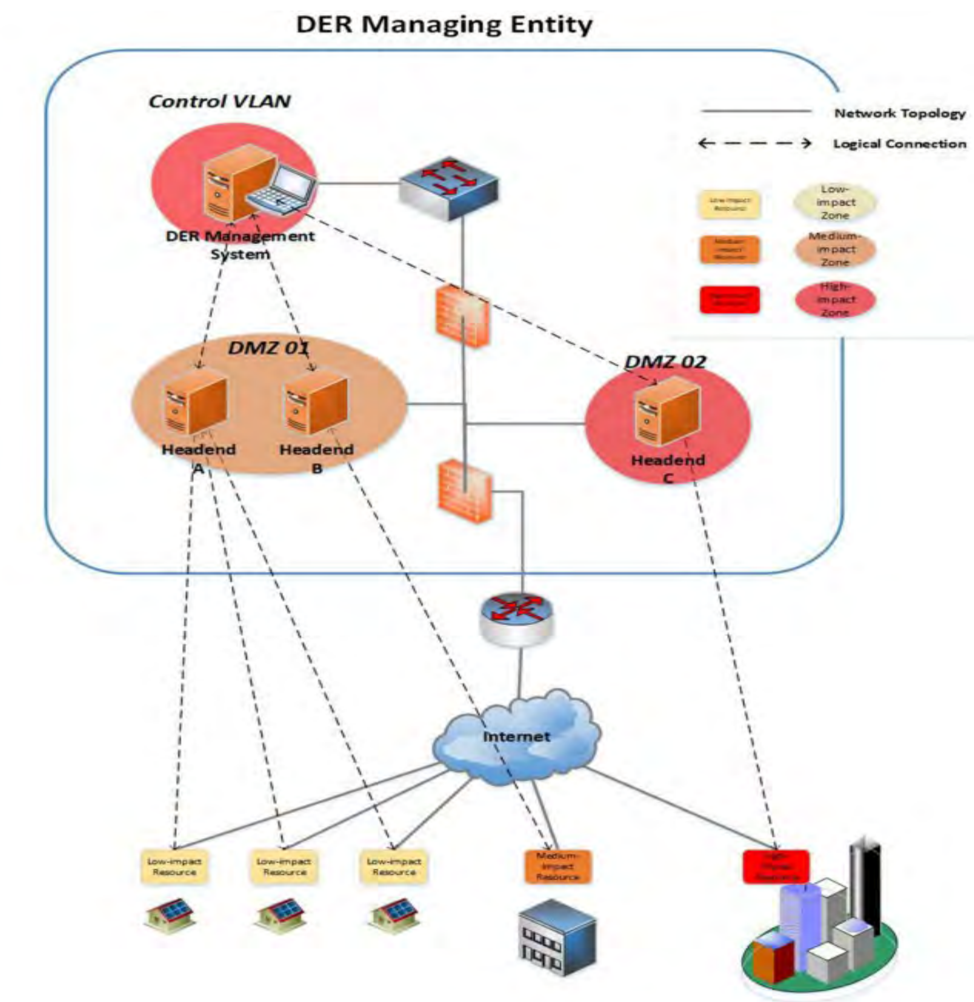

Figure 2: Example DER Managing Utility Architecture [Source: EPRI]

In general, network and protocol security is fundamental to proper cybersecurity practices. As such, the types of threats and tactics they mitigate are diverse and numerous.

Internal Network Security Monitoring

Internal network security monitoring (INSM) controls are available for the DER owner's network,[12] the DER Aggregator's network, a utilities network, and an OEM's network. INSM monitors the traffic flowing internal to the network and provides alerts when suspect traffic is detected and takes action to mitigate the threat. These actions included logging and alerting when malicious traffic is detected. Some INSM implementation may also block network communications to and from suspected compromised nodes. Proper patching and updates to malicious code signatures or heuristic detection schemes is critical to assure effectiveness of these network based security controls.

Monitoring and logging controls are a prerequisite for any automated prevention or response based controls including access control lists (ACL), endpoint security, and security orchestration tools. In addition, the monitoring controls and their associated logs and reports facilitate security event triage and are a key component[13] of security incident response activities.

Complete INSM solutions would be implemented for full network visibility, but limitations in architecture, bandwidth, or device capabilities may preclude the monitoring of 100% of all network segments. The monitoring described here is analogous to the current and voltage relaying equipment[14] typically found on the electrical monitoring equipment in substations; however, these controls can take some automated action to mitigate against specific traffic. The following malicious activities can typically be detected by successful implementations of internal network security monitoring:

- Active Scanning of networks by malicious actors
- Lateral movement between internal network nodes such as servers and workstations, DER endpoints, etc.
- Download of known malware
- Command and control traffic (C^2)

In general, INSM defends against internal reconnaissance, lateral movement within the network, and malware deployment. Additionally, should a malicious actor compromise a DER or DER Aggregator network INSM may be able to detect outbound command and control communications which is a prerequisite for a coordinated attack utilizing many compromised DER devices.

Interactive Remote Access Controls

Physical access to the DER by the utility or DER Aggregator is typically unlikely. Consequently, DER communication interfaces will need to facilitate remote access capability to perform routine patching, firmware updates, or even the altering inverter settings. Any remote access[15], and the communications network required to facilitate it, introduces a credible attack vector to the DER and DER Aggregator

[12] It is not expected that residential DER owners would implement advanced controls beyond the default configuration at the time of their DER installation
[13] Due to their pivotal nature, these controls are required for Medium impact or higher control centers
[14] As substation circuit breakers requires the voltage and current waveforms in order to isolate faults from the system. As such, more complex security solutions require monitoring and logging to perform their objective.
[15] Programmatic or interactive

ecosystem. Non-existent security controls, improperly configured and maintained security controls, and vulnerabilities at the DER device level or within a DER Aggregator's network could be exploited. Securely implemented and maintained remote access implementations are critical for DER Aggregators, utilities, and OEMs to be able to service and manage DERs.

Remote access may require software and certain functionality on both sides of the communication stream. Thus, security controls may exist on the utility network, DER Aggregator network, and / or on the DER device or ER gateway in order to provide remote access capability in a secure manner. A simple, and inadequate, form of a security control are authentication credentials; however, more sophisticated mechanisms are needed. Secure remote access technologies include:

- Virtual Private Networks (VPNs) using encrypted tunnels for network traffic
- Network Access Controls limiting device connections to authorized and accessed[16] devices
- Multi-Factor Authentication (MFA) for interactive remote access
- Certificate based authentication for programmatic application access or system-to-system access
- Zero Trust architectures requiring constant re-authentication and re-authorization
- Secure protocols

These components are of high priority for securing remote access, a high demand function for our current digitalized landscape. With an increasing amount of access points through remote DER connections, secure networks are paramount to facilitating DER adoption and management through DER aggregator and utility systems. While the implementation and specific technology will determine the vulnerability to specific threats and attacks, secure remote access implementations generally mitigate the following types of malicious activities:

- Unauthorized external remote access
- Man-in-the-middle attacks
- Remote system discovery and reconnaissance
- Compromised trust relationships

Any security controls improperly configured or systems not patched for vulnerabilities may allow remote access controls to be circumvented. Thus, proper cyber-hygiene and a defense-in-depth approach is critical to balance the need for remote access with the security risk such access brings.

Data Management and Access Controls

Data, particularly at the DER Aggregator level, can reach extreme quantities. Data management policies, including storage, use, transit, and retention measures need to be in place. This is where data management

[16] Assessed in this context means assessing the security posture of the device prior to it being allowed access to network resources. Security posture assessment may include firmware patch level, antivirus version, hardening level, MAC address, or other criteria used to assess the security 'health' of the device.

and access controls aid in securing access and management functions of corporate data. Applied to DER and DER Aggregators, these controls limit the credentials of who can read, write, and transfer data from a particular entities network. At the DER device level, these functions are broad per 1547-2018, particularly Clause 10 language that allows for a broad read, write, and transfer capabilities built in to the DER equipment itself. As stated in sections above, 1547-2018 does not inherently apply cybersecurity protections at this local DER network, so DER Aggregators and DER owners would need to implement these controls on their respective networks. The controls themselves reside in the privileges granted to users in order to read, write, extract, and otherwise alter the data on the DER, DER Aggregator, or other entity's network. Good security controls in this area also deal with storage, extraction, and deletion policies for data. This is particularly useful when exchanging equipment at the DER Aggregator level that may have private information stored about the DER it controls, or even for DER owners that exchange devices to wipe the confidential information stored locally concerning the local DER network. Effective implementations enhance the security and privacy of data, as well as mitigate against IT sourced attacks on OT equipment in this space. Specific attacks mitigated by data management and access controls include:

- Credential Harvesting or Access
- Privilege Escalation
- Account Manipulation
- Data deletion, encoding, obfuscation, or manipulation

Data management controls can further mitigate against data exfiltration or ransomware by a malicious actor. Privilege escalation is a common technique in the cyber criminal's toolbox, allowing the individual or malware to overcome a number of inhibiting controls to access data. However, controls such as data loss prevention (DLP), IDS/IPS, and endpoint security may help detect or outright prevent the exfiltration or malicious encryption of said data.

DER Gateways

Key Takeaway:
DER Gateways mitigate the lack of endpoint controls on the DER devices themselves. Alternatively, endpoint controls on the DER devices may accomplish some of the same security objectives accomplished through a DER Gateway.

DERs face a variety of local threats and vulnerabilities which are likely outside of utility responsibility and control. For example, the DER itself can be exposed to a variety of different interfaces in addition to the utility's connection, including those for aggregator, owners, and OEM management. Each of these interfaces present a potential backdoor to the DER, its local network, and the upstream managing entity's systems. IEEE 1547-2018 does not specify cybersecurity requirements for DER and its local networks because they are generally untrusted systems to the DER managing entity[17] due to these risk exposures. Furthermore, current compliance and certification frameworks are limited in their scope of enforcement[18] to ensure that necessary security controls are adequately met among owners of DER. In the absence of enforceable requirements, managing entities

[17] The special case exception to this is when the DER managing entity is also the DER manufacturer.
[18] Due to the voluntary nature of the IEEE Standards, and the varying nature of the regulatory framework for the local distribution of energy.

cannot establish assurances that critical security controls used for secure communications, including certificate management, private key protection, firewall policies, user access control, and other device-specific security features are routinely reviewed and maintained over the DER's lifetime. This presents a challenge for managing entities where integrity and availability of data and functionalities cannot be fully established for communications to the DER, where risk exposures[19] are most significant. This exposes all interfacing parties to a variety of attack scenarios against communications critical for grid interoperability, including:

- Man-in-the-Middle – Data that is supposed to flow only between a managing entity and the DER flows through a middle node that reads or modifies data before it is sent on its way.
- Denial of Service – A group of compromised DERs deliberately overload upstream managing systems with useless traffic and the resource-exhausted network or managing system cannot perform its functions. Alternatively, a certificate expires on the DER and prevent the managing system from access. In both cases, this could impact a power system operator trying to control the power system.
- Replay – A command being sent from the managing entity to the DER is copied by an attacker. This command is then used at some other time to cause unexpected actions performed by the DER.
- Malware – An attacker adds malware to a DER, allowing it to propagate upstream to the managing entity.

DER gateways can serve as local platforms housing features and functions important to the DER managing entity, but they can also perform several important perimeter security functions that prevents against these attack scenarios. This local platform physically resides at the local DER site and, as defined by IEEE 1547, includes a wired, physical interface that establishes a private connection to the DER only through the gateway. Security requirements for DER gateways assume that there are deficiencies in DERs and establish trust in the communications to and from DER sites to protect critical utility systems, such as DERMS and Advanced Distribution Management System (ADMS), from internal and external threats. These requirements includes translating the DER's untrusted communication to trusted TLS-based communications, implementing data access rights through role-based controls, configuring network access control and segmentation through firewall policy, performing network and application-layer monitoring for threats, and verifying firmware updates through signature-based methods. Because these and other security features are implemented on a gateway that is owned, implemented, maintained, and certified by the managing entity rather than the DER-owner, managing entities can ensure secure integration over public, untrusted networks with its DERMS or other management software operations.

A new IEEE implementation guideline, the *IEEE P1547.10 Recommended Practice for Distributed Energy Resources (DER) Gateway Platforms*[20], is currently under development with contributions of different stakeholder groups (e.g., DER and DER gateway developers, owners, and operators, software producers, distribution and transmission system planners and operators, certification providers, etc.). The purpose of this project is to maintain coherency between the family of P1547.x and P2030.x standards, and other

[19] This is especially true for cases where DERs integrate using public, internet-based networks.
[20] PAR available at https://development.standards.ieee.org/myproject-web/app - viewpar/13494/9866

related projects for DER and Distributed Energy Resources Management Systems (DERMS) within the evolving smart grid interoperability reference model with a focus on Distributed Energy Resources (DER) Gateway Platforms. The recommended practice enables utilities deploying DERMS and other DER integration systems to integrate DER with grid edge intelligence, while DER devices serve their core functions focusing on simplicity, interoperability, and long-term stability. The scope of IEEE P1547.10 includes Gateway platform functions and communications, including operational procedures and data collection recommendations. Additionally, recommended procedures for cybersecurity, centralized manageability, monitoring, grid edge intelligence and control, multiple entities management, error detection and mitigation, events tracking, and notification, communication protocol translation, and communication network performance monitoring. Figure 3 shows the location of where a DER Gateway sites between networks in the latest efforts for IEEE implementation guideline

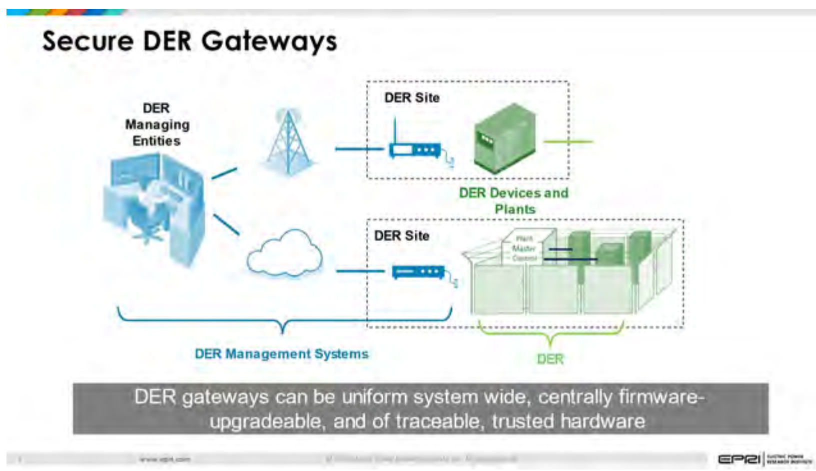

Figure 3: Example DER Gateway interface [Source: EPRI]

Carrier Controls Inherent in Communication

Many of the communications channels anticipated for information sharing between DER and DER Aggregators will likely traverse some fiber network and likely uses TCP/IP protocols. In unique circumstances, this may be different, yet the underlying assumption is that the traffic will need to be routable to the intended device (e.g., DER inverter or DER Aggregator control center). As many of these fiber networks, including some private fiber networks, will have a carrier entity install and maintain these communication lines, the carrier of these fiber networks inherently have some security controls in the way they handle communication on their network. It should not be assumed that carriers of these networks will provide the security controls necessary to thwart OT cyber criminals, but rather acknowledges that carriers of the networks may be helpful in implementing a strong security posture of the electric ecosystem that includes DER and DER Aggregators.

Current Distribution Security Landscape of DER and DER Aggregators

As evidenced in recent presentations[21] to SPIDERWG and SITES, the distribution landscape is primarily supported by equipment standardization with little to no standard design criteria about specific hardware, technologies, and engineering. This is in an effort to ensure that non-engineering technicians can install cost-effective solutions geared to mitigating customer-reported problems in that portion of the system. In the lens of cyber security, this may seem like an unknown world of major interoperability that would need solid endpoint controls to limit the access to the centralized ecosystem. This, however, is left up to each distribution entity's regulatory and corporate bodies to enable specific security controls on DER. Additionally, FERC Order 2222 does not have any specific security protections required to enable the participation of DER in the wholesale ISO/RTO markets. Thus, the SPIDERWG and SITES reviewed the information it had available on the distribution system and characterized a few main points, summarized below.

Telecommunications Networks: Distribution utilities use a combination of private fiber connections, public internet fiber connections, and radio communication interfaces for their monitoring and switching action. Utility level DERs are more likely to emulate BPS architectures, using private networks for communication back to their shared locally geographic control centers. Most concerning, however, are geographically decentralized residential and commercial DERs utilizing public networks, i.e., the internet. Public internet access for DERs is utilizing Wi-Fi and cellular 4G/5G wireless networks which are susceptible to interception and require strong encryption and authentication, or wired Ethernet and fiber-optic networks potentially compromised through physical access or device vulnerabilities at the site of the DER endpoint. In some of cases, private networks between the DER aggregator and their controlled DERs are achieved over the internet through the use of VPNs, offering increased security. Regardless of the medium for access, the use of public internet leaves both DERs and DER aggregators' control systems more exposed to remote attacks from anywhere on the globe. To ensure the resilience and stability of residential and commercial DER ecosystems, it is crucial to implement comprehensive security measures tailored to the specific requirements of each telecommunication network.

Electrical Protection Measures: It is still a common practice for protection in most distribution networks to use fuse-based protection while some distribution entities may use more advanced solid state relay protection. In those instances, however, the protection seeks to limit backfeed to the transmission system or to enhance a secondary area network scheme's ability to recover from fault. The distribution system is thus much more fuse-based which provides physics-based protections that are not present in the same ways or same densities on the transmission grid.

Distribution entities rely on equipment standardization: With the need to lower cost to their consumers, distribution companies rely on turnkey solutions based on standard designs when upgrading or fixing a circuit. This allows the distribution system to be reconfigured by non-engineering staff and field crews while still maintaining high levels of reliability (e.g., using proven designs to limit SAIFI and SAIDI)

[21] In particular the presentations at the SPIDERWG February 2023 meeting. Available here: https://www.nerc.com/comm/RSTC/SPIDERWG/SPIDERWG_Presentations.pdf

Security is not integrated in distribution system design: As the other main points may allude to, security is an afterthought for most distribution system upgrades or alterations. Rather than installing security protections, distribution companies rely on well-run line crews to recover the system and restore damaged equipment using local spare equipment. As distribution poles and associated equipment is relatively cheap, some perceive this as a cost effective solution to the security challenge posed by overhead distribution. However, the proliferation of DER, the upward trends of cyber attacks against both internet of things (IoT) and industrial control systems (ICS), and the potential for aggregate attack against DER ecosystems are changing these perspectives.

These main points are not to say that the distribution systems across NERC are under consistent malicious threat and are a critical nature, but rather that the common distribution system does not have a robust set of controls to protect it from all malicious activity. Rather, the system is currently designed around quick response to equipment damage (e.g., due to tree limbs, downed distribution poles, or other faults) and reconfiguration to maintain a high degree of reliability to their system. Current research and scenario development[22] to secure the distribution system and DERs at large is progressing rapidly, especially by review of equipment standards and implementing security controls. This research is feeding and developing equipment level standards to aid distribution entities to be able to use standard equipment when integrating DERs into their system. For example, Underwriter Laboratories[23] is seeking to investigate at an equipment level a way to certify the functional requirements of secure communication to limit the impact of a security compromise of a single DER. These updates to equipment standards and certification of distribution equipment are anticipated to maintain the current distribution paradigm and enhance it to support a strong security posture.

Differentiation of Utility-scale DER versus Retail-scale DER landscape

The security posture between U-DER and R-DER can differ. The retail-scale will likely not have a private fiber connection to the utility itself and will likely use public networks for communication. Further, the DER Owners of R-DER are not able to practically acquire, implement, and maintain the above security controls. In the utility-scale side there is a higher chance that the connection will be over a private network to the utility and may already have stronger security controls inherent to the design. These end-use devices will then move towards having lesser recommended additional controls for managers of U-DER only opposed to management of R-DER devices. Namely, R-DER devices are assumed untrustworthy as a default. These categorizations do not alter the current distribution landscape, however, as the same equipment standardization will likely be used to electrically connect both U-DER and R-DER to the distribution system. These categorizations are important when considering the “trustworthiness” of a type of communication and in producing standardized design to incorporate U-DER, R-DER, or a combination of both into the distribution system. DER Aggregators in particular should contain security controls that allow a strong protection against attack through the DER it controls, regardless of U-DER or R-DER classification.

[22] One example of the research into recommendations and test cases for cybersecurity scenarios pertaining to DERs is available here: https://www.osti.gov/biblio/1832209

[23] Specifically UL2941, available here: https://www.shopulstandards.com/ProductDetail.aspx?productId=UL2941_1_O_20230113

Security posture of DER Aggregators

DER Aggregators are different as they are a relatively new entity to this ecosystem that aggregate control of multiple end-use devices to participate in the wholesale ISO/RTO markets. The ISO/RTOs consist of the PCs, BAs, and RCs of the transmission system while the DER Aggregator is a middle entity (or entities) that constitute a pathway for previously independently controlled DER assets are under command from this middle entity. A DER Aggregator currently does not have known security requirements relative to the risk-impact is has on the bulk system, nor does it have known OT security requirements outside of those required by regulators over the DER Aggregator. As such, the NERC SPIDERWG and SITES have assumed the following with respect to the DER Aggregator:

1. The DER Aggregator will protect itself against common IT attacks targeting personal data required to award bids
2. The protections a DER Aggregator has on its IT software will not allow OT compromise by an IT intrusion
3. The DER Aggregator has minimal OT security and relies on the utility (i.e., ISO/RTOs) to dictate the required security controls on it and the DER it controls.

Confidentiality of Data at the DER and DER Aggregator

In order to conduct a proper study of the electrical impact of DER and DER Aggregators, specific electrical models would need to be developed and shared to represent the aggregate impact DER have on the bulk system. The SPIDERWG has multiple reliability guidelines associated with the model development of aggregate DER; however, the representation of a DER Aggregator can vary and should be able to be represented in the impact it has on loadflow and transient stability of the bulk system. As with bulk-connected resources, some information may be tied to confidential agreements between OEMs or owners and data sharing of that confidential data is not allowed. This requirement to represent the end-use electrical equipment to study impact of aggregate DER[24] does not require the type of data typically secured under confidential and private agreements between the DER owner, manufacturer, DER Aggregator, or the utility. Entities handling DER information (e.g., TPs, PCs, and DPs) should ensure that the security controls they have in place include proper data management and access controls to ensure the sharing of required modeling data can occur while maintaining a high level of confidence in the treatment of private end-user data.

NERC Reliability Standards Relationships

As both DER Aggregators and DERs do not have a registered function that directly covers their applicability to NERC Reliability Standards, SPIDERWG and SITES identified any similarities to where the privacy and security practices of DERs and DER Aggregators may need to be examined in order to determine any applicability to NERC Reliability Standards. In particular, if DER or DER Aggregators provide BES Reliability Operating Services (BROS). These services, as seen in Table 1, are typically assessed for any impact over a 15 minute time frame. The following table is from CIP-002-5.1a[25], which can help relate the electrical function provided by a registered entity and what has been identified to have a grid reliability impact.

[24] Operated under a DER Aggregator or in independent operation
[25] CIP-002-5.1a is available here: https://www.nerc.com/pa/Stand/Reliability%20Standards/CIP-002-5.1a.pdf

SPIDERWG and SITES note that the DER Aggregator in particular can, in some instances, provide some of these functions for the DER it controls; however, the capacity of the DER Aggregator in a particular area can determine if the service has impact to BROS.

Table 1: Impact of Registered Entity and Associated Reliability Functions

Entity Registration	RC	BA	TOP	TO	DP	GOP	GO
Dynamic Response		X	X	X	X	X	X
Balancing Load & Generation	X	X	X	X	X	X	X
Controlling Frequency		X				X	X
Controlling Voltage			X	X	X		X
Managing Constraints	X		X			X	
Monitoring and Control			X			X	
Restoration			X			X	
Situation Awareness	X	X	X			X	
Inter-Entity coordination	X	X	X	X		X	X

In Order No. 2222 Paragraph 130, FERC specified that RTO/ISOs must “allow distributed energy resources to provide all services that they are technically capable of providing through aggregation.” If capable, DER Aggregations may begin providing services that resemble BES Reliability Operating Services. To determine whether DER Aggregator’s Cyber Assets meet the definition of a BES Cyber Asset, new and improved models for simulating a DER Aggregator’s impact on the Bulk Electric System will be required. Without accurate development of electrical models[26] that represent the control behavior pertinent to the functions above, completing the impact test of whether the control of the asset may materially impact the bulk system requires engineering judgement. For instance, if DER Aggregators are providing Frequency Regulation – balancing supply and demand on the electric system by changing energy injection or energy withdrawal within seconds – then the impact of rendering the DER aggregation Cyber Asset “unavailable, degraded, or misused” within 15 minutes on the Balancing Authority Area should be carefully studied. A DER Aggregator providing 1 MW of Frequency Regulation compared to a DER Aggregator providing 100 MW of Frequency Regulation will simply have a different level of impact to the Bulk Electric System (i.e., to Area Control Error).

BES Cyber Asset

A Cyber Asset that if rendered unavailable, degraded, or misused would, within 15 minutes of its required operation, misoperation, or non-operation, adversely impact one or more Facilities, systems, or equipment, which, if destroyed, degraded, or otherwise rendered unavailable when needed, would affect the reliable operation of the Bulk Electric System. Redundancy of affected Facilities, systems, and equipment shall not be considered when determining adverse impact. Each BES Cyber Asset is included in one or more BES Cyber Systems.

[26] These models can take on a variety of data sources, the most common software platforms that represent the Bulk Electric System are positive sequence models. Models here include loadflow and transient dynamic representations of the behavior exhibited by DER and DER Aggregator actions. Current SPIDERWG modeling documents exist for DER operating independently of a DER Aggregator, available here: https://www.nerc.com/comm/Pages/Reliability-and-Security-Guidelines.aspx

Limitations on Assessment and Applicability of DER, DER Aggregators, or other Distribution Entities

The NERC Rules of Procedure Appendix 5B's material impact test[27] defines the way in which a potentially compromised asset in the generation, transmission, or distribution of energy can have an impact on the BES. The materials impact test's questions are reproduced here:

1. Is the entity specifically identified in the emergency operation plans and/or restoration plans of an associated Reliability Coordinator, Balancing Authority, Generator Operator or Transmission Operator?
2. Will intentional or inadvertent removal of an Element owned or operated by the entity, or a common mode failure of two Elements as identified in the Reliability Standards (for example, loss of two Elements as a result of a breaker failure), lead to a reliability issue on another entity's system (such as a neighboring entity's Element exceeding an applicable rating, or loss of non-consequential load due to a single contingency)? Conversely, will such contingencies on a neighboring entity's system result in issues for Reliability Standards compliance on the system of the entity in question? Appendix 5B – Statement of Compliance Registry Criteria (Revision 7) 8
3. Can the normal operation, misoperation or malicious use of the entity's cyber assets cause a detrimental impact (e.g., by limiting the operational alternatives) on the operational reliability of an associated Balancing Authority, Generator Operator or Transmission Operator?
4. Can the normal operation, misoperation, or malicious use of the entity's Protection Systems (including UFLS, UVLS, Special Protection System, Remedial Action Schemes and other Protection Systems protecting BES Facilities) cause an adverse impact on the operational reliability of any associated Balancing Authority, Generator Operator or Transmission Operator, or the automatic load shedding programs of a PC or TP (UFLS, UVLS)?

As seen by the language above, the way material impact to the bulk system is identified is through an element's ability to affect the operational state and functions performed by a BA, GOP, or TOP. A few other questions focus on distribution enabled relaying (i.e., UFLS and UVLS), which DER and DER Aggregators may have a stronger impact depending on feeder configuration and specific implementation[28] of a PC's UFLS program. Many of these questions do not currently apply to OEM interactions for proprietary connections to the asset, but deal with the element's electric impact to the bulk system. Proprietary connections are allowable per 1547-2018 at the local DER interface, which can allow for the DER device to be compromised and lead to misoperation or malicious use if unprotected. Thus, it is important for the ability to represent the potential impact of these devices in studies that assess the performance of the bulk system including the applicable level these assets reach in NERC's Reliability Standard CIP-002-5.1a. These devices should be appropriately categorized based on the impact test, which requires a thorough understanding of the interaction of DERs, DER Aggregators, and utility systems.

[27] Available here: https://www.nerc.com/FilingsOrders/us/RuleOfProcedureDL/Appendix%205B.pdf
[28] SPIDERWG has drafted a reliability guideline on this topic, which is available here: https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Recommended_Approaches_for_UFLS_Program_Design_with_Increasing_Penetrations_of_DERs.pdf

BES Impact Test and Meaning

DER Aggregators may potentially meet the material impact test as per the “BES Cyber Asset” definition as part of the NERC Glossary of Terms[29] and through the understanding of the control of assets the DER Aggregator has in its system. SPIDERWG and SITES do not anticipate that any one DER outage will have the size and impact that can adversely affect the impact or operational reliability of any associated BA, GOP, TOP, RC, or other NERC entity. Rather, the aggregate impact of DERs onto the bulk system are found in the performance of the bulk system during grid disturbances. SPIDREWG has developed reliability guidelines[30] to address the modeling and verification of DERs in bulk system studies, and is currently drafting guidance[31] on the studies performed that incorporate these aggregate models. Further, the SITES has also identified[32] that the individual DER under malicious control has a different impact than the DER Aggregator. Depending on the size[33] and control mechanisms in place, a DER Aggregator may reach a level of BES impact. The SPIDERWG and SITES recommend further analysis in this area to determine the impact of a DER Aggregator (or similar entity) has on the bulk system.

Security Standards, Frameworks, or Alternatives in this Area

Outside of the NERC CIP standards, other governmental and national labs have provided frameworks to categorize multiple aspects of a strong security posture for the electric ecosystem. Other cybersecurity forums have also provided certification, tests, and other communication protocols that enhance the efficacy of modern security controls. In some instances, these alternatives can include resilience focused projects that do not fully rely on security controls, akin to how many distribution companies have “hot swappable” equipment. Some of these alternatives include:

1. The Cybersecurity Capability Maturity Model[34] (C2M2), which is a tool for organizations to evaluate cybersecurity capabilities for IT and OT environments.
2. The Distributed Energy Resource Cybersecurity Framework[35] by NREL, which is a tool designed specifically to evaluate the cybersecurity posture of DERs for the U.S. federal government.
3. Idaho National Lab’s Standards to Secure Energy Infrastructure[36] that allows for quick searches of applicable standards or guidance material in this area
4. Underwriter Laboratory Cybersecurity Assurance Program[37] (UL CAP), which offers a suite of tools, testing, and certifications (e.g., UL 2941[38]) to manage and apply commercially available cybersecurity capabilities

[29] Glossary of terms here: https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf
[30] The SPIDERWG reliability guidelines are available here: https://www.nerc.com/comm/Pages/Reliability-and-Security-Guidelines.aspx
[31] See SPIDERWG Work Plan, available here: https://www.nerc.com/comm/RSTC/SPIDERWG/SPIDERWG%20Work%20Plan.pdf
[32] Identified in *Cyber Security for Distributed Energy Resources and DER Aggregators*, available here: https://www.nerc.com/comm/RSTC_Reliability_Guidelines/White_Paper_Cybersecurity_for%20DERs_and_DER_Aggregators.pdf
[33] For reference, the CIP-002-5.1a Medium impact threshold for generator control centers is 1,500 MW of active power resources and 1,000 MVAR of reactive power resources
[34] Available here: https://www.energy.gov/ceser/cybersecurity-capability-maturity-model-c2m2
[35] Available here: https://dercf.nrel.gov/
[36] Available as part of the Office of Cybersecurity, Energy Security, and Emergency Response here: https://energyicsstandards.inl.gov/
[37] Available here: https://www.ul.com/services/ul-cybersecurity-assurance-program-ul-cap
[38] Standard available here: https://www.shopulstandards.com/ProductDetail.aspx?productId=UL2941_1_O_20230113

5. Sunspec's Cybersecurity Certification Program[39] that also seeks to certify functions for DERs, particularly for compliance to IEEE 2030.5.
6. Sandia National Lab's Recommendations for Distributed Energy Resource Access Control,[40] which provides a framework to minimize the risk of unauthorized access to DER systems.
7. The National Institute of Standards and Technology's set of protocol[41] standards, which define information system security practices.

Many of these alternatives are self-answered questionnaires that highlight areas of improvement for an organization to build new capabilities or leverage existing technology to improve their cybersecurity postures. As such, the SPIDERWG and SITES encourage DER owners, DER Aggregators, and similar entities to leverage these more exhaustive tools in addition to the recommendations found in this paper.

Market rules may also offer an avenue for enhanced cybersecurity measures for DERs as they dictate the participation requirements for each participant in the energy market. It is outside the scope of this paper to evaluate particular markets for their structure or adequacy in meeting cybersecurity objectives; however, market rules that specify heightened cyber security postures for all participants may be an avenue to ensure DERs and DER Aggregators maintain cyber security practices in both the IT and OT environments. ISOs and RTOs are encouraged to incorporate reliability-focused security practices in their rules such that the reliable operation of the bulk power system is not compromised by latent or unknown security threat by the participants of the electric market. Utilities are likewise recommended to ensure proper cybersecurity hygiene when integrating command and control over DERs into their distribution control centers or DER Management Systems[42] (DERMS).

Sponsored certification programs reach a sort of standardization depending on the test bed and protocol. One example from the National Renewable Energy Laboratory (NREL) aims to provide testing and certification procedures[43] for common cybersecurity controls. Additionally, NREL is also working to identify a framework[44] that comprehensively identifies the common threats against DERs in order to standardize incident response and other key players in securing the DER landscape.

National and International Lessons Learned

Current efforts to aggregate the control and dispatch of DERs include the PG&E VPP pilot project[45] with Tesla to leverage distribution-connected Battery Energy Storage Systems during times of high peak demand. These efforts have led to many thousands of end-users supplying a peak power output of, at the time of

[39] Available here: https://sunspec.org/sunspec-cybersecurity-certification-work-group/
[40] Available here: https://www.osti.gov/biblio/1765273
[41] Primarily NIST's *Security and Privacy Controls for Information Systems and Organizations*, available at https://csrc.nist.gov/publications/detail/sp/800-53/rev-5/final, and their Technical Note 2182, available at https://nvlpubs.nist.gov/nistpubs/TechnicalNotes/NIST.TN.2182.pdf.
[42] A DER Management System is identified in the IEEE 2030.X family of standards. Particularly 2030.11-2021, which can be found here: https://standards.ieee.org/ieee/2030.11/7259/
[43] Available here: https://www.nrel.gov/docs/fy22osti/80581.pdf
[44] Available here: https://www.nrel.gov/docs/fy20osti/75044.pdf
[45] Information related to this pilot program can be found on PG&E's website for the Emergency Load Reduction Program. Available here: https://elrp.olivineinc.com/

this paper, nearly 30 MW of generation during times of high strain on the grid. Internationally, Vehicle to Grid (V2G) initiatives that aggregate the ability for electric vehicles to discharge when called upon by the system operator have had some success in the European Union (EU). One EU program's V2G VPP currently is looking at a pilot project[46] to provide short-term frequency response to grid disturbances using strong collaboration between the grid operator and the VPP operator. These pilot projects have the same structural compositions seen by DER Aggregators.

Further, it is known that many cybersecurity recommendations, standards, and frameworks speak to a limited scope of applicable assets, threats, and known threat actors. In areas like DER and the distribution system security landscape, many of these frameworks are vague in their applicability to the threats facing DER, DER Aggregators, and the distribution system at large. Entities in this space have learned that where these functions lack, technical design specifications and framework adaptations to threats facing the distribution system readily improve the overall reliability and security posture of the electric ecosystem. Current advancements in this area include specifying technical security requirements[47] that historically have not existed for DERs.

Conclusions and Recommendations to DER and DER Aggregators

While there are a variety of security controls available to the DER Aggregator and DER owners, there are some controls that are better suited at the end-user device (i.e., the DER) or at the entity that controls and aggregate amount of DER (e.g., DER Aggregator or VPP). The types of security controls, types of mitigated attack, implementation notes and recommended entity for these security controls are summarized in Table 2. This table is a summary of the information contained in the above sections.

Table 2: Security Control Recommendations

Security Control	Types of Attacks Mitigated by Proper Control Implementation	Applicable Entitles	Implementation Notes
Internal Network Security Monitoring	Phishing, Active Scanning, Gathering Victim network or organization information, Malware Deployment	DER Aggregators	Some controls do not automatically use the reports. These may be prerequisite for other security controls
DER Gateways	Man in the middle, malware deployment, Denial of Service, and Replay attacks	DER Aggregators**	DER Gateways are currently under development for technical specification and may alter per P1547.10 outcomes
Remote Access Controls	Unauthorized External Remote Access, Trusted Relationship compromises, Remote System	All Entities*	DER Aggregators in particular should enable strong remote access security controls on the DER it controls

[46] Information for this one particular project is available here: https://www.next-kraftwerke.com/products/balancing-energy. For this pilot, available lessons learned can be found at the integrating German utility, available here: https://www.amprion.net/

[47] One example of these specifications comes from NREL. Their report on functional specifications is available here: https://www.nrel.gov/docs/fy22osti/79974.pdf

Table 2: Security Control Recommendations			
Security Control	**Types of Attacks Mitigated by Proper Control Implementation**	**Applicable Entitles**	**Implementation Notes**
	discovery, and most forms of Reconnaissance		
Data Management and Access Controls	Credential Harvesting or Access, Privilege Escalation, Account manipulation; and a broad set of data deletion, encoding, obfuscation, or manipulation	DER Aggregator**	These controls can also be used to mitigate privacy concerns by end-users as well as their intended security function
Network and Protocol Security	A majority of current and future cybersecurity threats.	DER Aggregator	Certain endpoints in the chosen DER Aggregator's environment may not support all desired protocols. The implementation of these controls may be software-based, specifically for cloud implemented controls.

* denotes that a DER owners implementation of the control doesn't need to be as sophisticated as DER Aggregators or utilities
** denotes that while DER Aggregators are applicable, the control may require DER owner coordination to implement

The SPIDERWG and SITES joint team has developed recommendations for the ISO/RTOs (collectively registered as BAs and RCs), DER Aggregators, and DERs in order to enhance the security posture of the electric ecosystem. Cyber attacks utilizing simple social engineering or other low-level tactics can readily compromise credentials, making security controls based on credentials alone insufficient. DERs constitute a large attack surface with potentially thousands of entry points into a network. That is, the compromise of any one side of a communications network can allow for interconnected networks to also become compromised and propagate (e.g., DER devices, DER Aggregator networks, and utility networks). With an ever increasing number of DER access points, robust security controls are of high priority to ensure the security of the electric ecosystem.

To that end, SPIDERWG and SITES jointly developed the following high-level recommendations for the ISO/RTOs:

1. ISOs/RTOs should ensure that their market rules do not prohibit entities to enhance their cyber security posture beyond a minimum level of protection.
2. ISOs/RTOs should also explore and consider market rule enhancements such that participants incorporate cybersecurity best practices and do not impose a risk to the reliable operation of the BES. In general, this is part of proper cyber hygiene for entities.

SPIDERWG and SITES also jointly developed the following high-level recommendations for DER Aggregators:

1. DER Aggregators should implement proper data management and access controls for its network in order to assure confidentiality of private data as well as mitigate against specific cyber attacks.

2. DER Aggregators should implement strong network access controls, particularly for remote access, and require MFA for remote access of their network and applications.
3. DER Aggregators should implement strong external perimeter controls, such as intrusion detection systems, such that they are notified of a compromise and can take proper actions to mitigate the intrusion.
4. DER Aggregators should ensure endpoint controls, such as through DER Gateways, are deployed at the DER sites and deploy endpoint controls where a gap exists.

Furthermore, SPIDERWG and SITES jointly developed the following high-level recommendations for DERs:

1. DER owners should ensure they wipe personal information from old hardware and, to the degree possible, implement data management and access control to their network. In particular, U-DERs should implement strong access controls.
2. U-DERs, to the extent possible, should implement network access controls, particularly for remote access. For programatic remote access, PKIs through a DERMS or other management system by the utility should be enabled.

State Coordination of Implementation of Recommendations

Key Takeaway:
The DER Aggregator should register for NERC Reliability Standards applicability when it acts as a BES Cyber Asset and thus can impact the reliable operation of the BES.

FERC Order 2222 does not specify requirement for cybersecurity and data privacy. Rather the order recommends that "that RTOs/ISOs coordinate with distribution utilities and relevant electric retail regulatory authorities (e.g., state PUCs) to establish protocols for sharing metering and telemetry data, and that such protocols minimize costs and other burdens and address concerns raised with respect to privacy and cybersecurity." Due to the various jurisdictions on utility procedures and security measures, strong collaboration and coordination among transmission and distribution entities is highly recommended.

The overall security posture of the bulk system can be impacted by the potential security risk associated with DER or DER Aggregators, and the SPIDERWG and SITES recommend that DER Aggregators register for NERC standards applicability when they act as a BES Cyber Asset and thus can impact the reliability of the BES. The recommendations above should be coordinated with appropriate and open stakeholder engagement where the security measures and controls are agreed on for the local distribution system. These entities can assist in building the design basis threat or other risk assessment that prioritize the most effective security controls to mitigate their anticipated threats. State coordination is a high priority where DER-site specific physical security measures are identified.

In general, the key risk considerations which should be considered in this broader coordination effort[48] include 1) data privacy, including both personal and market data, 2) data integrity among entities, and 3) data availability.

Data Confidentiality

Per FERC Order 2222, RTO/ISO must revise their tariffs such that DERAs provide "a list of the individual resources in its aggregation, necessary information that must be submitted for individual DERS, and retain performance data for individual DERs." Entities participating in energy markets must be aware of data privacy regulations, understand the potential impact to customer privacy in the event of data-loss-events, and ensure both technical and procedural controls are implemented to ensure both transparencies in how data is used and adequate protections for consumer data. The recommended coordination should identify these and similar confidentiality requirements, especially as they relate to protecting against a widespread compromise of DERs.

Data Integrity

Entities should coordinate development of cybersecurity criteria for DER systems and communication protocols used for interoperability and data exchanges, includes NIST-approved cryptographic suites and protocols to protect against data manipulation, as well as establish protocols to ensure adequacy of security control implementations. Testing standards for DER systems and communication protocols should also be included in the implementation of recommendations.

Data Availability

Creation of risk assessment methodologies is needed to evaluate a grid entity's role in the electric sector and their associated security control and redundancy measures these roles must adopt and maintain. These measures can account for various financial, safety, reliability, privacy considerations resulting from cyber attacks against the entity's systems and data.

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[48] Additional resources on how this participation in markets can be influenced by DER Aggregators is available at:
EPRI, DER Aggregation Participation in Electricity Markets: EPRI Collaborative Forum Final Report and FERC Order 2222 Roadmap, Palo Alto, 3002020599

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NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

White Paper – Privacy and Security Impacts of DER and DER Aggregators

Request for Review

Shayan Rizvi, NPCC – SPIDERWG Chair

Wayne Guttormson, SaskPower - RSTC Sponsor

NERC Reliability and Security Technical Committee

June 21, 2023

RELIABILITY | RESILIENCE | SECURITY

Background

- Joint SITES and SPIDERWG work plan item
- Follows up recommendations on future work of:
  - *White Paper: BPS Reliability Perspectives on Distributed Energy Resource Aggregators*
  - *White Paper: Cyber Security for Distributed Energy Resources and DER Aggregators*

Structure

- Controls available to DERs and DER Aggregators
- Current assessment of distribution landscape for DERs and DER Aggregators
- Relationships and comparisons to NERC CIP
- Alternatives and other security frameworks for DERs and DER Aggregators
- Recommendations
  - One set to ISOs/RTOs (i.e., the BAs and RCs)
  - One set on DER Aggregators
  - One set to DERs (focusing on good cyber hygiene)

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Request

- SPIDERWG and SITES are seeking broad review and input on this paper.
- Requesting RSTC Reviewers at this time

Questions and Answers

SAR EOP-004

Action
Request for RSTC Comments

Background
This SAR has been through the EAS and PAS for their comment, which is included in the draft SAR.

Summary
Recent large-scale disturbances (e.g., the August 2019 disturbance in the United Kingdom)[1] have demonstrated that unexpected loss of DERs during BPS faults can compromise reliable operation of the BPS. Despite potential impact to reliable operation, EOP-004-4 does not currently require reporting by Balancing Authorities (BAs) and Reliability Coordinators (RC) of the loss of aggregate DERs to NERC. The purpose of EOP-004-4[2] is to "improve the reliability of the Bulk Electric System by requiring the reporting of events by Responsible Entities." Further, NERC disturbance analysis have demonstrated net load jumps that have been attributed to DER tripping yet there is no reflection in EOP-004-4 as to the treatment of this type of event in the categories in Attachment 1. Clarity on which Event Type in Attachment 1 as well as the establishment of a threshold for reporting of loss of aggregate DER support the purpose of EOP-004 in reporting of large grid disturbances.

[1] Available: https://www.ofgem.gov.uk/publications/investigation-9-august-2019-power-outage
[2] EOP-00404 available here: https://www.nerc.com/pa/Stand/Reliability%20Standards/EOP-004-4.pdf

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Standard Authorization Request (SAR)

Complete and submit this form, with attachment(s) to the NERC Help Desk. Upon entering the Captcha, please type in your contact information, and attach the SAR to your ticket. Once submitted, you will receive a confirmation number which you can use to track your request.

The North American Electric Reliability Corporation (NERC) welcomes suggestions to improve the reliability of the bulk power system through improved Reliability Standards.

Requested information			
SAR Title:	Reporting of Aggregate loss of DER during Grid Disturbances in EOP-004		
Date Submitted:	MM/DD/2023		
SAR Requester			
Name:	Shayan Rizvi, NPCC (NERC SPIDERWG Chair) John Schmall , ERCOT (NERC SPIDERWG Vice-Chair)		
Organization:	The NERC System Planning Impacts of DER Working Group (SPIDERWG)		
Telephone:	Shayan – 212-840-1070 John – 512-248-4243	Email:	Shayan – srizvi@nppc.org John – john.schmall@ercot.com
SAR Type (Check as many as apply)			
☐ New Standard ☒ Revision to Existing Standard ☐ Add, Modify or Retire a Glossary Term ☐ Withdraw/retire an Existing Standard		☐ Imminent Action/ Confidential Issue (SPM Section 10) ☐ Variance development or revision ☐ Other (Please specify)	
Justification for this proposed standard development project (Check all that apply to help NERC prioritize development)			
☐ Regulatory Initiation ☐ Emerging Risk (Reliability Issues Steering Committee) Identified ☐ Reliability Standard Development Plan		☒ NERC Standing Committee Identified ☐ Enhanced Periodic Review Initiated ☒ Industry Stakeholder Identified	
Industry Need (What Bulk Electric System (BES) reliability benefit does the proposed project provide?):			
Recent large-scale disturbances (e.g., the August 2019 disturbance in the United Kingdom)[1] have demonstrated that unexpected loss of DERs during BPS faults can compromise reliable operation of the BPS. Despite potential impact to reliable operation, EOP-004-4 does not currently require reporting by Balancing Authorities (BAs) and Reliability Coordinators (RC) of the loss of aggregate DERs to NERC. The purpose of EOP-004-4[2] is to "improve the reliability of the Bulk Electric System by requiring the reporting of events by Responsible Entities." Further, NERC disturbance analysis have demonstrated net load jumps that have been attributed to DER tripping yet there is no reflection in EOP-004-4 as to the treatment of this type of event in the categories in Attachment 1. Clarity on which Event Type in Attachment 1 as well			

[1] Available: https://www.ofgem.gov.uk/publications/investigation-9-august-2019-power-outage
[2] EOP-00404 available here: https://www.nerc.com/pa/Stand/Reliability%20Standards/EOP-004-4.pdf

Commented [A1]: From James Hanson (EAS):

1.The SAR deals solely with IBR reductions on the distribution system (I understand that is SPIDERWG's focus). I was looking for an alteration to the EOP-004 standard to also include IBR reductions on the BPS/BES to be included as well. Please excuse this comment if this is an effort from the IRPS or another group.
2.This can be challenging to determine whom should be doing the reporting if the reduction spans multiple BA's or even RC's. A BA may not even know the threshold for the event has been met if the reduction within their footprint is below the limit. In this case, would it become the RC's responsibility to report? I bring this up for consideration, and suggest some guidance be included on scenarios like this.
3.This loss of DER's can be difficult to accurately identify. I have heard of a few approaches. There may need to be some instruction given on what to look for. Maybe a lessons learned document covering a few approaches or something similar.

All and all, the SAR reads well and I think the SPIDERWG is plugging an existing gap. I appreciate the group's hard work with this effort.

Commented [A2R1]: 1)EOP-004 is under revision for bulk connected IBR in Project 2023-01 https://www.nerc.com/pa/Stand/Pages/Project-2023-01-EOP-004-IBR-Event-Reporting.aspx
2)Edits in SAR to accommodate on the first point for the project to identify applicable entities and ensure coverage of events of concern.
3)SPIDERWG identified a RG to come on improving accurate detection of DER loss during grid events. As identified in the comment, current infrastructure exists to quantify DER loss.

Requested information
as the establishment of a threshold for reporting of loss of aggregate DER support the purpose of EOP-004 in reporting of large grid disturbances.
Purpose or Goal (How does this proposed project provide the reliability-related benefit described above?):
Some of NERC's objective in the Rules of Procedure[3] identify that the Reliability Assessment and Performance Analysis Program are to "analyze off-normal events on the Bulk Power System" and "identify the root causes of events that may be precursors of potentially- more serious events". Event analysis for major events is part of the NERC's process following these disturbances, but requires a notification process to determine if a grid disturbance meets the criteria for a major event. ~~directly supports "evaluating bulk power system events, undertaking appropriate levels of analysis to determine the causes of events, promptly assuring tracking of corrective actions to prevent recurrence, and providing lessons learned to industry".[4]~~ The notification of disturbances, including both minor and major ~~that~~disturbances that impact the bulk power system, is required in order for the ERO Event Analysis ~~staff~~ program to perform their procedures. The proposed project provides clarity for the attribution of tripping of aggregate DER and establishes a threshold for which loss of aggregate DER warrants notice to the ERO. Both objectives provide the event analysis process the information needed to conduct their reliability-focused objective.
Project Scope (Define the parameters of the proposed project):
The scope of the project is to modify EOP-004 to account for loss of aggregate DER during grid disturbances. At a minimum, the standard team should clarify how loss of aggregate DER and loss of firm load are accounted so they are not canceled by netting the two. The standard drafting team should also define a threshold for reporting of events where the loss of aggregate DER exceed such threshold. Further, as Attachment 2 specifies that the DOE OE-417 report can be submitted in lieu of the EOP-004 report, the SDT should align the forms for such instances to ensure the OE-417 form submissions cover events where aggregate amounts of DER trip above the threshold the SDT establishes.

[3] Quotations are from NERC Rules of Procedure, available here: https://www.nerc.com/AboutNERC/RulesOfProcedure/NERC%20ROP%20effective%2020220825_no%20appendicies.pdf
~~[4] Taken from the Event Analysis NERC website here: https://www.nerc.com/pa/rrm/ea/Pages/default.aspx~~

Commented [A3]: From EAS:
I just wanted to suggest that you not mention the event analysis process in the supporting language. The EAP does not deal with DERs nor does the EOP-004 directly connect to the EAP as the EOP is simply a standards notification requirement. It is true that the EAP leverages the EOP, but the EOP is in existence for standards purposes and not the EAP specifically. It would be more appropriate to talk in terms of the ERO EA Program (Section 800, NERC ROP authorities) concerning ERO EA staff analyzing.

Commented [A4R3]: Edits made to clarify to NERC ROP over EAP.

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Requested information
Detailed Description (Describe the proposed deliverable(s) with sufficient detail for a drafting team to execute the project. If you propose a new or substantially revised Reliability Standard or definition, provide: (1) a technical justification[5] which includes a discussion of the reliability-related benefits of developing a new or revised Reliability Standard or definition, and (2) a technical foundation document (*e.g.,* research paper) to guide development of the Standard or definition):
DERs are generation resources that are on the distribution system, and they sometimes are netted with load. As such, the loss of aggregate DER on the system can be interpreted to fill both generation loss and firm load shedding categories of Attachment 1 of EOP-004, so clarity is needed to account for DER in the reporting form. Further, the linkage of EOP-004 to OE-417 reporting should also be considered for Attachment 2 such that loss of aggregate DER reported on the DOE's OE-417 report that is accepted in lieu of EOP-004 also covers the identified threshold of aggregate DER loss in the proposed revisions. SPIDERWG recommends that a standard drafting team review and revise EOP-004-4 to require reporting, including the threshold for reporting, of the loss of aggregate DERs to NERC. These are accomplished by: 1) Requiring of reporting of loss of aggregate DER by applicable entities such as ~~the~~ requiring both[6] the BA and RC. The SDT should ensure that the chosen registered entity applicability does not prevent notification of the loss of aggregate DER to the ERO during grid disturbances. 2) Establish a MW threshold for loss of aggregate DER to be reported to the ERO. The SDT can consider other technical thresholds in addition to a MW threshold. 3) Ensuring consistency of reporting by the forms accepted for this reporting in the Attachments of the Reliability Standard.
Cost Impact Assessment, if known (Provide a paragraph describing the potential cost impacts associated with the proposed project):
The material costs are unknown. This project requires the reporting of loss of aggregate DER, which may require additional staffing should bulk disturbances result in wide-spread tripping of aggregate DER. However, net loading quantities currently tracked by BAs, RCs, and TOPs to run their Operating Planning Assessments, Real-Time Assessments, and real-time monitoring of their area are able to track loss of aggregate DER, so additional metering is unlikely not needed to meet the scope of changes of this.
Please describe any unique characteristics of the BES facilities that may be impacted by this proposed standard development project (*e.g.*, Dispersed Generation Resources):
There are no required alterations to BES Facilities based on this project. The project focuses on reporting requirements of entities, which are not BES Facilities.

[5] The NERC Rules of Procedure require a technical justification for new or substantially revised Reliability Standards. Please attach pertinent information to this form before submittal to NERC.
[6] Current information available to the RCs and BAs include a net load quantity. Major jumps in this quantity can indicate DER tripping.

Requested information
To assist the NERC Standards Committee in appointing a drafting team with the appropriate members, please indicate to which Functional Entities the proposed standard(s) should apply (*e.g.*, Transmission Operator, Reliability Coordinator, etc. See the most recent version of the NERC Functional Model for definitions):
Impacted: Reliability Coordinator (RC), Balancing Authority (BA), and Distribution Provider (DP) Potentially Impacted: Transmission Owner (TO) and Transmission Operator (TOP)
Do you know of any consensus building activities[7] in connection with this SAR? If so, please provide any recommendations or findings resulting from the consensus building activity.
This SAR has been submitted through the RSTC and has been vetted by the SPIDERWG membership. The SPIDERWG membership includes BAs, RCs, TOs, TPs, TOPs, PCs, and DPs. The SAR drafting has been circulated to the Event Analysis Subcommittee and the Performance Analysis Subcommittee under the RSTC. The SPIDERWG recommended this standard be revised in *White Paper: SPIDERWG NERC Reliability Standards Review*.[8]
Are there any related standards or SARs that should be assessed for impact as a result of this proposed project? If so, which standard(s) or project number(s)?
This SAR is covering the aggregate loss of DER and the development of a threshold to notify the ERO when such losses exceed the threshold. The Inverter-Based Resources Subcommittee has recently submitted an EOP-004 SAR that covers bulk-connected equipment, which is currently approved and progressing under Project 2023-01.[9] While different scopes and risks, the projects are covering the same Reliability Standard and complement each other. The creation of standards projects can coordinate teams working on the same Reliability Standard.
Are there alternatives (e.g., guidelines, white paper, alerts, etc.) that have been considered or could meet the objectives? If so, please list the alternatives.
The SPIDERWG considered Standards revisions alongside compliance implementation guidance and reliability guidelines. Neither compliance implementation guidance nor reliability guidelines were determined to be sufficient for the risk identified by SPIDERWG in their consensus-based white paper above. SPIDERWG guidance for state-of-the-art detection is planned, but does not cover the items identified in the SAR.

[7] Consensus building activities are occasionally conducted by NERC and/or project review teams. They typically are conducted to obtain industry inputs prior to proposing any standard development project to revise, or develop a standard or definition.
[8] Paper available here: https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Whitepaper_SPIDERWG_Standards_Review.pdf e
[9] Project page available here: https://www.nerc.com/pa/Stand/Pages/Project-2023-01-EOP-004-IBR-Event-Reporting.aspx

Reliability Principles	
Does this proposed standard development project support at least one of the following Reliability Principles (Reliability Interface Principles)? Please check all those that apply.	
☒	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☐	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
☒	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
☐	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.
☐	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.
☐	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☐	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.
☐	8. Bulk power systems shall be protected from malicious physical or cyber attacks.

Market Interface Principles	
Does the proposed standard development project comply with all of the following Market Interface Principles?	Enter (yes/no)
1. A reliability standard shall not give any market participant an unfair competitive advantage.	Yes
2. A reliability standard shall neither mandate nor prohibit any specific market structure.	Yes
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard.	Yes
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards.	yes

Identified Existing or Potential Regional or Interconnection Variances	
Region(s)/ Interconnection	Explanation
None	N/A

For Use by NERC Only

SAR Status Tracking (Check off as appropriate).	
☐ Draft SAR reviewed by NERC Staff ☐ Draft SAR presented to SC for acceptance ☐ DRAFT SAR approved for posting by the SC	☐ Final SAR endorsed by the SC ☐ SAR assigned a Standards Project by NERC ☐ SAR denied or proposed as Guidance document

Version History

Version	Date	Owner	Change Tracking
1	June 3, 2013		Revised
1	August 29, 2014	Standards Information Staff	Updated template
2	January 18, 2017	Standards Information Staff	Revised
2	June 28, 2017	Standards Information Staff	Updated template
3	February 22, 2019	Standards Information Staff	Added instructions to submit via Help Desk
4	February 25, 2020	Standards Information Staff	Updated template footer

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Standard Authorization Request (SAR)

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The North American Electric Reliability Corporation (NERC) welcomes suggestions to improve the reliability of the bulk power system through improved Reliability Standards.

Commented [A1]: RTOS wishes to collaborate on this SAR, which we can do so after obtaining RSTC comment. They submitted one comment from their chair,

"in my opinion, if DER were to be a Blackstart Resource it maybe more of a Reliability Risk".

Commented [A2R1]: No alterations made based on this comment. We look forward to addressing and collaborating after we get RSTC comments on this SAR.

Requested information			
SAR Title:	Inclusion of DER in Blackstart Plans – EOP-005		
Date Submitted:	MM/DD/2022		
SAR Requester			
Name:	Shayan Rizvi, NPCC (NERC SPIDERWG Chair) John Schmall , ERCOT (NERC SPIDERWG Vice-Chair)		
Organization:	The NERC System Planning Impacts of DER Working Group (SPIDERWG)		
Telephone:	Shayan – 212-840-1070 John – 512-248-4243	Email:	Shayan – srizvi@nppc.org John – john.schmall@ercot.com
SAR Type (Check as many as apply)			
☐ New Standard ☒ Revision to Existing Standard ☐ Add, Modify or Retire a Glossary Term ☐ Withdraw/retire an Existing Standard		☐ Imminent Action/ Confidential Issue (SPM Section 10) ☐ Variance development or revision ☐ Other (Please specify)	
Justification for this proposed standard development project (Check all that apply to help NERC prioritize development)			
☐ Regulatory Initiation ☐ Emerging Risk (Reliability Issues Steering Committee) Identified ☐ Reliability Standard Development Plan		☒ NERC Standing Committee Identified ☐ Enhanced Periodic Review Initiated ☒ Industry Stakeholder Identified	
Industry Need (What Bulk Electric System (BES) reliability benefit does the proposed project provide?):			
In order to "ensure plans, Facilities, and personnel are prepared to enable System restoration from Blackstart Resources to ensure reliability is maintained during restoration"[1], clarity is needed for how to account for DER in EOP-005. If DER are considered "Blackstart Resources", then there is a need to study the switching path[2] from the DER to the BPS system restoration plan objective to ensure reliability during these time periods. Even if DER are not part of the "Blackstart Resources", accounting for DER automatic response to energization of distribution equipment is necessary to ensure the reliable operation of the bulk system during System restoration activities.			

[1] Taken from EOP-005-3. Available: https://www.nerc.com/pa/Stand/Reliability%20Standards/EOP-005-3.pdf
[2] Sometimes this is called a "cranking path".

Requested information
Purpose or Goal (How does this proposed project provide the reliability-related benefit described above?):
The purpose of the SAR is to revise EOP-005 to include DER data in Requirements R1.4, R6, R7, and R11 to allow for the TOP to account for DER in their system restoration plan as well as account for DER in the Blackstart Resource Agreements with the TOP's respective GOPs.
Project Scope (Define the parameters of the proposed project):
Modify EOP-005 to account for the following: 1) Update the EOP-005 requirements to reflect additional required information for DER for when a DER is selected as a Blackstart Resource. 2) Require the TOP to capture the automatic response of DER when performing load pickup of distribution equipment during System restoration. 3) Require the DP to provide DER data to the TOP to perform the study in Item 2. 4) Require the TOP to establish telemetry and communication requirements as part of their studies to ensure the success of their System restoration plans.
Detailed Description (Describe the proposed deliverable(s) with sufficient detail for a drafting team to execute the project. If you propose a new or substantially revised Reliability Standard or definition, provide: (1) a technical justification[3] which includes a discussion of the reliability-related benefits of developing a new or revised Reliability Standard or definition, and (2) a technical foundation document (*e.g.,* research paper) to guide development of the Standard or definition):
Under the current applicability section of EOP-005-3, the requirements for resource integration into the plan, in most cases, fall to the TOP or the TO. Typically these entities receive only load data from the DP, not the operating characteristics of underlying resource control systems. The TOP or TO are therefore frequently unable to confidently predict resource response to system conditions. If DERs are to be accepted to participate as blackstart resources in a system restoration plan, there will be a need to study the switching path from the DER to the BPS system restoration plan objective that is being supported. Thus, additional information related to the switching path between the DER and the supported portion of the BPS for the Blackstart Plan may be required. As such, standard revisions should provide flexibility to ensure reliability is maintained during system restoration should DERs be accepted as blackstart resources to participate in restoration plans. Regardless of whether DERs are blackstart resources, DERs will respond to energization of distribution substations in load pickup, potentially creating adverse conditions. Without access to modeling data and operating characteristics for modeling the DERs in these instances, the studies required to build a system restoration plan under EOP-005-3 would provide only a weak estimate of the distribution system response to an event, such as in steady-state and dynamic

[3] The NERC Rules of Procedure require a technical justification for new or substantially revised Reliability Standards. Please attach pertinent information to this form before submittal to NERC.

Commented [A3]: RTOS identified that if DER is chosen for Blackstart, it may be a reliability risk.

Can we alter to state that?

"Modify EOP-005 to reflect additional requirements for when a DER is selected as a Blackstart Resource, or reflect the burden the DP would need in order to ensure the DER is Blackstart capable."

Requested information
simulations. The ability to obtain this information in a vertically integrated environment may not present challenges, but Regional Trade Organizations/Independent System Operators (ISO)/TOP's past experience has shown difficulty in obtaining new technology or resource mix data and operating characteristics when not enforceable under a standard in market environments. Integration of demand response (DR) in the forward capacity market is an example. DR resides on the distribution system and causes data concerns for the Regional Trade Organization/ISO/TOP around potential real-time dispatch of DR on the wrong side of a constraint. The potential data gathering challenges described here bring into question the accuracy of the studies. Historical events have shown that the lack of data and modeling from distribution systems has resulted in inaccurate assessments of transmission system performance and contingency responses. Some contributing factors to events were a lack of visibility and understanding of the distribution system resource controls responses to transmission system contingencies. With the integration of DER as a blackstart resource in a system restoration plan makes it critical to evaluate the transmission system contingency response prior to accepting the resource into the system restoration plan. Understanding the resource's expected response is particularly important in the early stages of restoration when the transmission system is weak and frequency and voltage control can be challenging for system operations with frequency and voltage excursions beyond the normal range. This is true regardless of if a DER is identified as a "Blackstart Resource" or if the DER is reacting to load energization. Coordination of roles among the DP, TOP, and GOP of Blackstart Resources in a system restoration plan is necessary to properly study frequency and voltage response during the early stages of system restoration. These findings are documented in the SPIDERWG white paper *NERC Reliability Standards Review*[4].
Cost Impact Assessment, if known (Provide a paragraph describing the potential cost impacts associated with the proposed project):
Material cost impacts are unknown. Clarity enhancements are not anticipated to have a significant cost and the extra time spent on studying the cranking path may have a needed extra cost to evaluate and develop a reliability-focused cranking path. It should be noted that blackstart is a topic whose cost to benefit calculations are fairly skewed towards spending to ensure reliability in this regard.
Please describe any unique characteristics of the BES facilities that may be impacted by this proposed standard development project (*e.g.*, Dispersed Generation Resources):
None anticipated. However, if a DER is selected as a Blackstart Resource, they become a BES facility in effect to deliver the power as part of a cranking path.
To assist the NERC Standards Committee in appointing a drafting team with the appropriate members, please indicate to which Functional Entities the proposed standard(s) should apply (*e.g.*, Transmission

[4] Available here: https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Whitepaper_SPIDERWG_Standards_Review.pdf

Requested information
Operator, Reliability Coordinator, etc. See the most recent version of the NERC Functional Model for definitions):
Distribution Provider (DP), Transmission Operator (TOP), Transmission Owner (TO), and Generation Operator (GOP).
Do you know of any consensus building activities[5] in connection with this SAR? If so, please provide any recommendations or findings resulting from the consensus building activity.
This SAR has been submitted through the RSTC and has been vetted by the SPIDERWG membership. The SPIDERWG membership includes BAs, RCs, TOs, TPs, TOPs, PCs, and DPs. The SPIDERWG recommended this standard be revised in *White Paper: SPIDERWG NERC Reliability Standards Review*. The SAR was also circulated to the Real-Time Operating Subcommittee and the Event Analysis Subcommittee and their comments and edits are incorporated in language.
Are there any related standards or SARs that should be assessed for impact as a result of this proposed project? If so, which standard(s) or project number(s)?
There are no other standards projects or anticipated SARs that will address the study of DER in blackstart restoration plans or account for the nuances of a DER being selected for a Blackstart Resource.
Are there alternatives (e.g., guidelines, white paper, alerts, etc.) that have been considered or could meet the objectives? If so, please list the alternatives.
The SPIDERWG considered Standards revisions alongside compliance implementation guidance and reliability guidelines. The SPIDERWG identified that specific standards revisions are necessary to ensure the reliable operation of the system during system restoration. A reliability guideline is useful in identifying best practices for sharing DER information for development of a system restoration plan, but not in addressing the critical need to capture DER response to actions taken in a system restoration plan such that the plan is successful.

Reliability Principles	
Does this proposed standard development project support at least one of the following Reliability Principles (Reliability Interface Principles)? Please check all those that apply.	
☒	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.

[5] Consensus building activities are occasionally conducted by NERC and/or project review teams. They typically are conducted to obtain industry inputs prior to proposing any standard development project to revise, or develop a standard or definition.

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Reliability Principles	
☐	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
☒	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
☐	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.
☐	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.
☐	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☐	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.
☐	8. Bulk power systems shall be protected from malicious physical or cyber attacks.

Market Interface Principles	
Does the proposed standard development project comply with all of the following Market Interface Principles?	Enter (yes/no)
1. A reliability standard shall not give any market participant an unfair competitive advantage.	Yes
2. A reliability standard shall neither mandate nor prohibit any specific market structure.	Yes
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard.	Yes
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards.	yes

Identified Existing or Potential Regional or Interconnection Variances	
Region(s)/ Interconnection	Explanation
None	N/A

For Use by NERC Only

SAR Status Tracking (Check off as appropriate).	
☐ Draft SAR reviewed by NERC Staff ☐ Draft SAR presented to SC for acceptance ☐ DRAFT SAR approved for posting by the SC	☐ Final SAR endorsed by the SC ☐ SAR assigned a Standards Project by NERC

	☐ SAR denied or proposed as Guidance document

Version History

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1	June 3, 2013		Revised
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3	February 22, 2019	Standards Information Staff	Added instructions to submit via Help Desk
4	February 25, 2020	Standards Information Staff	Updated template footer

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EOP-004 and EOP-005 SARs

Request for Review

Shayan Rizvi, NPCC – SPIDERWG Chair

Wayne Guttormson, SaskPower - RSTC Sponsor

NERC Reliability and Security Technical Committee

June 21, 2023

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EOP-004 SAR

- Sought EAS and PAS comment and review prior to meeting.
  - Approved coordination by RSTC EC in December 2022
- PAS and EAS members supportive of SAR
  - Provided clarity edits
  - Provided stronger technical foundations to linked documents.
- Project focuses on reporting to the ERO when an event occurs that includes DER response.
  - The project scope is flexibly to determine who reports and how much DER loss warrants a report.
  - Project also includes alignment of acceptable forms (i.e., EOP-004 and OE-417)
- **Seeking RSTC Review**

EOP-005 SAR

- Sought EAS and RTOS comment and review prior to meeting.
  - Approved coordination by RSTC EC in December 2022
- RTOS and EAS members supportive of SAR
  - RTOS desires the collaboration in response to RSTC comments
  - RTOS highlighted concerns about selection of DER for Blackstart.
- Project focuses on clear identification of DER during load pickup in system restoration plans.
  - Includes scope for procedural and data enhancements w.r.t. DER
- **Seeking RSTC Review**

Questions and Answers

Time Monitoring Reference Document

Introduction

This reference document outlines responsibilities of Reliability Coordinators serving as time monitors in the North American Interconnections. This document specifies how Manual Time Error Corrections (MTEC) are to be implemented, if needed, to resolve Time Error accumulations and outlines procedural responsibilities assigned to the time monitor.[1] Changes to this reference document will be at the direction of the NERC ~~Operating~~ Reliability and Security Technical Committee (~~O~~RSTC).

Designation of Time Monitor

There will be one designated time monitor within each Interconnection. NERC's Real Time Operating ~~Reliability~~ Subcommittee (RTO~~OR~~S) will select a time monitor for each Interconnection. At the annual December RSTC~~OC~~ meeting, the RTOS~~ORS~~ will notify the RST~~O~~C of the designated time monitors for the next two time monitor terms.

The minimum term of each time monitor shall be no less than one (1) year. With the exception of the Eastern Interconnection, the time monitor term shall be automatically renewed unless requested otherwise by providing a minimum of six (6) months' notice to the RTO~~OR~~S. The Eastern Interconnection time monitor will rotate on an annual basis as outlined below. Should an existing or future time monitor no longer be willing or able to fulfill its responsibilities, the RST~~O~~C will, within the six (6) month period after notice, direct the RTO~~OR~~S to select a replacement and communicate the transition plan to the RST~~O~~C.

NERC's Resources Subcommittee (RS) will report to the RTS~~O~~C and RTO~~OR~~S any Time Error accumulations resolved by implementing MTEC and provide the technical basis for the determination.

If a time monitor fails to fulfill its responsibilities, the RTO~~OR~~S will work with the time monitor to resolve the problem. The RTO~~OR~~S will submit a report to the RST~~O~~C either identifying corrective measures taken or providing a recommendation for a new time monitor.

In the western interconnection time error correction is performed by all balancing authorities through automatic time error correction (ATEC). Each balancing authority operates with ATEC in service as a part of their ACE calculation with procedures to disable if needed due toreliability related risk.

Responsibilities of the Time Monitor

When a Time Error accumulation is resolved through MTEC, the time monitor will start and stop MTEC as outlined in Attachment A of this reference.

[1] This reference document is provided for guidance and does not reflect binding norms or mandatory requirements.

The time monitor will terminate any MTEC believed to be adversely impacting reliability. Requests for termination may be made by any Reliability Coordinator or by a Balancing Authority through its respective Reliability Coordinator. The time monitor will provide reports (as determined by the ~~O~~RSTC), including but not limited to accumulated Time Error following each MTEC.

Time Monitor Transition

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

References

A copy of each time monitor's local procedure is available on an as needed basis. For additional information or to request a copy of the time monitor's local procedures, an entity should contact the current time monitor.

Interconnection Time Monitors

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

1. ERCOT Interconnection – ERCOT Reliability Coordinator
2. Québec Interconnection – Hydro-Québec TransÉnergie Reliability Coordinator
3. WECC Interconnection – California ISO - RC West
4. Eastern Interconnection – The Reliability Coordinators in the Eastern Interconnection will rotate the time monitor responsibilities on an annual basis as follows:

   ~~a. SaskPower – February 1, 2019 through January 31, 2020~~

   ~~b.a. Southeastern – February 1, 2020 through January 31, 2021~~

   ~~c.a. TVA – February 1, 2021 through January 31, 2022~~

   ~~d.a. MISO – February 1, 2022 through January 31, 2023~~

   ~~e.~~a. IESO (Ontario) – February 1, 2023 through January 31, 2024

   ~~f.~~b. NBP (New Brunswick Power) – February 1, 2024 through January 31, 2025

   ~~g.~~c. VACAR-South – February 1, 2025 through January 31, 2026

   ~~h.~~d. SPP – February 1, 2026 through January 31, 2027

   ~~i.~~e. NYISO – February 1, 2027 through January 31, 2028

   ~~j.~~f. PJM – February 1, 2028 through January 31, 2029

~~k.~~g. ISO-NE – February 1, 2029 through January 31, 2030

h. FRCC – February 1, 2030 through January 31, 2031

i. SaskPower – February 1, 2031~~2019~~ through January 31, ~~2020~~2032

j. Southeastern – February 1, ~~2020~~2032 through January 31, ~~2021~~2033

k. TVA – February 1, ~~2021~~2033 through January 31, ~~2022~~2034

~~MISO – February 1, 2022 through January 31, 2023~~

Attachment A

Introduction

Interconnection frequency is normally scheduled at 60.00 Hz. Since control is imperfect, frequency will average slightly above or below 60.00 Hz. The implementation of a MTEC will correct Time Error~~oor~~ accumulation outside the established control bands by adjusting the Interconnection's scheduled frequency.

Each Balancing Authority is expected to participate in Interconnection MTEC procedures unless it is operating asynchronously to its Interconnection. If a Balancing Authority is experiencing a reliability problem that would be aggravated by the correction, it must inform its Reliability Coordinator, so that the Reliability Coordinator can take appropriate action. The requirement to participate will be enforced through an Operating Instruction from the Reliability Coordinator acting as the time monitor.

Single Balancing Authority Interconnections or Balancing Authorities operating asynchronously may establish their own time error control bands and time correction methodology, but should notify the RST~~O~~C of the bands utilized, as well as subsequent changes.

Interconnections may choose to follow alternative procedures. If so, those procedures should be shared with the RST~~O~~C and approved by the RST~~O~~C.

General Practices

MTEC Notice and Commencement: MTEC is conducted following the process below.

1. **Time Error Correction Initiation and Termination.** MTEC starts and ends on the hour or half-hour with notice by the time monitor generally given at least one hour before the MTEC is scheduled to start or terminate. Time zone references in any correspondance will be the time zone being observed by current active time monitor. The time monitor must clearly state which time zone is being observed during all correspondence.
2. **Time Error Correction labeling.** MTEC notifications are labeled on a monthly basis using an Interconnection approach (e.g. A-Z, AA-AZ, BA-BZ,…).
3. **Time Correction Offset.** The Balancing Authority may participate in MTEC by either of the following two methods:
   a. **Frequency Offset (Preferred Approach).** The Balancing Authority may offset its frequency schedule by 0.02 Hz (or other smaller offset designated by the time monitor[2]), leaving the Frequency Bias Setting normal, or
   b. **Schedule Offset.** If the frequency schedule cannot be offset, the Balancing Authority may offset its net Interchange Schedule (MW) by an amount equal to the computed bias contribution times the desired frequency offset.
4. **Request for Termination or Halt of Scheduled MTEC**. Any Reliability Coordinator in an Interconnection may request the termination of an MTEC or of the initiation of a scheduled MTEC.

[2] Alternative procedures should be approved the NERC OC prior to implementation.

A Balancing Authority that has a reliability concern with the execution of an MTEC should notify their Reliability Coordinator to request a termination of the MTEC. A Reliability Coordinator requesting a termination or halt of an MTEC is asked to forward the reasons for requesting the termination to the chairs of the RS and ORS.

General Manual Time Error Correction Practice

~~Unless local Interconnection procedures prevail,~~ MTECs will last a minimum of 4[3] hours unless terminated by a Reliability Coordinator for reliability concerns. Corrections for fast Time Error in the Eastern Interconnection should not be initiated such that they would run during the morning load ramp[4]. Generally, the normal MTEC process is to offset the scheduled frequency by 0.02 Hz, *e.g.*, slow time error is corrected by setting frequency to 60.02 Hz and fast time error is corrected by setting frequency to 59.98 Hz.

[3] The minimum 4 hour duration is intended to reduce the likelihood of errors. A 4-hour correction would reduce a 30 second Time Error to approximately 25 seconds.

[4] Avoiding MTEC initiation for fast Time Error during the morning load ramp reduces the likelihood of low frequency excursions during schedule changes and can preclude a MTEC where load increase would naturally reduce fast Time Error.

Agenda Item 23
Reliability and Security Technical
Committee Meeting
June 21, 2023

BES-Initiated Load Loss Data Collection

Action
Approve

Background
A presentation will be provided summarizing a white paper that was developed to address a substantial gap in NERC's ability to comprehensively measure a critical aspect of the reliability of the Bulk Electric System (BES) - the recorded performance of the transmission system in delivering electrical energy continuously to planned in-service delivery points sufficient to meet the loads of and ensure continuity of service to end use customers.

Currently, NERC relies on a voluntary data collection effort for daily load loss conducted by the IEEE Distribution Reliability Working Group. This is the source data for NERC's annual calculation of the load loss component of the Severity Risk Index, a measure of reliability performance. The voluntary data is often not representative of the interconnection. There are additional data quality issues resulting in the inability to tie load loss that are below reporting thresholds to BES events.

The purpose of this white paper is to inform industry stakeholders of the framework and recommendations to implement appropriate application for collection of load loss data. The Performance Analysis Subcommittee (PAS) and the NERC Performance Analysis staff will develop the Data Request Instructions (DRI) and corresponding Section 1600 Data Request materials, in collaboration with the TADS User Group. Industry and stakeholder review of the Section 1600 data request process in 2024 will include a review by FERC, a public comment period, request for RSTC endorsement, and presentation to the NERC Board of Trustees for approval.

Estimated Timeline for BES-Initiated Load Loss Data Section 1600 Data Request	
Date	**Description**
December 21, 2022	White paper presented at PAS Meeting
April 19, 2023	PAS endorsed sub-team draft white paper
June 21, 2023	Present to RSTC for endorsement of proposal
Q4 2023	Complete DRI and Section 1600 Data Request materials
Q1 2024	PAS and RSTC endorsement for Section 1600 Data Request
Q2 2024	FERC review and public comment period
Q4 2024	PAS and RSTC final endorsement for Section 1600 Data Request

Measuring Reliability Performance of the Bulk Electric System – White Paper

Improvements to Measuring the Reliability of the Bulk Electric System

This white paper discusses a substantial gap in NERC's ability to comprehensively measure a critical aspect of the reliability of the Bulk Electric System (BES) - the recorded performance of the transmission system in delivering electrical energy continuously to planned in-service delivery points sufficient to meet the loads of and ensure continuity of service to end use customers. This white paper was developed in response to the identification of needed improvements to the load loss component of the Severity Risk Index (SRI), which is reported annually in NERC's State of Reliability report.

In order to evaluate the effectiveness of the BES, NERC's Performance Analysis Subcommittee (PAS) (then known as the Reliability Metrics Working Group (RMWG)), developed the SRI as a comprehensive daily measure of the reliability performance of the BES. The SRI integrates data on generation, transmission and load losses to produce a single, overall measure of BES performance.

As the SRI evolved and achieved recognition as a useful measure of reliability performance, PAS has continued to refine and enhance the SRI's underlying components. In its first incarnation, the calculation relied upon OE417 as the data source for the load loss component. Upon further review (described in Section 3), PAS determined there was a need to refine the SRI load loss component. The PAS subsequently identified and then incorporated information collected annually by the IEEE Distribution Reliability Working Group (DRWG) as a more comprehensive source of information on the load loss component. Recent experiences (also detailed in Section 3) have confirmed the importance of further improving the load loss component of the SRI.

This white paper was developed by an internal ERO team of NERC and industry experts who reviewed current reliability performance metrics and available data in order to develop findings and recommendations to improve the SRI load loss component. While PAS will continue to review the sources of information relied on by the other components of the SRI, this white paper focuses only on recommendations to improve the information relied on for the load loss component of the SRI. This white paper:

1. Defines the scope or aspect of load loss information needed so that the SRI represents a comprehensive measure of this aspect of the reliability performance of the BES;
2. Lists the information required to measure the load loss component of the SRI comprehensively;
3. Describes limitations of approaches that have to date been relied on to provide the information required;
4. Identifies the registered BES entities that are in the best position to provide the information required; and,

5. Recommends a process for collecting this information from these entities on a routine basis pursuant to the Rules of Procedure Section 1600 and the development of data collection methods through a pilot process led by the Transmission Availability Data System (TADS).

The continuous transmission of electrical energy to planned in-service delivery points in amounts sufficient to ensure continuity of service to end use customers is the most direct and comprehensive measure of the load loss component of the SRI

Serving all customer load continuously is the core function of the electric power system. Accordingly, recording interruptions to customers (i.e., losses of firm load) is the most basic measure of the reliability of the power system.[1] There are long-standing, well-accepted measures of this aspect of the reliability performance of electric power systems, such as SAIFI and SAIDI. However, these measures were developed at a time when most utilities were vertically integrated and, often, they did not distinguish among the sources or causes of interruptions. Over time, the usefulness of identifying specific causes in order to prioritize efforts to improve reliability became apparent and practices evolved to define and record causes systematically. Of direct relevance for this white paper, interruptions due to loss of supply emerged as an important cause to track separately. This was especially true for distribution-only utilities because expectations regarding a supplier's performance in delivering electricity to the distribution-only utility were normally specified by contract.

Today, the industry is faced with a situation in which contractual relationships outlining reliability performance expectations have been augmented by legally enforceable responsibilities for ensuring reliability. Federal rules, administered by NERC, now govern the reliability of the BES. State rules or local practices continue to govern the reliability of distribution systems. The reliability performance of the entities following one set of rules should be assessed separately from the reliability performance of entities following a different set of rules.

In view of these considerations, the load loss aspect of BES reliability performance is best measured by assessing the extent to which the transmission system has continuously transmitted electrical energy to planned in-service delivery points sufficient to ensure continuity of service to end use customers. This measure is comprehensive because it does not focus on the reasons why electricity has not been transmitted to a distribution system. It focuses only on whether or not the transmission system has transmitted electricity to those responsible for serving real-time customer load in an amount equal to real-time customer demand. For example, this measure does not distinguish between load curtailment, which is operator-directed, and customer service interruptions resulting from the forced outage of transmission equipment (for example, due to severe weather). Finally, the measure also recognizes that, when there are multiple delivery points, the loss of one or more of them may not result in customer service interruptions.

In editing this white paper, the PAS sub-team has drawn extensively from an EPRI report published in 2007 that sought to "develop, evaluate, and recommend performance metrics for the retrospective assessment of the impact of transmission facility availability or capability events (both forced and planned) upon

[1] Note: Actions by customers to improve the reliability of their facilities by, for example, investments in self-generation do not contribute to the reliability of the power system because they only improve reliability on the customer's side of the meter. For example, self-generation by customers has never been captured by distribution system reliability metrics such as SAIDI and SAIFI.

transmission system deliverability and delivery."[2] The 2007 EPRI report predates the introduction of TADS, yet provides a solid foundation for the recommendations set forth in this white paper. The insights and examples presented in the 2007 EPRI report are directly applicable to the recommendations herein, with one minor modification.

The 2007 EPRI report distinguishes between transmission system "deliverability" and transmission system "delivery." Deliverability is defined as "[T]he capability of a transmission system to provide for the movement or transfer of electric energy between the point of supply and the point of delivery." Delivery is defined as "[T]he provision of transmission service continuity by the transmission service provider to the transmission customer at a transmission delivery point location(s) to provide for the transfer of power to (or from) the transmission system." Deliverability impacts serve as leading indicators of system reliability performance, while delivery impacts provide a lagging indicator for transmission reliability assessment. The report concludes that "delivery impacts stand on their own merit, providing an excellent retrospective summary of the functional impact of transmission service continuity."

These distinctions help to explain how the load loss measure proposed in this white paper can be understood in relation to the reliability performance objectives set forth in NERC's definition of Adequate Level of Reliability (ALR).[3] NERC's ALR definition includes five BES performance objectives. (See Table 1) NERC's annual State of Reliability report assesses the performance of the BES in meeting these objectives using a series of the ALR-specific metrics that are indicative of the extent to which the ALR performance objectives may or may have not been met. With respect to the distinctions presented in the EPRI report, the ALR-specific metrics are measures of BES deliverability.

Table 1: Adequate Level of Reliability Performance Objectives

Normal operations and predefined disturbances (i.e., more probable disturbances to which the power system is planned, designed, and operated)			**Less probable severe events that generally fall outside of BES owner and operator design and operating criteria**	
1. The BES does not experience instability, uncontrolled separation, cascading, or voltage collapse	2. BES frequency is maintained within defined parameters.	3. BES voltage is maintained within defined parameters.	4. Adverse reliability impacts on the BES following low probability disturbances are managed.	5. Restoration of the BES after major system disturbances is performed in a coordinated and controlled manner.

The proposed loss of load reliability performance measure is a delivery metric. It complements and provides needed context to existing ALR deliverability metrics by adding an ultimate retrospective measure of the BES' role in maintaining continuity of service to end use customers.

In order to serve this role, the delivery metric must distinguish between BES reliability performance and non-consequential load loss due to the behavior of customer-owned equipment in response to

[2] Electric Power Research Institute. *EPRI Transmission Reliability Impact Metrics.* Palo Alto, CA: 2007. 1013959.
[3] Informational Filing on Definition of "Adequate Level of Reliability," May 10, 2013.

disturbances originating on the BES. As discussed in more detail in the NERC System Analysis and Modeling Subcommittee's (SAMS) March 2021 whitepaper entitled "Possible Misunderstandings of the Term 'Load Loss',"[4] since the 1970s and continuing to the present day, utilities have observed that immediately after a transmission system fault occurred load would be less than the pre-fault level and gradually recover to the pre-fault level typically within 15-20 minutes. The SAMS whitepaper notes customer-owned controls that react to a fault or disturbance on the BES prompt a significant amount of customer-initiated load reduction, however these customers do not experience actual service interruptions.

Regular collection of comprehensive information is needed to measure the load loss component of the SRI

The information required to measure and assess the loss of load component of the SRI includes the following:

1. The time when the transmission system equipment used to transmit electrical energy to planned in-service delivery points is de-energized, and, as a result, a service to end use customers is interrupted for more than five minutes.
2. The time when de-energized transmission system equipment required to reconnect interrupted end use customers is re-energized.[5]

De-energization and re-energization of needed transmission system equipment may take place in stages over the course of a single event. Hence, the above information is needed for each stage during an event when the equipment needed to meet the energy demand of a distinct identifiable group of interrupted customers served from a delivery point(s) has been de-energized and then re-energized.

As noted in the previous section, separating out customer load response from actual customer service interruptions is an essential step in defining a meaningful delivery metric. For this reason, SAMS ultimately recommended that the term "load loss" refer only to customers that experience loss-of-service, and that load loss reporting be based on a count of end-use customer meters without electric service. However, SAMS also noted that in cases it may be necessary to communicate the amount of load represented by the count of end-use customer meters without electric service, e.g., 500 MW of customers are without electric service. Accordingly, in order to assess the severity of these events the following information is also required:

1. The amount of load and the number of customers interrupted/reconnected at each stage when transmission system equipment is de-energized and then re-energized.
2. For de-energized stages that result in service interruptions exceeding three hours, the most recent forecast of hourly loads over the duration of each stage at the de-energized delivery point(s).

[4] https://www.nerc.com/comm/RSTC_Reliability_Guidelines/White_Paper_Load_Loss.pdf

[5] The end of a BES-initiated load loss event can occur during a Recovery and System Restoration time period which precedes the point at which BES operations return to normal operating, or steady-state, conditions. See, Informational Filing on Definition of "Adequate Level of Reliability," May 10, 2013 at p. 4.

The five-minute reporting threshold corresponds to the definition of a sustained interruption that is used widely by distribution utilities.[6] It is important to maintain consistency among reporting definitions, particularly in developing data reporting thresholds that Transmission Owners (TO) can readily implement. In this instance, it is expected that many TOs will need to work with the distribution utilities they supply in order to obtain information as to the numbers of customers interrupted/reconnected. Selecting a reporting threshold that is already in widespread use by distribution utilities should facilitate collection of this information.

Current approaches to measure the load loss component of the SRI are in need of improvement

NERC has long recognized the importance of incorporating information on the BES's performance in serving load in various reliability metrics. Current methods and sources of this information, however, are in need of improvement. This sub-section provides more details on the efforts of the RMWG (now known as the PAS) to improve the load loss information used to calculate the SRI in order to illustrate the challenges presented by relying on currently available data sources. It concludes with a brief review of the load loss information that is currently collected for energy emergency alert (EEA) 3 events.

The initial source of information relied on by RMWG was that which is currently available to NERC through mandatory reporting following EOP-004 or to the US government via Form OE-417. The RMWG quickly concluded that these sources were incomplete because data submissions are limited to events that exceed a threshold size; it further recognized that many of the data being captured related to impacts within the distribution networks, not the transmission system. The RMWG also concluded that these sources of information would always be incomplete because the reporting does not identify when or at what point a customer service interruption is (or is no longer) due to de-energization of transmission system equipment the end use customer's electricity provider depends upon to serve load.

The current source of load loss information relied on by PAS to calculate SRI is provided by the IEEE DRWG. The DRWG conducts an annual survey, which collects daily SAIDI information that is provided voluntarily by utilities across the US. Following reporting procedures promulgated by the IEEE through Standards 1366 and 1782, the SAIDI data include all interruptions lasting more than five minutes and – of direct relevance to this white paper – only interruptions due to "loss of supply."

While these two features – capture of interruptions regardless of size and capture of only those interruptions originating "upstream" from distribution systems – have dramatically improved the calculation of SRI, recent experiences of the PAS have prompted the current need for a more comprehensive and consistent means for collecting load loss information. In recent years, PAS has encountered instances when data provided by DRWG has not been sufficient to calculate SRI for an interconnection. In response, NERC staff have had to estimate missing information manually through reliance on supplementary data sources.

The root cause is that data are reported to DRWG on a voluntary basis and hence the number of utilities submitting their data varies by year, which has led to gaps in geographic coverage. It has also been noted that the loss of supply information reported to the DRWG benchmark survey does not indicate the extent

[6] The Institute of Electrical and Electronics Engineers, Inc. *IEEE Std 1366-2022, IEEE Guide for Electric Power Distribution Reliability Indices.* New York, New York. September, 2022. ISBN 978-1-5044-9006-1

to which the loss is due to de-energization of transmission system equipment versus de-energization of sub-transmission system equipment. See, also, Eto, et. al. 2018.[7]

Information on EEA 3 operator-directed load sheds collected by NERC is an essential, yet by itself not a complete source of information on the load loss aspects of the reliability performance of the transmission system. Information on EEA 3 events is important because it captures the times when the ability of the transmission system to deliver demanded electrical energy in real-time has been compromised, or energy supply is inadequate to the extent that the operator must direct load shedding in order to maintain energy deliveries to the remaining majority of customers. Yet, information on EEA 3 events, by itself, is nevertheless not complete because these instances constitute only a subset of the times energy deliveries from the transmission system are insufficient to maintain continuity of service to end use customers. In particular, EEA 3 events do not record customer service interruptions that result directly from transmission system equipment outages, due, for example, to severe weather.

In order to develop a comprehensive measure, information is needed on each instance when the transmission system does not (or cannot) in real-time deliver electrical energy demanded by end use customers to in-service delivery points.

Transmission system owners and operators are in the best position to collect and provide to the ERO information needed to measure the load loss component of SRI

Transmission system-initiated load loss events comprise a relatively small percentage of load loss events, but like all load loss, event records are maintained. Although the data to identify, track and monitor transmission system-initiated load loss events, i.e. customer service interruptions, exists, it likely resides within a number of different entities. The challenge in reporting and monitoring this data lies in collecting and combining from various data sources the MW loss, number of customers impacted and restoration progress milestones that comprise the life cycle of a transmission system-initiated load loss event on one or more specific transmission systems.

The ERO team recommends that the collection and reporting of comprehensive information on these events should be the responsibility of TOs and Transmission Operators (TOP). TOs/TOPs are in the best position to know when and for how long the BES equipment they own/operate and is required to deliver electricity to in-service delivery points in order to serve load has been outaged or otherwise de-energized, as well as how much load was being served at the time load was interrupted due to de-energized BES equipment at delivery points. They are also in the best position to know when and which BES equipment can be re-energized to resume serving load. Finally, TOs/TOPs are also in the best position to work with other TOs/TOPs, Distribution Providers, Balancing Authorities, Reliability Coordinators and others as necessary to determine how many customers are impacted when their BES equipment is de-energized.

These data collection challenges were also recognized in the 2007 EPRI report that was introduced in Section 1. Specifically, the EPRI report recognizes “for transmission owners, data retention is a long term endeavor which requires enterprise tools and resources. Data attainability issues have several causes.” In

[7] Eto, Joseph H, Kristina Hamachi LaCommare, Heidemarie C Caswell, and David Till. "Distribution system versus bulk power system: identifying the source of electric service interruptions in the US." *IET Generation, Transmission & Distribution* 13.5 (2019) 717-723. DOI: 10.1049/iet-gtd.2018.6452

addition, "functional responsibility is organizationally split, e.g., between RTO organizations and transmission owners, which complicates data attainability. In general, working across organizations to access data is more difficult because the requests are not necessarily of equal priority to the organization from which data is requested. The organization with the visibility and functional responsibility to see the impacts of transmission facility unavailability, e.g., the RTO, may not have the same usage needs for the data as the transmission owner."

Despite these challenges, it is important to note that mandatory reliability rules were not adopted until after publication of the EPRI report. Compliance with the rules, moreover, has required all registered entities to identify the elements of their systems that are subject to these rules. Hence, all TOs and TOPs should now, at least in principle, be in a position to support the reporting required on a consistent basis.

Nevertheless, important implementation elements will need to be addressed going forward. First there is an immediate need to work with industry to better understand current practices including the trade-offs that may be involved in collecting high-quality information. To this end, the PAS recommends that TADS lead a pilot data collection process to refine the data request instructions. Among the topics PAS recommends TADS review is current practices for collecting load loss information when load is netted due to the presence of behind the meter DER.[8] Second, with this understanding, it is essential that reporting follow consistent procedures developed from best practices that can be implemented uniformly. For example, data submission should allow for updating through Q1 of the following year with allowance for tracking of load loss spanning across years, e.g., December through January.

NERC should immediately initiate steps toward the collection of information needed to assess load loss component of SRI.

There are several steps involved in collecting information on the retrospective performance of the transmission system in ensuring continuity of service to end use customers. These steps begin with socializing the need for this information through the ERO Enterprise, followed by the stakeholder process to review and accept the Section 1600 data request.

- Present this ERO Continuity of Service Task Force (TF) whitepaper to:
  - NERC RAPA Reliability Team for review and comment.
  - PAS for the purpose of developing a Section 1600 Data Request in 2023.
- Develop the data reporting instructions (DRI) and corresponding Section 1600 Data Request materials based on findings from a pilot data collection process led by TADS.
- Complete the Section 1600 data request process, including review by FERC staff, a public comment period endorsed by the Reliability and Security Technical Committee, and ultimately approval by the NERC Board of Trustees.
- Implement the appropriate application to allow for the collection of the continuity of service data defined in the DRI and train TOs/TOPs on data reporting procedures.

[8] PAS has been made aware of a SAR that the SPIDERWG is developing to revise EOP-004 to require reporting on qualifying loss of load events involving load that has been netted due to behind the meter DER. PAS anticipates that the DRI may need to be revised to ensure consistency if/when these revisions to EOP-004 are made.

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

BES–initiated Load Loss Data Collection

White Paper Overview

Donna Pratt, Manager, Performance Analysis

Reliability and Security Technical Committee

June 21, 2023

RELIABILITY | RESILIENCE | SECURITY




Existing Load Loss Data Collection Process

- NERC currently relies on a voluntary data collection effort for daily load loss conducted by IEEE Distribution Reliability Working Group
- IEEE DRWG data provides source data for NERC's annual calculation of Severity Risk Index load loss component
  - With the IEEE DRWG, two members of NERC's Performance Analysis Subcommittee (PAS) aggregate the confidential, voluntarily reported data
  - Provides estimate of daily load loss by interconnection and NERC-wide.
- Challenges
  - Voluntarily reported data is often not representative of the interconnection
  - Data quality issues
    - Unable to calculate SRI for 2018 SOR
    - Problems continue, requiring, at times, use of proxy information
  - Inability to tie load loss below reporting thresholds (e.g., OE-417) to BES events

Load Loss Data Collection Team (LLDCT)

- Convened in January 2022
- Membership comprised of staff from:
  - NERC
  - RF
  - SERC
  - WECC
- Objective to develop a white paper documenting ERO need for and collection of BES-initiated load loss information
- Seven meetings over the period January-September 2022

NERC
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RELIABILITY CORPORATION

LLDCT Topics of Discussion

- Distinguishing customer load response from interruption of customer service
- Means of quantifying loss of load
  - customers/meters disconnected
  - MW of loss
  - number of de-energized Transmission Delivery Points
- Accounting for impact of DER charging and discharging
  - Determined to be outside LLDCT scope
- Transmission operator and LSE access to data
- Calculating unserved energy
- Tracking load restoration progress & end of BES load loss event
- Defining magnitude & duration of reportable load loss event

LLDCT White Paper Summary

- Customer load response to BES events v. loss of firm load
  - Include BES-initiated loss-of-service, exclude customer load response
    - SAMS 3/21 White Paper - Possible Misunderstandings of the Term 'Load Loss'
- Quantifying loss of load
  - Use both customer meter count and MW of lost load
- Magnitude, minimum duration of reportable BES load loss event
  - LLDCT discussed minimum reportable magnitude of between 0-20 MW
  - LLDCT discussed minimum reportable load loss duration
    - should filter out most customer responsive load effects
- Tracking load restoration progress & end of BES load loss event
  - Re-energization of BES facilities necessary to restore service to interrupted customers measures progress & defines end of BES-initiated load loss event
    - Distribution Provider likely responsible for final service reconnections
    - Further BES facility re-energizations restore energy delivery reliability & economics

LLDCT White Paper Summary cont'd

- Calculating unserved energy
  - Impacted TO/TOP's most recent hourly load forecast potentially useful for unserved energy calculation
    - For example, if a BES-initiated load loss comprised 10% of a forecasted transmission owner/operator's load and lasted for three hours, multiplying the hourly load forecasts for those three hours by 10% might provide a reasonable estimate
- Obtaining and collating load loss data from Transmission operator/owners, unaffiliated distribution providers, & other parties
  - The transmission system operator/owner is best positioned to collect, combine and report to the ERO BES-initiated load loss data from disparate parties impacted by BES-initiated loss of load.

PAS Review and Endorsement

- LL DCT White Paper Presented to PAS at 12/21/22 PAS Meeting
- PAS Sub-team created and assigned to review
  - Followed up on PAS recommendation to review and include as appropriate concepts from 2007 EPRI white paper "*EPRI Transmission Reliability Impact Metrics.*"
  - Added recommendation to coordinate with TADS User Group to develop and refine data request instructions.
  - Determined 5 minute minimum duration reporting threshold
    - Maintains consistency with sustained interruption reporting definition used widely by distribution utilities.
    - Reporting threshold that TO/TOPs can readily implement.
- PAS endorsed sub-team draft "*Measuring BES Reliability Performance*" white paper at 4/19/23 meeting.

LLDCT White Paper – Path Forward

- Informational presentation to RSTC 6/21
- Post to Performance Analysis web page on NERC.com
- PAS and staff to develop Data Request Instructions (DRI) & corresponding Section 1600 Data Request materials
  - Develop and implement TADS pilot data collection process to refine DRI
- Complete Section 1600 data request process, including review by FERC, public comment period, obtain RSTC endorsement & approval by NERC Board of Trustees
- Implement appropriate application for collection of load loss data defined in the DRI
- Train TO/TOPs on new load loss data reporting procedures

Questions and Answers

System Protection and Control Working Group Position Paper on Impact of FERC Orders 881 and 881A on Relay Loadability

Action

Endorse

Background

FERC orders 881 and 881A will require industry to develop and implement Ambient Adjusted Ratings for transmission facilities in the United States. These ratings will require industry to account for the impacts that ambient conditions impart on transmission facilities. The resulting changes to the rating will have some impacts on relay loadability and may require a significant number of relays to be reviewed, and if needed, adjusted to retain a desired loadability margin. This could result in a significant implementation period, which will need to be accounted for.

Summary

The SPCWG requests the RSTC to endorse the conclusions and recommendations of the position paper, which can then be used to help work out an appropriate implementation timeframe and may provide some guidance to the industry.

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SPCWG Position on FERC 881/881a

Lynn Schroeder and Manish Patel
RSTC Meeting
June 21, 2023

RELIABILITY | RESILIENCE | SECURITY




Background

- Order 881 requires transmission providers to:
  - Use at least four seasonal line ratings when evaluating longer-term point-to-point transmission service ending more than 10 days in the future.
  - It also requires that AARs be determined for at least every hour for near-term (10 days into the future) requests for point-to-point and network service.
  - Those AARs must be calculated for both day and night with the knowledge that there is no solar heating during the nighttime calculation.

Background

- Order 881 states that:
  - The commission believes that settings changes will not be required to "thousands" of relays (P99) to comply with PRC-023
    - Because "PRC-023-4 related relay settings are currently calculated based on practical limitations which in the majority of cases should ~~not~~ exceed AAR values." (P99) (Order 881-A stated that this is an error by the Commission and should be "…should exceed AAR values").
- FERC 881A clarifies "We clarify two aspects of the AAR requirements related transmission protection relay settings.
  - First, if a transmission provider establishes higher transmission line ratings, it will have to evaluate or reevaluate its applicable protection systems for that facility.
  - Second, we clarify that in a majority of situations the relay setting should exceed AAR values."

Background

- Paragraph 26 states that:
  - "a transmission provider must evaluate its applicable protection systems for that facility in order to comply with PRC-023-4 and prevent protection systems from limiting transmission loadability" as a result of favorable ambient conditions.
  - However - P26 does not claim that the PRC-023 needs to change to address AAR values and can be interpreted to mean that the transmission line rating increases must refer to newly required seasonal ratings since those are the pertinent ratings in PRC-023.

Examples

- **Utility A**
  - Utility A currently has four seasonal ratings and uses 41° F to calculate seasonal ratings used to evaluate loadability as required by PRC-023. The utility's initial assessment of historical temperatures shows that it may need to calculate AAR for temperatures as low as 15° F. The utility found that this change would increase transmission line ratings less than 10%.
- **Utility B**
  - Utility B currently bases its seasonal winter rating on a temperature of 50° F. The utility calculated ratings for three of its 345 kV lines using a historical low temperature of -20° F and found that ratings increased by 13–20%.

Examples

- **Utility C**
  - Utility C currently has only one seasonal rating and its compliance with PRC-023 is based on that seasonal rating. Utility C has drafted proposed seasonal ratings in accordance with order 881, and the winter rating will increase nearly all ratings with some as high as 70%. Re-evaluation of its protection system loadability with PRC-023 applicability will be required under the current version of the standard.
- **Utility D**
  - Utility D currently calculates winter ratings based on a temperature of 32° F with some wind. These ratings are used for PRC-023 compliance. New ratings calculated at -30° F with wind are 5–18% higher than the current ratings.

Key Points

- Protection systems required to comply with PRC-023 are a subset of protections systems to which Orders 881 and 881-A apply.
  - It is unknown how many additional systems will need to be reviewed to ensure that the protection systems meet those orders. A survey of some entities suggested that the relays covered by PRC-023-04 are only 20–60% of the relays that will now need to be evaluated to meet the new loadability requirement in the orders.

Key Points

- The SPCWG acknowledges that:
  - Relays should allow some margin above the maximum loadability required by new AARs to ensure that the relays won't trip under load.
- Based on the examples:
  - Entities that have historically calculated winter season ratings for transmission lines subject to PRC-023 will likely have at least 20% margin above the AAR loadability requirements,

881 and PRC-023

- Based on these findings, the SPCWG believes that no changes to PRC-023 are necessary, and protection systems that are presently applicable and compliant with PRC-023 based on winter seasonal ratings do not need to be revised to meet the margin required in PRC-023 for the AAR that are determined by the entities

Conclusion

- Review loadabilities for all protection systems that fall under the order to ensure sufficient margin above normal and emergency AARs.
  - SPCWG believes that reaching margins specified in PRC-023 (e.g., Criteria 1's 150%) above AARs is not necessary and would increase the amount of setting modifications entities would be required to implement.
- 881 and 881-A will require most entities to expend significant resources to ensure that protection system loadabilities will accommodate newly required seasonal ratings and AAR.
  - Up to 70% of existing transmission line protection systems may be impacted
  - Work associated with this review and possible settings changes is likely to exceed the implementation time frame allowed in 881 and 881-A.

Questions and Answers

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2023 ERO Reliability Risk Priorities Report, RSTC Strategic Plan Update and RSTC Work Plan Priorities

Rich Hydzik, RSTC Vice Chair
June 21, 2023

RELIABILITY | RESILIENCE | SECURITY




RISC and RSTC

- The ERO mission requires establishing a consistent framework to identify, prioritize and address known and emerging reliability and security risks.
- To support its mission the ERO has developed the *Framework to Address Known and Emerging Reliability and Security Risks* (Framework).
- Mitigation of risks to Bulk Electric System (BES) reliability can be classified according to the likelihood of the risk occurring and the severity of its impact.

RISC and RSTC

- The RISC and RSTC collaborate to ensure that risks identified through the development and publication of the biennial ERO Reliability Risk Priorities Report are prioritized and mitigated.
- The two committees also consider risks identified through other ERO Programs such as Reliability Assessments, Event Analysis and a variety of industry engagements.
- The Framework is an iterative six-step risk management framework shown in the diagram below.

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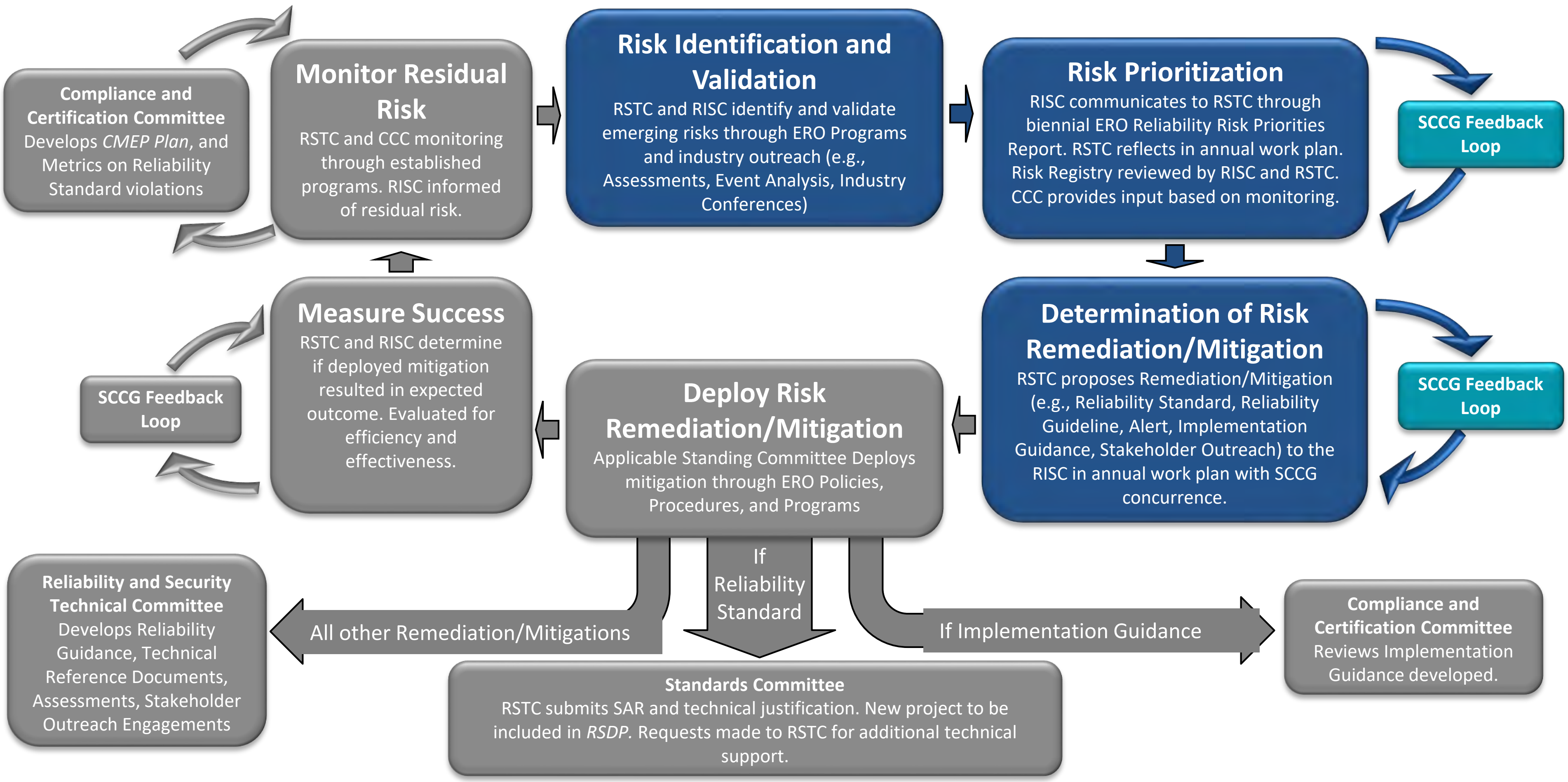
ERO Risk Management Framework:

Standing Committees and RISC Coordination



RSTC Strategic Plan and Work Plan

- In 2022, the RSTC developed its Strategic Plan which identified four key strategic priorities:
  - 1) Energy Security,
  - 2) Inverter-Based Resources,
  - 3) Distributed Energy Resources, and
  - 4) Supply Chain Security.
- These priorities were assessed in February 2023 against the RSTC Work Plan to develop a list of high priority work plan items to address the strategic risk priorities.
- The RSTC Charter requires an annual update of the RSTC Strategic plan.

Next Steps

- RSTC to assemble a review team to:
  - Review the 2023 ERO Reliability Risk Priorities Report
    - On August Board of Trustees agenda for approval
  - Update the RSTC Strategic Plan (including Strategic Priorities if applicable)
  - Update the RSTC Work Plan to identify gaps and assess high priority work plan items
- Review team to provide assessment of updated Strategic Plan and Work Plan for RSTC approval in December 2023.
- ***If you wish to participate on the review team, please notify Stephen Crutchfield via email by COB on June 30, 2023.***

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Questions and Answers

RSTC Nominating Subcommittee

Wayne Guttormson – RSTC Nominating Subcommittee Member
RSTC Meeting
June 21, 2023

RELIABILITY | RESILIENCE | SECURITY




Nominating Subcommittee Overview

- The Nominating Subcommittee (RSTC NS) consists of seven (7) members (the RSTC Vice-Chair and six (6) members drawing from different sectors and at-large representatives). Apart from the Vice-Chair, members of the RSTC Executive Committee (RSTC EC) shall not serve on the RSTC NS.
- The NS members are nominated by the RSTC chair and voted on by the full RSTC membership.
- The term for members of the NS is one (1) year.
- In addition to recommending individuals for at-large representative seats, the NS manages the process to select the chair and/or vice chair of the RSTC.

Nominating Subcommittee Overview

- Nominating Subcommittee members
  - Rich Hydzik, RSTC Vice Chair*
  - Truong Le – Sector 6
  - William Allen – At-large
  - Wayne Guttormson – At-large, Canadian
  - Ian Grant – At-large
  - John Stephens – Sector 5*
  - Srinivas Kapagantula – At-large

  - *Nominated for Chair or Vice Chair and recused from process

Chair and Vice Chair Nominations

- From RSTC Charter - Officers shall be selected as follows:
  - The NS solicits nominations for chair and vice-chair through an open nomination process. Self-nominations are permitted.
  - The NS proposes a chair and/or a vice-chair candidate. ***The full RSTC will elect the chair and vice chair.***
  - The chair and vice chair shall ***not be from the same sector***.
  - The elected chair and vice-chair are ***approved by the NERC Board.***
  - Unless an exception is approved by the Board, no individual may serve more than one term as vice chair and one term as chair.

Chair and Vice Chair Election Timeline

- Open nomination period March 23 - April 10, 2023
  - RSTC members only
- RSTC NS met April 18 to review nominations and requested additional information from the vice chair candidates
- RSTC NS met again on May 15 and developed a slate of nominations for RSTC election
- June 21 – Full RSTC vote for Vice Chair
- June – Board Action Without a Meeting to appoint Vice Chair

Chair and Vice Chair Terms

- When the NERC Board of Trustees (Board) appointed the initial RSTC Chair and Vice Chair, their terms were for two years ending June 30, 2022.
- The Board extended RSTC leadership an additional year to end June 30, 2023.
- All other Standing Committees leadership terms expire at year end. In order to align with the other committees, we are seeking an extended term 2 and a half years) to end December 31, 2025 rather than June 30, 2025.
- This was noted in the March 23, 2023 RSTC meeting discussion of Chair and Vice Chair nominations.

Election Process

- The RSTC NS presents candidate(s).
- Elections will be held as follows:
  - The Committee will vote on the Nominating Subcommittee’s presented candidates for Chair and Vice Chair. If the presented candidates are approved with a 2/3 majority, the presented candidates are elected and the election is closed.
  - Should the presented candidates not get elected the Chair will ask the NS to do the following:
    - Reconvene a review of the nominations already submitted;
    - Open for a second, shortened nomination process for additional submissions; and,
    - Convene a second meeting to evaluate the nominations and present a candidate to be considered at the next RSTC meeting.

Recommended Slate

- For the RSTC Chair position, the Nominating Subcommittee nominates:
  - Rich Hydzik, Avista
- For the RSTC Vice Chair position, the Nominating Subcommittee nominates:
  - John Stephens, City of Springfield

- **Motion: Elect Rich Hydzik RSTC Chair and John Stephens RSTC Vice Chair for a term ending December 31, 2025.**

Questions and Answers