NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Agenda
Reliability and Security Technical Committee

Conference Call

March 3, 2021 | 1:00–4:30 p.m. Eastern Time

Attendee Webex Link: Join Meeting

Call to Order

NERC Antitrust Compliance Guidelines and Public Announcement

Introductions and Chair's Remarks

1. **White Paper: Possible Misunderstandings of the Term "Load Loss"* - Approve –** John Skeath, NERC Staff

   The System Analysis and Modeling Subcommittee developed a White Paper to address possible misunderstandings of the Term "Load Loss". The subcommittee received input from the Operating and Planning Committees and also requested input from RSTC members in October. The comments received have been addressed by an ad hoc team and conforming revisions made to the white paper. The team is seeking approval of the revised white paper.

2. **Standing Committees Coordinating Group (SCCG) Scope* - Endorsement –** David Zwergel, Vice Chair, RSTC

   The SCCG has been in existence for a number of years as an informal means for the standing committees reporting to the Board to coordinate their work plans. The group is formalizing their scope and activities and are seeking RSTC endorsement of their scope document.

3. **Reliability Guideline Metrics* – Information** – Candice Castaneda, NERC Legal

   This discussion will provide a brief overview of Federal Energy Regulatory Commission approved process to review the effectiveness and efficiency of Reliability Guidelines.

4. **Reliability Guideline: Model Verification of Aggregate DER Models used in Planning Studies* – Approve** – Kun Zhu, SPIDERWG Chair

   The Reliability Guideline was posted for a 45-day comment period and the SPIDERWG has responded to comments and made conforming revisions to the Guideline. They are seeking approval of the Reliability Guideline.

5. **Battery Energy Storage Systems (BESS) and Hybrid Power Plant Modeling and Performance Guideline – Approve –** Julia Matevosyan, IRPWG Vice Chair

   The Guideline was posted for a 45-day comment period and the IRPWG has responded to comments and made conforming revisions to the Guideline. They are seeking approval of the Guideline.

6. **Standards authorization Request (SAR) to revise TPL-001-5.1* – Endorse** – Kun Zhu, SPIDERWG Chair
Considering current trends, the NERC SPIDERWG and NERC Inverter-Based Resource Performance Working Group (IRPWG) independently undertook review of the TPL-001 standard for considering DERs and BPS-connected IBRs, respectively. These reviews are captured in the following RSTC-approved white papers:

    SPIDERWG: Assessment of DER impacts on NERC Reliability Standard TPL-001 (here)

    IRPTF/IRPWG: IRPTF Review of NERC Reliability Standards – March 2020 (here)

    This SAR proposes to update TPL-001-5.1 to address the issues identified in both white papers. The SPIDERWG is seeking endorsement of the SAR.

7. **Wildfire Mitigation Reference Guide – Information -** Al McMeekin, NERC Staff

    As stated in the 2019 ERO Reliability Risk Priorities Report; Risk Profile #2, wildfires are extreme natural events that can impact the equipment, resources, or infrastructure required to operate the BPS. In recent years, wildfires have wrought havoc throughout the Western Interconnection but changing weather conditions increase the opportunities for wildfires to ignite and propagate throughout North America. Electric infrastructure and equipment can: (1) cause ignitions that could lead to wildfires, and (2) be impacted by wildfires. The electric industry should consider having plans and operational strategies in-place to address and mitigate the risks to reliability that wildfires pose. This document is intended to serve as a resource for utilities in high fire-threat areas that want to proactively develop wildfire mitigation plans to maintain and promote the reliability and resilience of the electric grid. The reference guide is posted on the NERC website at https://nerc.com/comm/RSTC/Documents/Wildfire%20Mitigation%20Reference%20Guide_January_2021.pdf

2:35 P.M. - BREAK – 10 MINS

8. **Supply Chain Compromise Presentation – Information** – Jeff Jones, E-ISAC Staff

    Security issues with a significant impact on critical infrastructures are unfortunately becoming more common. The E-ISAC's collaboration with its members and partners has provided a unique perspective on these recent developments. This presentation will provide an update on activities related to the supply chain compromise, the recent attack on a Florida water utility, and other relevant issues.

9. **Forum and Group Reports** – **Information**

    a. North American Generator Forum* – Allen Schriver

    b. North American Transmission Forum* – Roman Carter

10. **RSTC 2020 Calendar Review – Stephen Crutchfield**

2021 Meeting Dates	Time	Location	Hotel
June 8, 2021 June 9, 2021	1:00 to 4:30 p.m. 1:00 to 4:30 p.m.	WebEx	None
September 22, 2021 September 23, 2021	1:00 to 4:30 p.m. 1:00 to 4:30 p.m.	WebEx	None

2021 Meeting Dates	Time	Location	Hotel
December 14, 2021 December 15, 2021	Please reserve entirety of both days	TBD	TBD

11. Chair's Closing Remarks and Adjournment

*Background materials included.

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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.

RSTC Meetings – Governance Management

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

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

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

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

Guiding principle is one thing at a time.

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

Possible Actions for other Deliverables

1. **Approve:**

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

2. **Accept:**

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

3. **Remand:**

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

4. **Endorse:**

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

White Paper: Possible Misunderstandings of the Term “Load Loss”

Action
Approve

Summary
The System Analysis and Modeling Subcommittee developed a White Paper to address possible misunderstandings of the Term “Load Loss”. The subcommittee received input from the Operating and Planning Committees and also requested input from RSTC members in October 2020. The comments received have been addressed by an ad hoc team and conforming revisions made to the white paper. The team is seeking approval of the revised white paper.

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White Paper

Possible Misunderstandings of the Term “Load Loss”

JP Skeath, Engineer II
March RSTC Meeting
March 03, 2021

RELIABILITY | RESILIENCE | SECURITY

Major Theme of White Paper

- Depending on interpretation, outcome of the study, report, or document can be altered
  - Possible Perspective – load that experiences a loss-of-service
  - Possible Perspective – load that is reduced in an event is “lost” and not the long-term reduction creating an over reporting of events
  - Possible Perspectives – load in predictive models that is reduced is considered “load loss”, even when system planning criteria are met

Recommendations

- Standards Changes
  - EOP-004 to clarify "loss of firm load" with customer-initiated load reduction
  - TPL standards to include customer-initiated load reduction
- TPs and PCs should have their respective Transmission Operators be aware of areas with significant levels of customer-initiated load reduction with BPS disturbances.
- Discussion with states and other regulators to be aware of areas with significant levels of customer-initiated load reduction with BPS disturbances.
- Discussion with DOE for the recommendations to be included in their relevant documents that refer to loss of load

Comments Received

- Editorial comments throughout
  - Grammatical changes
  - Sentence clarity
- Two categories received
  - Recommended standards changes
    - Low priority and can be handled in normal review cycles
  - Clarifying acceptable performance
    - Voltage Criteria
    - “Customer-Initiated Load Reduction”
- Additionally, one RSTC commenter provided possible resources for any team to consider on any standards revision.

Document Process

- Requested by PC for SAMS to develop memo on the subject
- SAMS development altered to white paper and approved at subcommittee in Q2 2020
- Requested RSTC review in Q3 2020. At this same time, SAMS was voted to be disbanded
- RSTC attempted to resolve comments at inter-quarterly meetings.
- Ad hoc team formed from previous SAMS members for comment resolution.

Request of RSTC

- The ad hoc team restates the original SAMS request to approve the White Paper: Possible Misunderstandings of the term "Load Loss" per the old SAMS work plan.

Questions and Answers

Possible Misunderstandings of the Term "Load Loss"

March 2021

Problem Statement

Inconsistent use of the term "load loss" may mislead some industry stakeholders. Planning engineers, operating personnel, and other industry staff may refer to customer load that is temporarily shut down or transferred to an emergency standby power source as load loss. State and federal regulators may interpret load loss to be customers that were subjected to a loss of electric service due to an unplanned outage or misoperation of elements within the Bulk Power System (BPS). This also occurs within some NERC and industry documents.

The potential for significant misunderstandings is created regarding the severity of actual or potential future events, reporting requirements for events, and the need to provide network improvements based on projected system performance.

The NERC System Analysis and Modeling Subcommittee[1] (SAMS) prepared this whitepaper in response to a request from the NERC Planning Committee[2] (PC) to describe relevant concerns and provide recommendations.

Background

Historically, the term "load loss" (or load dropped) has been used to communicate the loss of service to customer load due to an unforeseen event within the BPS, such as a summer thunderstorm causing outages of distribution and transmission facilities for a specific utility's service area. The affected utility estimates load loss by determining the number of impacted customers and the amount of load which was lost or dropped" and considers that as "load loss".

- In the aboveexample, if the number of customers with no electric service was 200,000, the utility might estimate the corresponding "load loss" to be about 1000 MW. The utility would then report to the state utility commission(s) that about 200,000 customers experienced an outage and the load dropped was about 1000 MW.

In the 1970's some utility systems began observing that load in a control area (or balancing area) would be less than the pre-fault level immediately after a transmission system fault occurred. The load in the control area would gradually recover to the pre-fault level typically within 15-20 minutes. This was also observed in situations where customers did not actually experience a loss-of-service due to the transmission fault.

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[1] While the paper was developed under the NERC SAMS, such a group has been disbanded by the RSTC at time of publication. Recommendations contained from the NERC SAMS should be taken as recommendations by the NERC RSTC.
[2] The predecessor to the NERC Reliability and Security Technical Committee (RSTC)

Subsequent investigations discovered that, in some instances, the temporary reduction in system load was due mainly to residential air conditioners shutting down due to the action taken by controls in each air conditioner, which could cause the air conditioner to shut down and then restart 10-20 minutes later. Phenomena such as this were observed to cause load in a control area to be temporarily reduced by 10% or more for these events. The exposure to this phenomenon has continued to the present.

End-user equipment is being installed with controls that respond quickly to disturbances within the BPS. Adjustable speed drives used in many industrial processes, as well as chillers and air handlers for large commercial buildings, will typically respond to a transmission system fault by shutting down. This occurs even though the fault is very remote from the customer's location and does not cause a loss-of-service to the customer. Depending on the control system, such as an energy management system used in an industrial facility or commercial property, the equipment may restart automatically after a time delay or may restart only after a human operator takes action. Large customers may switch over to a stand-by power source automatically even if faults on the BPS are very remote and do not result in an actual loss-of-service to the facility. Many such facilities perform the automatic switch to BPS level faults.

Customer-owned controls that react to a fault or disturbance on the BPS may prompt a significant amount of customer-initiated load reduction, however these customers do not experience an actual loss-of-service, and is not considered a "load loss", in the historic use of the term.

Opportunities for Term Misunderstanding

There are three main areas of potential misunderstandings around the use of the term "load loss"

- Regulatory entities interpretation of information on actual or possible future BPS events
- Transmission Operator's and industry agencies' understanding of and reporting on actual BPS events
- Transmission Planner's and Planning Coordinator's interpretation of projected system performance as determined by modeling and simulations.

Each of these three perspectives are described in greater detail below.

Regulatory Entities' Interpretation of BPS Events – Actual and Projected

Informal and formal reports and other documents describing the extent of an actual system disturbance may quote levels of load loss without clarifying how much of the load loss was due to customers experiencing a loss-of-service and how much load reduction occurred due to customer-owned control equipment. Regulators and other stakeholders may not be aware that customer-initiated load reduction in response to a BPS disturbance is very common and may be fairly large, thereby assuming that all of the reported load loss consisted of customers without electric service for a period of time. This load loss assumption would be consistent with the historic use of the term, and the regulator or other stakeholder would have an incorrect understanding of the scope of the event.

Informal and formal reports and other documents related to projected future performance of the BPS may refer to possible future events and state the exposure to load loss without clarifying if customers that experienced a loss of service for the scenario(s) described, or if the load loss is an estimate of the customer-initiated load reduction (e.g., customer load temporarily shut off by customer-owned controls). Again, a regulator or other stakeholder could have an incorrect understanding of the scope and relative risk of the scenario(s) described by using the historic assumption of the term.

Transmission Operator and Industry Agencies – Reporting Requirements

Transmission Operators have responsibilities for reporting system events which, in some instances, the threshold for reporting is based on loss of load with no definition or clarification. For example, EOP-004 uses 300 MW for loss of firm load as a reporting requirement threshold. Similarly, the DOE OE-417 refers to loss of firm system loads with no clarification on what is meant by loss. It seems likely that the intent for EOP-004 and OE-417 reporting would be load/customers that had experienced a loss-of-service. The load from a temporary customer-initiated load reduction does not fit the presumed intent for these reporting requirements.

The lack of clarity or definition of what is meant by “load” or “loss” may result in miscommunication. For example, if a summer-peaking electric utility serves a fairly dense metropolitan area that has 10,000 MW of load in the summer and experiences a three-phase fault on a transmission line near the metro area. The fault is then cleared in 7 cycles by breakers that remove the faulted line from service. Zero customers experience a loss-of-service. The transient voltage criteria is met. Due to the response of customer control equipment, the utility sees a temporary reduction in load of 1,000 MW. The load for the utility begins recovering after 10 minutes, but the full 1,000 MW is not recovered until approximately 20 minutes after the incident. The customer-initiated load reduction was 1,000 MW but zero customers experienced a loss of service. The presumed intent behind the EOP and DOE reporting requirements would indicate that the utility does not need to report the incident. However, the staff at the Transmission Operator may not consider the intent behind the reference to loss of load and may simply consider the temporary change in load for the company thereby determining the incident needs to be reported. The need to report the incident might also be misunderstood by staff at DOE or some other entity. It is possible that someone at an agency may hear an informal report that 1,000 MW of load loss occurred, and form the opinion that reporting the event is required by assuming the temporary reduction of load by end-user equipment was a loss of service for those 1,000 MWs.

Transmission Planners and Planning Coordinators – Evaluation of Future System Performance

Transmission Planners and Planning Coordinators use the metrics in the NERC Transmission Planning (TPL) Standards to evaluate the future performance of the BPS[3]. Those standards use the definitions[4] of Consequential Load Loss and Non-Consequential Load Loss. Those definitions are reproduced below.

> **Consequential Load Loss** – “All Load that is no longer served by the Transmission system as a result of Transmission Facilities being removed from service by a Protection System operation designed to isolate the fault.”

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[3] See https://www.nerc.com/pa/Stand/Project%20200602%20Assess%20Transmission%20Future%20Needs%20an/ATFNSDT_Implementation_Plan_clean_D4_2009Sept16.pdf

[4] See https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf

Non-Consequential Load Loss – “Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive Load, or (3) Load that is disconnected from the System by end-user equipment.”

Customer-initiated load reductions are covered by exclusions (2) and (3) in the definition of Non-Consequential Load Loss. Customer-initiated load reductions are not either type of Load Loss as defined in the NERC TPL Standards.

Customer-initiated load reductions are not considered directly by any performance metric in the TPL Standards. However, Transmission Planners and Planning Coordinators should include the effect of customer-initiated load reductions in simulations of the BPS to evaluate the response of the BPS to the various contingencies considered in planning studies.

Many planning engineers have started using system models that can predict the amount of residential air conditioning, and other loads, that may temporarily shut down due to a voltage sag associated with a system fault. When reporting the results of simulations, it is possible that a description of the projected system response to an event might be worded in a way that may mislead industry stakeholders. For example, a planning engineer may report an exposure to a "1000 MW load loss" based on the analyses completed. Stakeholders may interpret these predictions of "load loss" to be a loss-of-service to a large number of customers, when the load loss was actually a customer-initiated load reduction, with zero customers projected to experience a loss-of-service.

Recommended Actions

Industry stakeholders should use the term/phrase "load loss" only to refer to customers that experienced (or might experience, if the scenario is predictive) a loss-of-service. When reporting information on system disturbances (actual or predicted) to industry stakeholders, it is recommended that information on customers that have or might experience a loss of service be based on the *number* of customers without electric service. In cases where customer count is not available or it is necessary to communicate the amount of load represented by the customers without electric service, the amount of load should be clarified by stating that it represents the load for customers that have or would experience a loss-of-service (e.g., 500 MW of customers are without electric service).

When reporting the extent of actual system disturbances to industry stakeholders, information on the amount of customers/load that experienced a loss-of-service and the temporary load reduction due to the response of customer-owned equipment should be listed separately and with ample description to communicate the meaning of the two numbers. In instances where an event contains both distinctions in coincidence and thus proves difficult in categorizing the measurements and attributing it to customers that temporarily reduced their load or that experienced a loss-of-service, engineering judgement should be used to approximate the numbers and such judgement should be documented and accompany the reporting of the numbers. This recommendation is already partially reflected in the ERO Event Analysis Process document[5]. Appendix C, Items 8-9 request information for the load/customers impacted[6]. That section reads, in part, “The load that was disconnected from the system by utility/entity equipment opening. Load loss due to the response of voltage sensitive load and load that is disconnected from the system by end-user equipment is not included. Do not use change in area load as the load loss.” As an example, a summary of the extent of a system disturbance could say, "*The event resulted in 100,000 customers (500 MW) without electric service. Also, there was a temporary load reduction as viewed from the utility system due to the action of customer-owned equipment (transfers to stand-by power, residential air conditioners temporarily shut off, etc.) of 1500 MW*."

Summaries of predicted situations identified by system simulations should be worded carefully. If system simulations indicate that an extreme sequence of events would result in customers experiencing a loss-of-service, the summary of those simulations should state the amount of load for the customers as load loss. Summaries of system simulations that estimate the amount of customer-initiated load reduction should not refer to that reduction as load loss. That temporary load reduction should be clearly stated to be a temporary customer-initiated load reduction.

In summary, NERC SAMS recommends the following actions:

- The RSTC should pursue changes to the NERC EOP-004 standard to clarify the meaning of “loss of firm load” in order to explicitly exclude changes in balancing area load due to customer-initiated load reduction.
- The RSTC should pursue changes to the TPL standards and the NERC Glossary of Terms to include Customer-Initiated Load Reduction (or something similar) as a defined term[7].
- Transmission Planners and Planning Coordinators should discuss this issue with their respective Transmission Operators to assure that the Transmission Operators are aware of the potential for significant levels of customer-initiated load reductions in association with a BPS disturbance.
- The RSTC should facilitate discussions with state commissions with regulatory responsibilities for electric utilities to assure that those commissions have an awareness of the potential for significant levels of customer-initiated load reductions in association with a BPS disturbance.
- The RSTC should facilitate discussions with the DOE to recommend changes to language in relevant documents that refer to loss of load.

[5] The latest Event Analysis Process documents can be found here
[6] Appendix C can be found here. Page 4 on the linked document contains items 8 and 9.
[7] Note: creating a defined term to cover load reduction due to end-user equipment (akin to exclusions 2 and 3 of the Non-Consequential Load Loss definition) would significantly reduce the potential for misunderstandings.

Possible Misunderstandings of the Term “Load Loss”

March 2021

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The potential for significant misunderstandings is created regarding the severity of actual or potential future events, reporting requirements for events, and the need to provide network improvements based on projected system performance.

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- In the aboveexample, if the number of customers with no electric service was 200,000, the utility might estimate the corresponding “load loss” to be about 1000 MW. The utility would then report to the state utility commission(s) that about 200,000 customers experienced an outage and the load dropped was about 1000 MW.

In the 1970’s some utility systems began observing that load in a control area (or balancing area) would be less than the pre-fault level immediately after a transmission system fault occurred. The load in the control area would gradually recover to the pre-fault level typically within 15-20 minutes. This was also observed in situations where customers did not actually experience a loss-of-service due to the transmission fault.

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Commented [A1]: From Todd:

- •Adding a NERC Glossary Term for “Customer Initiated Load Reduction” appears to be an appropriate action.
- •Because this is not an urgent issue I suggest that, where applicable, standards/requirements, such as TPL or EOP, incorporate the additional defined term in the normal review cycle opposed to initiating SDTs for the sole purpose of incorporating the new term.
- •Any engagement with state commissions or local regulatory agencies should be handled by the local utilities with the state jurisdictional load serving responsibility, not the RSTC or NERC. I recommend removing that recommendation.
- •Since this paper recommends a change to the NERC Glossary, shouldn’t it be posted for industry comment after revisions are incorporated from this RSTC review? Is that the intent?
- •Regarding the fifth recommendation…”initiate a dialogue with DOE…”. In Appendix B of OE-417 (Glossary) a definition of Firm Load is provided: **Power provided to customers that is continuously available on demand and which is subject to interruption only under extreme circumstances**. Given this definition, is there confusion? If customer load is reduced due to customer voltage sensitive equipment or customer controls and not the power company interrupting service, then there was no interruption of firm load by the utility. If a conversation is needed, not sure it should be with the RSTC but likely NERC/FERC/DOE after industry provided input is considered. I assume any changes by DOE would include a public comment period.
- •Procedural questions: Since SAMS has been disbanded, how will these comments be reconciled? How will a change to the NERC Glossary be initiated?

Commented [A2R1]: Thank you for your comments, we will attempt to address them line by line per SAMS discussions/decisions:

-SAMS agrees with this action
-SAMS agrees this would meet the recommendation. The RSTC can move on the recommended action at its discretion.
-Previous NERC stakeholder groups have initiated conversation with NARUC and other bodies that represent state commissions or local regulatory agencies. SAMS intends this recommendation to follow the same process.
-The SAR that would contain the revisions would be posted for industry comment. This paper exists independent of that SAR. In the standards procedure manual, an allocation exists for a SAR plus White Paper combination. SAMS, however, did not anticipate pursuing that option.
-Even with the definition of Firm Load, SAMS believes that there is an opportunity to prevent misunderstandings by having the NERC RSTC (or, as you suggested NERC) discussing with DOE to ensure that the recommendations in this white paper are considered to ensure uniformity on reporting of “load loss”.
-This response can serve as response to RSTC comments. The actions have been altered to have the RSTC initiate now that SAMS cannot.

Subsequent investigations discovered that, in some instances, the temporary reduction in system load was due mainly to residential air conditioners shutting down due to the action taken by controls in each air conditioner, which could cause the air conditioner to shut down and then restart 10-20 minutes later. Phenomena such as this were observed to cause load in a control area to be temporarily reduced by 10% or more for these events. The exposure to this phenomenon has continued to the present.

End-user equipment is being installed with controls that respond quickly to disturbances within the BPS. Adjustable speed drives used in many industrial processes, as well as chillers and air handlers for large commercial buildings, will typically respond to a transmission system fault by shutting down. This occurs even though the fault is very remote from the customer's location and does not cause a loss-of-service to the customer. Depending on the control system, such as an energy management system used in an industrial facility or commercial property, the equipment may restart automatically after a time delay or may restart only after a human operator takes action. Large customers may switch over to a stand-by power source automatically even if faults on the BPS are very remote and do not result in an actual loss-of-service to the facility. Many such facilities perform the automatic switch to BPS level faults.

Customer-owned controls that react to a fault or disturbance on the BPS may prompt a significant amount of customer-initiated load reduction, however these customers do not experience an actual loss-of-service, and is not considered a "load loss", in the historic use of the term.

Commented [A3]: Suggest just "many end users". Since we are intending to accurately report the actual numbers when and if events occur, I am not sure we need to say "significant" here since the actual amount will vary depending on the event and the specific customers and location. "Significant percentage" could mislead people to expect that these end use controls consistently represent a significant amount of MWs from any given amount reported.

Commented [A4R3]: Based on other commenter's mark ups, this comment is resolved with the removal of the "significant percentage" sentence.

Opportunities for Term Misunderstanding

There are three main areas of potential misunderstandings around the use of the term "load loss"

- Regulatory entities interpretation of information on actual or possible future BPS events
- Transmission Operator's and industry agencies' understanding of and reporting on actual BPS events
- Transmission Planner's and Planning Coordinator's interpretation of projected system performance as determined by modeling and simulations.

Each of these three perspectives are described in greater detail below.

Regulatory Entities' Interpretation of BPS Events – Actual and Projected

Informal and formal reports and other documents describing the extent of an actual system disturbance may quote levels of load loss without clarifying how much of the load loss was due to customers experiencing a loss-of-service and how much load reduction occurred due to customer-owned control equipment. Regulators and other stakeholders may not be aware that customer-initiated load reduction in response to a BPS disturbance is very common and may be fairly large, thereby assuming that all of the reported load loss consisted of customers without electric service for a period of time. This load loss assumption would be consistent with the historic use of the term, and the regulator or other stakeholder would have an incorrect understanding of the scope of the event.

Informal and formal reports and other documents related to projected future performance of the BPS may refer to possible future events and state the exposure to load loss without clarifying if customers that experienced a loss of service for the scenario(s) described, or if the load loss is an estimate of the customer-initiated load reduction (e.g., customer load temporarily shut off by customer-owned controls). Again, a regulator or other stakeholder could have an incorrect understanding of the scope and relative risk of the scenario(s) described by using the historic assumption of the term.

Transmission Operator and Industry Agencies – Reporting Requirements

Transmission Operators have responsibilities for reporting system events which, in some instances, the threshold for reporting is based on loss of load with no definition or clarification. For example, EOP-004 uses 300 MW for loss of firm load as a reporting requirement threshold. Similarly, the DOE OE-417 refers to loss of firm system loads with no clarification on what is meant by loss. It seems likely that the intent for EOP-004 and OE-417 reporting would be load/customers that had experienced a loss-of-service. The load from a temporary customer-initiated load reduction does not fit the presumed intent for these reporting requirements.

The lack of clarity or definition of what is meant by "load" or "loss" may result in miscommunication. For example, if a summer-peaking electric utility serves a fairly dense metropolitan area that has 10,000 MW of load in the summer and experiences a three-phase fault on a transmission line near the metro area. The fault is then cleared in 7 cycles by breakers that remove the faulted line from service. Zero customers experience a loss-of-service. The transient voltage criteria is met. Due to the response of customer control equipment, the utility sees a temporary reduction in load of 1,000 MW. The load for the utility begins recovering after 10 minutes, but the full 1,000 MW is not recovered until approximately 20 minutes after the incident. The customer-initiated load reduction was 1,000 MW but zero customers experienced a loss of service. The presumed intent behind the EOP and DOE reporting requirements would indicate that the utility does not need to report the incident. However, the staff at the Transmission Operator may not consider the intent behind the reference to loss of load and may simply consider the temporary change in load for the company thereby determining the incident needs to be reported. The need to report the incident might also be misunderstood by staff at DOE or some other entity. It is possible that someone at an agency may hear an informal report that 1,000 MW of load loss occurred, and form the opinion that reporting the event is required by assuming the temporary reduction of load by end-user equipment was a loss of service for those 1,000 MWs.

Commented [A5]: Did the system respond within the entity's transient voltage recovery criteria, or not?

I realize that the transient voltage recovery is a "planning" concept, but the idea is a basic one – this is what is considered "acceptable" system performance.

Commented [A6R5]: Regardless of the transient voltage criteria, a planning scenario cannot have non-Consequential load loss for such a contingency, so it would not pass the contingency and require investment to correct even when the loss was not due to utility owned, but customer-owned equipment. Additionally, SAMS members have voiced that while the utility met their transient voltage criteria, a large portion of the load would initiate into some shut down or reduction.

This example assumes that no loss of service occurred and that the removal of the faulted line from service returned the voltage to within acceptable conditions.

Transmission Planners and Planning Coordinators – Evaluation of Future System Performance

Transmission Planners and Planning Coordinators use the metrics in the NERC Transmission Planning (TPL) Standards to evaluate the future performance of the BPS[3]. Those standards use the definitions[4] of Consequential Load Loss and Non-Consequential Load Loss. Those definitions are reproduced below.

> **Consequential Load Loss** – "All Load that is no longer served by the Transmission system as a result of Transmission Facilities being removed from service by a Protection System operation designed to isolate the fault."

[3] See https://www.nerc.com/pa/Stand/Project%20200602%20Assess%20Transmission%20Future%20Needs%20an/ATFNSDT_Implementation_Plan_clean_D4_2009Sept16.pdf

[4] See https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf

Non-Consequential Load Loss – "Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive Load, or (3) Load that is disconnected from the System by end-user equipment."

Customer-initiated load reductions are covered by exclusions (2) and (3) in the definition of Non-Consequential Load Loss. Customer-initiated load reductions are not either type of Load Loss as defined in the NERC TPL Standards.

Customer-initiated load reductions are not considered directly by any performance metric in the TPL Standards. However, Transmission Planners and Planning Coordinators should include the effect of customer-initiated load reductions in simulations of the BPS to evaluate the response of the BPS to the various contingencies considered in planning studies.

Many planning engineers have started using system models that can predict the amount of residential air conditioning, and other loads, that may temporarily shut down due to a voltage sag associated with a system fault. When reporting the results of simulations, it is possible that a description of the projected system response to an event might be worded in a way that may mislead industry stakeholders. For example, a planning engineer may report an exposure to a "1000 MW load loss" based on the analyses completed. Stakeholders may interpret these predictions of "load loss" to be a loss-of-service to a large number of customers, when the load loss was actually a customer-initiated load reduction, with zero customers projected to experience a loss-of-service.

Recommended Actions

Industry stakeholders should use the term/phrase "load loss" only to refer to customers that experienced (or might experience, if the scenario is predictive) a loss-of-service. When reporting information on system disturbances (actual or predicted) to industry stakeholders, it is recommended that information on customers that have or might experience a loss of service be based on the *number* of customers without electric service. In cases where customer count is not available or it is necessary to communicate the amount of load represented by the customers without electric service, the amount of load should be clarified by stating that it represents the load for customers that have or would experience a loss-of-service (e.g., 500 MW of customers are without electric service).

When reporting the extent of actual system disturbances to industry stakeholders, information on the amount of customers/load that experienced a loss-of-service and the temporary load reduction due to the response of customer-owned equipment should be listed separately and with ample description to communicate the meaning of the two numbers. In instances where an event contains both distinctions in coincidence and thus proves difficult in categorizing the measurements and attributing it to customers that temporarily reduced their load or that experienced a loss-of-service, engineering judgement should be used to approximate the numbers and such judgement should be documented and accompany the reporting of the numbers. This recommendation is already partially reflected in the ERO Event Analysis Process

Commented [A7]: From Carl:

Minor Concern: Some of the recommendations will not be as easy as is implied. For example, in planning models we have no information on customer count. If the issue happens in my PA footprint, after some digging and back-and-forth with the affected utility, I can make some determination at customer count. But if it happens somewhere else in the model, all bets are off. Similarly, while many folks have OMS and AMI systems, it may be harder from some operating entities than others to get a customer count within the timeframes necessary for some of the required reports. Thirdly, if there is a mix of loss-of-service and customer-initiated load reduction, it may be a little harder than we think to figure out precisely how much of each occurred – this depends on the specifics of the event, where the loads are, and where we have good synchronized data sources. That said, since we are just recommending that we use customer count and differentiate/separately and explicitly list each type of load reduction/loss whenever possible (and this won't be too hard fo ...

Commented [A8R7]: Thank you for your comment, responses in line below:
-Minor concern: The document has altered to cover instances where customer count is not available to report on load reduction in MW quantities. This still has the recommendation to include load reduction opposed to load loss in order to be clea ...

Commented [A9]: From Edison:

•We think the recommendation to include a NERC glossary definition for 'customer initiated load reduction' is fine. We don't see a reason why there should be any deviation on distinguishing between consequential and non-consequential load loss, that still appears to be needed even after this ...

Commented [A10R9]: Thank you for your comments, responses inline below:
-Such terms of Consequential and Non-Consequential Load Loss currently exists in TPL-001 and in the NERC Glossary of Terms used in Standards. This white paper desires the term "Customer-Initiated Load Reduction" to be considered alongside current or proposed definitions used in the TPL standards and to develop ...

Commented [A11]: Suggest saying "whenever possible" or "whenever this data is available". Reporting customer count might work for the operating horizon where entities that have outage management systems and/or AMI can quickly and easily tell exactly how many customers were affected (note not everyone has this technology), but in planning studies, we only have load data and we do not have number of customers readily available. ...

Commented [A12R11]: Clarified that the recommendation for communicating the MW quantity of load also applies to instances where customer count is not available.

Commented [A13]: I agree in principle, but this could be quite difficult in practice if we have an event where both loss of service and customer load reduction occurred, depending on where we have metering data and other electronic data sources such as digital relays.

Commented [A14R13]: SAMS believed that this was important to separate to the level capable. The "ample description" is intended to allow for instances highlighted in the comment so that the level of detail needed for the particular instance accompanies the number. Added clarity where both occur to use engineering judgement in this case.

document[5]. Appendix C, Items 8-9 request information for the load/customers impacted[6]. That section reads, in part, "The load that was disconnected from the system by utility/entity equipment opening. Load loss due to the response of voltage sensitive load and load that is disconnected from the system by end-user equipment is not included. Do not use change in area load as the load loss." As an example, a summary of the extent of a system disturbance could say, "*The event resulted in 100,000 customers (500 MW) without electric service. Also, there was a temporary load reduction as viewed from the utility system due to the action of customer-owned equipment (transfers to stand-by power, residential air conditioners temporarily shut off, etc.) of 1500 MW*."

Summaries of predicted situations identified by system simulations should be worded carefully. If system simulations indicate that an extreme sequence of events would result in customers experiencing a loss-of-service, the summary of those simulations should state the amount of load for the customers as load loss. Summaries of system simulations that estimate the amount of customer-initiated load reduction should not refer to that reduction as load loss. That temporary load reduction should be clearly stated to be a temporary customer-initiated load reduction.

In summary, NERC SAMS recommends the following actions:

- The RSTC should pursue changes to the NERC EOP-004 standard to clarify the meaning of "loss of firm load" in order to explicitly exclude changes in balancing area load due to customer-initiated load reduction.
- The RSTC should pursue changes to the TPL standards and the NERC Glossary of Terms to include Customer-Initiated Load Reduction (or something similar) as a defined term[7].
- Transmission Planners and Planning Coordinators should discuss this issue with their respective Transmission Operators to assure that the Transmission Operators are aware of the potential for significant levels of customer-initiated load reductions in association with a BPS disturbance.
- The RSTC should facilitate discussions with state commissions with regulatory responsibilities for electric utilities to assure that those commissions have an awareness of the potential for significant levels of customer-initiated load reductions in association with a BPS disturbance.
- The RSTC should facilitate discussions with the DOE to recommend changes to language in relevant documents that refer to loss of load.

[5] The latest Event Analysis Process documents can be found here
[6] Appendix C can be found here. Page 4 on the linked document contains items 8 and 9.
[7] Note: creating a defined term to cover load reduction due to end-user equipment (akin to exclusions 2 and 3 of the Non-Consequential Load Loss definition) would significantly reduce the potential for misunderstandings.

Commented [A15]: Appendix C does not appear to reference Items 8 or 9 directly
See - https://www.nerc.com/pa/rrm/ea/ERO_EAP_Documents%20DL/Clean%20Appendix%20C%20-%20Brief%20Report%20Template%20V3.1.docx

Check reference and correct; add link in footer w applicable page number(s)

Commented [A16R15]: The document linked has both Items 8 and 9 listed on page 3. Adding link to document in footer and links to latest EA documents.

Commented [A17]: Who to perform changes?

Commented [A18R17]: The RSTC would craft such a requested change. As NERC SAMS is disbanded by RSTC vote with NERC SAMS' work plan divided up, any actions normally done by the NERC SAMS as one of the RSTC subcommittees now would be formulated by RSTC action.

Commented [A19]: I think we need to look at acceptable system performance before we write this off as a black and white change.

Commented [A20R19]: The NERC SAMS was looking at transient voltage criteria until that task was moved to the (now) NERC LMWG. This effort to provide clarity exists independent of acceptable system performance; however, NERC SAMS agreed that both needed to be looked at to ensure reliability of the BES.

Commented [A21]: Who to perform changes?

Commented [A22R21]: Clarified recommendation now that SAMS can no longer take up the task. It was anticipated this would be rolled into a SAR of some sort, whether that is in the periodic review of standards or a separate SAR.

Commented [A23]: Who to perform changes?

Commented [A24R23]: Clarified recommendation now that SAMS can no longer take up the task. It was anticipated this would be rolled into a SAR of some sort, whether that is in the periodic review of standards or a separate SAR.

Commented [A25]: I understand the added clarity you are suggesting, in that having two mutually exclusive definitions is better than one with carve-outs. However, do we really need a standard change to a standard that technically is treating this iss ...

Commented [A26R25]: Under specific TPL-001 contingencies Non-Consequential Load Loss is not allowed. Under the current TPL-001 standard, customer-initiated load reduction is covered as no ...

Commented [A27]: Who leads or coordinates?
NERC should facilitate…

Commented [A28R27]: Per the recommendation, TPs and PCs should lead the discussions.

Commented [A29]: I'm fine with that so long as we address my comment above before-hand, regarding acceptable system performance.

Commented [A30R29]: Acceptable system performance is a very broad topic. The LMWG is currently working on a document to deal with the Transient Voltage Dip and Recovery Criteria portior ...

Standing Committees Coordinating Group (SCCG) Scope

Action
Endorsement

Summary
The SCCG has been in existence for a number of years as an informal means for the standing committees reporting to the Board to coordinate their work plans. The group is formalizing their scope and activities and are seeking RSTC endorsement of their scope document.

NERC
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Standing Committees Coordinating Group Scope Document

Endorse

David Zwergel, RSTC Vice Chair
NERC Reliability and Security Technical Committee Meeting
March 2021

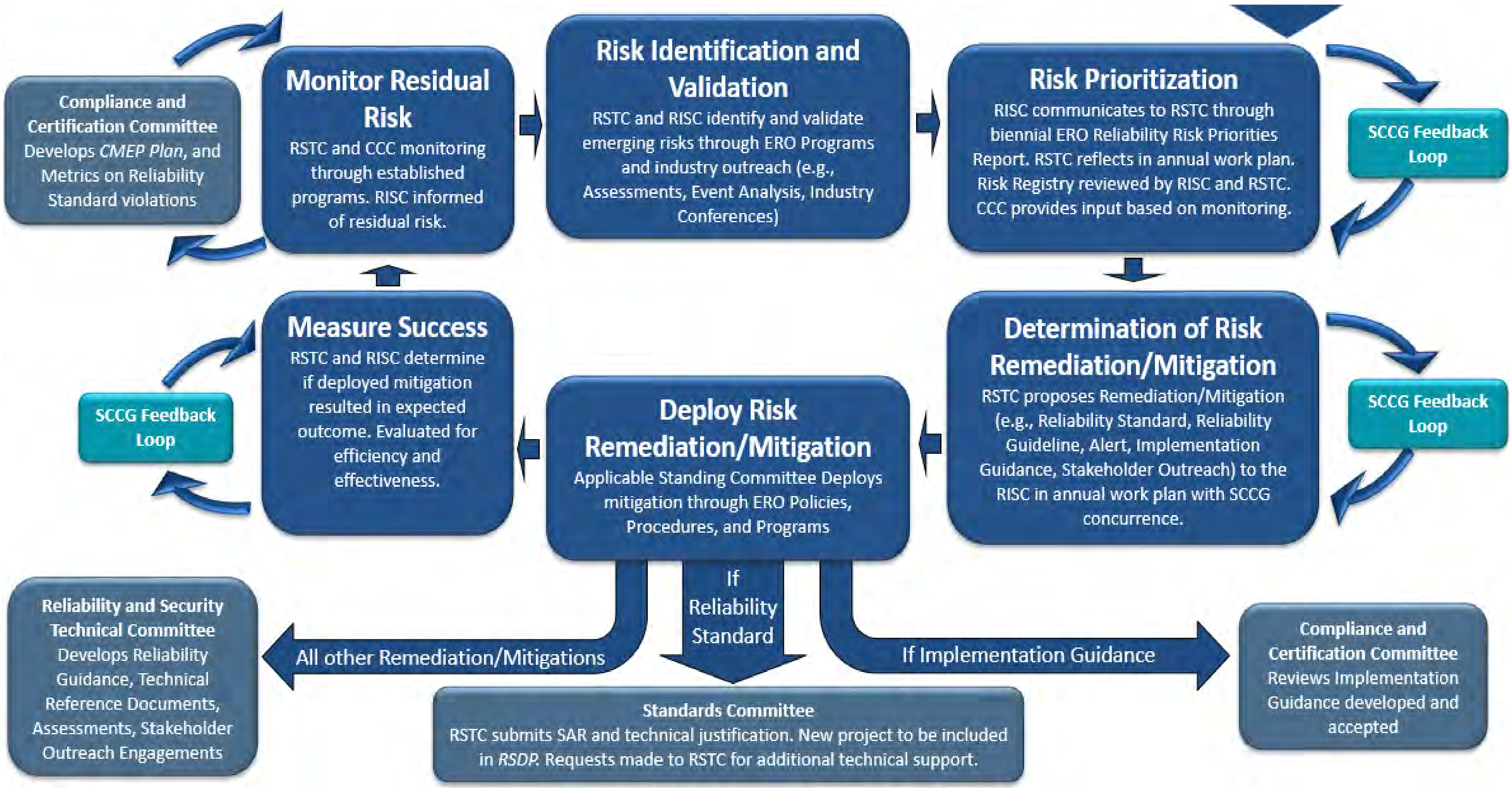
RELIABILITY | RESILIENCE | SECURITY




Background

- The Standing Committee Coordination Group (SCCG) is an advisory committee that supports coordination between the North American Electric Reliability Corporation (NERC) standing committees on cross-cutting matters of importance to bulk power system (BPS) reliability, security and resilience.
- The SCCG has been in existence for years but in an informal capacity.
- The SCCG is putting forth a scope document for formal approval and adoption by the NERC Board of Trustees.

Coordination Activities



SCCG Functions

- The SCCG performs two primary functions for the standing committees.
  - The first function of the SCCG is to evaluate the manner in which standing committee address risks to the reliability, security and resilience of the BPS by providing a cross-cutting mitigations in a coordinated fashion.
  - The SCCG provides strategic advice to the standing committees and others on the ERO Enterprise's holistic efforts to triage key reliability, security and resilience risks and propose solutions to manage those risks.

SCCG Functions

- Second, the SCCG provides an annual analysis of NERC initiatives to address risks to the BPS. The comparison of initiatives to ERO Enterprise priorities is designed to support the following activities:
  - Support a BPS risk registry:
    - Identification and description of risks
    - Prioritization of risks
    - Work plan to address risks
    - Status of the work plan
    - Status of risk management or monitoring
  - Feedback on mitigation activities, risk prioritization and measurement of success when addressing risks identified in the risk registry
  - Annual standing committee work plan planning and quarterly coordination

SCCG Membership

- The SCCG shall be comprised of the Chairs and Vice-Chairs of the following NERC Standing Committees:
  - Reliability Issues Steering Committee
  - Reliability and Security Technical Committee
  - Standards Committee
  - Compliance and Certification Committee
  - Personnel Certification Governance Committee

Request

- The SCCG requests that the Reliability and Security Technical Committee **endorse** the scope document.

Questions and Answers

NERC
NORTH AMERICAN ELECTRIC
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Standing Committee Coordination Group Scope Document

February 4, 2021

RELIABILITY | ACCOUNTABILITY




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Standing Committee Coordination Group

SCCG Scope Document

Purpose

The Standing Committee Coordination Group (SCCG or Committee) is an advisory committee that supports coordination between the North American Electric Reliability Corporation (NERC) standing committees (including the Reliability Issues Steering Committee, Personnel Certification Governance Committee, Standards Committee, Compliance and Certification Committee, and Reliability and Security Technical Committee) on cross-cutting matters of importance to bulk power system (BPS) reliability, security and resilience.

The SCCG advises the NERC standing committees, NERC staff, regulators, Regional Entities, and industry stakeholders on standing committee cross-cutting initiatives to address risks to the BPS by implementing the risk framework and addressing issues identified in the risk registry and/or NERC assessments. The SCCG's activities enhance transparency, efficiency, and effectiveness of NERC Standing Committee work, by ensuring communication and coordination on a regular basis.

See Figure 1 below for illustration of standing committee feedback loop.

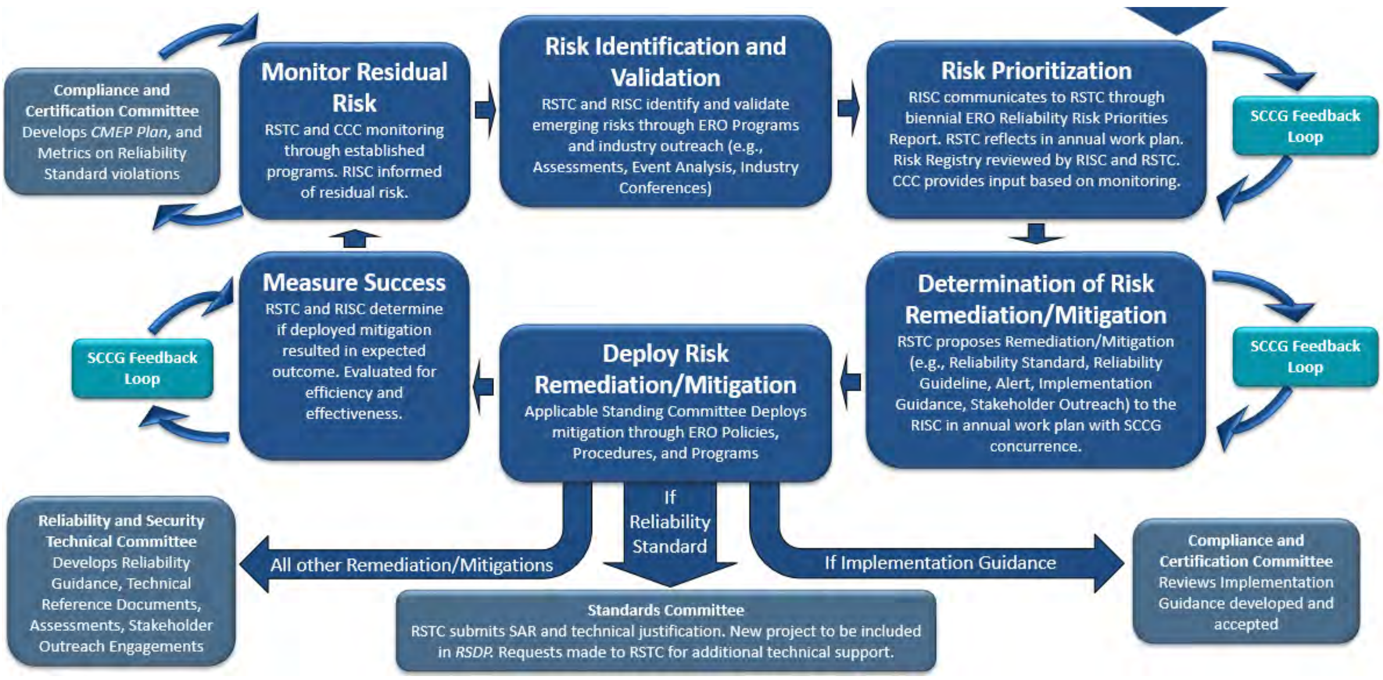

Figure 1 - Standing Committee feedback loop

Reporting

The SCCG shall provide quarterly reports to the standing committees for inclusion in their public Agenda posting on cross-cutting initiatives addressing risks to the reliability, security, and resilience of the BPS. This report shall be prepared in advance and voted on by the SCCG at the SCCG's quarterly meetings.

Overview and Functions

The SCCG performs two primary functions for the standing committees.

- The first function of the SCCG is to evaluate the manner in which standing committee address risks to the reliability, security and resilience of the BPS by providing a cross-cutting mitigations in a coordinated fashion. The SCCG provides strategic advice to the standing committees and others on the ERO Enterprise's holistic efforts to triage key reliability, security and resilience risks and propose solutions to manage those risks.

- Second, the SCCG provides an annual analysis of NERC initiatives to address risks to the BPS. The comparison of initiatives to ERO Enterprise priorities is designed to support the following activities:
  - Support a BPS risk registry:
    - Identification and description of risks
    - Prioritization of risks
    - Work plan to address risks
    - Status of the work plan
    - Status of risk management or monitoring
  - Feedback on mitigation activities, risk prioritization and measurement of success when addressing risks identified in the risk registry
  - Annual standing committee work plan planning and quarterly coordination

In addition, the SCCG performs such other functions that may be required.

Membership

The SCCG shall be comprised of the following members:

The Chairs and Vice-Chairs of the following NERC Standing Committees:

- Reliability Issues Steering Committee,
- Reliability and Security Technical Committee,
- Standards Committee,
- Compliance and Certification Committee, and
- Personnel Certification Governance Committee,

Officers

1. **Selection of the Chairs -** The Vice-Chairs of each of the standing committees shall serve as rotating co-chairs of the SCCG, for a two-year term. The initial co-chairs shall be the Vice-Chairs of the Reliability and Security Technical Committee and Reliability Issues Steering Committee. They will direct the activities of the SCCG and work toward reaching consensus on all recommendations and actions.
2. **Selection and Duties of the Secretary -** NERC will appoint one senior staff person to serve as a secretary with the responsibility to:
   a. Prepare and distribute notices of Committee meetings, record meeting proceedings, and prepare and distribute post meeting minutes and reports.
   b. Maintain a record of all Committee proceedings, including responses, and correspondence.
   c. Maintain Committee membership records.

Meetings

1. **Meetings -** Meetings shall occur at least once every quarter on a timeline aligned with the NERC Board of Trustee Meeting calendar and can be in person or by conference call as determined by the co-chairs. Notices shall describe the purpose of meetings and shall identify a readily available source for further information about the meeting.
2. **General Requirements -** The Committee shall hold meetings as needed and may use conference calls or email to conduct its business.
3. **Notice -** The SCCG secretary shall announce its regularly scheduled meetings with a written notice (letter or e-mail) to all Committee members not less than ten and no more than sixty calendar days prior to the date of the meeting. This notice requirement may be shortened for special meetings by unanimous consent of the Committee members.
4. **Agenda -** The SCCG secretary shall provide an agenda with a written notice (letter, facsimile, or e-mail) for Committee meetings no less than five business days before a proposed meeting.
    a. The agenda shall include, as necessary, background material for agenda items requiring a decision.
    b. Items not in the agenda that require a decision cannot be added at a meeting without unanimous consent of the members present. Such items may also be deferred to the next meeting so that Committee members have time to consult with others.
5. **Quorum.** The quorum necessary for the transaction of business (*i.e*., formal actions, if any) at meetings of the committee is a majority of the members currently on the committee roster (*i.e.,* not including vacancies). The Committee may engage in discussions without a quorum present.
6. **Proxies.** Proxies are not permitted.

Evaluating Reliability Guideline Effectiveness
Industry Survey, Triennial Review, and Metrics

Action
Information

Summary
On January 19, 2021, the Federal Energy Regulatory Commission ("FERC") accepted the North American Electric Reliability Corporation's ("NERC") proposed approach for evaluating Reliability Guidelines, as proposed in the Five Year Assessment proceeding.[1] This evaluation process takes places under the leadership of the Reliability and Security Technical Committee ("RSTC") and includes (i) industry survey on effectiveness of Reliability Guidelines; (ii) triennial review with a recommendation to NERC on the effectiveness of a Reliability Guideline and whether risks warrant additional measures; and (iii) NERC's determination whether additional action might be appropriate to address potential risks to reliability of the Bulk Power System in light of the RSTC's recommendation and other data pertaining to the issue.

Initial triennial review of existing Reliability Guidelines is due June 2023. To accomplish this in a timely manner through the RSTC and its subgroups, industry survey per the metrics may begin approximately December 2021-January 2022. More information will follow on that matter.

In addition, metrics should begin to be incorporated into Reliability Guidelines. Those Reliability Guidelines out for public comment and being presented to the RSTC at this meeting, should include the first three metrics listed below (the "baseline metrics"). The baseline metrics are those presented to and accepted by FERC.

Reliability Guidelines still within the development process, those created in the future, and those under triennial review should add metrics specific to each Reliability Guideline.

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;
- Industry assessment of the extent to which a Reliability Guideline is addressing risk as reported via survey; and
- Metrics specific to each Reliability Guideline, included within a Reliability Guideline by the RSTC (or a committee subgroup).

---

[1] *North American Electric Reliability Corporation*, 174 FERC ¶ 61,030 (2021).

Reliability Guideline: Model Verification of Aggregate DER Models Used in Planning Studies

Action

Approve

Summary

The Reliability Guideline was posted for a 45-day comment period and the SPIDERWG has responded to comments and made conforming revisions to the guideline. They are seeking approval of the Reliability Guideline: Model Verification of Aggregate DER Models Used in Planning Studies.

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Reliability Guideline

Model Verification of Aggregate DER Models used in Planning Studies

March 2021

RELIABILITY | RESILIENCE | SECURITY

3353 Peachtree Road NE
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 the North American Electric Reliability Corporation (NERC) and the six Regional Entities (REs), is a highly reliable and secure North American bulk power system (BPS). Our mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid.

Reliability | Resilience | Security
Because nearly 400 million citizens in North America are counting on us

The North American BPS is divided into six RE boundaries as shown in the map and corresponding table below. The multicolored area denotes overlap as some load-serving entities participate in one RE 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

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

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

Preamble

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

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

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.

- No additional metrics

Executive Summary

With the rapid growth of distributed energy resources (DERs) across many areas of North America, and new power flow and dynamic modeling practices being developed to accommodate these resources into the BPS planning assessments, focus turns to ensuring that the models used to represent aggregations of DERs are verified to some degree. Previous SPIDERWG guidance[1] provides recommended practices for DER modeling. DER models[2] are used to represent the impact of the DER as it impacts the Transmission-Distribution interface in BPS planning assessments. 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 Transmission Planners (TPs) and Planning Coordinators (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.

This guideline provides Transmission Planners (TPs) and Planning Coordinators (PCs) with tools and techniques that can be adapted for their specific systems to verify that the aggregate DER models created are a suitable representation of these resources in planning assessments. 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. PCs and TPs may typically obtain DER information for facilities five MW and above through Small Generator Interconnection Procedures (SGIPs). For facilities connected to distribution systems, the only NERC registered entity that can provide the data is the Distribution Provider. Measurements of DERs (individual or aggregate) are currently sparse, and this guideline recommends practices for ensuring adequate data are collected for larger utility-scale DERs as well as capturing the general behavior of aggregated retail-scale distributed resources. This guideline discusses when model verification is triggered, as well as how to understand the mix of different DER characteristics. This guideline 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 Transmission Owners (TOs) TPs, PCs, and Distribution Providers (DPs) understand the types of data needed for analyzing DER performance for these 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.[3]

Key Findings

During the development of this guideline, the NERC System Planning Impacts from DERs Working Group (SPIDERWG) identified the following key findings:

- **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[4].
- **Aggregation of U-DER and R-DER Behavior:** Verification of aggregate DER models becomes more complex when both U-DER and R-DER are modeled on the distribution system with different performance capabilities and operational settings, and verification practices will need to adapt to each specific scenario.

[1] https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability_Guideline_DER_A_Parameterization.pdf and https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability_Guideline_DER_Data_Collection_for_Modeling.pdf
[2] In the modeling guidance developed by NERC SPIDERWG, two types of DERs are distinguished by utility-scale DERs (U-DERs) or retail-scale DERs (R-DERs) for the purposes of modeling.
[3] https://www.ofgem.gov.uk/publications-and-updates/ofgem-has-published-national-grid-electricity-system-operator-s-technical-report
[4] For more discussion on placement of measurement devices, see Chapter 1.

- **Data Requirements:** Data requirements vary between steady-state and dynamic model verification; however, both steps are critical to developing a useful aggregate DER model. DER verification practices should ensure that both steady-state and dynamic modeling are supported.
- **Event Selection:** A relatively large disturbance on the BPS (e.g., 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, as and when more events happen and the measurement data becomes available the verified models should be checked to ensure that they indeed can replicate the other events that have happened in the system.
- **Concept of Verified Models:** Developing an aggregate DER model is not equivalent to having a verified model[5]. 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. Whereas, 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.[6]

Recommendations

From the key findings listed above, 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[7].
- 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 the purposes of DER modeling and model verification, and jointly develop requirements or practices that will ensure this data is available. As the availability of the TPs, PCs and TOs to have this data is dependent on the DP to have the data made available, this will likely require actions from state regulatory bodies[8] 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[9], 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.
- TPs and PCs should coordinate with their TOs, TOPs, and DPs to gather measurement data to verify the general behavior of aggregate DER[10]. 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.

[5] This is true for all sets of models, and is not exclusive to aggregate DER models.
[6] 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).
[7] 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.
[8] SPIDERWG has published guidance on this. Found here
[9] E.g. Root-Mean-Squared (RMS) three-phase models.
[10] SPIDERWG is actively developing guidance on how this coordination should take place to ensure reliability of the BPS.

Introduction

Many areas across the BPS in North America are experiencing an increase in the penetration of DERs, and TPs and PCs are adapting their long-term transmission planning practices to accommodate these relatively new resources into their reliability studies. Aggregate amounts of DERs should be modeled and reflected up to the BPS level when performing these studies. BPS fault events in 2018[11] highlighted the growth of DERs in California and the potential impact these resources can have on BPS performance during grid disturbances. Rapidly growing penetrations of DERs across North America have sparked the need for modeling the aggregate behavior of DERs, and in some instances the individual behavior of larger U-DERs, to a suitable degree to incorporate into BPS planning studies, much like how TPs and PCs currently account for aggregated load. SPIDERWG has provided recommended practices for DER modeling.[12,13] These guidance materials provide TPs and PCs with recommendations for modeling aggregate amounts of DERs. 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. Verification of models is paramount to obtaining reasonable and representative study results. The goal is for TPs and PCs to gain more confidence in their aggregate DER models and utilize them for BPS planning studies.

There will inherently be lag between the time in which steady-state and dynamic models for DERs are created and when verification of these models using actual 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 behaviors of DERs. Explicit modeling of aggregate amounts of DERs is strongly recommended,[14] versus netting these resources with load, as the key functional behaviors are different.

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 seeks to comprehensively understand 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. This document is intended to help TPs and PCs ensure DER model fidelity using data from actual system disturbances. Model verification's purpose is to add fidelity to models. While some recorders can be used in the same process as event analysis, the processes are quite different.

Recommended DER Modeling Framework

SPIDERWG recently published NERC *Reliability Guideline: Parameterization of the DER_A Model*, which describes recommended dynamic modeling practices for aggregate amounts of DERs. That guideline also builds on previous efforts within SPIDERWG and the NERC Load Modeling Task Force (LMTF) laying out a framework for recommended DER modeling in BPS planning studies. DER models are typically representative of either one or more larger U-DERs or aggregate amounts of smaller R-DERs spread across a distribution feeder[15]. The steady-state model for these

[11] https://www.nerc.com/pa/rrm/ea/April_May_2018_Fault_Induced_Solar_PV_Resource_Int/April_May_2018_Solar_PV_Disturbance_Report.pdf

[12] https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability_Guideline_DER_A_Parameterization.pdf

[13] https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability_Guideline_DER_Data_Collection_for_Modeling.pdf

[14] https://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/Distributed_Energy_Resources_Report.pdf

[15] References to U-DER and R-DER here are model related discussions. This designation should be only be used with respect to transferring the measurements taken from the DER into its model representation.

resources is placed at a single modeled distribution bus, with the T-D transformer modeled explicitly in most cases. The modeling framework is reproduced in **Figure I.1**. This guideline uses modeling concepts consistent with the recommended modeling framework previously published and used by industry on recommended DER model verification practices. Please refer to the aforementioned guidelines for more information.

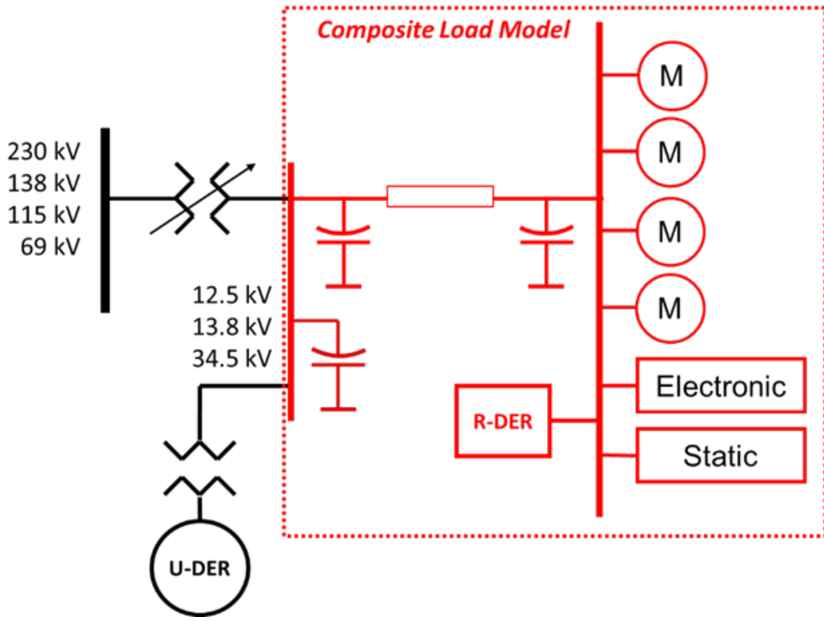

Figure I.1: DER_A Modeling Framework

Guide to Model Verification

Model verification first requires an adequate model be developed, and then for an entity to gather 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[16] 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[17]. Those model outputs and the measured outputs are compared and if there is a sufficient match based on the TP/PC procedures, the verification procedure stops. 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 B, which details an example using the playback models to verify a set of DER models. As some of the Interconnection-wide base cases predict a future condition for resources not yet built, measurement data is not available and the forecasted conditions[18]. 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.

[16] Generally, this is done by Reliability Coordinators (RCs), Transmission Operators (TOPs), and Transmission Owners (TOs); however, this can also be done by DPs in reference to monitoring equipment on their system

[17] 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 DER in other work products.

[18] SPIDERWG is developing separate guidance to verify aspects of these base cases.

Three Phase versus Positive Sequence Model Verification

The majority of planning studies performed by TPs and PCs use RMS[19] fundamental frequency, positive sequence simulation tools.[20] Hence, steady-state powerflow and dynamic simulations assume[21] a balanced three-phase network, which 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 three-phase RMS dynamic simulation, electromagnetic transient (EMT), or co-simulation . Those methods require more detailed modeling data and verification activities. However, DER model verification using those 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.

Data Collection for Model Verification of DERs

Key Takeaway:
The process of model verification requires two key aspects: a suitable model to be verified and measurement or other data that can be compared against model performance.

The process of model verification requires two key aspects: a suitable model to be verified and measurement or other data that can be compared against model performance. This guideline will cover the necessary data points for performing model verifications for developing an aggregate DER model. However, varying degrees of model verification can be performed for different levels of data available. While having all the necessary data available for model verification would be preferable, it is understood that this data may not be available and that monitoring capability may be limited in many areas today. Measurement data is a critical aspect of understanding the nature of DER and its impact on the BPS. Applicable entities that may govern DER interconnection requirements are encouraged to develop interconnection requirements for large-scale DERs that will enable data to be available for the purposes of developing accurate DER models moving forward. Further, monitoring equipment at the T-D interface would make available data to capture the aggregate behavior of DERs and load. These measurements support DER model verification process[22].

Considerations for Distributed Energy Storage

Recent discussions regarding the expected growth of energy storage, particularly battery energy storage systems (BESSs), relate to both BPS-connected and distribution-connected resources. This guideline focuses on the distributed BESSs where energy storage is concerned. Other documents coming from the NERC IRPTF are dealing with BPS-connected devices and their impact, which includes BPS-connected BESSs. 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.

[19] Root-mean-square

[20] 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.

[21] This assumption is inherently built into the power flow and dynamic solutions used by the simulation tools.

[22] Or, for that matter, any verification of flows across a T-D interface. This can include load model verification, DER model verification, or a combination of both load and DER depending on the circumstances surrounding the measurements.

Chapter 1: Data Collection for DER Model 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 to collect information pertaining to existing DERs, and also work with the DP and other applicable entities to forecast future levels of DERs 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.

Before describing the verification process in subsequent chapters, this chapter first describes the data and information used for verifying the DER model(s) created. The guidance provided here builds off the previously published guidance[23] regarding DER model development for planning assessments

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 to provide data and information pertaining to DERs within their footprint since DPs conduct their interconnection processes for resources interconnecting 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), upon their review of interconnection requirements for DERs connecting to the DPs footprint, 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 or other distribution entity, who is not a functional NERC entity. TPs, PCs, and Transmission Owners (TOs) are encouraged to coordinate with DPs and respective DER developers, generators, owners, or other distribution entities related to DER 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. Two of the primary goals of this guideline are to help ensure that DPs, TPs, PCs, and TOs understand the types of data needed to successfully verify DER models, and to provide recommended practices for gathering this data and applying it for verification purposes. It is intended that with clear coordination on the needs for the data, the best "source" of this data will become apparent.

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 these are discussed in this chapter in more detail.

Monitoring Requirements in IEEE 1547

The IEEE 1547 standard represents a series of standards that provide requirements, recommended practices, and guidance for addressing standardized interconnection of DER. IEEE 1547 was first published in 2003 and later updated in 2018 to address the proliferation of DER interconnections. Both IEEE 1547-2003[24] and IEEE 1547-2018[25] standards are technology neutral. The monitoring requirements for both standards are presented here:

[23] Links provided here and here.
[24] https://standards.ieee.org/standard/1547-2003.html
[25] https://standards.ieee.org/standard/1547-2018.html

- **IEEE 1547-2003:** The IEEE 1547-2003 standard, applicable for DER installations installed prior to the full adoption and implementation of IEEE 1547-2018,[26] included provisions for DERs with a single unit above 250 kVA or aggregated more than 250 kVA at a single Point of Common Coupling (PCC) 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). For legacy R-DERs, 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 (which 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 PCC, 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 DER. It is critical to understand these capabilities when considering additional recording devices.

Entities may receive nominal nameplate information for the resource but the actual output characteristics will be influenced by factors such as the resource's age and weather conditions. Recording devices should be capable of collecting, archiving and managing disturbance, fault information and normal operation conditions identified by protection equipment such as relays and significant changes observed during normal operating conditions (e.g. PMU reading).

An example of a recording device is the Power Quality meters (PQ meters), which are 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 as well as during system events. These types of measurement devices record both RMS and sinusoidal waveforms at

[26] It is expected that DERs compliant with IEEE 1547-2018 will become widely available around the 2021 timeframe based on the progress and approval of IEEE 1547.1: http://grouper.ieee.org/groups/scc21/1547.1/1547.1_index.html

many different sample rates and are IEC code compliant on their RMS and sinusoidal samplings. These types of meters are viable when capturing the aggregate performance of DER 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 the objectives of each entity. 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. The following recommendations should be considered by TPs, PCs, and DPs 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[27]. This may be acquired by measurements at the distribution substation for each T-D transformer bank or along a different distribution connected location[28].
- **U-DER:** U-DER models represent a single (or group of) DER; therefore, the measurements needed to verify this dynamic model must be placed at a location where the response of the U-DER (or group of DER) can be differentiated from other DERs and load response. For U-DER 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 (using 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-DER should have monitoring equipment at their Point of Connection[29] (PoC) to the DP's distribution 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.

Key Takeaway:
Measurement locations of DER performance depend on the type of DER model (U-DER vs. R-DER) 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.

As described, the type of DERs and how they are modeled will dictate the placement of measurement devices for verifying DER models. **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 ANSI acceptable continuous service voltage. These parameters represent the aggregated impact of individual feeders, as indicated by the dashed box in **Figure 1.1**. Each of the highlighted points in **Figure 1.1** pose a different electrical connection that this guideline calls out. At a minimum, placement at the high

[27] 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.

[28] 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.

[29] 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.

or low side of the transformer provides enough information for both steady-state and dynamic model verification. For U-DER, it is suggested that monitoring devices are placed at their terminal as shown in **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.

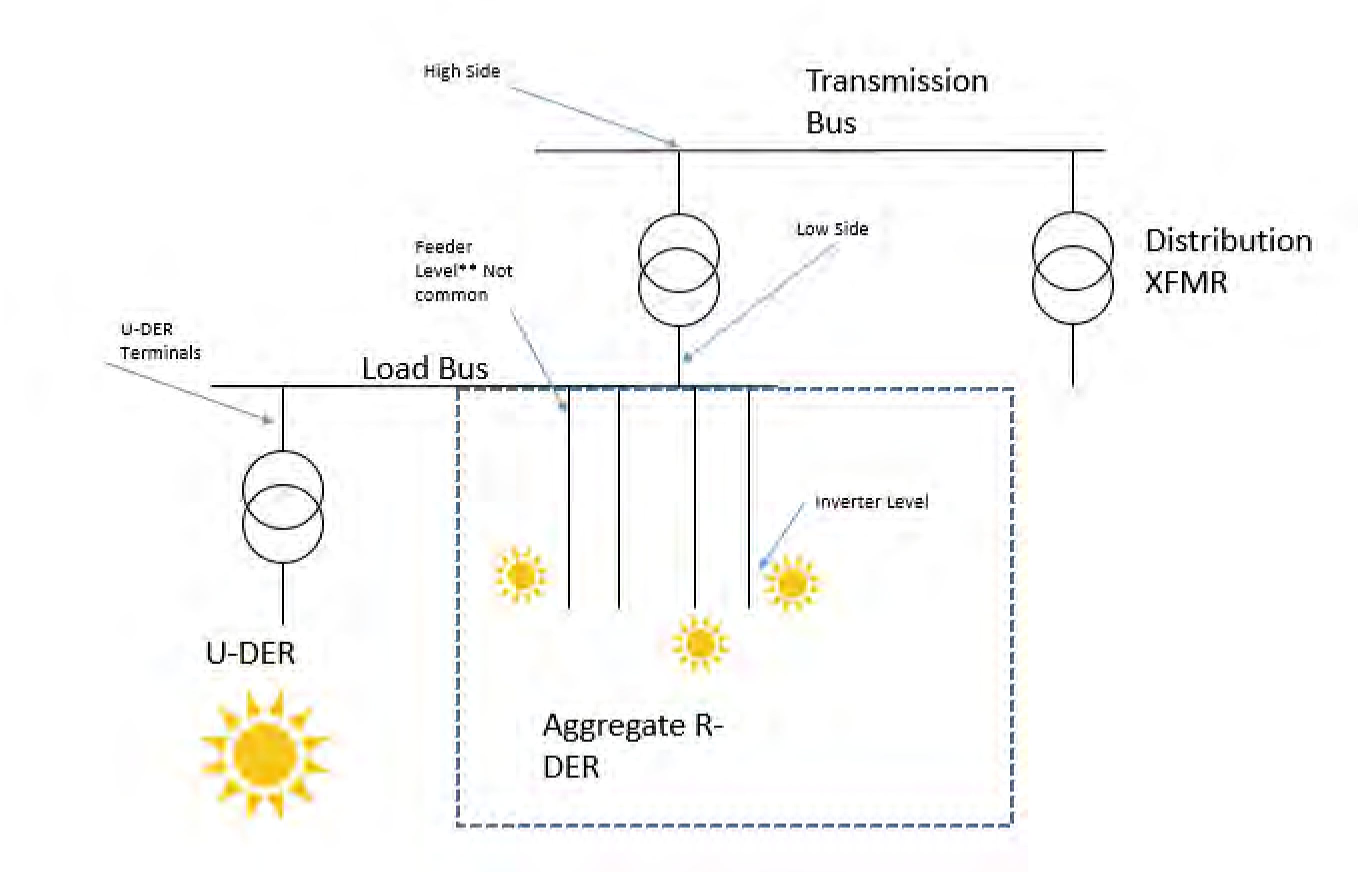

Figure 1.1: Illustration of Measurement Locations for DER Model Verification

Measurement Quantities used for DER Model Verification

Measurement devices used for DER steady-state model verification for both U-DER and R-DER should be capable of collecting the following data at their nominal frequency:

- Steady state RMS voltage (Vrms)
- Steady state RMS current (Irms)
- Active power (W)
- Reactive power (Vars)

Measurement devices used for DER dynamic model verification for both U-DER and R-DER should be capable of collecting the following data:

- RMS[30] voltage and current (Vrms, Irms)
- Frequency (Hz)
- Active power (W)
- Reactive power (Vars)
- Harmonics[31]
- Protection Element Status
- Inverter Fault Code

DER monitoring equipment systems[32] should be able to calculate or report the following quantities in addition to the measurements described above:

- Power Factor (PF)
- Apparent Power (magnitude and angle)
- Positive, negative, and zero sequence voltages and currents
- Instantaneous voltage and current waveforms as seen by the measurement device

Based on the types of measurements desired, preferred, and helpful, **Table 1.1** provides a summary between the steady-state and dynamic recording devices. Each of the measurements above is categorized in **Table 1.2** as necessary, preferred, or helpful to assist in device selection. For dynamic data capture, Digital Fault Recorders (DFRs) and distribution Phasor Measurement Units (PMUs) are two high resolution devices that are useful in capturing transient events, but are not the only devices available to record these quantities. In some instances, already installed revenue meters may provide this RMS information[33].

Table 1.1: Recording Device Summary

Topic	Steady-State	Dynamic
R-DER		
Useful Location(s) of Recording Devices	High-side or low-side of T-D transformer(s); individual distribution circuits[34] (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.

[30] References to RMS here are fundamental frequency RMS.

[31] 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 (IEEE std. 519 for example) and such standards refer to the upper harmonic boundary for measurement.

[32] 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.

[33] 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

[34] individual distribution circuit data is not necessary but can be useful either in addition to or in replacement of T-D transformer data

Table 1.1: Recording Device Summary		
Topic	**Steady-State**	**Dynamic**
R-DER		
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-DER; 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[35].
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[36]; Sinusoidal Voltage and Currents

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.

Steady-State DER Data Characteristics

As **Table 1.2** summarizes the measurement quantities needed, 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

[35] For wide-area model validation, the outputs from these devices should be time synchronized, such as by GPS.

[36] 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 which are applied from the BPS perspective and including this information can assist with both root cause analysis as well as verification of aggregate DER settings.

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 AVRs, 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.[37] SCADA data streams come in at typically 2 to 4 seconds per sample; however, these speeds are not always realizable.
Duration	Largely, a handful of instantaneous samples will verify the dispatch of the DER and load for each Interconnection-wide base case. Further durations nearing days or weeks of specific samples may be needed to verify U-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..
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., GPS)[38] to align measurements from across the system.
Aggregation	Based on the modeling practices for U-DER and R-DER established by the TP and PC,[39] 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-DER and R-DER 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 PV DERs[40].

[37] The resolution needs to be able to reasonably capture large variations in power output over the measurement period.
[38] https://www.gps.gov/
[39] https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability_Guideline_DER_A_Parameterization.pdf
[40] See Chapter 2, section titled "Battery Energy Storage System Performance Characteristics" for more information on this topic particularly.

Table 1.2: Steady State DER Model Verification Data Considerations

Topic	Key Considerations
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 cyclic energy during times of solar irradiance, wind resources provide output during times of increased wind, and BESSs may inject or consume energy based on market signals or other factors. In general, these recommendations can apply to sampling measurements for these resources: 1. 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. 2. Wind: Capture output patterns during coincident times of high solar PV output (if applicable), as well as high average wind speeds. 3. BESSs: BESSs should be sampled during times when the resource is injecting and during times when the resource is consuming power.
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. Not taking this into consideration makes DER mapping to BES model susceptible to inaccurate DER connection points. 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 DER may require more complex measurements, 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 to verify BES interaction characteristics. It is beneficial to include steady-state current and voltage waveforms to this effect, especially for inverter-based DER.

Dynamic DER Data Characteristics

Dynamic recorders uses in capturing the transient conditions of an event have differing data considerations than the steady-state recorders. The data characteristics and considerations typically discussed in dynamic recording of measurements 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 time period. The data captured from dynamic disturbance recorders can be used for the purposes of dynamic model verification.

Table 1.3: 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 on a trigger basis.
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 such that a BPS fault is detected or that nearby protection relays 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[41] • Over-frequency events[42] • Under-frequency events Although higher 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, both R-DER and U-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[43]. 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., GPS) 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[44].

[41] 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.
[42] These 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.
[43] 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.
[44] Per PRC-002-2, SER and FR data shall be time synchronized for all BES busses per R10 (link here). This same concept should be true for these measurements that may not be taken from BES buses.

Table 1.3: Dynamic DER Model Verification Data Considerations	
Topic	**Key Considerations**
Aggregation	Based on the modeling practices for U-DER and R-DER established by the TP and PC,[45] 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-DER and R-DER 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-DER or R-DER by operational characteristics based on the TP and PC's modeling practices.
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 in. If it does not come in a known Excel format, ASCII[46] files are typically used that would be converted into a file format readable in Excel. However, other files types, such as COMTRADE[47], 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.

Management of Large Quantities of DER Information

Management of the increasing diversity of DER functional settings 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 so-called manufacturer-automated profiles (MAPs) that preset certain functional parameters to the values specified in applicable rules (e.g., CA Rule 21, HI Rule 14H, or the default values of a certain IEEE 1547-2018 performance category). To date, these MAPs 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 MAP 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 cornerstone 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[48]. 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, which will be used to exchange and store DER settings. Potential use cases of such common file format include:

- 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.

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45 https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability_Guideline_DER_A_Parameterization.pdf

46 ASCII stands for American Standard Code for Information Interchange as a standard for electronic communication.

47 COMTRADE is an IEEE standard for communications (IEEE Std. C37.111) that stands for Common Format for Transient Data Exchange

48 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.

- 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, and settings for DER frequency-droop across between DPs and TPs.

One way to exchange these common DER settings file could be a central database, for example that 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[49].

[49] 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 Model Verification

After collecting the data for steady-state model verification for aggregate DER, the first set of models to verify is generally the steady-state DER model. Please refer to the recommended DER modeling framework section, which references documents that indicate the usage of generator records for these steady-state models, for information on the modeling practices. This steady-state model feeds into many of the loadflow studies that TPs conduct, and is the starting point around which dynamic model initializes. 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.

System Conditions for DER Model Verification

Steady state verification procedures can use lower time resolution data and does not need such data to be tied 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 DER was incorrectly modeled. In this scenario the aggregation in question was R-DER modeled DER. 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, the connection voltage, and analyzed its path the BPS bus to get appropriate impedances between the R-DER and 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[50].

There are a few conditions that the TP should ensure is verified in their set of models and each is to be verified systematically when the data becomes available. This is to ensure their set of models is of high fidelity for their study's conditions. A set of important conditions to verify, accounting for gross demand and aggregate DER output, include the following[51]:

- DER output at a (gross or net) peak demand condition
- DER output at some off-peak demand condition
- When the percentage of DER is significantly high[52]

At each of these points, the collected 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.

Temporal Limitations on DER Performance

> **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.

Due to a multitude of reasons, DER operational characteristics can inhibit the DER performance. For solar PV, solar irradiance inherently limits the output of the DER resource. 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. Much of the inverter control settings are still applicable for dynamic performance verification for the measured data. For instance, if the aggregate DER response was indicated to have a maximum power of 10 MW, that power has a specific minimum irradiance value associated with the output of the devices. Lower values of irradiance will produce a lower associated available power

[50] For example, this can include voltage reduction tests, overnight low load conditions, or other operational conditions based on engineering judgement.
[51] These examples are used to be in alignment with the conditions in TPL-001-4 (link: here).
[52] This is typically decided based on engineering judgement and does not necessarily coincide with developed peak or off-peak Interconnection-wide base cases.

to extract from the solar cells and vice versa for higher irradiance values with respect to low and high limits. Similar considerations for other resource types will be needed in order to ensure the available power from the resources is correctly determined prior to adjusting the other parameters of the model. The unavailability of such data should not stop the process as verification of other parameters can be performed.

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 a 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 that 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, this particular site had a few controllability settings to verify, namely load following settings.

Key Takeaway:
The large majority of U-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.

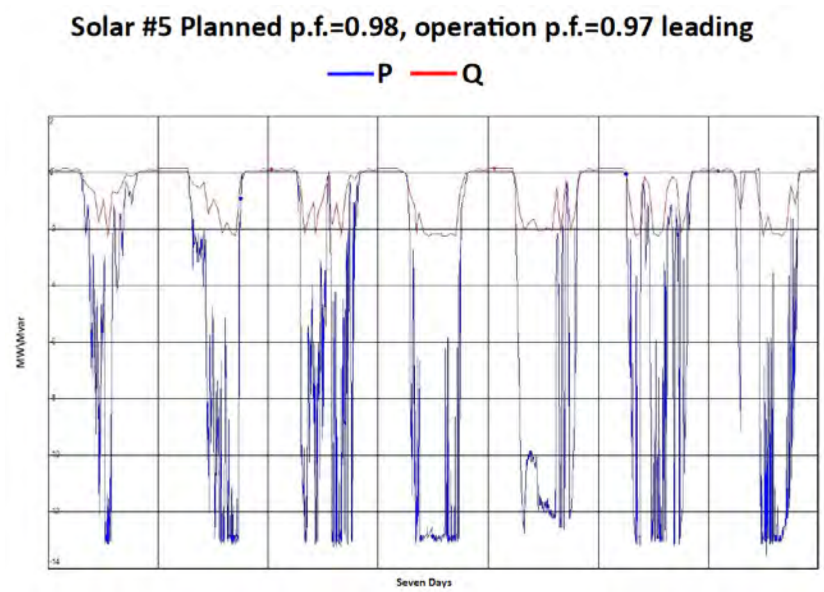


Figure 2.1: Load Following U-DER Response

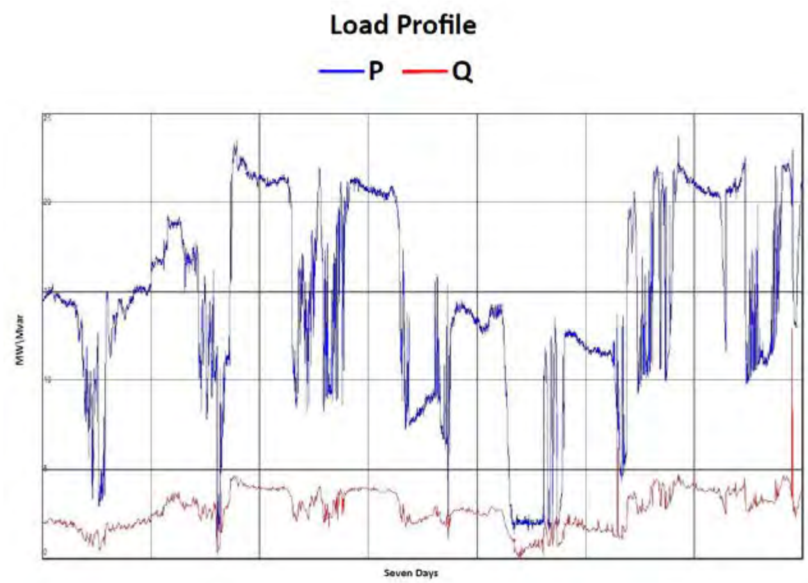


Figure 2.2: Load Response near the U-DER

In the steady state, the DER MW and MVAR output could be verified based on day 4 only. To reiterate, the MW and MVAR relationships could be verified by simply providing the MW and MVAR measurements on day 4. However, as this installation indicated the U-DER followed the nearby station load, a different time was needed. To verify the load following setting, day 5 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 (i.e. to prevent back feeding).

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) and such separation allows for the steady-state verification process to be easier. Each TP/PC should consult with the DP to ensure the data required to verify their facility as part of the modeled aggregation is submitted. Care should be taken to ensure that the data will be used for its intended purpose of model verification and will not be misused or shared outside of the DPs and other distribution entities intended use; however, it is graphs like these that allow TPs to verify the MW, MVAR, and V characteristics in their steady state models. If there isn't data measurements like Figure 2.1 and Figure 2.2 made available, by asking questions of the DP and applicable entities, the TP is able to adjust their set of planning models to account for any changes to the DER aggregation from the submitted model. Table 2.1 highlights some of these important questions.

Table 2.1: Sample DER Steady-State Questions and Anticipated Parameters

Data Collected	Anticipated Parameters
What is the aggregated operational characteristics of DERs[53] at substation within specified time domain?*	This will help set the maximum power output of all DER represented in the verification process. This accounts for the aggregated coincidental capacity potential 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.

[53] A "DER" here is be taken from the Interconnection Request. In such a request, the total MW of output is listed. That is the MW used in the summation of all "DER installations"

Table 2.1: Sample DER Steady-State Questions and Anticipated Parameters	
Data Collected	**Anticipated Parameters**
What is the magnitude and type of aggregated coincidental load connected to the transmission substation?**	This data point will assist in determining how the overall model set will perform when adjusting both the DER model and load model at the substation.
What reactive capability is supplied at the DER installations?	This 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.
Minimum power of DER***	For non-solar related DER devices such as microturbines or BESS, this parameter provides the minimum required output of the DER resource in transient stability.

* This question is useful for BESS DERs in discharging mode
** This questions is useful for BESS DERs when in charging mode
*** This question is useful for BESS DERs regardless of charging or discharging

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 DER. For example, when coupling U-DER BESS and other U-DER modeled Solar PV devices in the same model, care needs to be taken to ensure that the U-DER facilities are adequately represented and that the storage aspect of the model is correctly implemented. Including BESS during verification procedures may require measurement devices for aggregate U-DER BESS installations as well as other U-DER modeled DER installations. If the model verified is an R-DER BESS installations along with other R-DER, DPs and other entities may need to contact the OEM or DER developer for some of the questions in **Table 2.1**. It is recommended that DPs and other entities establish a good relationship with the OEMs of BESS such that steady-state BESS parameters are captured and can be highlighted in any measurement device for R-DER modeled resources. Regardless of how the DER is modeled, current practices include surveys or other written means to obtain an operational profile of BESS DER, which helps validate the parameters used in steady-state analysis.

It is recommended to utilize a single DER model for aggregate U-DER, but some complexities or modeling practices may dictate otherwise. Examples for moving to separate aggregations is related to the frequency or voltage regulation settings. Some modeling practices aggregate each technology type separately; however, the benefit of a single DER model for each U-DER allows for a one to one relationship in any measurements provided. The TP and PC is recommended to use engineering judgement and readily available information to determine if these considerations are necessary for their models and alter their verification practices accordingly.

Steady-State Model Verification for Aggregate DERs

The verification of multiple facilities as they pertain to the aggregation 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 both U-DER and R-DER at the T-D interface some assumptions help the verification process. Most legacy DERs (IEEE 1547-2003 may operate at constant power factor mode only and typically are set at unity power factor, making this a safe assumption. The IEEE 1547-2018 standard has introduced more DER operating modes such as volt-var, watt-var or volt-watt and this may require reaching out to the DP to verify as the settings could be piecewise 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 in order to aggregate the impacts of the data, while leaving the monitoring of R-DER at the high side of the T-D interface.

Figure 2.3 shows an example from a 44 kV feeder measurements. The four solar plants, each rated 10 MW, and one major industrial load are connected to the feeder at different 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 travel through a long feeder with lower X/R ratio. The data show that the third solar plant's reactive power output was opposite to the planned direction (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 is recommended to supplement these graphs. From the graphs, the following steady-state DER values would be compared against the modeled representation and corrected (assuming DER is at maximum output) if there was a sufficient discrepancy:

- 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

Both the aggregate R-DER steady-state component and the gross load component would be difficult to gather this from the measurement alone; however, if the values gathered on this particular graph align with that entered in the load record, that load record is more likely to be a correct representation of the combined R-DER and load. 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 2 (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.

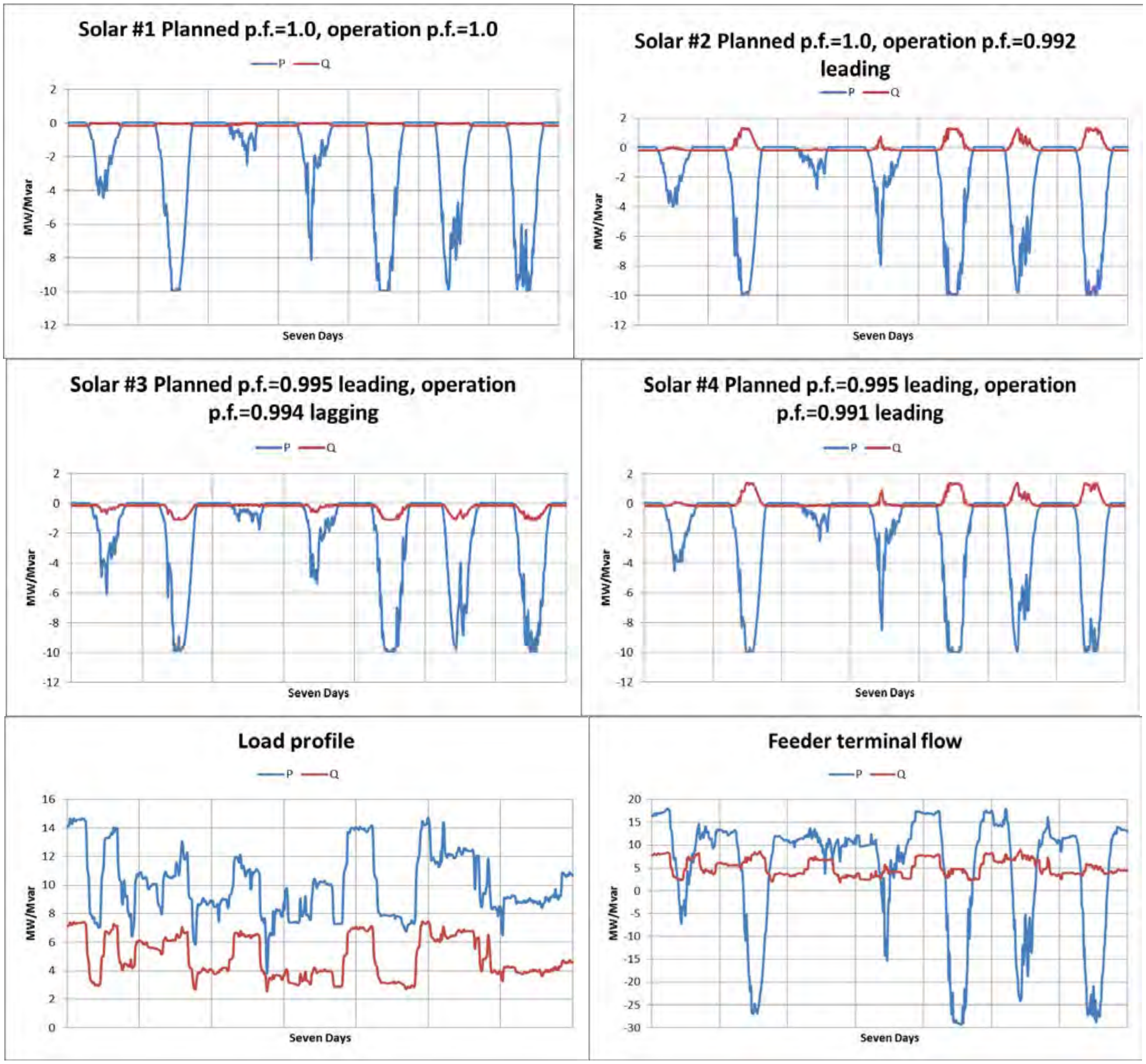
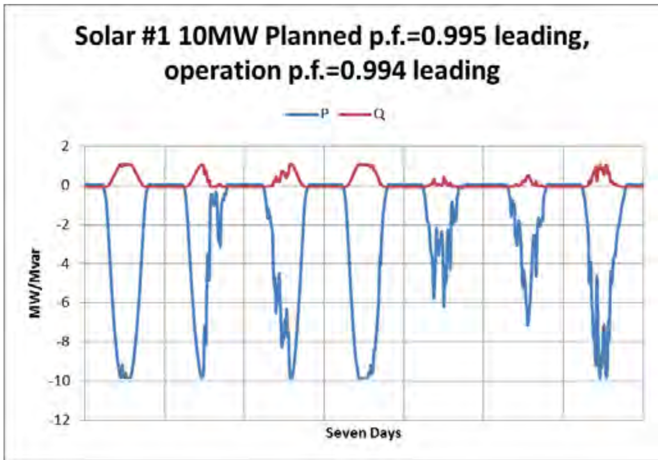
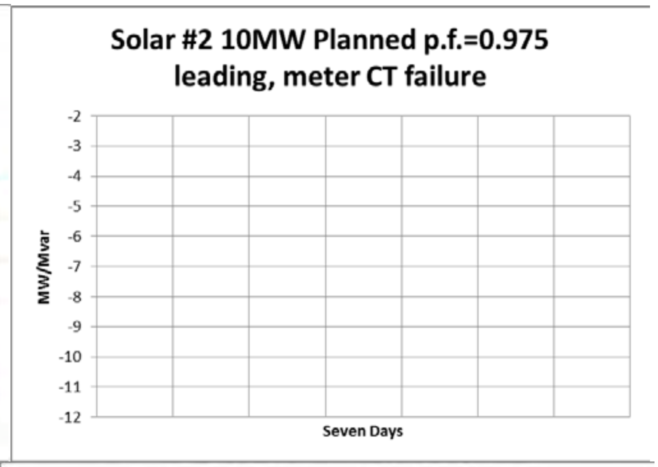


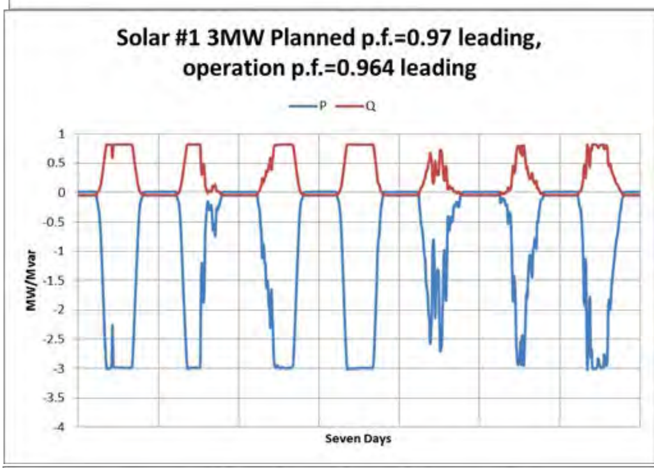
Figure 2.3: Active and Reactive Power Measurements from U-DERs, Load, and Substation

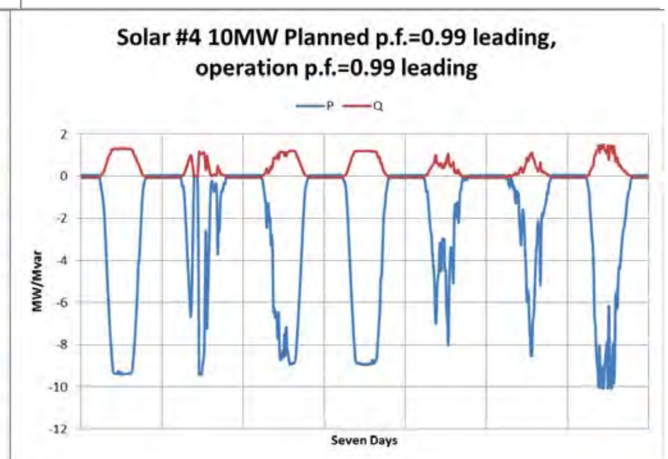
Figure 2.4 shows another 230kV station-wide measurement. Power trends from eight monitored DERs connected to 44kV feeders supplied from the station are plotted in the figure. The meter at Solar #2 was out of service in the week due to failed CT. Note the 6th solar DER is a behind the meter installation, the 7th is a biomass DER and the 8th is aggregation of three solar DERs and load[54]. 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. While not provided in the figures, the voltage at these locations should be used when verifying the voltage characteristics in the model. 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.

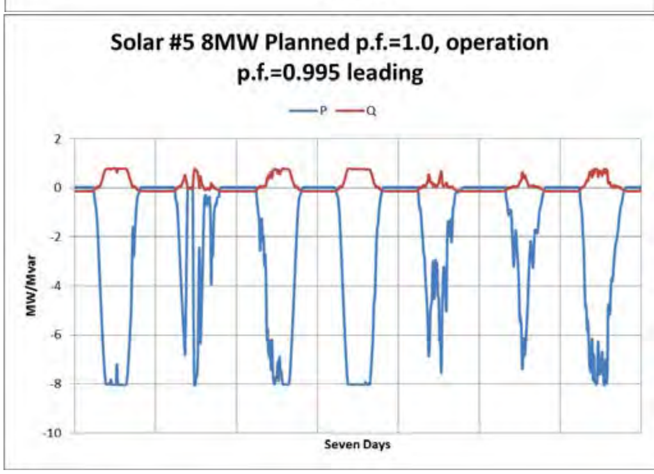
[54] This would represent the contributions of R-DER in the aggregate DER model

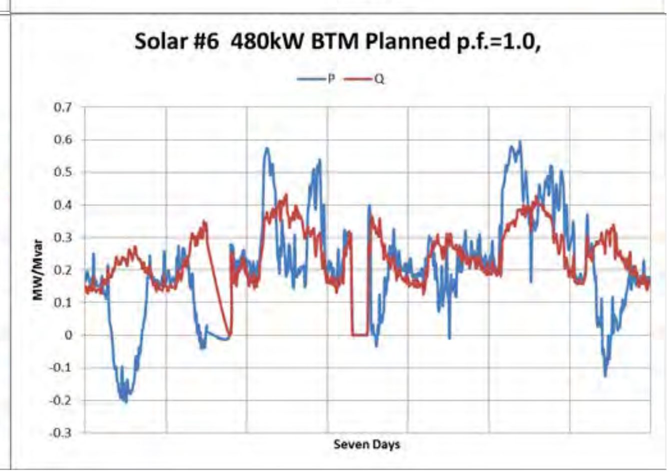

Solar #1 10MW Planned p.f.=0.995 leading, operation p.f.=0.994 leading
P
Q
MW/Mvar
Seven Days


Solar #2 10MW Planned p.f.=0.975 leading, meter CT failure
MW/Mvar
Seven Days


Solar #1 3MW Planned p.f.=0.97 leading, operation p.f.=0.964 leading
P
Q
MW/Mvar
Seven Days


Solar #4 10MW Planned p.f.=0.99 leading, operation p.f.=0.99 leading
P
Q
MW/Mvar
Seven Days


Solar #5 8MW Planned p.f.=1.0, operation p.f.=0.995 leading
P
Q
MW/Mvar
Seven Days


Solar #6 480kW BTM Planned p.f.=1.0,
P
Q
MW/Mvar
Seven Days

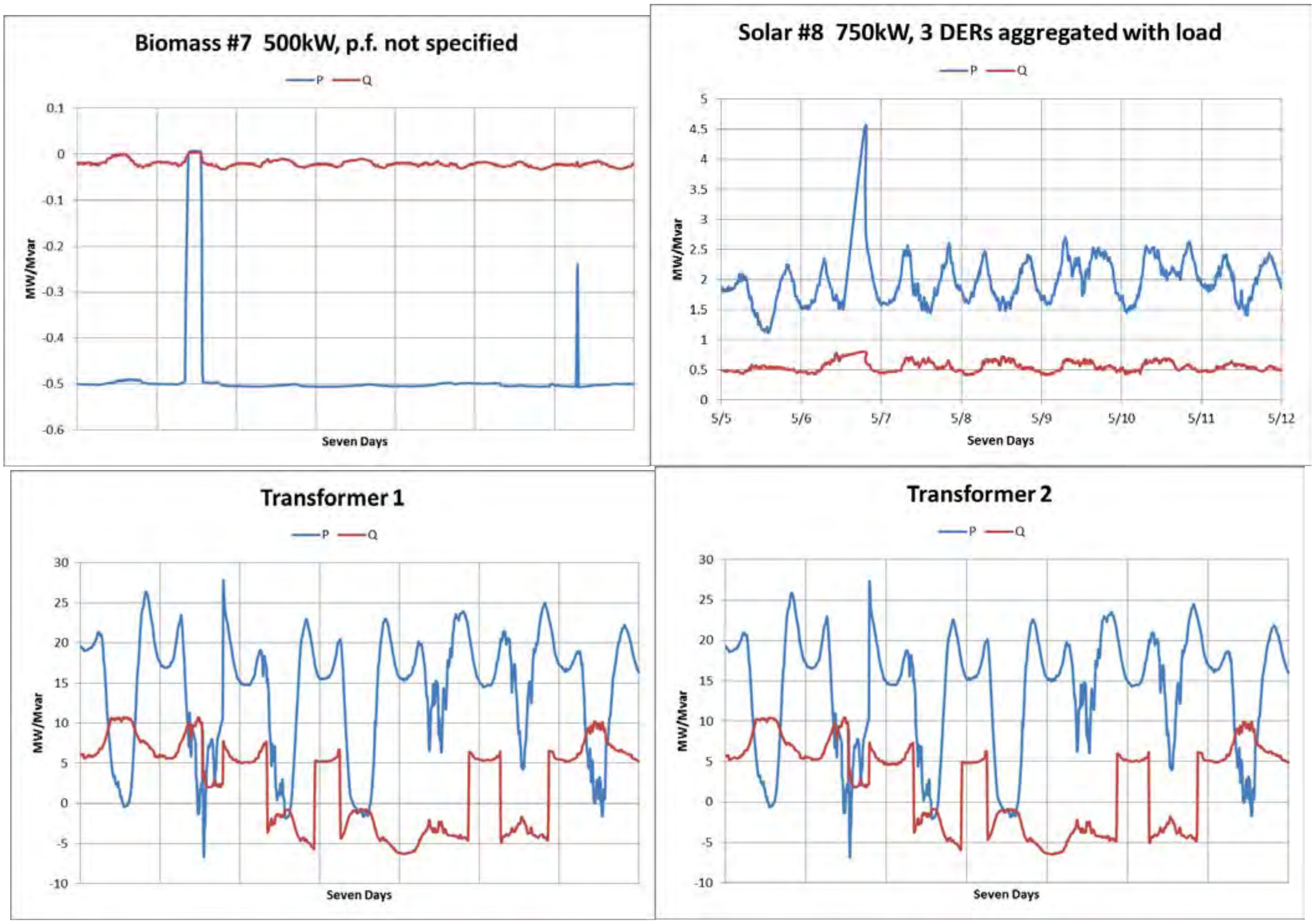


Figure 2.4: **Active and Reactive Powers Measured from Various DERs and Substation Transformers**

As with the aggregations in Figure 2.3, the TP or PC can use these measurements 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 the figures, 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 behind the meter (BTM)
- Aggregate R-DER production of about 1.5 MW from the daily changes in the BTM solar load
- Gross load of about 40 to 42 MW taken from both transformer graphs and backing out the aggregate DER (both U-DER and R-DER) production.

In this example, since one of the U-DER modeled DER did not have measurements, the TP/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/PC to verify their models such that the behavior of DER 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 a total of nearly 55 MW of gross load, which impacts the simulated performance of the transmission station.

Steady-State Model Verification when R-DER and U-DER Modeled Separately

> **Key Takeaway:**
> Increasing the number of generator records when modeling DER increases the importance of having additional measurement locations.

Once the model contains both aggregate U-DER and R-DER, the dispatch of the U-DER and R-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 aggregated at 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 details a high level of the U-DER and R-DER pertaining to the distribution transformer as seen in a planning base case. 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 that measurement pertains to (i.e. the U-DER or R-DER representation). As each model record represents an aggregation of DER facilities, note that more data will help refine the process. Additionally, some modeling practices have more than one generator record for different aggregations of DER technology types, namely for U-DER. 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 general, when viewing measurements from a T-D bank, assumptions will be required to categorize the U-DER response in relationship to the R-DER response

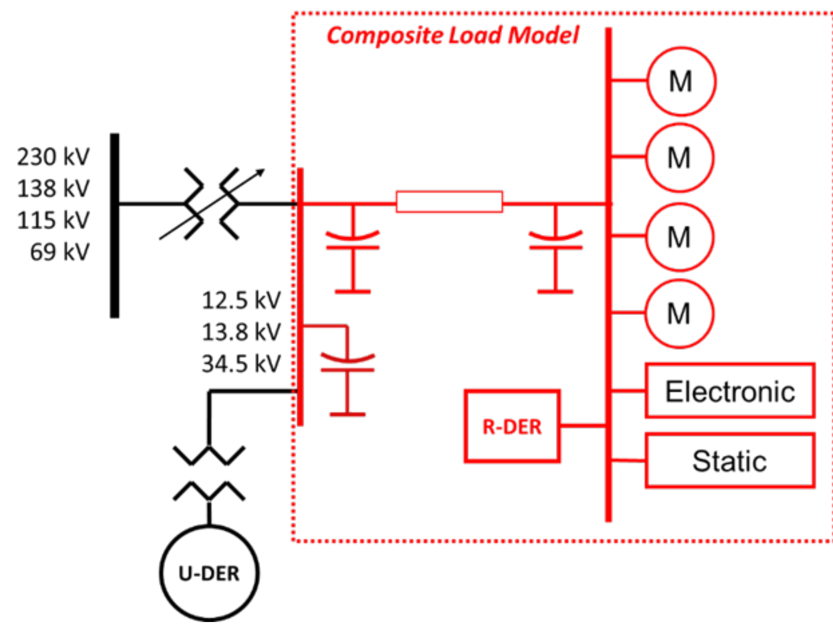


Figure 2.5: **Aggregate U-DER and R-DER Steady-State High Level Representation**

Chapter 3: DER Dynamic Model Verification

This section covers the verification of the aggregate DER model 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. For some entities, individually large DER installations are explicitly modeled, and does not need playback information from the BPS events to perform the verification.

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:

- Events that occur during nonoperational or disconnected periods of the DER
- Other events that do not contain a large signal response of DER. This is the case with very low instantaneous penetration of DER.

Even with previously verified models for one event, additional events will also provide TPs additional assurance on the validity of the dynamic DER model. One of the most telling aspects on this would be that the Event Cause Code is different between verified model and new event and such differences impact model performance[55]. Based on the above factors, it is crucial to the model verification process that each recorded event have sufficient detail to understand 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 model.

DER Dynamic Model Verification for a Single Aggregation

If the TP/PC determines there are sufficient amounts of aggregate DER in a study area, then models should adequately represent dynamic performance of aggregate DER. U-DER and R-DER differ in that dynamic performance characteristics of individual installations of U-DER are practically accessible, while the dynamic performance characteristics of individual installations of R-DER are not. By having the individual performance readily available, this allows for the TP or PC to tune their transmission models representing those resources[56]. 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 dynamic capability of the devices. Thus, though this section focuses on the dynamic performance of U-DER, many of the same performance characteristics

[55] 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.

[56] Whether using an aggregate dynamic model such as DER_A, or an individual dynamic model set such as the second generation renewable models or a synchronous facility. Because U-DER generally will dominate the model performance, individual U-DER performance can verify both types of choices.

may be inferred under engineering judgment to apply to R-DER[57]. With data made available, model verification can occur. See **Figure 3.1** for a high-level representation of U-DER topology with load and other modeled components. The composite load model here contains a modeled R-DER input; however, in this section the composite load model is considered to not include that input. 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 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[58] models to a reasonable state for its representation in transmission models[59] is the goal.

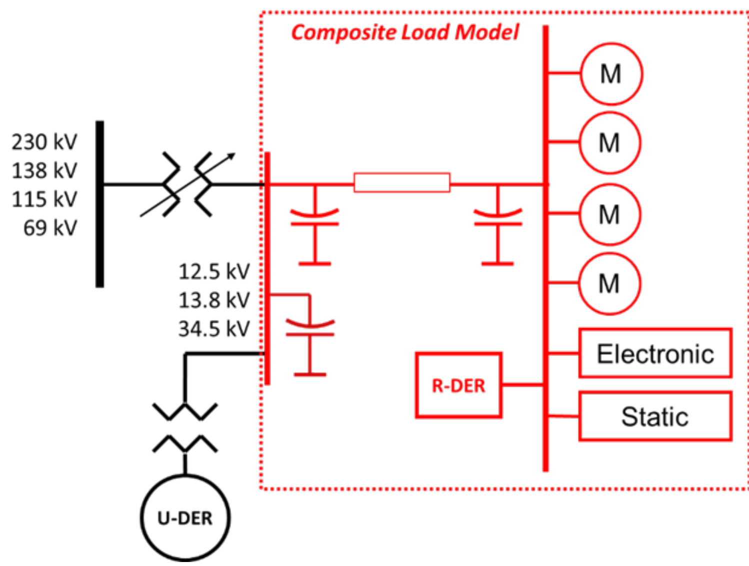


Figure 3.1: High Level Individual U-DER and Load Model Topology

Dynamic Parameter Verification without Measurement Data

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[60] in representing U-DER in their set of BPS models, and should be used only as an aide in determining those parameters required for the dynamic performance verification as the model and system changes between the initial model build and the current set of models. 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 generic models provided for representing inverter-based DER, those parameters are

> **Key Takeaway:**
> Ensuring correctly modeled IEEE 1547 vintage through data requests allows the TP to ensure their dynamic DER model is correctly parameterized

[57] 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. In cases where this is not the case, the TP should consider moving that DER facility from the classification of U-DER to R-DER 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.

[58] Note that both the composite load model and the DER_A model are aggregate models that represent aggregate equipment.

[59] 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.

[60] Primarily this is due to interconnection requirements, but can also be due to other external documents.

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[61] 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 DER 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.

[61] Or other equivalent applicable equipment standard

Table 3.1: DER Dynamic Model Data Points and Anticipated Parameters		
Data Collected	**Anticipated Parameters**	**Example DER_A parameters**
What vintage of 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 percent 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 can represent choices made inside the vintage.	Voltage: Vrfrac Frequency: Handled by the Ffrac block[62]
What interruptible load is represented at the substation?	This data point will allow TPs and PCs to be able to coordinate the various protection schemes (such as Under Frequency Load Shedding) along with any of 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[63].	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.[64] And per FERC Order No. 792, metering data is also provided to the transmission provider.[65] Thus, the TP/PC have access to data for verification of U-DER dynamic performance for units applicable to the SGIA. In utilities with larger penetrations of DER, more prescriptive language may exist to supplement the SGIA. Data at the

[62] 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.

[63] Even in the standalone model situation here, answers to this question will help the TP and PC verify the load responses for model verification. This subject, however, is out of scope of this document.

[64] Order No. 828, 156 FERC ¶ 61,062.

[65] Order No. 792, 145 FERC ¶ 61,159.

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[66] 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 applicable units, not all of the DER facilities will be under the SGIA. See **Table 3.2** to get an understanding of the amount of resources ISO-NE considers as DER[67]. For the representations here, the Solar PV Generation not participating in the wholesale market is 1532 MW while 858 MW participates and is SGIA applicable. In this region, reliance on the SGIA alone will only apply to a third of the installed Solar PV DER. In addition, generation from other sources totals 1351 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 DER 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 3.2: New England Distributed energy Resources as of 01/01/2018

DER Category[68]	Settlement Only Resource Nameplate Capacity [MW]	Demand Resource (DR) Maximum Capacity [MW]	Total DER Capacity [MW]
Energy Efficiency	-	1765	1765
Demand Resources (excluding behind-the-meter DG capacity)*	-	99	99
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	-	-	1532
Total DER Capacity	1436	2656	5625

[66] E.g. measurements from a fault recorder, PQ meter, recording device, or device log.

[67] The full ISO-NE letter can be found here.

[68] 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.)

Total DER Capacity/ Total Wholesale System Capability**	4.1%	7.5%	15.9%

* To avoid double-counting, demand response capacity reported here excludes any behind-the-meter DG capacity located at facilities providing demand response. Registered demand response capacity as of 01/2018 is 684 MW

** System Operable Capacity (Seasonal Claimed Capability) plus SOR and DR capacity as of 01/2018 is 35,406 MW

In current models, the composite load model may be used to represent the load record in the verification process. PC/TPs should be aware that in the composite load model there are parameters for aggregate R-DER representation. If modeling only U-DER, the DER parameters in the load model should be set to inactive. If there are R-DER impacts, a TP can use the composite load model to insert these parameters.

Aggregate DERs Dynamic Model Verification

Similarly to verifying U-DER, the model of an aggregation of U-DER and R-DER will be conducted similarly, with the same concerns discussed for steady-state verification.[69] Detailed in **Figure 3.2** is a complex set of graphs that represent R-DER and U-DER, along with load, connected to a 230 kV substation to the response of an electrically close 115 kV three phase fault. 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.

Under a 115 kV system three-phase fault outside the station, the entire 230kV station sees the voltage profile[70], 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 transformers (T1 and T2). Two solar farms (Solar 5 and Solar 6) and other loads with behind-the-meter generation are connected to the 28 kV feeders. The voltage of the 230kV substation returns to normal after the fault; however, the current contributions across the distribution transformers changes from that of expected. At the 44kV yard all four solar installations rode through the fault with increased current injection during fault. The load rode through the event. Aggregated current at T3 shows total current unchanged after fault but big increase during fault. This is different from fault signatures in traditional load supply stations, which is 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 3.2 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 DER. This demonstrates that the pickup of the load was across the T1/T2 transformers. Based upon this figure, 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 Transmission Planner decides to model this complex distribution substation into the planning models. In summary, with metering at each U-DER[71], large load and station terminals, this example has enough information for verification of the complex models that represent these DERs. Primarily, the verification

[69] Please 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

[70] Left top corner of the figure

[71] Note that some required monitoring at the end of the feeder

process would show a need to parameterize such that T1 and T2 reflect the reduction of DER from Solar 5 and Solar 6, yet having T1's DER representation parameterized such that this reduction is not present[72].

[72] 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.

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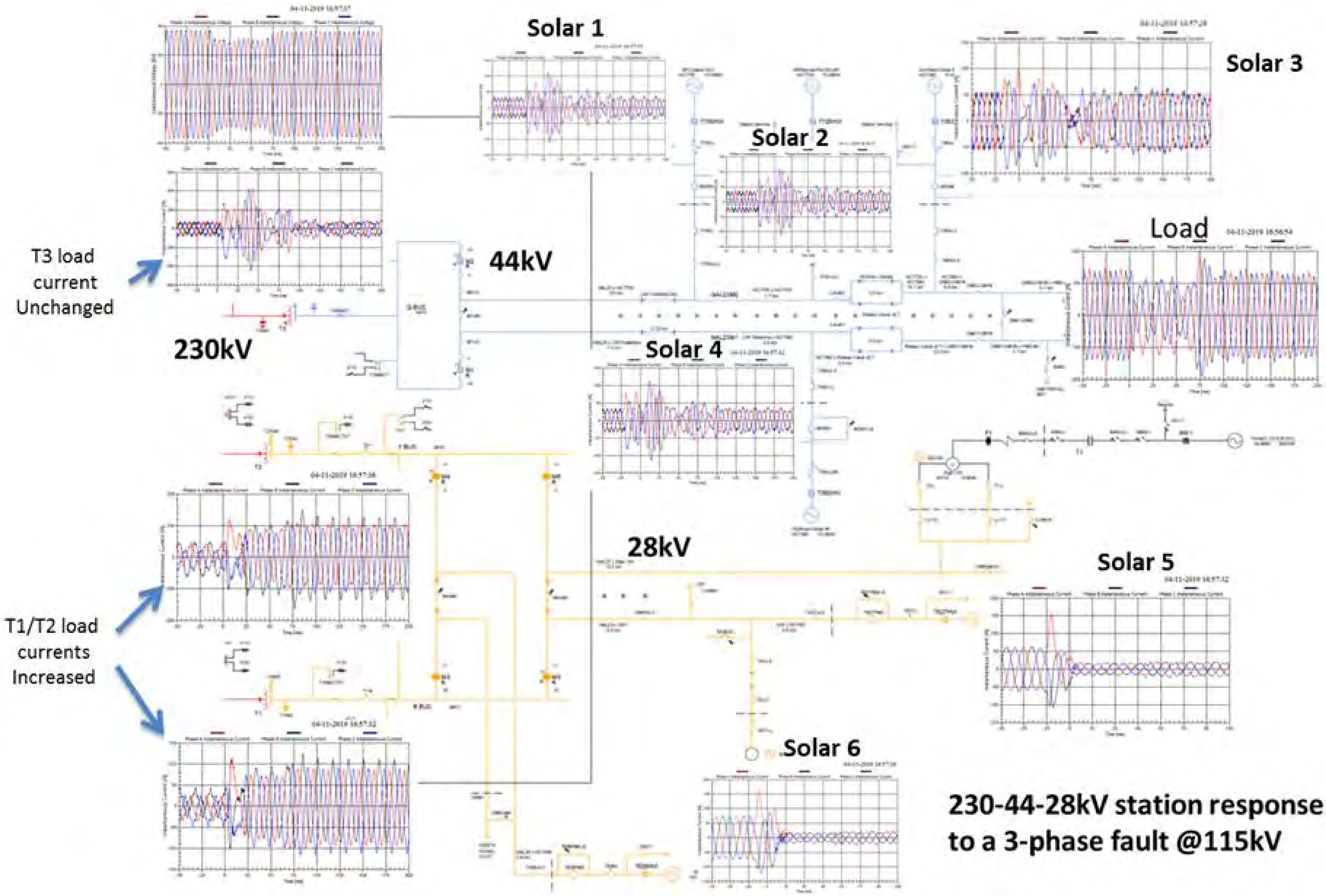

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899 **Figure 3.2: 230 – 44 -28 kV Substation Response to a 115 kV Three Phase Fault**

Dynamics of Aggregate DER Models

Similar to the process for individual DER models, the aggregation of R-DER and U-DER models pose just a few more nuances in the procedure. As the framework shows, the U-DER inputs and the R-DER inputs 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 3.3** describes the overall dynamic representation of U-DER modeled DER and R-DER modeled DER with respect to the T-D interface, and Similar to **Table 3.2**, the same number of data points can help to verify the parameters in the DER model associated with the resource. However, a few additional points help with attributing the total aggregation towards each model as seen in **Table 3.3**.

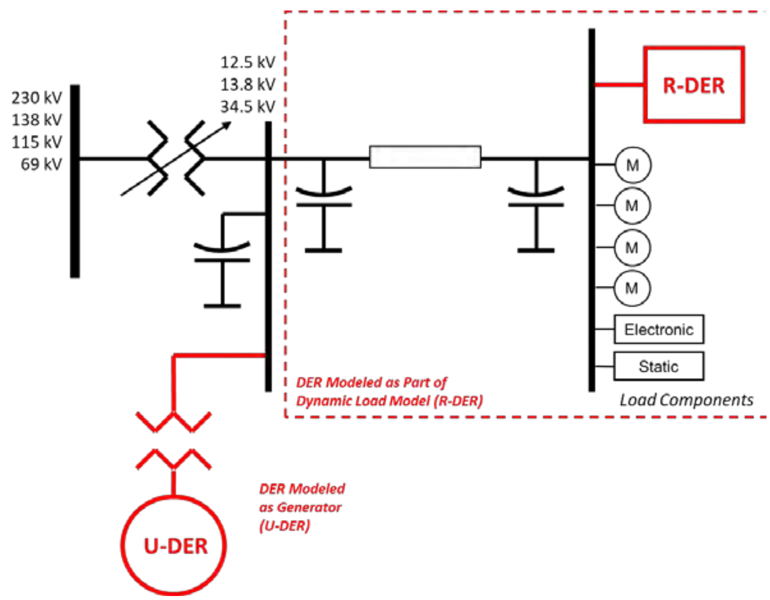

Figure 3.3: Aggregate DER Dynamic Representation Topology Overview

Table 3.3: 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 R-DER installation	Substation level to calculated mean	Resistive loss and Voltage Drop	Feeder, Voltage Drop / Rise Parameters.

Notes: * This question is useful for BESS DERs regardless of charging or discharging

Most notably, the last two rows of the table detail a way to help separate the R-DER and U-DER tripping parameters and voltage profiles seen at the terminals of the inverters. Should any of the above data be restricted or unavailable, following the engineering judgments in the *Reliability Guideline: DER_A Parameterization*[73] will assist in identifying

[73] https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability_Guideline_DER_A_Parameterization.pdf

the parameters to adjust based on inverter vintages. However, 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 referenced 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 latest available guidance on specific models should be used to identify the parameters to tune in the model.

Initial Mix of U-DER and R-DER

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-DER and R-DER 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 DER if tracking DER at all, it is expected that the initial verification of an aggregate U-DER and R-DER model to require more than simply the measurements at the location in order to attribute model changes. TPs and DPs are encouraged to coordinate to 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-DER may be different than R-DER. If such standards exist, the TP/PC should verify the mix of U-DER and R-DER are representative of the equipment standards pertaining to the type of DER.

Battery Energy Storage System Performance Characteristics

With regard to BESS, the performance of both aggregate U-DER and R-DER is doubly as complicated in the BESS plus U-DER example. As highlighted in that section, control mechanisms exist that could cloud and complicate the interaction of different DER types when utilizing a singular dynamic model, but could perform adequately for steady-state DER model verification. With respect to adding in modeled R-DER and assuming retail scale connected BESS devices, it becomes even trickier to understand. Including R-DER modeled BESS devices proves to mix not only between two different DER control schemes, but also with the load. Additionally, contracts with R-DER BESS can pose challenges to obtain parameters or measurements for use in dynamic model verification[74]. It then becomes harder to separate the response of load and DER as a charging BESS system can mask increased DER output for R-DER modeled devices, and the ride-through characteristics of the aggregate BESS DER and the aggregate R-DER modeled solar PV DER can be different. In turn, model verification can become computationally complex just to attribute the response to U-DER BESS, other U-DER, R-DER BESS, other R-DER, or load in the model. TPs and PCs are encouraged to utilize engineering judgement and to coordinate with the DP and other available resources to attribute the response characteristics of load, BESS, and other DER types when performing the model verification for situations like the above.

Parameter Sensitivity Analysis

As with most models, certain parameters in the DER_A model may impact the model output 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.[75] While TSA is commonly implemented differently across multiple organizations, certain software packages include a basic implementation. Among them are MATLAB Sensitivity Analysis Toolbox[76] and MATLAB Simulink. TSA analysis with respect to verifying DER_A dynamic model parameters can be found in Appendix A.

[74] As many of the dynamic parameters from OEMs are largely considered proprietary
[75] Hiskens, Ian A. and M. A. Pai. "Trajectory Sensitivity Analysis of Hybrid Systems." (2000).
[76] https://www.mathworks.com/help/sldo/sensitivity-analysis.html

TSA is one of many methods for TPs and PCs to gain understanding of the sensitivity of the dynamic model to small changes in model parameters; however, this is not a required step in model verification nor a required activity for tuning dynamic models. Further, 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 important 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.

Summary of DER Model Verification

Some of the general characteristics of performing DER model verification are re-emphasized here. With the purpose of taking a correctly parameterized model, the following few things are important to consider:

- Location of Voltage, Frequency, Power, or other quantity with respect to the electrical terminals of the DER devices
- Relationship of the DER devices with respect to end use demand as well as other DER devices in the aggregation[77]
- Accurate and robust metering equipment on the high or low side of the T-D transformer as well as equipment near the large DER terminals

With those three bullets in mind, TPs and PCs are encouraged to begin utilizing measurements for steady-state or dynamic model verification of DER. Since all DER generators can be tested,[78] the DER models will likely be tuned over time to represent the growth of DER in a specific area. 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[79]
- Electrical changes between verified model and study model[80]
- Sensitivity considerations on the study[81]

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.

[77] This is particularly true of BESS DERs

[78] Nor should they be absent a technical analysis and justification

[79] Irradiance and other meteorological quantities are affected by time and some DER types are dependent upon this weather data

[80] For example, distribution system reconfiguration due to lost transformer affected the verified model, but study model has normal configuration

[81] For example, if studying cloud cover over a wide area, Solar PV DER will affected and should be adjusted accordingly

Appendix A: 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 A.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% and the event simulated was a three phase 500 kV fault on the line between buses 201-202. Parameters of the DER_A model not listed in **Table A.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 section of the dynamic performance that is needing to adjust (i.e. before, during, or after the fault) in the verification process and that the parameter under adjustment makes sense to adjust. To help illustrate this, take the Trv example in **Figure A.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 A.2** to Figure A.4, respectively.

Table A.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	High	Maximum power limit
Imax	1.2	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	1.2	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	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

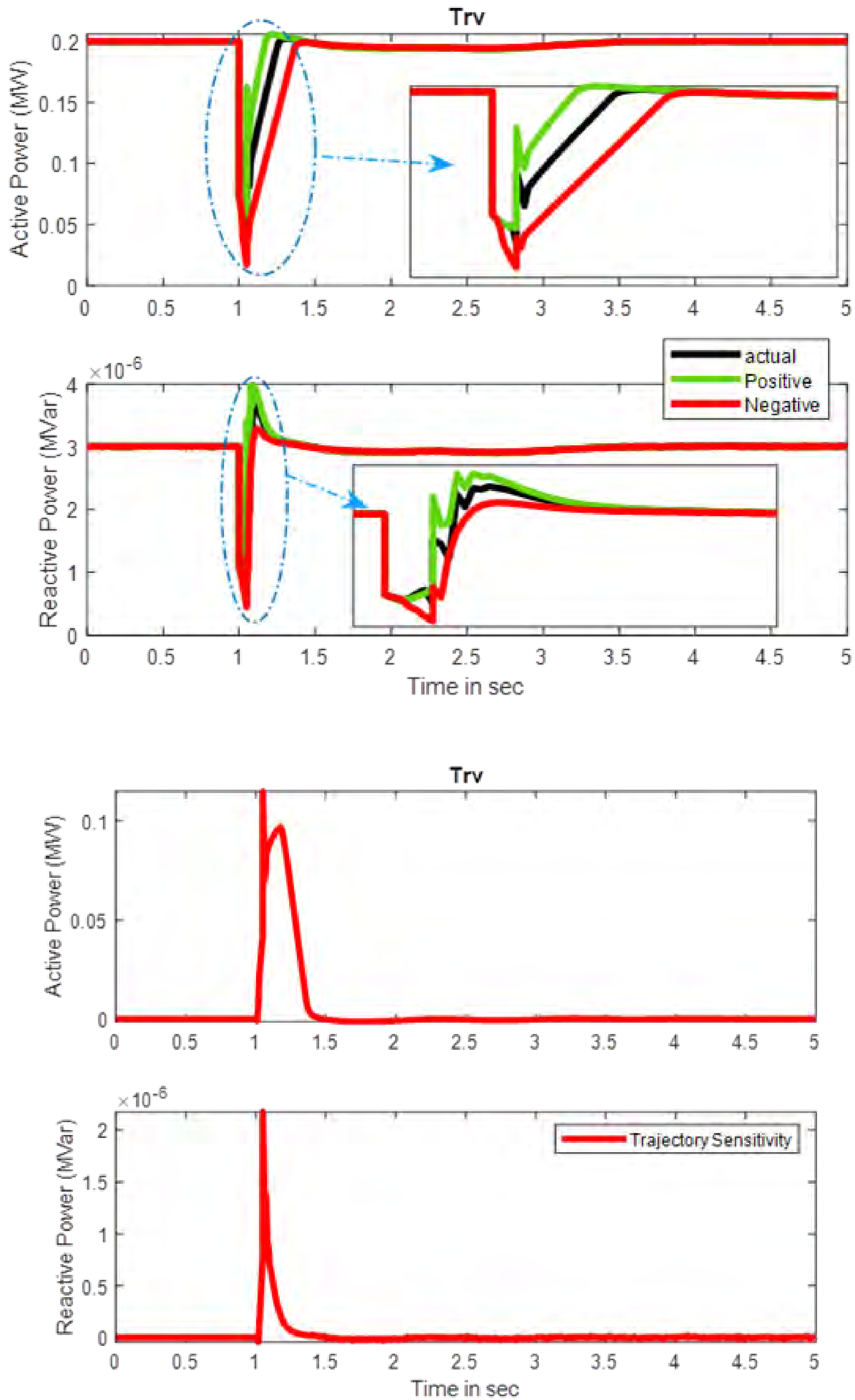

Figure A.1: Simulation Output and the Resulting TSA Calculation on Trv[82].

[82] 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 you increase 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.

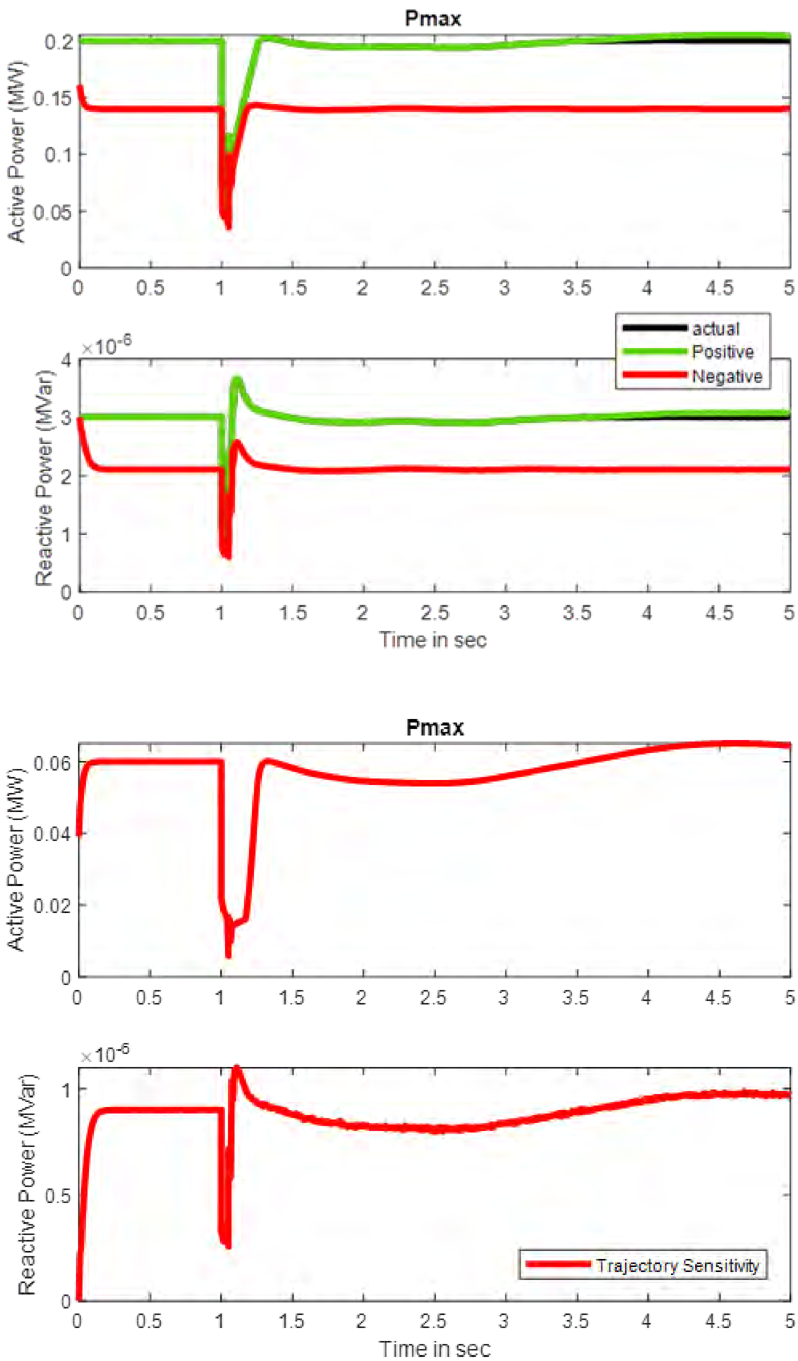

Figure A.2: Simulation Output and the Resulting TSA Calculation on Pmax.

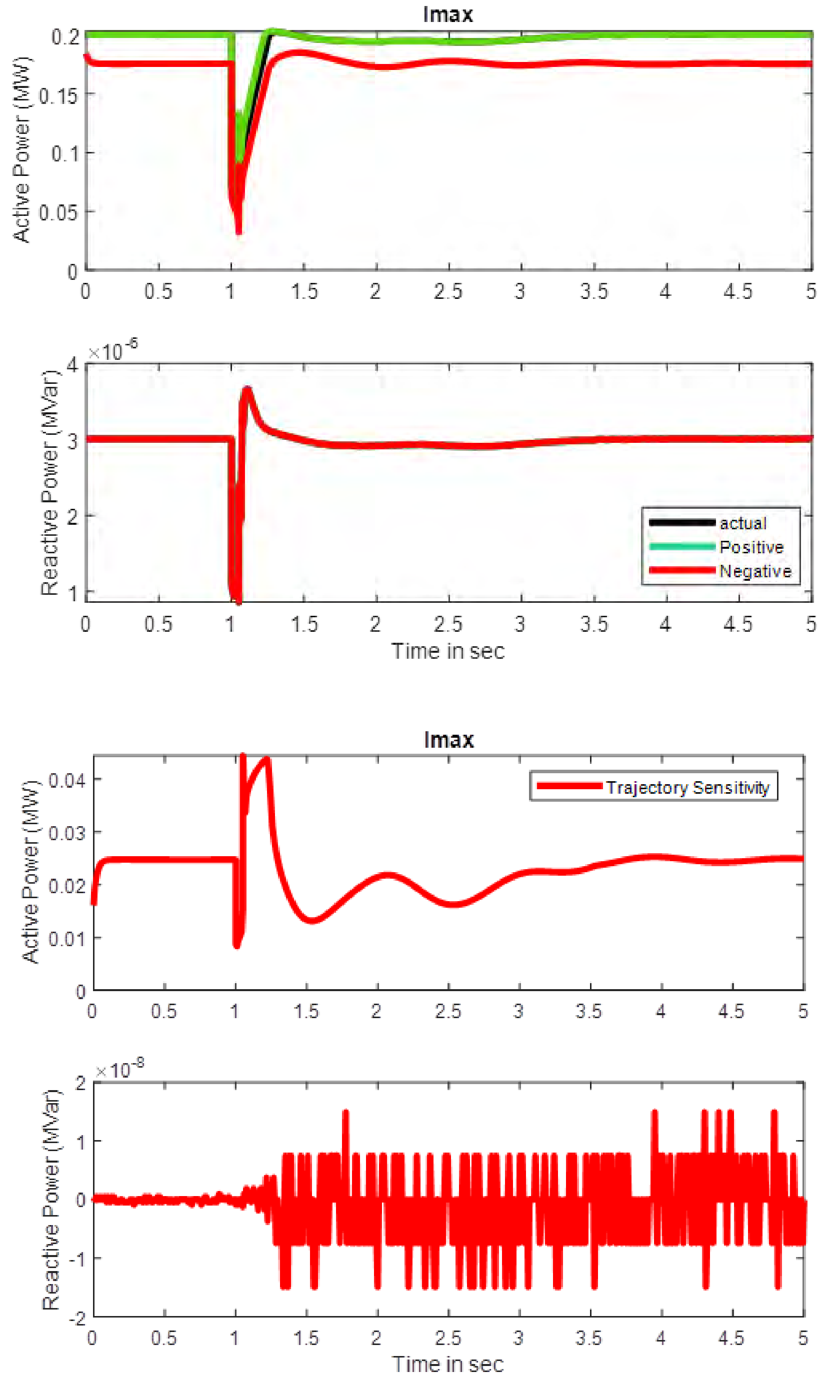

Figure A.3: Simulation Output and the Resulting TSA Calculation on Imax

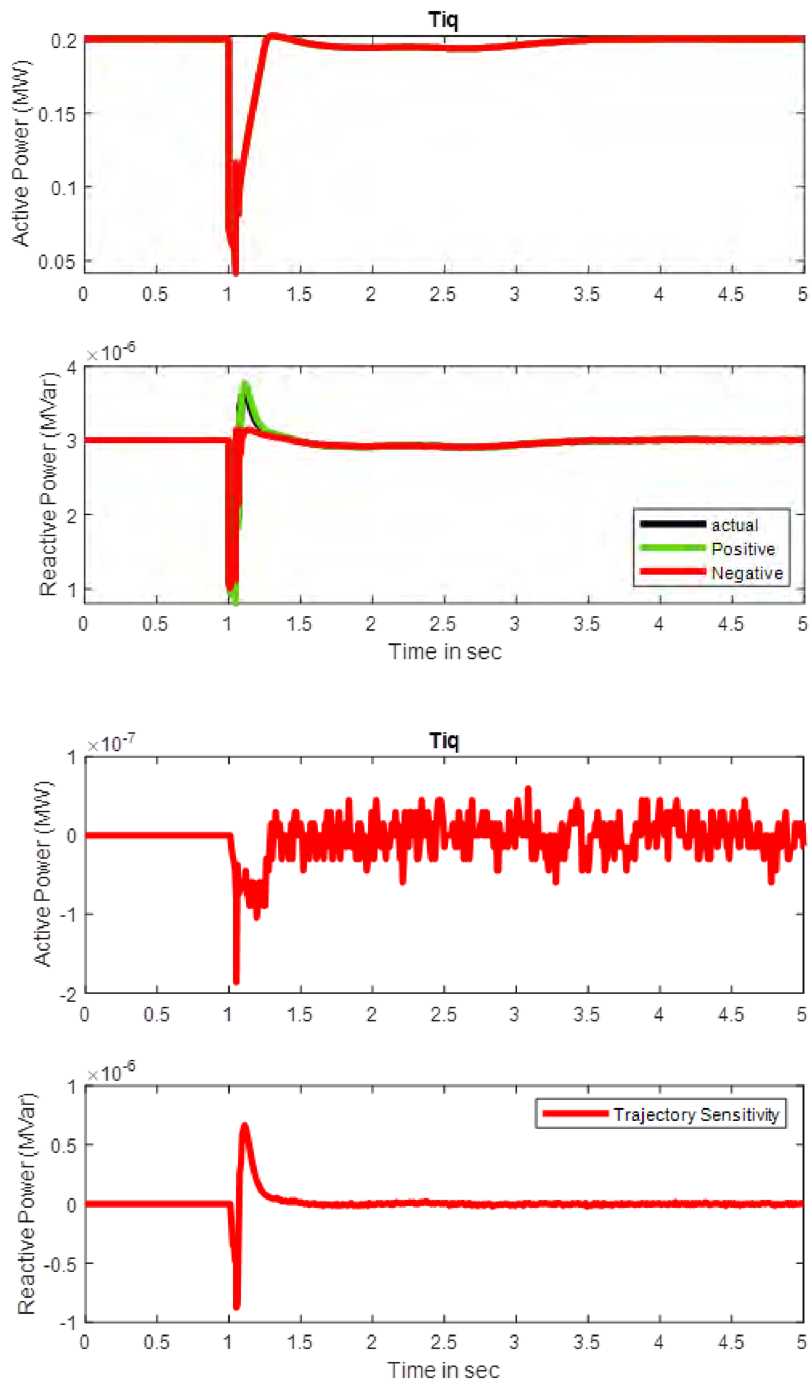

Figure A.4: Simulation Output and the Resulting TSA Calculation on Tiq.

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 (e.g., PfFlag, FreqFlag, PQFlag, GenFlag, VtripFlag and FtripFlag). **Figure A.5** shows where these flags are located with respect to the DER_A dynamic model.

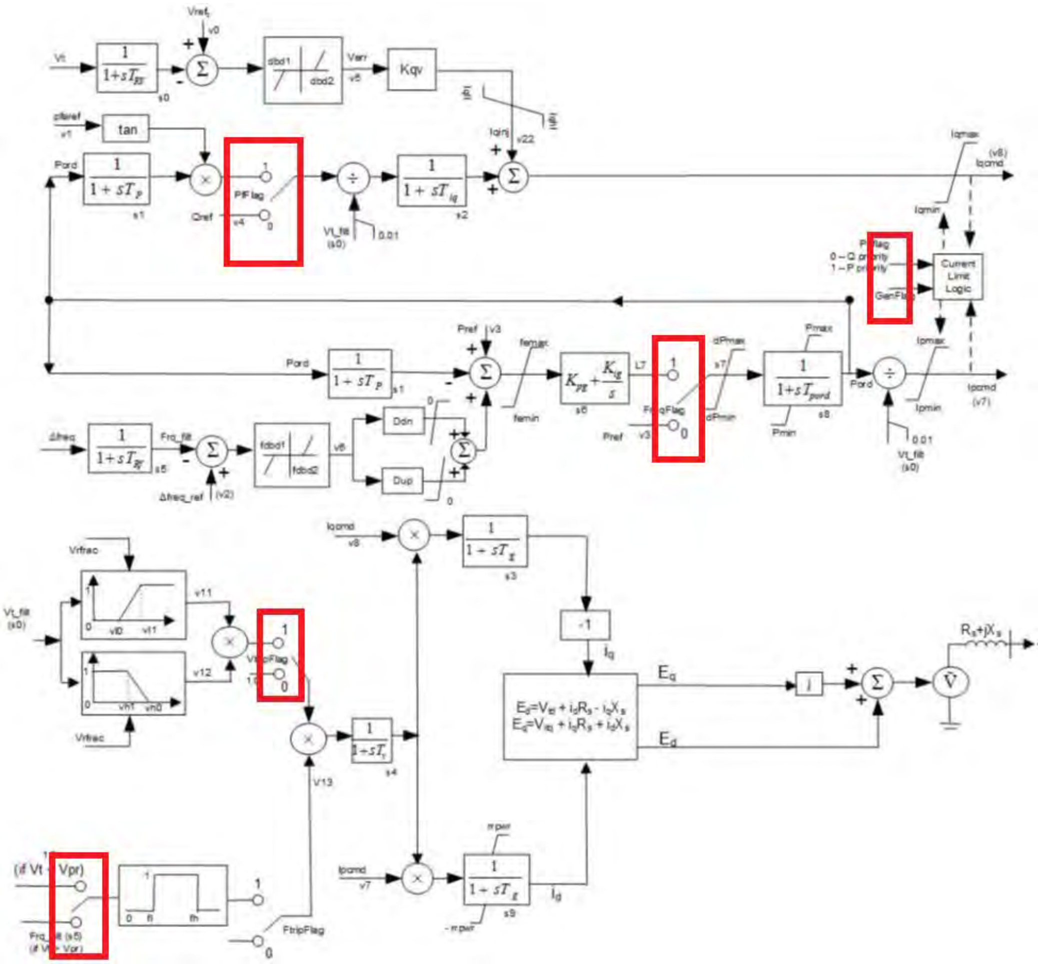

Figure A.5: DER_A Control Block Diagram in PSS®E [Source: Siemens PTI][83]

[83] PSSE model Documentation

Appendix B: 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 B.1**, a Synchronous Machine Infinite Bus (SMIB) 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, modeled as a jumper.

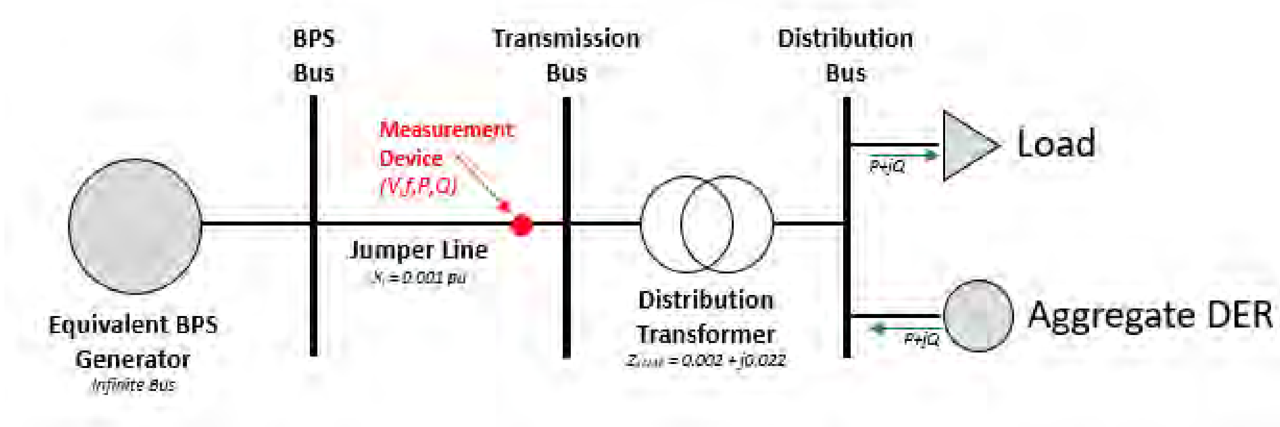

Figure B.1: Simulation SMIB Representation for High Level Aggregate U-DER

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 XFMR 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 B.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 B.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 areseparate from the load response and are fully attributed to the DER. The list of parameters that were provided in the original model were is found in **Figure B.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 B.1**.

In this example, the following models[84] 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 B.1**.

- 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

[84] 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 B.2: Starting Set of Dynamic Parameters

Model Comparison to Event Measurements

The event that was chosen to verify these set of models was a fault that occurred 50 miles away from the measurement location, and such fault caused a synchronous generator to trip offline. The measurements shown here are simulation outputs from a different set of parameters and are assumed to be the reference MW and MVAR measurement for verification purposes. For the purposes of illustration, the event is assumed to be a balanced fault[85]. The event is detailed in the first set of graphs in **Figure B.3**. The active power and reactive power measurements are taken at the high side of the T-D transformer corresponding to **Figure B.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 B.4**, and demonstrate two separate distinctions in the process. Firstly, that the load model responds similarly between the measurement values and the reported model. Secondly, that the changes and adjustments to the DER model do not impact the response in a way that would misalign the model with the measurements.

85 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.

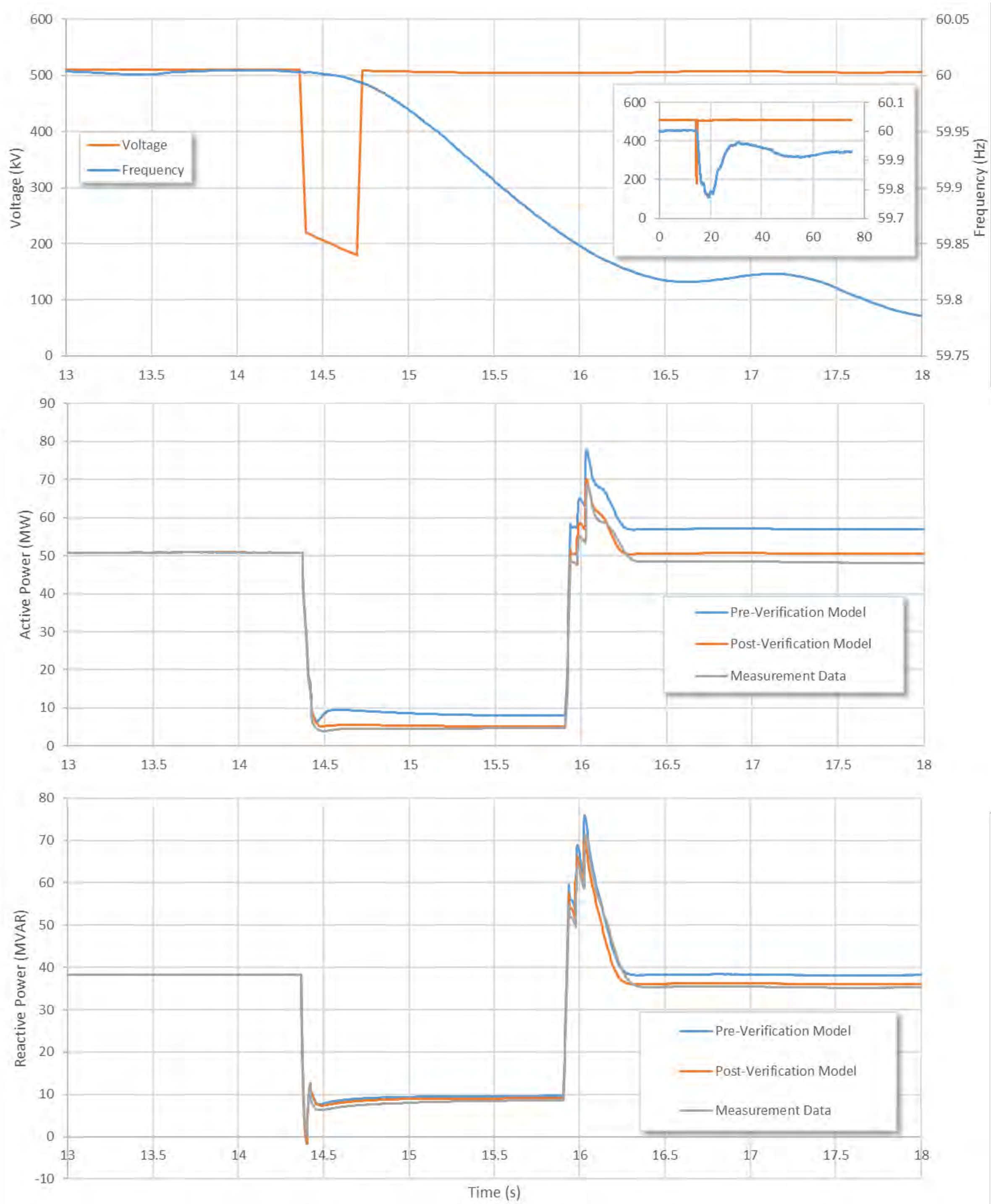

Figure B.3: Voltage, Frequency, Active, and Reactive Power Measurements

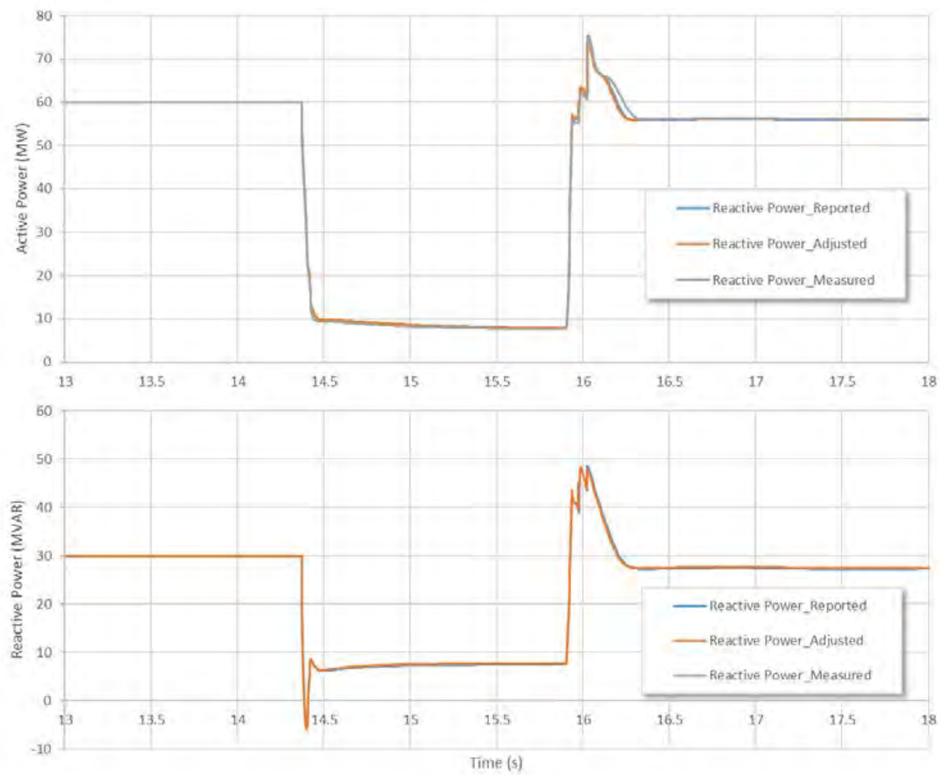

Figure B.4: Active and Reactive Power of Load Model

After demonstrating that the two active power measurements across the transformer were not equivalent, namely that the model had more active power flowing from the system into the distribution bank post disturbance as opposed to the measurements, which actually show a drop in the flow across the transformer after the disturbance. During the fault, very similar characteristics between the model and the measured power across the T-D transformer during the disturbance yet differed primarily in the post-disturbance recovery. Based on how it seems the low voltage ride through settings seem to be too restrictive in the model, the parameters were adjusted as detailed in **Table B.2**.

Table B.2: DER Parameter Changes		
Parameter Name	**Pre-Verification Value**	**Post-Verification Value**
Vrfrac	0	0.2
Vfth	0.8	0.4
Vl0	0.44	0.35
Tvl0	0.16	0.75
Tvh0	0.16	0.75

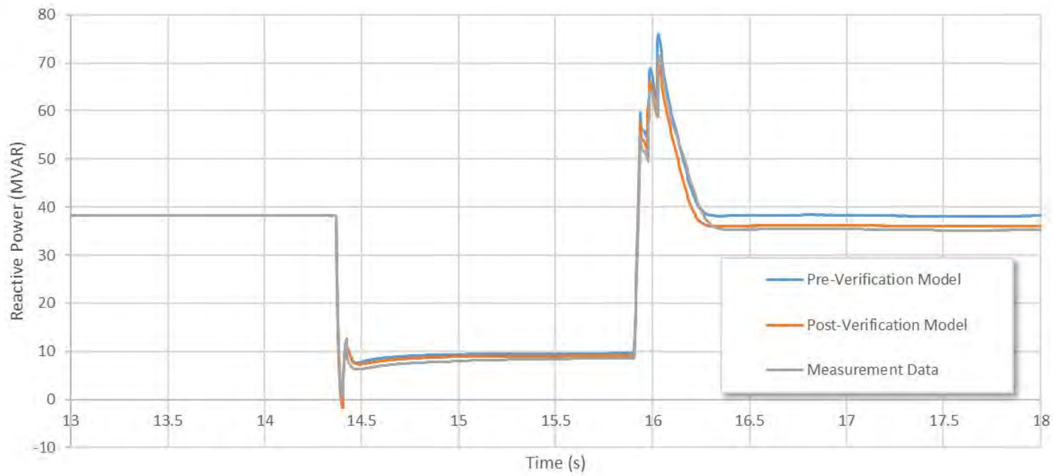

Figure B.5: Active Power of Model versus Measurements after Parameter Adjustment

After the adjustments were made in **Table B.2** and simulating the model response, the active power is looked at closely, reproduced in **Figure B.5**, to determine the effect of the changes. Based on the closeness of fit, the verification process ends and the model is now verified against this particular event's performance. If the TP/PC determines that this verification closeness of fit 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 C: Data Collection Example

Specific types of BPS events have demonstrated a characteristic response in load meters, which has been attributed to DER response;[86] 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 C.1**, which shows an example of U-DERs responding to a 500kV single-line-to-ground fault in Ontario. More than 30 DER meters recorded interruptions upon the fault and **Figure C.1** highlights seven locations as far as 300km from the fault location (voltage and current waveforms side by side, with nameplate MW indicated). The DERs were all installed under the IEEE 1547-2003; therefore, most of them tripped offline 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 PoC.

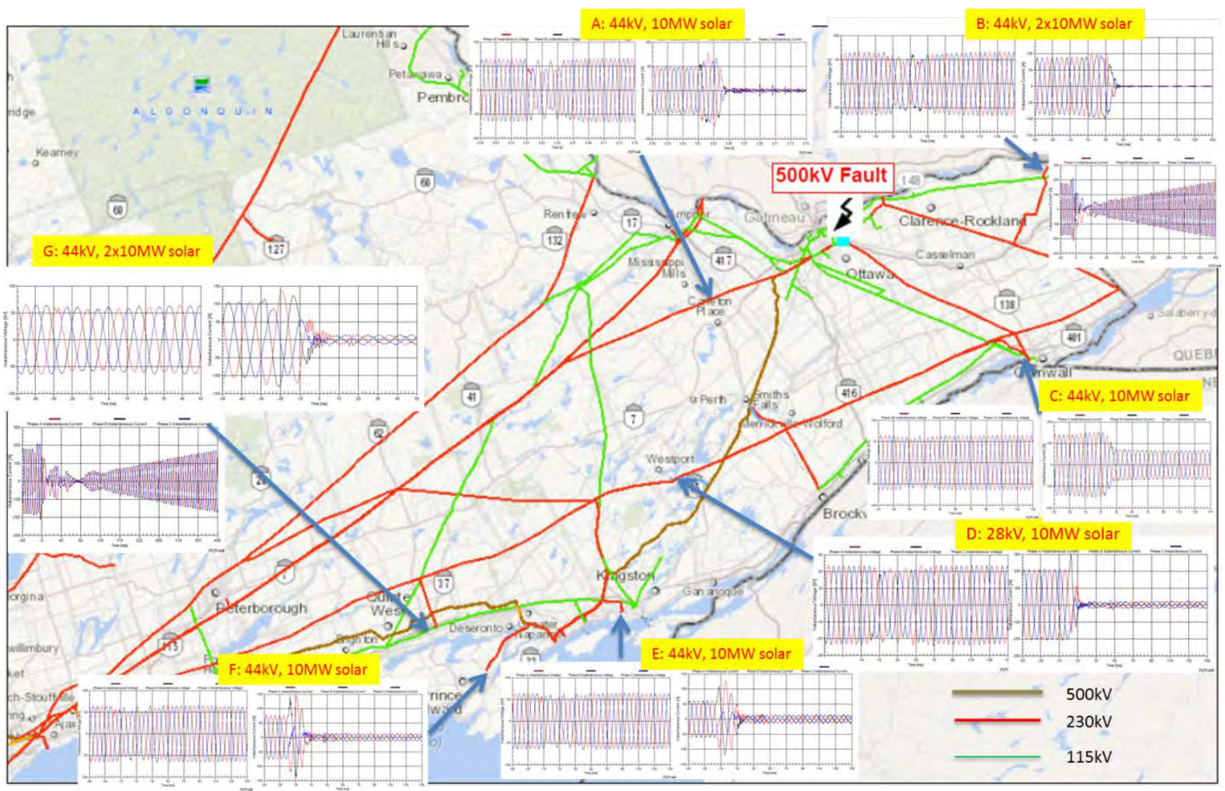

Figure C.1: Solar U-DER Voltage and Current Waveforms for a 500kV Fault

TPs can further verify the tripped loss of DER by using aggregated measurements from revenue meters at substation. **Figure C.2** plots current waveforms from one out of two paralleled 230/44kV step-down transformers at Site B where multiple solar generators are connected through the substation to 44kV feeders. The fault started near 0.0s in **Figure**

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86 https://www.nerc.com/pa/rrm/ea/April_May_2018_Fault_Induced_Solar_PV_Resource_Int/April_May_2018_Solar_PV_Disturbance_Report.pdf

C.2 and was cleared after three cycles (0.05 seconds). Increased net load current through the transformer can be seen after the fault clearing, which suggests most solar DERs could not recover immediately after fault clearing.

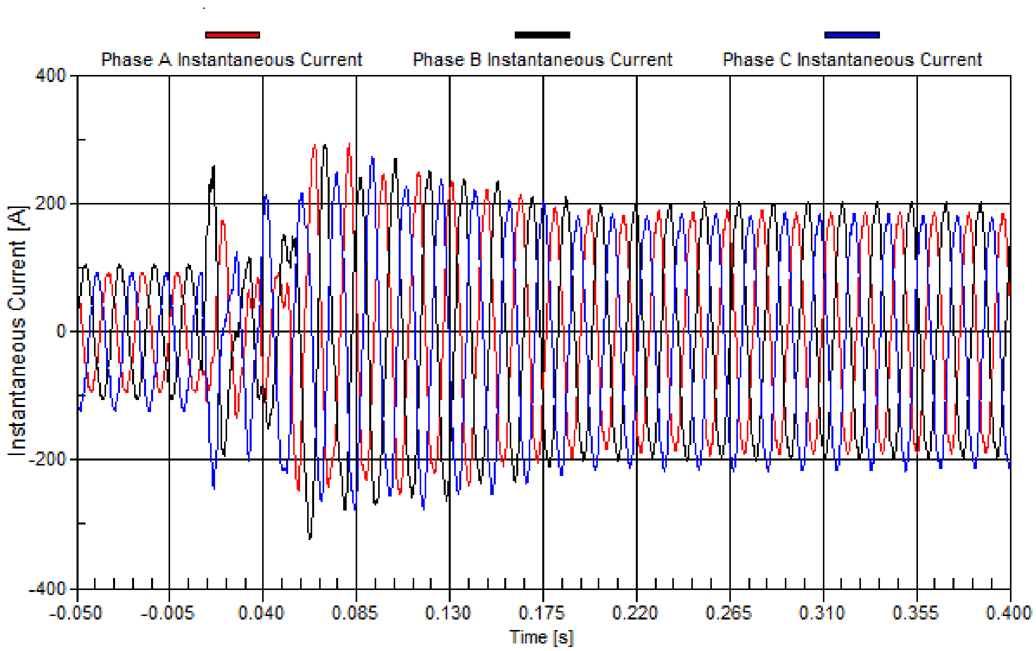

Figure C.2: Current waveforms from 230/44kV transformer at Site B

DER operating logs show various reasons that may initiate DERs 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 decisions of tripping offline were delayed.

Figure C.3 compares performances of two 44kV solar plants under a common 500kV single-line-to-ground fault. The two plants connect to the same substation bus but have different control strategies. The inverter on left side (10MW nameplate) stopped operating under voltage sag by design. The one on right side (9MW nameplate), in contrast, was configured to inject reactive current under the same voltage sag. It can be verified from Figure C.3 that the current waveforms of the two plants were very similar between -25ms and 0ms. However, the controllers made different decisions based on the information from the 25ms: the first solar plant stopped generating at t=0ms while the second one continued current injection during the BPS fault and beyond, even though they were looking at almost identical voltages at the PoCs.

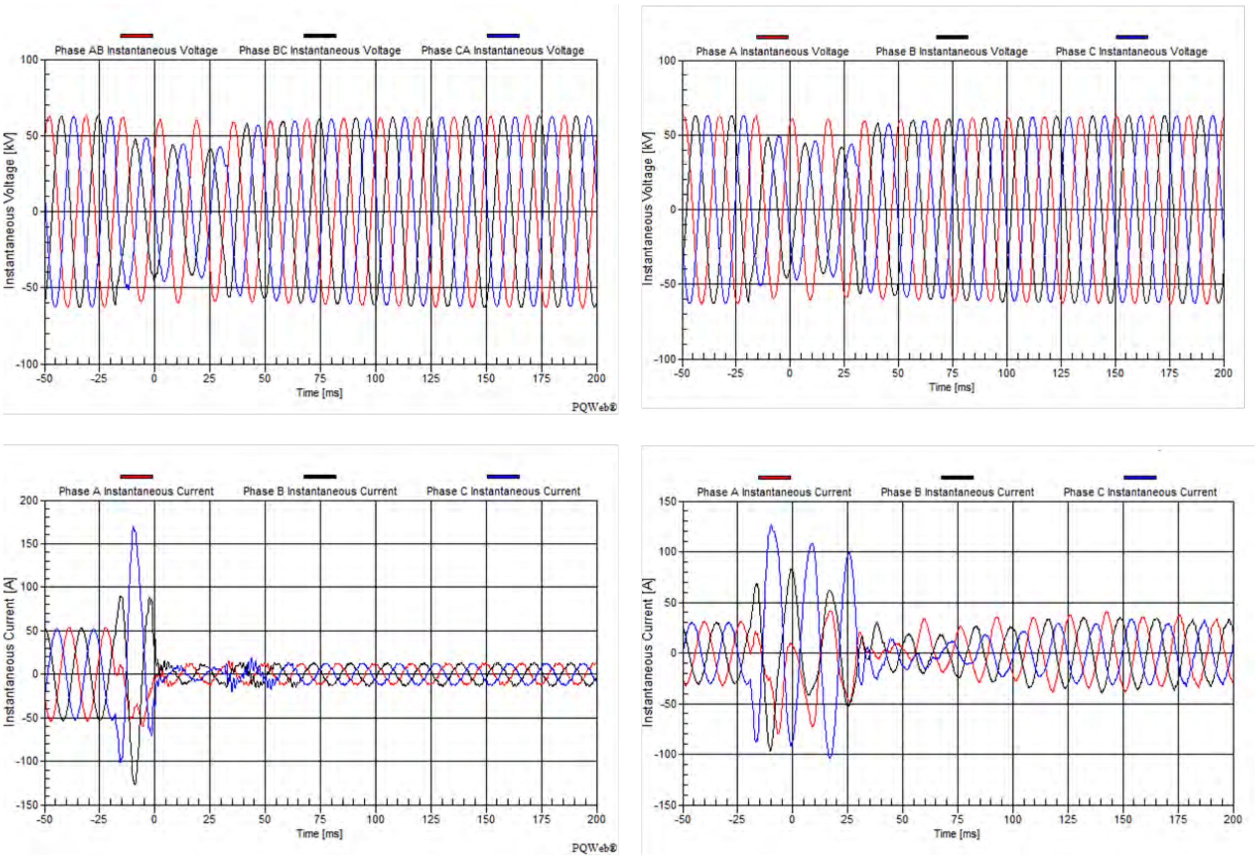

Figure C.3: Comparison of Two Adjacent Solar Plants' Responses to the Same 500kV Fault (top: voltage, bottom: current)

Installation data may suggest the overall majority of DERs are solar generators, but wind turbines 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 C.4** and **Figure C.5** show Type IV and Type III wind plants responses to a common 500kV bus fault, respectively. While the wind plants are connected at different locations and voltage levels (28kV vs. 44kV), both shut down under the BPS fault. **Figure C.6** shows load current increase measured from one out of two paralleled 115kV/44kV step-down transformers as a result of wind generation loss in the 44kV 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 issue is expected to diminish with the new 2018 standard revision, which requires at least 160ms time delay to accommodate transmission fault clearing.

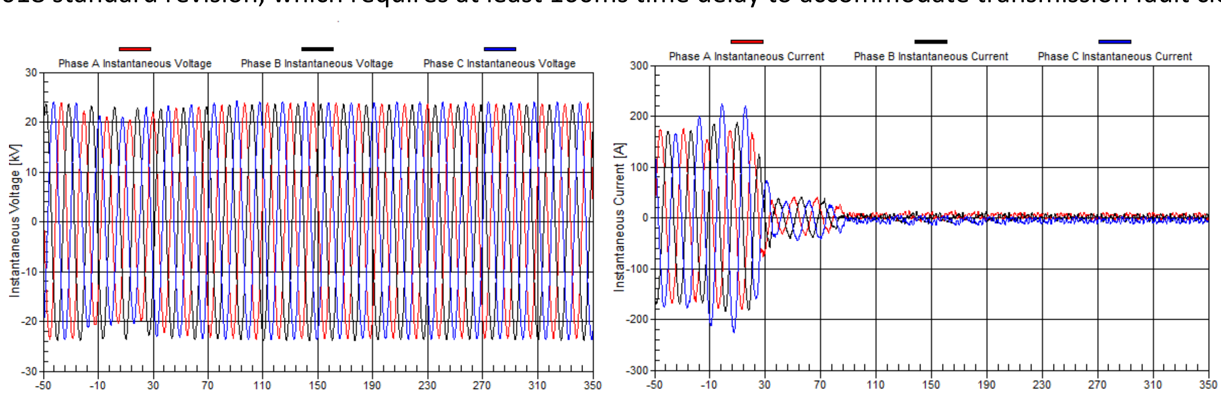

Figure C.4: Type IV Wind Plant (28kV/10MW) Response to 500kV Single-Line-to-Ground Fault

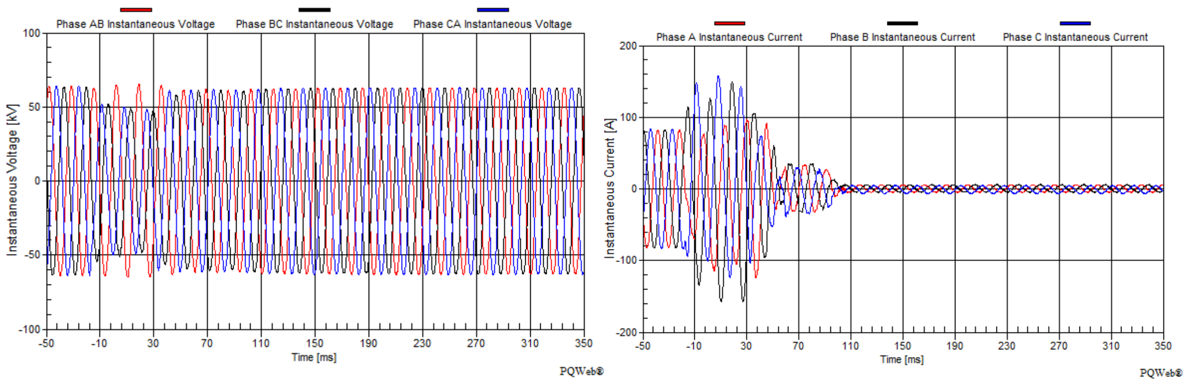

Figure C.5: Type III Wind Plant (44 kV/10 MW) Response to 500kV Single-Line-to-Ground Fault

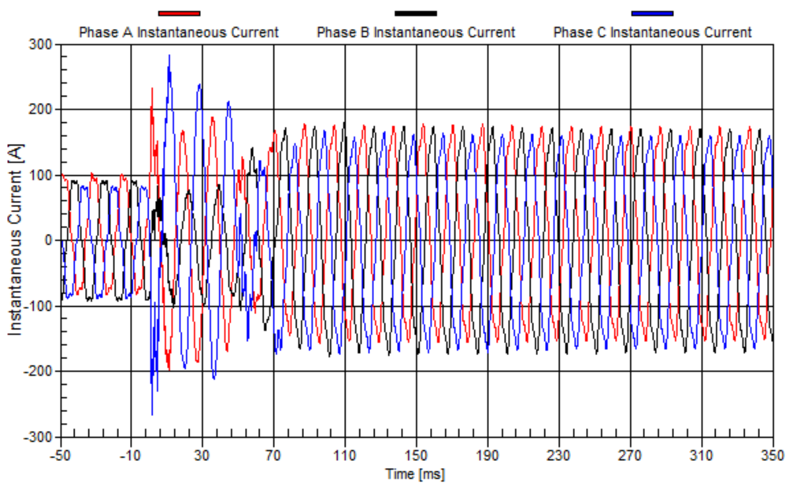

Figure C.6: Load Current Increase at a 115 kV/44 kV Transformer after Loss of Wind Generation

April-May 2018 Disturbances Findings

In the Angeles Forest and Palmdale Roost disturbances, a noticeable amount of net load increase was observed at the time of the disturbances.[87] DERs were verified to be involved in the disturbance using a residential rooftop solar PV unit captured in the Southern California Edison (SCE) 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 behind-the-meter solar PV DERs; however, the availability, resolution, and accuracy of this information was fairly limited at the time of the event analysis. **Figure C.7** shows the CAISO net load for both disturbances. It is challenging to identify exactly[88] the amount of DERs that either momentarily ceased current injection or tripped offline using BA-level net load quantities. Note that these measurements were taken at a system-wide level and represent many T-D interfaces, while the above IESO example is for specific T-D interfaces.

[87] https://www.nerc.com/pa/rrm/ea/Pages/April-May-2018-Fault-Induced-Solar-PV-Resource-Interruption-Disturbances-Report.aspx

[88] 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.

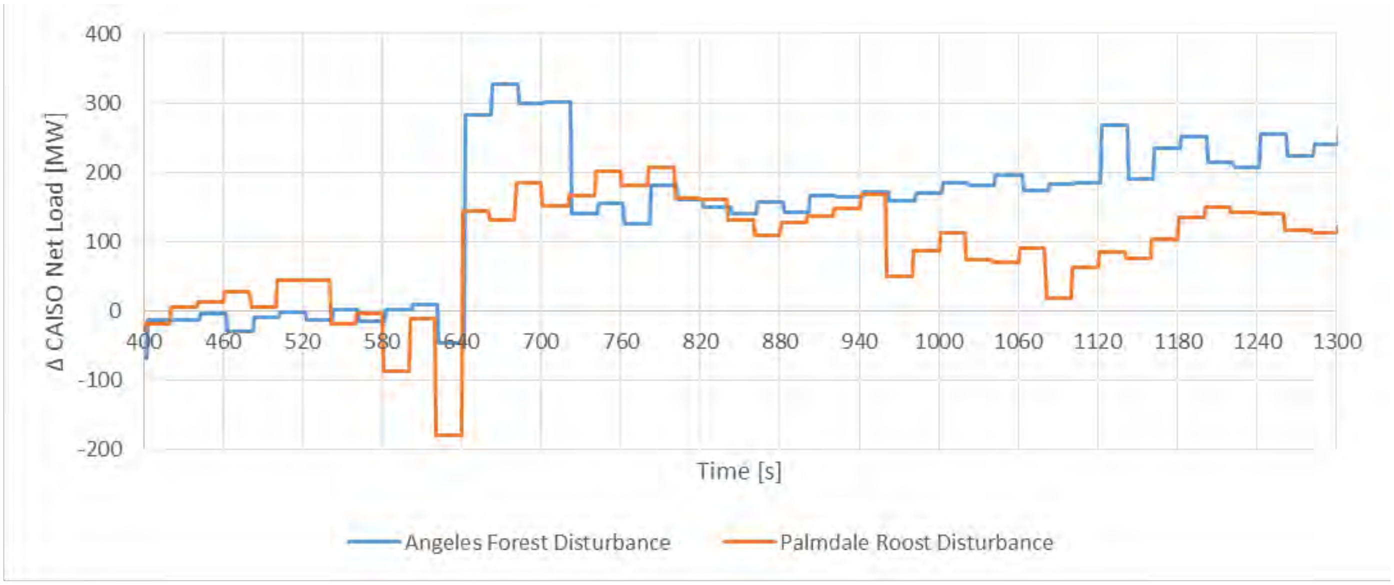

Figure C.7: CAISO Net Load during Angeles Forest and Palmdale Roost Disturbance [Source: CAISO]

SCE also gathered net load data for these disturbances (shown in **Figure C.8**). While an initial spike in net load is 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[89] solar PV in their footprint. However, it does account for the unmetered DERs that are mostly composed of Behind the Meter (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.[90] Therefore, the SCADA point does not differentiate between changes in net load and changes in losses.
- Typically for energy management systems (EMSs), the remote terminal units (RTUs) reporting 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 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 the reasons described above, the spikes in net load were accounted for as calculation errors and 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 when using area-wide net load SCADA points[91]. TPs and PCs, when gathering data for use in verification of DER models, should consider the bullets above when using SCADA or other EMSs when utilizing these points for verification of DER models, especially when utilizing system-wide measurements.

[89] Generally, generation greater than 1 MW is metered by SCE on the distribution, subtransmission, and transmission system.

[90] Net Load + Losses = Metered Generation + Intertie Imports

[91] For that matter, SCADA scans are not recommended to determine the total tripping of any IBR resource, including DERs that are IBRs.

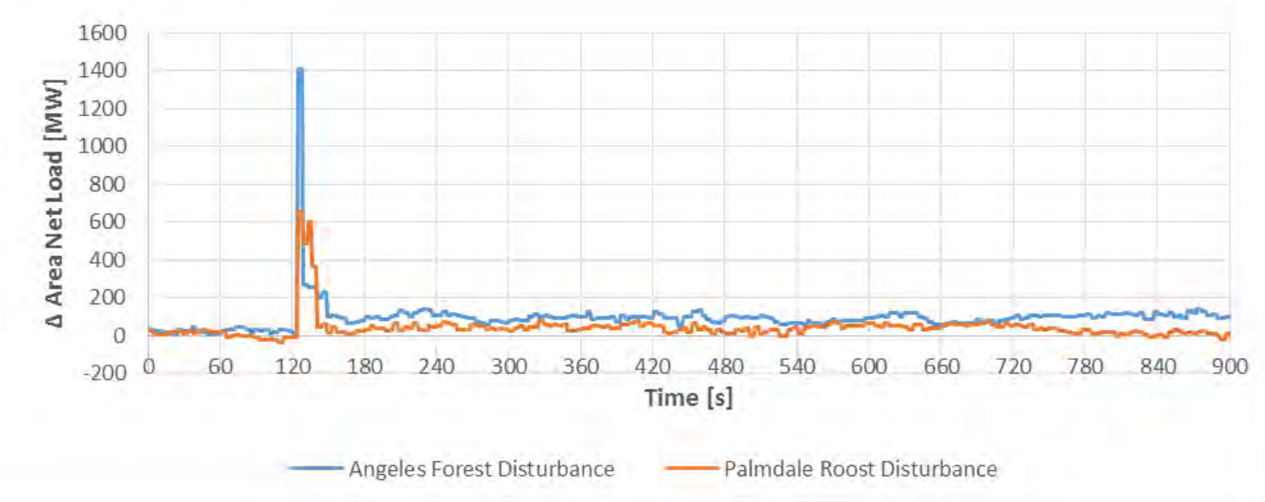

Figure C.8: SCE Area Net Load Response [Source: SCE]

It was determined that monitoring the T-D transformer bank flows using 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 above. Figure C.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.[92] After that time, the net loading returned back 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 data collection for DER and how to identify or attribute responses in already collected data, especially for higher impact T-D interfaces.

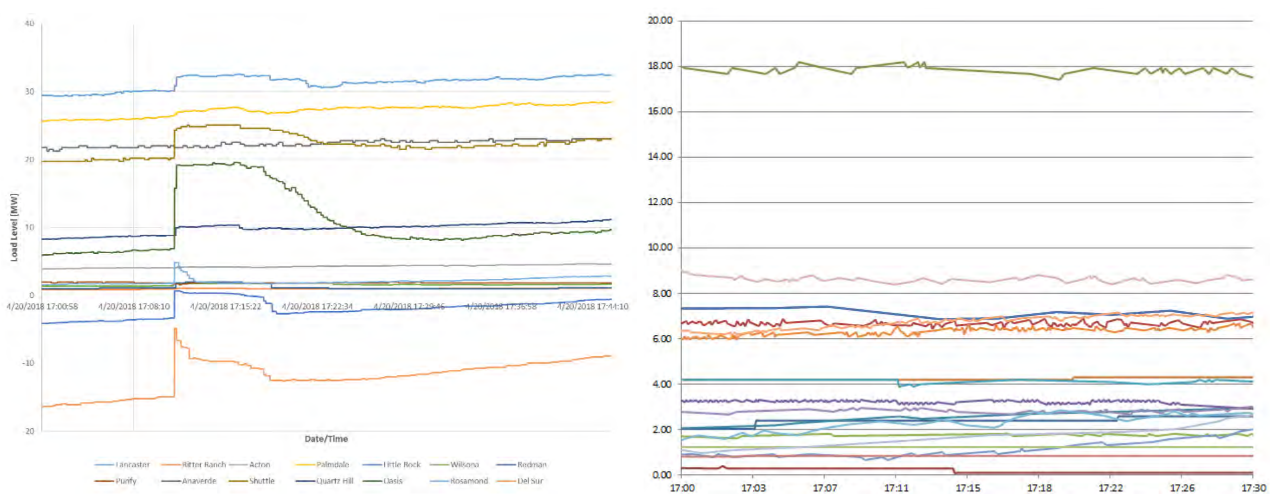

Figure C.9: SCE (left) and PG&E (right) Individual Load SCADA Points

[92] 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.

Contributors

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NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Reliability Guideline

Model Verification of Aggregate DER Models used in Planning Studies

~~November~~ March 2021~~0~~

RELIABILITY | RESILIENCE | SECURITY

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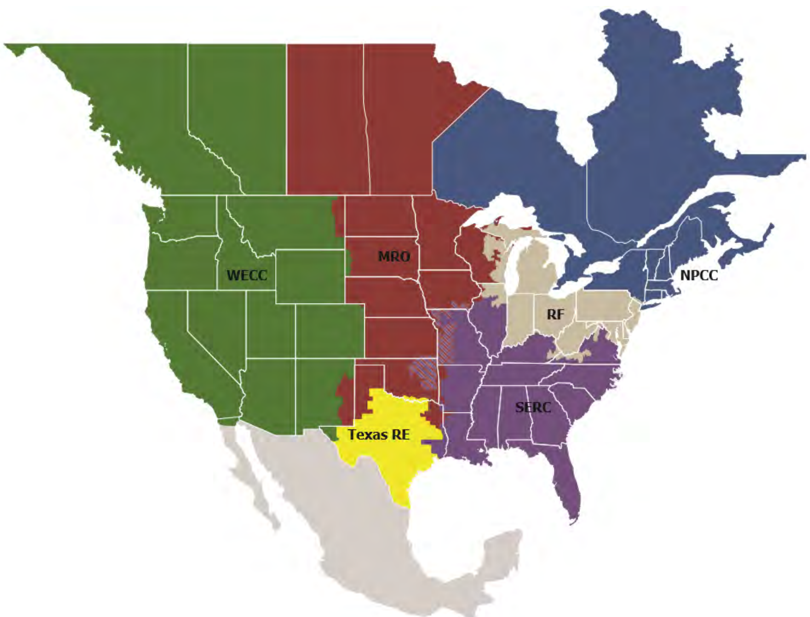
Preface

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

Reliability | Resilience | Security

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

The North American BPS is divided into six RE boundaries as shown in the map and corresponding table below. The multicolored area denotes overlap as some load-serving entities participate in one RE 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

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

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

Preamble

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

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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.

- No additional metrics

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Executive Summary

With the rapid growth of distributed energy resources (DERs) across many areas of North America, and new power flow and dynamic modeling practices being developed to accommodate these resources into the ~~planning~~ BPS planning ~~process~~assessments,~~[1]~~ focus turns to ensuring that the models used to represent aggregations of DERs are verified to some degree. Previous SPIDERWG guidance[2] provides recommended practices for DER modeling. DER models[3] ~~used in BPS planning assessments~~ are used to represent the impact of the DER as it impacts the Transmission-Distribution interface in BPS planning assessments. ~~either large utility-scale DERs (U-DERs) individually or aggregate amounts of many retail-scale DERs (R-DERs).[4]~~ 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 Transmission Planners (TPs) and Planning Coordinators (PCs) to effectively perform an appropriate level of model verification to ensure that ~~transmission~~ planning assessments are capturing the key impacts that ~~aggregate amounts of~~ DERs can have on BPS reliability.

This guideline provides Transmission Planners (TPs)~~0~~ and Planning Coordinators (PCs) with tools and techniques that can be adapted for their specific systems to verify that the aggregate DER models created are a suitable representation of these resources in planning assessments. 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. PCs and TPs may typically obtain DER information for facilities five MW and above through Small Generator Interconnection Procedures (SGIPs). For facilities connected to distribution systems, the only NERC registered entity that can provide the data is the Distribution Provider. Measurements of DERs (individual or aggregate) are currently sparse, and this guideline recommends practices for ensuring adequate data are collected for larger utility-scale DERs as well as capturing the general behavior of aggregated retail-scale distributed resources. This guideline discusses when model verification is triggered, as well as how to understand the mix of different DER characteristics. This guideline 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 Transmission Owners (TOs) TPs, PCs, and Distribution Providers (DPs) understand the types of data needed for analyzing DER performance for these 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.[5]

Key Findings

During the development of this guideline, the NERC System Planning Impacts from DERs Working Group (SPIDERWG) identified the following key findings:

- **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[6].

~~1 https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability_Guideline_DER_A_Parameterization.pdf~~

2 https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability_Guideline_DER_A_Parameterization.pdf and https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability_Guideline_DER_Data_Collection_for_Modeling.pdf

3 In the modeling guidance developed by NERC SPIDERWG, two types of DERs are distinguished by utility-scale DERs (U-DERs) or retail-scale DERs (R-DERs) for the purposes of modeling.

~~4 In the modeling guidance developed by NERC SPIDERWG, these types of DERs are referred to as utility-scale DERs (U-DERs) and retail-scale DERs (R-DERs) for the purposes of modeling.~~

5 https://www.ofgem.gov.uk/publications-and-updates/ofgem-has-published-national-grid-electricity-system-operator-s-technical-report

6 For more discussion on placement of measurement devices, see Chapter 1.

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- **Aggregation of U-DER and R-DER Behavior:** Verification of aggregate DER models becomes more complex when both U-DER and R-DER 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 vary between steady-state and dynamic model verification; however, both steps are critical to developing a useful aggregate DER model. DER verification practices should ensure that both steady-state and dynamic modeling are supported.
- **Event Selection:** A relatively large disturbance on the BPS (e.g., 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, as and when more events happen and the measurement data becomes available the verified models should be checked to ensure that they indeed can replicate the other events that have happened in the system.
- **Concept of Verified Models:** Developing an aggregate DER model is not equivalent to having a verified model[7]. 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. Whereas, 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.[8]

Recommendations

From the key findings listed above, the following recommendations are intended to help guide TPs and PCs in performing aggregate DER model verification in their planning studies:

- TPs, TOs, and ~~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~~. The expected data, as outlined in this guidance, is not necessarily more refined than any recommended data required for BPS-connected resources[9]~~.
- TPs, PCs, TOs, and other applicable entities that may ~~govern DER interconnection requirements~~ 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 the purposes of DER modeling and model verification, and jointly develop requirements or practices that will ensure this data is available. As the availability of the TPs, PCs and TOs to have this data is dependent on the DP to have the data made available, this will likely require actions from state regulatory bodies[10] 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~~other~~ DER models[11], rather than the existing DER models ~~current models~~, can be verified with additional data should a more accurate representation be required.

[7] This is true for all sets of models, and is not exclusive to aggregate DER models.
[8] 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).
[9] 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.
[10] SPIDERWG has published guidance on this. Found here
[11] E.g. Root-Mean-Squared (RMS) three-phase models.

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- 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.

- TPs and PCs should coordinate with their TOs, TOPs, and DPs to gather measurement data to verify the general behavior of aggregate DER[12]. 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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[12] SPIDERWG is actively developing guidance on how this coordination should take place to ensure reliability of the BPS.

Introduction

Many areas across the BPS in North America are experiencing an increase in the penetration of DERs, and TPs and PCs are adapting their long-term transmission planning practices to accommodate these relatively new resources into their reliability studies. Aggregate amounts of DERs should be modeled and reflected up to the BPS level when performing these studies. BPS fault events in 2018[13] highlighted the growth of DERs in California and the potential impact these resources can have on BPS performance during grid disturbances. Rapidly growing penetrations of DERs across North America have sparked the need for modeling the aggregate behavior of DERs, and in some instances the individual behavior of larger U-DERs, to a suitable degree to incorporate into BPS planning studies, much like how TPs and PCs currently account for aggregated load. SPIDERWG has provided recommended practices for DER modeling.[14,15] These guidance materials provide TPs and PCs with recommendations for modeling aggregate amounts of DERs. 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. Verification of models is paramount to obtaining reasonable and representative study results. The goal is for TPs and PCs to gain more confidence in their aggregate DER models and utilize them for BPS planning studies.

There will inherently be lag between the time in which steady-state and dynamic models for DERs are created and when verification of these models using actual 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 behaviors of DERs. Explicit modeling of aggregate amounts of DERs is strongly recommended,[16] versus netting these resources with load, as the key functional behaviors are different.

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 seeks to comprehensively understand the disturbance and to identify the root cause of the event. The data needed to execute event analysis typically includes ~~as~~ 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. This document is intended to help TPs and PCs ensure DER model fidelity using data from actual system disturbances. Model verification's purpose is to add fidelity to models. While some recorders can be used in the same process as event analysis, the processes are quite different.

Recommended DER Modeling Framework

SPIDERWG recently published NERC *Reliability Guideline: Parameterization of the DER_A Model*, which describes recommended dynamic modeling practices for aggregate amounts of DERs. That guideline also builds on previous efforts within SPIDERWG and the NERC Load Modeling Task Force (LMTF) laying out a framework for recommended DER modeling in BPS planning studies. DER models are typically representative of either one or more larger U-DERs or aggregate amounts of smaller R-DERs spread across a distribution feeder[17]. The steady-state model for these

[13] https://www.nerc.com/pa/rrm/ea/April_May_2018_Fault_Induced_Solar_PV_Resource_Int/April_May_2018_Solar_PV_Disturbance_Report.pdf

[14] https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability_Guideline_DER_A_Parameterization.pdf

[15] https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability_Guideline_DER_Data_Collection_for_Modeling.pdf

[16] https://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/Distributed_Energy_Resources_Report.pdf

[17] References to U-DER and R-DER here are model related discussions. This designation should be only be used with respect to transferring the measurements taken from the DER into its model representation.

resources is placed at a single modeled distribution bus, with the T-D transformer modeled explicitly in most cases. The modeling framework is reproduced in **Figure I.1**. This guideline uses modeling concepts consistent with the recommended modeling framework previously published and used by industry on recommended DER model verification practices. Please refer to the aforementioned guidelines for more information.

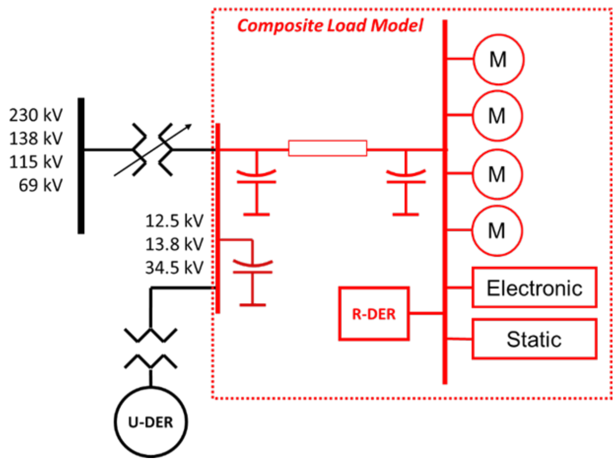

Figure I.1: DER_A Modeling Framework

Guide to Model Verification

Model verification first requires an adequate model be developed, and then for an entity to gather 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[18] 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[19]. Those model outputs and the measured outputs are compared and if there is a sufficient match based on the TP/PC procedures, the verification procedure stops. 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 B, which details an example using the playback models to verify a set of DER models. As some of the Interconnection-wide base cases predict a future condition for resources not yet built, measurement data is not available and the forecasted conditions[20]. 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.

[18] Generally, this is done by Reliability Coordinators (RCs), Transmission Operators (TOPs), and Transmission Owners (TOs); however, this can also be done by DPs in reference to monitoring equipment on their system

[19] 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 DER in other work products.

[20] SPIDERWG is developing separate guidance to verify aspects of these base cases.

Three Phase versus Positive Sequence Model Verification

The majority of planning studies performed by TPs and PCs use RMS[21] fundamental frequency, positive sequence simulation tools.[22] Hence, steady-state powerflow and dynamic simulations assume[23] a balanced three-phase network, which 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 three-phase RMS dynamic simulation, electromagnetic transient (EMT), or co-simulation . Those methods require more detailed modeling data and verification activities. However, DER model verification using those 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.

Data Collection for Model Verification of DERs

> **Key Takeaway:**
> The process of model verification requires two key aspects: a suitable model to be verified and measurement or other data that can be compared against model performance.

The process of model verification requires two key aspects: a suitable model to be verified and measurement or other data that can be compared against model performance. This guideline will cover the necessary data points for performing model verifications for developing an aggregate DER model. However, varying degrees of model verification can be performed for different levels of data available. While having all the necessary data available for model verification would be preferable, it is understood that this data may not be available and that monitoring capability may be limited in many areas today. Measurement data is a critical aspect of understanding the nature of DER and its impact on the BPS. Applicable entities that may govern DER interconnection requirements are encouraged to develop interconnection requirements for large-scale DERs that will enable data to be available for the purposes of developing accurate DER models moving forward. Further, monitoring equipment at the T-D interface would make available data to capture the aggregate behavior of DERs and ~~, which~~load. These measurements ~~can~~ support ~~both~~ DER model verification~~ and load model verification~~ process[24].

Considerations for Distributed Energy Storage

Recent discussions regarding the expected growth of energy storage, particularly battery energy storage systems (BESSs), relate to both BPS-connected and distribution-connected resources. This guideline focuses on the distributed BESSs where energy storage is concerned. Other documents coming from the NERC IRPTF are dealing with BPS-connected devices and their impact, which includes BPS-connected BESSs. 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.

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21 Root-mean-square

22 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.

23 This assumption is inherently built into the power flow and dynamic solutions used by the simulation tools.

24 Or, for that matter, any verification of flows across a T-D interface. This can include load model verification, DER model verification, or a combination of both load and DER depending on the circumstances surrounding the measurements.

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Chapter 1: Data Collection for DER Model Verification

The data and information needed to create a steady-state and dynamic model for individual or aggregate DERs is different tha~~t~~n the data and information used to verify those models. TOs, TPs, and PCs should work with their DPs to collect information pertaining to existing DERs, and also work with the DP and other applicable entities to forecast future levels of DERs for planning studies of expected future operating conditions. ~~The NERC *Reliability Guideline: DER Data Collection for Modeling in Transmission Planning Studies*[25] describes the types of data and information necessary to create a suitable steady-state and dynamic model for DERs used for planning studies. On the other hand~~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.

Before describing the verification process in subsequent chapters, this chapter ~~will~~ first describes the data and information used for verifying the DER model(s) created. The guidance provided here builds off the previously published guidance[26] regarding DER model development for planning assessments

Data Collection and the Distribution ~~Planner~~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 to provide data and information pertaining to DERs within their footprint since DPs conduct ~~the interconnection studies~~their interconnection processes for resources interconnecting 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), upon their review of interconnection requirements for DERs connecting to the DPs footprint, 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 or other distribution entity, who is not a functional NERC entity. TPs, PCs, and Transmission Owners (TOs) are encouraged to coordinate with DPs and respective DER developers, generators, owners, or other distribution entities related to DER 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. Two of the primary goals of this guideline are to help ensure that DPs, TPs, PCs, and TOs understand the types of data needed to successfully verify DER models, and to provide recommended practices for gathering this data and applying it for verification purposes. It is intended that with clear coordination on the needs for the data, the best “source” of this data will become apparent.

DER model verification starts with applicable entities having suitable DER modeling data available ~~for DERs~~ 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 these are discussed in this chapter in more detail.

Monitoring Requirements in IEEE 1547

The IEEE 1547 standard represents a series of standards that provide requirements, recommended practices, and guidance for addressing standardized interconnection of DER. IEEE 1547 was first published in 2003 and later updated

~~[25] Guideline found here (Review hyperlink upon completion)~~

[26] Links provided here and here.

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in 2018 to address the proliferation of DER interconnections. Both IEEE 1547-2003[27] and IEEE 1547-2018[28] standards are technology neutral. The monitoring requirements for both standards are presented here:

- **IEEE 1547-2003:** The IEEE 1547-2003 standard, applicable for DER installations installed prior to the full adoption and implementation of IEEE 1547-2018,[29] included provisions for DERs with a single unit above 250 kVA or aggregated more than 250 kVA at a single Point of Common Coupling (PCC) 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). For legacy R-DERs, 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 (which 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 PCC, 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 DER. It is critical to understand these capabilities when considering additional recording devices.

Entities may receive nominal nameplate information for the resource but the actual output characteristics will be influenced by factors such as the resource's age and weather conditions. Recording devices should be capable of collecting, archiving and managing disturbance, fault information and normal operation conditions identified by protection equipment such as relays and significant changes observed during normal operating conditions (e.g. PMU reading).

[27] https://standards.ieee.org/standard/1547-2003.html
[28] https://standards.ieee.org/standard/1547-2018.html
[29] It is expected that DERs compliant with IEEE 1547-2018 will become ~~available~~ widely available around the 2021 timeframe based on the progress and approval of IEEE 1547.1: http://grouper.ieee.org/groups/scc21/1547.1/1547.1_index.html

An example of a recording device is the Power Quality meters (PQ meters), which are 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 as well as during system events. These types of measurement devices record both RMS and sinusoidal waveforms at many different sample rates and are IEC code compliant on their RMS and sinusoidal samplings. These types of meters are viable when capturing the aggregate performance of DER 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 the objectives of each entity. 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. The following recommendations should be considered by TPs, PCs, and DPs 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[30]. This may be acquired by measurements at the distribution substation for each T-D transformer bank or along a different distribution connected location[31].
- **U-DER:** U-DER models represent a single (or group of) DER; therefore, the measurements needed to verify this dynamic model must be placed at a location where the response of the U-DER (or group of DER) can be differentiated from other DERs and load response. For U-DER 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 (using 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-DER should have monitoring equipment at their Point of Connection[32] (PoC) to the DP's distribution 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.

> **Key Takeaway:**
> Measurement locations of DER performance depend on the type of DER model (U-DER vs. R-DER) 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.

As described, the type of DERs and how they are modeled will dictate the placement of measurement devices for verifying DER models. **Figure 1.1** illustrates the concepts described above regarding placement of measurement

[30] Note that such a measurement, expectedly, could include the combined response from the load and the ~~R-~~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.

[31] 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.

[32] 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.

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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 ANSI acceptable ~~voltage~~ continuous service voltage. These parameters represent the aggregated impact of individual feeders, as indicated by the dashed box in **Figure 1.1**. Each of the highlighted points in **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-DER, it is suggested that monitoring devices are placed at their terminal as shown in **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.

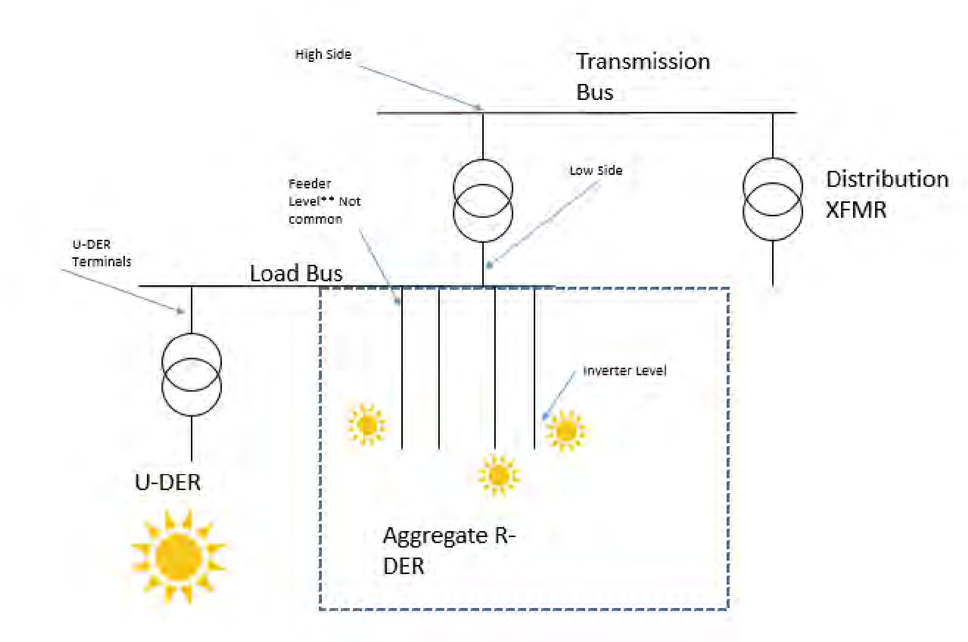

Figure 1.1: Illustration of Measurement Locations for DER Model Verification

Measurement Quantities used for DER Model Verification

Measurement devices used for DER steady-state model verification for both U-DER and R-DER should be capable of collecting the following data at their nominal frequency:

- Steady state RMS voltage (Vrms)
- Steady state RMS current (Irms)
- Active power (W)
- Reactive power (Vars)

Measurement devices used for DER dynamic model verification for both U-DER and R-DER should be capable of collecting the following data:

- RMS[33] voltage and current (Vrms, Irms)
- Frequency (Hz)
- Active power (W)
- Reactive power (Vars)
- Harmonics[34]
- Protection Element Status
- Inverter Fault Code

DER monitoring equipment systems[35] should be able to calculate or report the following quantities in addition to the measurements described above:

- Power Factor (PF)
- Apparent Power (magnitude and angle)
- Positive, negative, and zero sequence voltages and currents
- Instantaneous voltage and current waveforms as seen by the measurement device

Based on the types of measurements desired, preferred, and helpful, **Table 1.1** provides a summary between the steady-state and dynamic recording devices. Each of the measurements above is categorized in **Table 1.2** as necessary, preferred, or helpful to assist in device selection. For dynamic data capture, Digital Fault Recorders (DFRs) and distribution Phasor Measurement Units (PMUs) are two high resolution devices that are useful in capturing transient events, but are not the only devices available to record these quantities. In some instances, already installed revenue meters may provide this RMS information[36].

Table 1.1: Recording Device Summary

Topic	Steady-State	Dynamic
R-DER		
Useful Location(s) of Recording Devices	High-side or low-side of T-D transformer(s); individual distribution circuits[37] (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.

[33] References to RMS here are fundamental frequency RMS.

[34] 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 (IEEE std. 519 for example) and such standards refer to the upper harmonic boundary for measurement.

[35] 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.

[36] 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

[37] individual distribution circuit data is not necessary but can be useful either in addition to or in replacement of T-D transformer data

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Table 1.1: Recording Device Summary		
Topic	**Steady-State**	**Dynamic**
R-DER		
Minimum Set of Measurements	Active Power, Reactive Power	Frequency, RMS Voltage, Active Power, Reactive Power
Additional Preferred Measurements	RMS Voltage	RMS Current~~s~~
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-DER; 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 AM~~S~~I; DER owner SCADA	DFR, distribution PMU, modern digital relay, or other dynamic recording devices[38].
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[39]; Sinusoidal Voltage and Currents

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In regards to protection quantities, the identified U-DER protection device ~~statuses~~ 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.

Steady-State DER Data Characteristics

As **Table 1.2** summarizes the measurement quantities needed, 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

[38] For wide-area model validation, the outputs from these devices should be time synchronized, such as by GPS.

[39] 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 which are applied from the BPS perspective and including this information can assist with both root cause analysis as well as verification of aggregate DER settings.

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 AVRs, 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.[40] SCADA data streams come in at typically 2 to 4 seconds per sample; however, these speeds are not always realizable.
Duration	Largely, a handful of instantaneous samples will verify the dispatch of the DER and load for each Interconnection-wide base case. Further durations nearing days or weeks of specific samples may be needed to verify U-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. ~~Measured data should have relatively high accuracy and precision~~. ~~Data dropouts or other gaps in data collection should be eliminated.~~
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., GPS)[41] to align measurements from across the system.
Aggregation	Based on the modeling practices for U-DER and R-DER established by the TP and PC,[42] 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-DER and R-DER 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 PV DERs[43].

[40] The resolution needs to be able to reasonably capture large variations in power output over the measurement period.
[41] https://www.gps.gov/
[42] https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability_Guideline_DER_A_Parameterization.pdf
[43] See Chapter 2, section titled "Battery Energy Storage System Performance Characteristics" for more information on this topic particularly.

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Table 1.2: Steady State DER Model Verification Data Considerations	
Topic	**Key Considerations**
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 cyclic energy during times of solar irradiance, wind resources provide output during times of increased wind, and BESSs may inject or consume energy based on market signals or other factors. In general, these recommendations can apply to sampling measurements for these resources: 1. 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. 2. Wind: Capture output patterns during coincident times of high solar PV output (if applicable), as well as high average wind speeds. 3. BESSs: BESSs should be sampled during times when the resource is injecting and during times when the resource is consuming power.
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~~it~~ normal delivery point. Not taking this into consideration makes DER mapping to BES model susceptible to inaccurate DER connection points. 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 DER may require more complex measurements, 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 to verify BES interaction characteristics. It is beneficial to include steady-state current and voltage waveforms to this effect, especially for inverter-based DER.

Dynamic DER Data Characteristics

Dynamic recorders uses in capturing the transient conditions of an event have differing data considerations than the steady-state recorders. The data characteristics and considerations typically discussed in dynamic recording of measurements 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 time period. The data captured from dynamic disturbance recorders can be used for the purposes of dynamic model verification.

Table 1.3: 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 on a trigger basis.
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 such that a BPS fault is detected or that nearby protection relays 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[44] • Over-frequency events[45] • Under-frequency events Although higher 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 ~~case~~transmission system model, both R-DER and U-DER terminals are expected to have the same~~ as~~ 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 ~~E~~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[46]. ~~For short dynamic events such as faults, 1-2 seconds time window is common.~~ 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~~, and any gaps in the recorded data should be minimized and eliminated.~~. 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., GPS) 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[47].

[44] 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.

[45] These 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.

[46] 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.

[47] Per PRC-002-2, SER and FR data shall be time synchronized for all BES busses per R10 (link here). This same concept should be true for these measurements that may not be taken from BES buses.

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Table 1.3: Dynamic DER Model Verification Data Considerations	
Topic	**Key Considerations**
Aggregation	Based on the modeling practices for U-DER and R-DER established by the TP and PC,[48] 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-DER and R-DER 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-DER or R-DER by operational characteristics based on the TP and PC's modeling practices.
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 in. If it does not come in a known Excel format, ASCII[49] files are typically used that would be converted into a file format readable in Excel. However, other files types, such as COMTRADE[50], 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.

Management of Large Quantities of DER Information

Management of the increasing diversity of DER functional settings 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 so-called manufacturer-automated profiles (MAPs) that preset certain functional parameters to the values specified in applicable rules (e.g., CA Rule 21, HI Rule 14H, or the default values of a certain IEEE 1547-2018 performance category). To date, these MAPs 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 MAP 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 cornerstone 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[51]. 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, which will be used to exchange and store DER settings. Potential use cases of such common file format include:

- 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.

[48] https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability_Guideline_DER_A_Parameterization.pdf
[49] ASCII stands for American Standard Code for Information Interchange as a standard for electronic communication.
[50] COMTRADE is an IEEE standard for communications (IEEE Std. C37.111) that stands for Common Format for Transient Data Exchange
[51] 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.

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- 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, and settings for DER frequency-droop across between DPs and TPs.

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One way to exchange these common DER settings file could be a central database, for example that 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[52].

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[52] 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 Model Verification

After collecting the data for steady-state model verification for aggregate DER, the first set of models to verify is generally the steady-state DER model. Please refer to the recommended DER modeling framework section, which references documents that indicate the usage of generator records for these steady-state models, for information on the modeling practices. This steady-state model feeds into many of the loadflow studies that TPs conduct, and is the starting point around which dynamic model initializes. 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.

System Conditions for DER Model Verification

~~System Conditions for DER Model Verification~~ Steady state verification procedures can use ~~slower~~ lower time resolution data ~~records~~ and does not need such data to be tied to a particular event~~s to verify the steady state data~~. An entity in SPIDERWG provided an example of performing steady-state verification outside of an event on their system. ~~An example of this is that other studies can provide an insight into the local region.~~ When conducting short circuit studies, an entity found that an aggregation of DER was incorrectly modeled.~~-~~ In this scenario the aggregation ~~occurred~~ in question was ~~with~~ R-DER modeled DER. The R-DER aggregation ~~and~~ was modeled on the nearest BPS bus ~~and not modeled~~ 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, the connection voltage, and analyzed its path the BPS bus to get appropriate impedances between the R-DER and BPS transformer. SPIDERWG recommends entities proactively verify their steady-state ~~It is recommended that other entities utilize this approach where appropriate to create an accurate steady-state~~ DER model based on steady-state conditions that are not related directly to an event[53]. ~~.~~

There are a few conditions that the TP should ensure is verified in their set of models and each is to be verified systematically when the data becomes available. This is to ensure their set of models is of high fidelity for their study's conditions. A set of important conditions to verify, accounting for gross demand and aggregate DER output, include the following[54]:

- DER output at a (gross or net) peak demand condition
- DER output at some off-peak demand condition
- When the percentage of DER is significantly high[55]

At each of these points, the collected 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.

~~If the daily load trend is looking differently in the local area, the TP or PC is encouraged to review their load model validation procedures to determine the attributable jumps, discontinuities, or trends that may be due to DER as opposed to demand. TPs and PCs are encouraged to develop a DER model validation process for those system conditions such that the jumps, discontinuities, and trends of the DER are incorporated in the set of planning models appropriately.~~

[53] For example, this can include voltage reduction tests, overnight low load conditions, or other operational conditions based on engineering judgement.

[54] These examples are used to be in alignment with the conditions in TPL-001-4 (link: here).

[55] This is typically decided based on engineering judgement and does not necessarily coincide with developed peak or off-peak Interconnection-wide base cases.

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Temporal Limitations on DER Performance

> **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.

Due to a multitude of reasons, DER operational characteristics can inhibit the DER performance. For solar PV, solar irradiance inherently limits the output of the DER resource. 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. Much of the inverter control settings are still applicable for dynamic performance verification for the measured data. For instance, if the aggregate DER response was indicated to have a maximum power of 10 MW, that power has a specific minimum irradiance value associated with the output of the devices. Lower values of irradiance will produce a lower associated available power to extract from the solar cells and vice versa for higher irradiance values with respect to low and high limits. Similar considerations for other resource types will be needed in order to ensure the available power from the resources is correctly determined prior to adjusting the other parameters of the model. The unavailability of such data should not stop the process as verification of other parameters can be performed.

Steady-State Model Verification for an Individual DER Model

> **Key Takeaway:**
> The large majority of U-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.

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 a 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 that 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, this particular site had a few controllability settings to verify, namely load following settings.

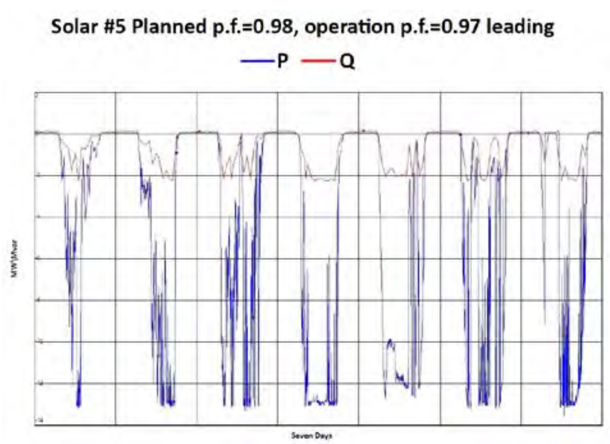

Figure 2.1: Load Following U-DER Response

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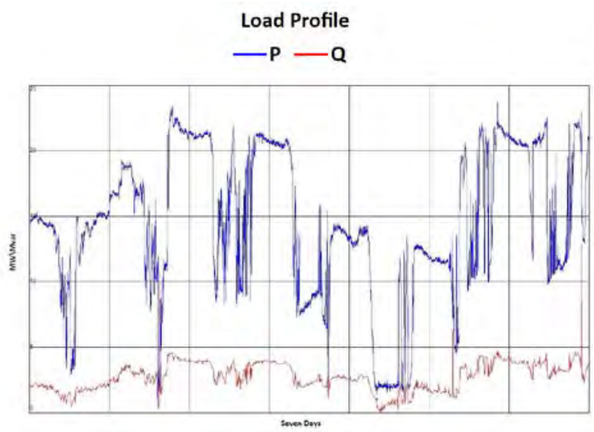

Figure 2.2: Load Response near the U-DER

In the steady state, the ~~points~~ DER MW and MVAR output ~~required~~ could be verified based on day 4 only. To reiterate, the ~~P~~ MW and ~~Q~~ MVAR relationships could be verified by simply providing ~~that one day~~ the MW and MVAR measurements on day 4. However, as this installation indicated the U-DER followed the nearby station load, a different time was needed. To verify the load following setting, day 5 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 (i.e. to prevent back feeding).

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) and such separation allows for the steady-state verification process to be easier. Each TP/PC should consult with the DP to ensure the data required to verify their facility as part of the modeled aggregation is submitted. Care ~~shall~~ should be taken to ensure that the data will be used for its intended purpose of model verification and will not be misused or shared outside of the DPs and other distribution entities intended use; however, it is graphs like these that allow TPs to verify the MW~~P~~, MVAR~~Q~~, and V characteristics in their steady state models. If there isn't data measurements like **Figure 2.1** and **Figure 2.2** made available, by asking questions of the DP and applicable entities, the TP is able to adjust their set of planning models to account for any changes to the DER aggregation from the submitted model. **Table 2.1** highlights some of these important questions.

Table 2.1: Sample DER Steady-State Questions and Anticipated Parameters

Data Collected	Anticipated Parameters
What is the aggregated operational characteristics of DERs [56] at substation within specified time domain?*	This will help set the maximum power output of all DER represented in the verification process. This accounts for the aggregated coincidental capacity potential of the resources.

[56] A "DER" here is be taken from the Interconnection Request. In such a request, the total MW of output is listed. That is the MW used in the summation of all "DER installations"

Table 2.1: Sample DER Steady-State Questions and Anticipated Parameters	
Data Collected	**Anticipated Parameters**
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 coincidental load connected to the ~~transsmission~~transmission substation?**	This data point will assist in determining how the overall model set will perform when adjusting both the DER model and load model at the substation.
What reactive capability is supplied at the DER installations?	This 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.
Minimum power of DER***	For non-solar related DER devices such as microturbines or BESS, this parameter provides the minimum required output of the DER resource in transient stability.

* This question is useful for BESS DERs in discharging mode
** This questions is useful for BESS DERs when in charging mode
*** This question is useful for BESS DERs regardless of charging or discharging

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 DER. For example, when coupling U-DER BESS and other U-DER modeled Solar PV devices in the same model, care needs to be taken to ensure that the U-DER facilities are adequately represented and that the storage aspect of the model is correctly implemented. Including BESS during verification procedures may require measurement devices for aggregate U-DER BESS installations as well as other U-DER modeled DER installations. If the model verified is an R-DER BESS installations along with other R-DER, DPs and other entities may need to contact the OEM or DER developer for some of the questions in **Table 2.1**. It is recommended that DPs and other entities establish a good relationship with the OEMs of BESS such that steady-state BESS parameters are captured and can be highlighted in any measurement device for R-DER modeled resources. Regardless of how the DER is modeled, current practices include surveys or other written means to obtain an operational profile of BESS DER, which helps validate the parameters used in steady-state analysis.

It is recommended to utilize a single DER model for aggregate U-DER, but some complexities or modeling practices may dictate otherwise. Examples for moving to separate aggregations is related to the frequency or voltage regulation settings. Some modeling practices aggregate each technology type separately; however, the benefit of a single DER model for each U-DER allows for a one to one relationship in any measurements provided. The TP and PC is recommended to use engineering judgement and readily available information to determine if these considerations are necessary for their models and alter their verification practices accordingly.

Steady-State Model Verification for Aggregate DERs

The verification of multiple facilities as~~t~~ they pertain to the aggregation 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 both U-DER and R-DER at the T-D interface some assumptions help the verification process. Most legacy DERs (IEEE 1547-200~~1~~3~~)~~ may operate at constant power factor mode only and typically are set at unity power factor, making this a safe assumption. The IEEE 1547-2018 standard has introduced more DER operating modes such as volt-var, watt-var or volt-watt and this may require reaching out to the DP to verify as the settings could be piecewise 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 in order to aggregate the impacts of the data, while leaving the monitoring of R-DER at the high side of the T-D interface.

Figure 2~~3~~.3 shows an example from a 44 kV feeder measurements. The four solar plants, each rated 10 MW, and one major industrial load are connected to the feeder at different 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 travel through a long feeder with lower X/R ratio. The data show that the third solar plant's reactive power output was opposite to the planned direction (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 ~~P~~ MW and ~~Q~~ MVAR flows from these facilities were recorded. Additional confirmation of steady-state voltage settings would require the voltages at these locations, and is recommended to supplement these graphs. From the graphs, the following steady-state DER values would be compared against the modeled representation and corrected (assuming DER is at maximum output) if there was a sufficient discrepancy:

- 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

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Both the aggregate R-DER steady-state component and the gross load component would be difficult to gather this from the measurement alone; however, if the values gathered on this particular graph align with that entered in the load record, that load record is more likely to be a correct representation of the combined R-DER and load. 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 2 (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.

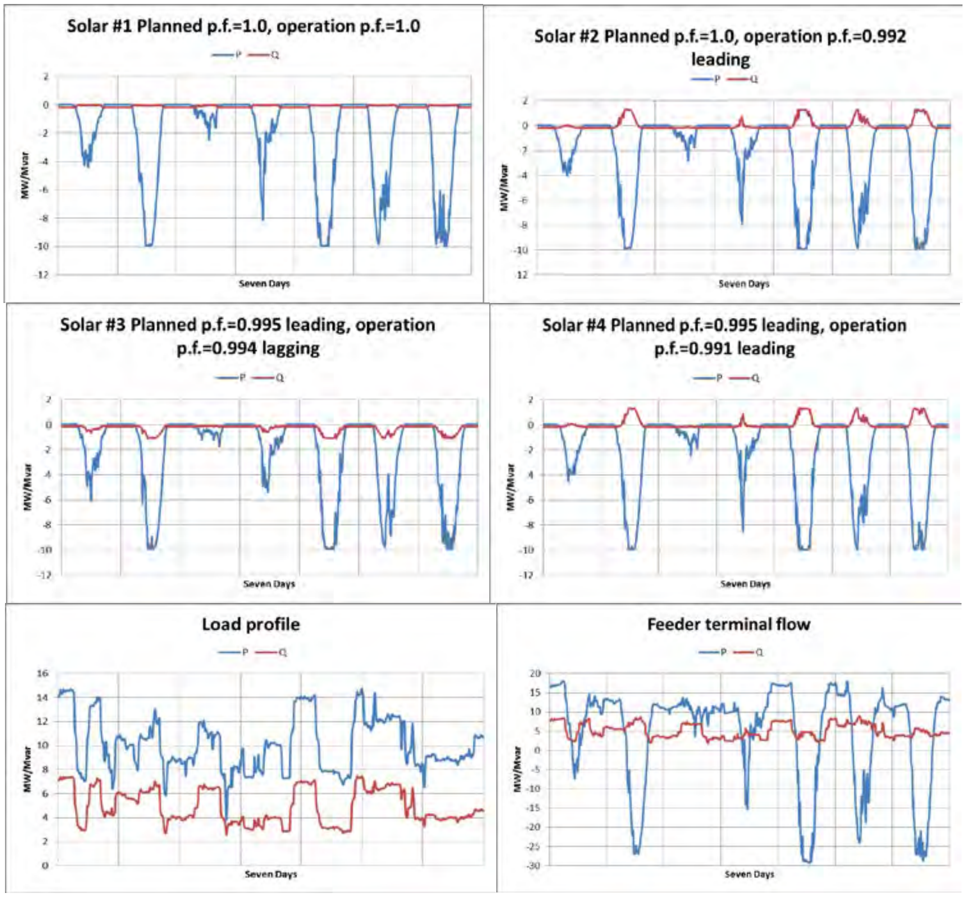

Figure 2.3: Active and Reactive Power Measurements from U-DERs, Load, and Substation

Figure 2.4 shows another 230kV station-wide measurement. Power trends from eight monitored DERs connected to 44kV feeders supplied from the station are plotted in the figure. The meter at Solar #2 was out of service in the week due to failed CT. Note the 6th solar DER is a behind the meter installation, the 7th is a biomass DER and the 8th is aggregation of three solar DERs and load[57]. The last two plots in **Figure 2~~3~~.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. While not provided in the figures, the voltage at these locations should be used when verifying the voltage characteristics in the model. 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.

[57] This would represent the contributions of R-DER in the aggregate DER model

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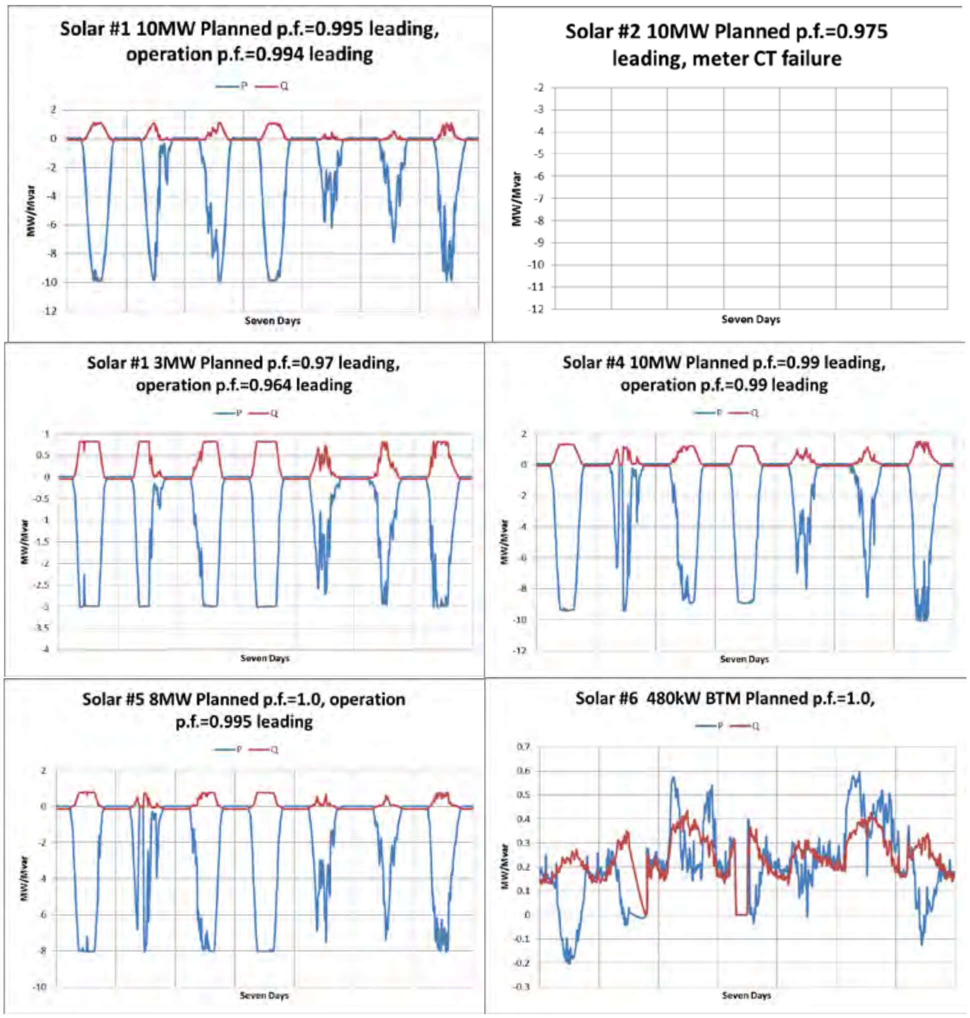
Solar #1 10MW Planned p.f.=0.995 leading, operation p.f.=0.994 leading
Solar #2 10MW Planned p.f.=0.975 leading, meter CT failure
Solar #1 3MW Planned p.f.=0.97 leading, operation p.f.=0.964 leading
Solar #4 10MW Planned p.f.=0.99 leading, operation p.f.=0.99 leading
Solar #5 8MW Planned p.f.=1.0, operation p.f.=0.995 leading
Solar #6 480kW BTM Planned p.f.=1.0,
MW/Mvar
Seven Days

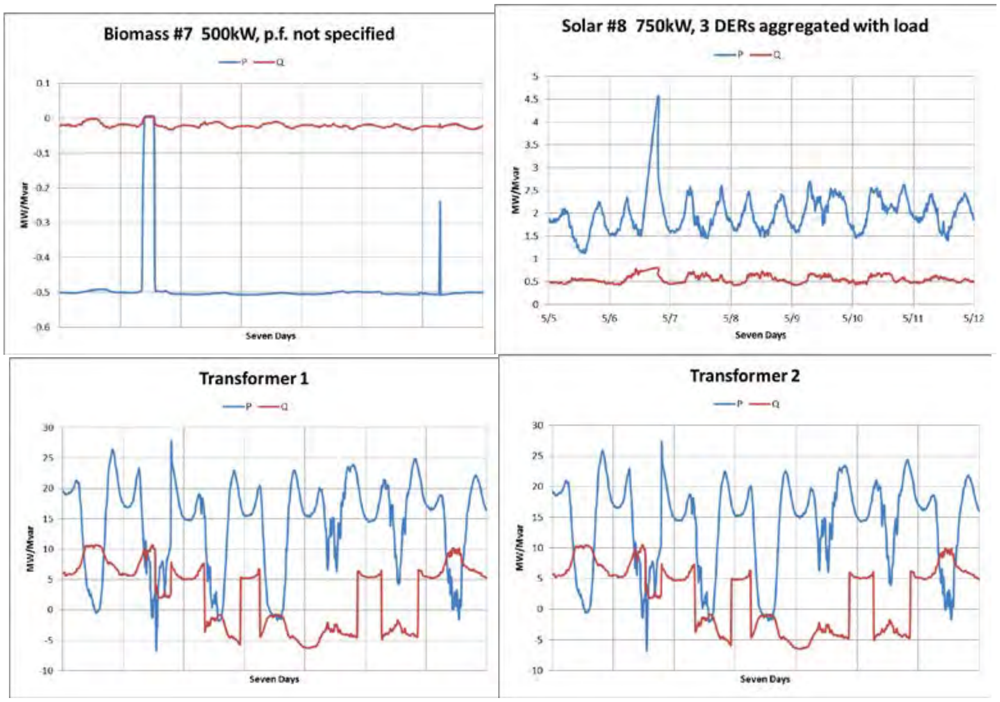

Figure 2.4: **Active and Reactive Powers Measured from Various DERs and Substation Transformers**

As with the aggregations in Figure 2.3, the TP or PC can use these measurements 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 the figures, 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 behind the meter (BTM)
- Aggregate R-DER production of about 1.5 MW from the daily changes in the BTM solar load
- Gross load of about 40 to 42 MW taken from both transformer graphs and backing out the aggregate DER (both U-DER and R-DER) production.

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In this example, since one of the U-DER modeled DER did not have measurements, the TP/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/PC to verify their models such that the behavior of DER 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 a total of nearly 55 MW of gross load, which impacts the simulated performance of the transmission station.

Steady-State Model Verification when R-DER and U-DER Modeled Separately

> **Key Takeaway:**
> Increasing the number of generator records when modeling DER increases the importance of having additional measurement locations.

Once the model contains both aggregate U-DER and R-DER, the dispatch of the U-DER and R-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 aggregated at 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** details a high level of the U-DER and R-DER pertaining to the distribution transformer as seen in a planning base case. 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~~P~~, MVAR~~Q~~, and V characteristics will need measurements of those quantities and which of the DER model inputs that measurement pertains to (i.e. the U-DER or R-DER representation). As each model record represents an aggregation of DER facilities, note that more data will help refine the process. Additionally, some modeling practices have more than one generator record for different aggregations of DER technology types, namely for U-DER. 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 general, when viewing measurements from a T-D bank, assumptions will be required to categorize the U-DER response in relationship to the R-DER response

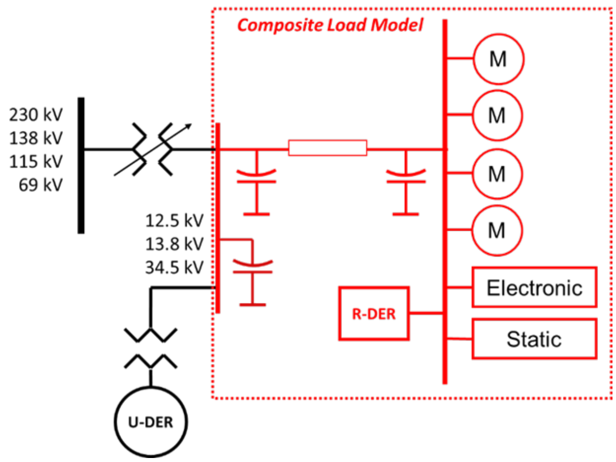

Figure 2.5: **Aggregate U-DER and R-DER Steady-State High Level Representation**

Chapter 3: DER Dynamic Model Verification

This section covers the verification of the aggregate DER model 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. For some entities, individually large DER installations are explicitly modeled, and does not need playback information from the BPS events to perform the verification. ~~If the DP/TP/PC has access to the commissioning tests, the availability of these results is also useful in DER model verification as some commissioning tests demonstrate the dynamic capability of the devices.~~

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:

- Events that occur during nonoperational or disconnected periods of the DER
- Other events that do not contain a large signal response of DER. This is the case with very low instantaneous penetration of DER.

Even with previously verified models for one event, additional events will also provide TPs additional assurance on the validity of the dynamic DER model. One of the most telling aspects on this would be that the Event Cause Code is different between verified model and new event and such differences impact model performance[58]. Based on the above factors, it is crucial to the model verification process that each recorded event have sufficient detail to understand 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 model.

~~Individual~~ DER Dynamic Model Verification for a Single Aggregation

If the TP/PC determines there are sufficient amounts of aggregate DER in a study area, then models should adequately represent dynamic performance of aggregate DER. U-DER and R-DER differ in that dynamic performance characteristics of individual installations of U-DER are practically accessible, while the dynamic performance characteristics of individual installations of R-DER are not. By having the individual performance readily available, this allows for the TP or PC to tune their transmission models representing those resources[59]. 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 dynamic capability of the devices. Thus,

[58] 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.

[59] Whether using an aggregate dynamic model such as DER_A, or an individual dynamic model set such as the second generation renewable models or a synchronous facility. Because U-DER generally will dominate the model performance, individual U-DER performance can verify both types of choices.

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though this section focuses on the dynamic performance of U-DER, many of the same performance characteristics may be inferred under engineering judgment to apply to R-DER[60]. With data made available, model verification can occur. See **Figure 3.1** for a high-level representation of U-DER topology with load and other modeled components. The composite load model here contains a modeled R-DER input; however, in this section the composite load model is considered to not include that input. 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 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[61] models to a reasonable state for its representation in transmission models[62] is the goal.

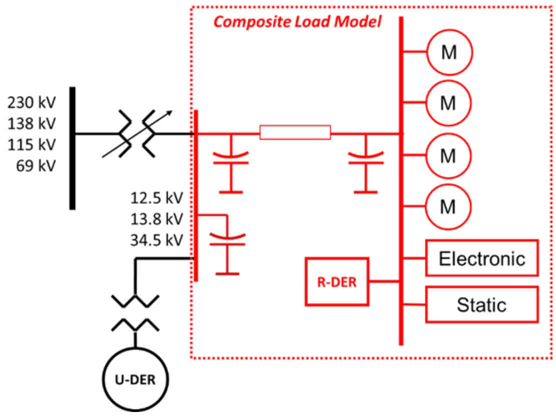

Figure 3.1: High Level Individual U-DER and Load Model Topology

Dynamic Parameter Verification without Measurement Data

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[63] in representing U-DER in their set of BPS models, and should be used only as an aide in determining those parameters required for the dynamic performance verification as the model and system changes between the initial model build and the current set of models. These parameters can be used to help adjust the model in order to assist in performing the iterative verification process. As the DER_A

Key Takeaway:
Ensuring correctly modeled IEEE 1547 vintage through data requests allows the TP to ensure their dynamic DER model is correctly parameterized

[60] 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. In cases where this is not the case, the TP should consider moving that DER facility from the classification of U-DER to R-DER 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.

[61] Note that both the composite load model and the DER_A model are aggregate models that represent aggregate equipment.

[62] 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.

[63] Primarily this is due to interconnection requirements, but can also be due to other external documents.

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model is one of the few current generic 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[64] 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 DER 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.

[64] Or other equivalent applicable equipment standard

Table 3.1: DER Dynamic Model Data Points and Anticipated Parameters

Data Collected	Anticipated Parameters	Example DER_A parameters
What vintage of 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 percent 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 can represent choices made inside the vintage.	Voltage: Vrfrac Frequency: Handled by the Ffrac block[65]
What interruptible load is represented at the substation?	This data point will allow TPs and PCs to be able to coordinate the various protection schemes (such as Under Frequency Load Shedding) along with any of 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[66].	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 ~~service~~ provider.[67] And per FERC Order No. 792, metering data is also provided to the transmission ~~service~~ provider.[68] Thus, the TP/PC have access to data for verification of U-DER dynamic performance for units applicable to the SGIA. In utilities with larger penetrations of DER, more prescriptive language may exist to

[65] 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.

[66] Even in the standalone model situation here, answers to this question will help the TP and PC verify the load responses for model verification. This subject, however, is out of scope of this document.

[67] Order No. 828, 156 FERC ¶ 61,062.

[68] Order No. 792, 145 FERC ¶ 61,159.

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, ~~and such data is not cumbersome to send to the TP/PC,~~ the data[69] 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 applicable units, not all of the DER facilities will be under the SGIA. See **Table 3.2** to get an understanding of the amount of resources ISO-NE considers as DER[70]. For the representations here, the Solar PV Generation not participating in the wholesale market is 1532 MW while 858 MW participates and is SGIA applicable. In this region, reliance on the SGIA alone will only ~~gather~~ apply to a third of the installed Solar PV DER. In addition, generation from other sources totals 1351 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 DER 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 3.2: New England Distributed energy Resources as of 01/01/2018

DER Category[71]	Settlement Only Resource Nameplate Capacity [MW]	Demand Resource (DR) Maximum Capacity [MW]	Total DER Capacity [MW]
Energy Efficiency	-	1765	1765
Demand Resources (excluding behind-the-meter DG capacity)*	-	99	99
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	-	-	1532

[69] E.g. measurements from a fault recorder, PQ meter, recording device, or device log.
[70] The full ISO-NE letter can be found here.
[71] 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.)

Total DER Capacity	1436	2656	5625
Total DER Capacity/ Total Wholesale System Capability**	4.1%	7.5%	15.9%

* To avoid double-counting, demand response capacity reported here excludes any behind-the-meter DG capacity located at facilities providing demand response. Registered demand response capacity as of 01/2018 is 684 MW
** System Operable Capacity (Seasonal Claimed Capability) plus SOR and DR capacity as of 01/2018 is 35,406 MW

In current models, the composite load model may be used to represent the load record in the verification process. PC/TPs should be aware that in the composite load model there are parameters for aggregate R-DER representation. If modeling only U-DER, the DER parameters in the load model should be set to inactive. If there are R-DER impacts, a TP can use the composite load model to insert these parameters.

Aggregate DERs Dynamic Model Verification

Similarly to verifying U-DER, the model of an aggregation of U-DER and R-DER will be conducted similarly, with the same ~~one to mancy c~~oncerns discussed for steady-state verification.[72] Detailed in **Figure 3.2** is a complex set of graphs that represent R-DER and U-DER, along with load, connected to a 230 kV substation to the response of an electrically close 115 kV three phase fault. Note that ~~As evident in the figure, it~~it is only applicable to collect multiple U-DER ~~terminal~~ locations ~~of data~~ 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.

Under a 115 kV system three-phase fault outside the station, the entire 230kV station sees the voltage profile[73], 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 transformers (T1 and T2). Two solar farms (Solar 5 and Solar 6) and other loads with behind-the-meter generation are connected to the 28 kV feeders. The voltage of the 230kV substation returns to normal after the fault; however, the current contributions across the distribution transformers changes from that of expected. At the 44kV yard all four solar installations rode through the fault with increased current injection during fault. The load ~~was not reduced after the event even with it providing reduced current during the fault~~rode through the event. Aggregated current at T3 shows total current unchanged after fault but big increase during fault. This is different from~~- traditional~~ fault ~~signature as~~ signatures in traditional load supply stations, which is characterized by reduced current during fault when the fault is outside of the station (i.e. upstream of the recording devices). ~~is expected when the fault is outside of the station~~. 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 3.2 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 DER. This demonstrates that the pickup of the load was across the T1/T2 transformers. Based upon this figure, 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 Transmission Planner decides to model this complex distribution substation into the planning models. In summary, with metering at each U-DER[74], large load and station terminals, ~~we~~ this example has~~ve~~ enough information for verification of the complex models that represent these DERs. Primarily, the verification

[72] Please 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
[73] Left top corner of the figure
[74] Note that some required monitoring at the end of the feeder

process would show a need to parameterize such that T1 and T2 reflect the reduction of DER from Solar 5 and Solar 6, yet having T1's DER representation parameterized such that this reduction is not present[75].

[75] 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.

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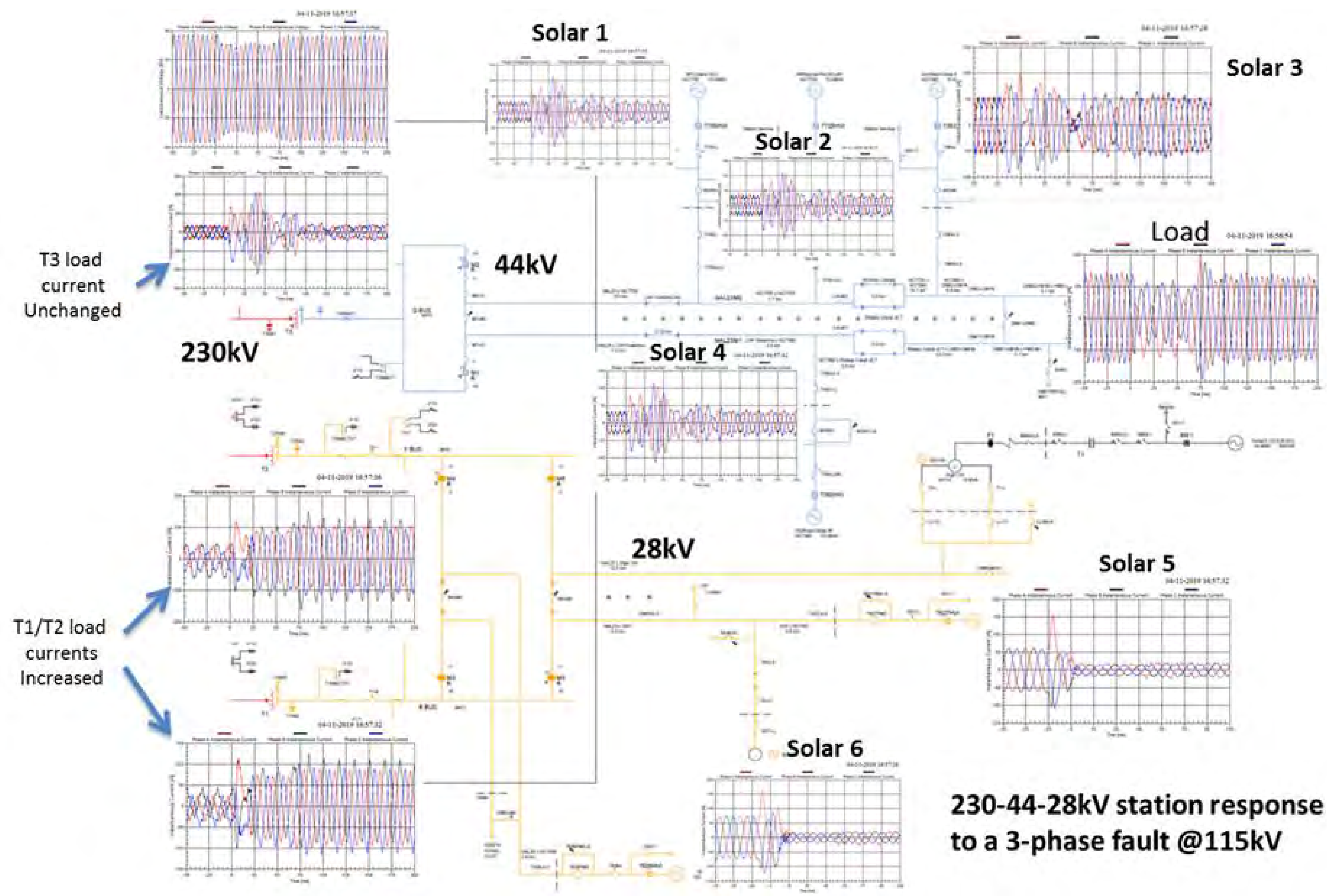

Figure 3.2: 230 – 44 -28 kV Substation Response to a 115 kV Three Phase Fault

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Dynamics of Aggregate DER Models

Similar to the process for individual DER models, the aggregation of R-DER and U-DER models pose just a few more nuances in the procedure. As the framework shows, the U-DER inputs and the R-DER inputs 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 3.3** describes the overall dynamic representation of U-DER modeled DER and R-DER modeled DER with respect to the T-D interface, and Similar to **Table 3.2**, the same number of data points can help to verify the parameters in the DER model associated with the resource. However, a few additional points help with attributing the total aggregation towards each model as seen in **Table 3.3**.

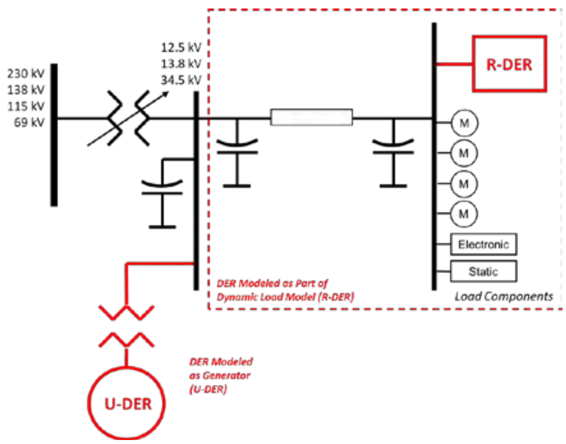


Figure 3.3: Aggregate DER Dynamic Representation Topology Overview

Table 3.3: 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 R-DER installation	Substation level to calculated mean	Resistive loss and Voltage Drop	Feeder, Voltage Drop / Rise Parameters.

Notes: * This question is useful for BESS DERs regardless of charging or discharging

Most notably, the last two rows of the table detail a way to help separate the R-DER and U-DER tripping parameters and voltage profiles seen at the terminals of the inverters. Should any of the above data be restricted or unavailable, following the engineering judgments in the *Reliability Guideline: DER_A Parameterization*[76] will assist in identifying the parameters to adjust based on inverter vintages. However, 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 referenced 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 latest available guidance on specific models should be used to identify the parameters to tune in the model.

Initial Mix of U-DER and R-DER

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-DER and R-DER 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 DER if tracking DER at all, it is expected that the initial verification of an aggregate U-DER and R-DER model to require more than simply the measurements at the location in order to attribute model changes. TPs and DPs are encouraged to coordinate to 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-DER may be different than R-DER. If such standards exist, the TP/PC should verify the mix of U-DER and R-DER are representative of the equipment standards pertaining to the type of DER.

Battery Energy Storage System Performance Characteristics

With regard to BESS, the performance of both aggregate U-DER and R-DER is doubly as complicated in the BESS plus U-DER example. As highlighted in that section, control mechanisms exist that could cloud and complicate the interaction of different DER types when utilizing a singular dynamic model, but could perform adequately for steady-state DER model verification. With respect to adding in modeled R-DER and assuming retail scale connected BESS devices, it becomes even trickier to understand. Including R-DER modeled BESS devices proves to mix not only between two different DER control schemes, but also with the load. Additionally, contracts with R-DER BESS can pose challenges to obtain parameters or measurements for use in dynamic model verification[77]. It then becomes harder to separate the response of load and DER as a charging BESS system can mask increased DER output for R-DER modeled devices, and the ride-through characteristics of the aggregate BESS DER and the aggregate R-DER modeled solar PV DER can be different. In turn, model verification can become computationally complex just to attribute the response to U-DER BESS, other U-DER, R-DER BESS, other R-DER, or load in the model. TPs and PCs are encouraged to utilize engineering judgement and to coordinate with the DP and other available resources to attribute the response characteristics of load, BESS, and other DER types when performing the model verification for situations like the above.

Parameter Sensitivity Analysis

As with most models, certain parameters in the DER_A model may impact the model output 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.[78] While TSA is commonly implemented differently across multiple organizations, certain software packages include a basic

[76] https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability_Guideline_DER_A_Parameterization.pdf
[77] As many of the dynamic parameters from OEMs are largely considered proprietary
[78] Hiskens, Ian A. and M. A. Pai. "Trajectory Sensitivity Analysis of Hybrid Systems." (2000).

implementation. Among them are MATLAB Sensitivity Analysis Toolbox[79] and MATLAB Simulink. TSA analysis with respect to verifying DER_A dynamic model parameters can be found in Appendix A.

TSA is one of many methods for TPs and PCs to gain understanding of the sensitivity of the dynamic model to small changes in model parameters; however, this is not a required step in model verification nor a required activity for tuning dynamic models. Further, 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 important 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.

Summary of DER Model Verification

~~In relationship to the verification of DER the procedures described above,~~ ~~s~~Some of the general characteristics of performing DER model verification are re-emphasized ~~when performing model verification~~here. With the purpose of taking a correctly parameterized model, the following few things are important to consider:

- Location of Voltage, Frequency, Power, or other quantity with respect to the electrical terminals of the DER devices
- Relationship of the DER devices with respect to end use demand as well as other DER devices in the aggregation[80]
- Accurate and robust metering equipment on the high or low side of the T-D transformer as well as equipment near the large DER terminals

With those three bullets in mind, TPs and PCs are encouraged to begin utilizing measurements for steady-state or dynamic model verification of DER. Since all DER generators can be tested,[81] the DER models will likely be tuned over time to represent the growth of DER in a specific area. 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[82]
- Electrical changes between verified model and study model[83]
- Sensitivity considerations on the study[84]

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

[79] https://www.mathworks.com/help/sldo/sensitivity-analysis.html
[80] This is particularly true of BESS DERs
[81] Nor should they be absent a technical analysis and justification
[82] Irradiance and other meteorological quantities are affected by time and some DER types are dependent upon this weather data
[83] For example, distribution system reconfiguration due to lost transformer affected the verified model, but study model has normal configuration
[84] For example, if studying cloud cover over a wide area, Solar PV DER will affected and should be adjusted accordingly

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.

Appendix A: 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 A.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% and the event simulated was a three phase 500 kV fault on the line between buses 201-202. Parameters of the DER_A model not listed in **Table A.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 section of the dynamic performance that is needing to adjust (i.e. before, during, or after the fault) in the verification process and that the parameter under adjustment makes sense to adjust. To help illustrate this, take the Trv example in **Figure A.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 A.2** to Figure A.4, respectively.

Table A.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	High	Maximum power limit
Imax	1.2	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	1.2	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	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

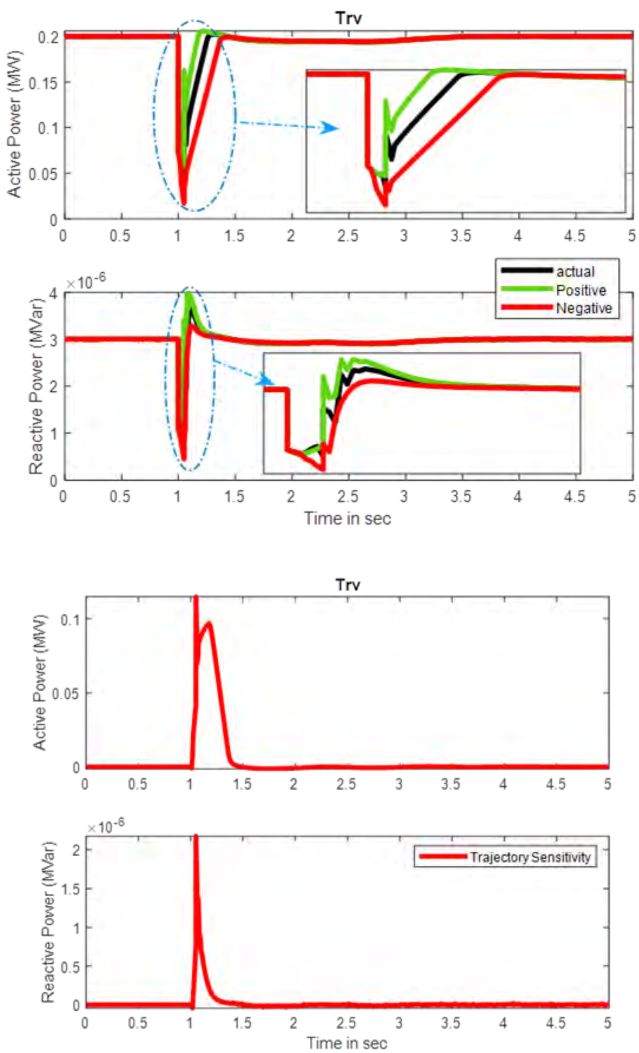


Figure A.1: Simulation Output and the Resulting TSA Calculation on Trv[85].

[85] 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 you increase 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.

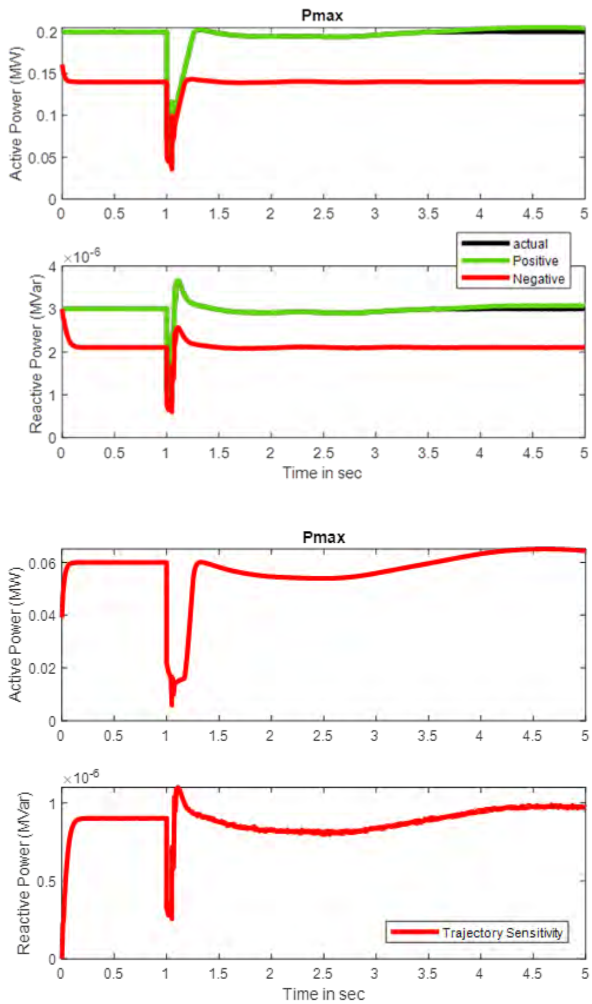


Figure A.2: Simulation Output and the Resulting TSA Calculation on Pmax.

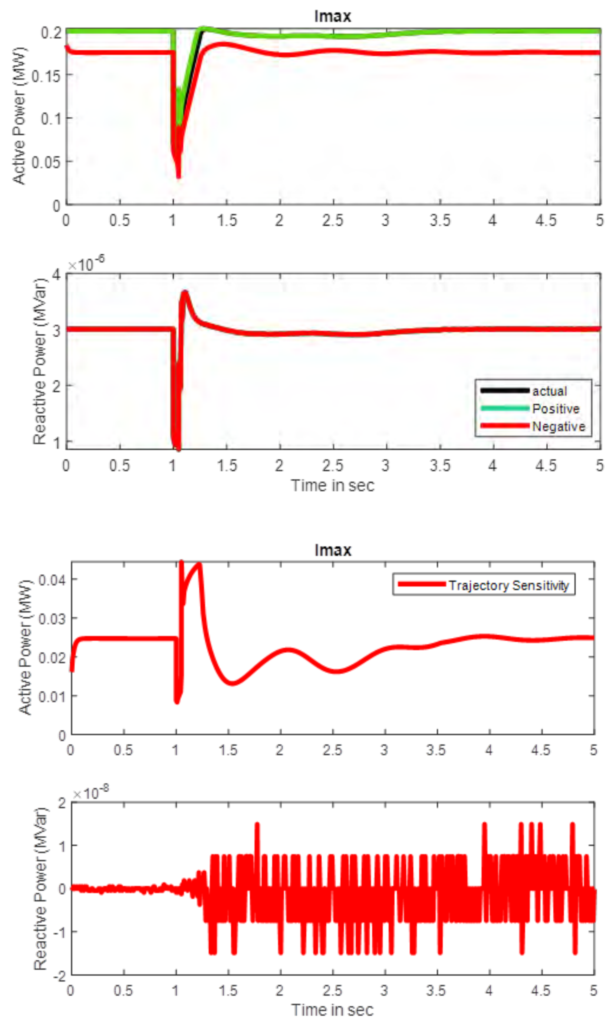


Figure A.3: Simulation Output and the Resulting TSA Calculation on Imax

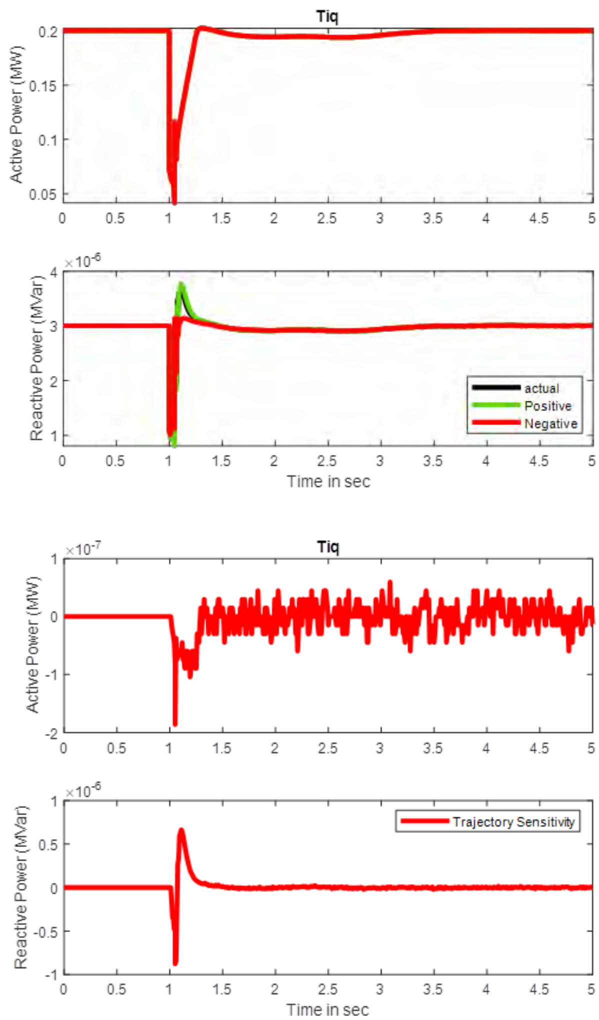


Figure A.4: Simulation Output and the Resulting TSA Calculation on Tiq.

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 (e.g., PfFlag, FreqFlag, PQFlag, GenFlag, VtripFlag and FtripFlag). **Figure A.5** shows where these flags are located with respect to the DER_A dynamic model.

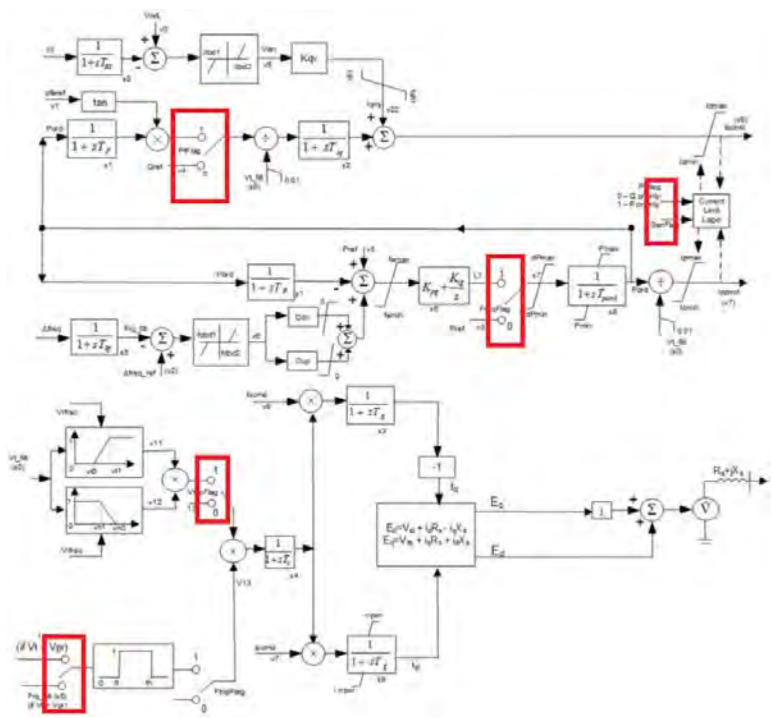


Figure A.5: DER_A Control Block Diagram in PSS®E [Source: Siemens PTI][86]

[86] PSSE model Documentation

Appendix B: 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 ~~Chapters 3 and~~Chapter 34, 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 B.1**, a Synchronous Machine Infinite Bus (SMIB) 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, modeled as a jumper.

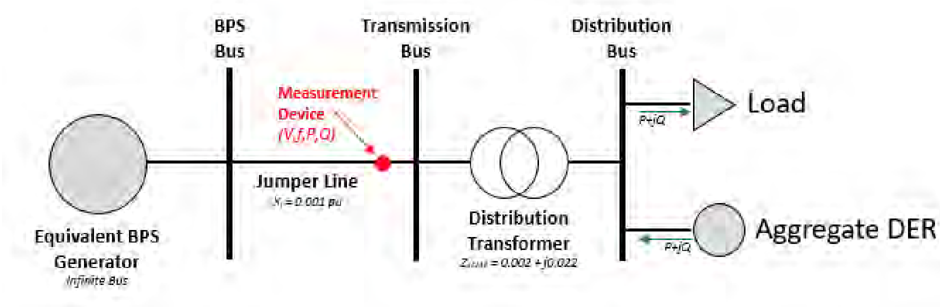


Figure B.1: Simulation SMIB Representation for High Level Aggregate U-DER

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 XFMR 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 B.-1: Steady State Parameters for Study

Input Name	Value
Load	60+j30~~j~~ MVA
Aggregate DER	10+j1~~j~~ MVA

In order to parameterize the Composite load model, the parameters in **Figure B.2** were used and are assumed to represent the ~~inductor~~ induction motors and other load characteristics. This example is set to verify the dynamic parameters of the aggregate DER, and assumes the impacts ~~were~~are separate~~d~~ from the load response and are~~is~~ fully attributed to the DER. The list of parameters that were provided in the original model were is found in **Figure B.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 B.1**.

In this example, the following models[87] 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 B.1**.

- 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~~P~~, MVAR~~Q~~, 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

[87] 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 B.2: Starting Set of Dynamic Parameters

Model Comparison to Event Measurements

The event that was chosen to verify these set of models was a fault that occurred 50 miles away from the measurement location, and such fault caused a synchronous generator to trip offline. The measurements ~~demonted~~ shown here are simulation outputs from a different set of parameters and are assumed to be the reference ~~P~~ MW and ~~Q~~ MVAR measurement for verification purposes. For the purposes of illustration, the event is assumed to be a balanced fault[88]. The event is detailed in the first set of graphs in **Figure B.3**. The active power and reactive power measurements are taken at the high side of the T-D transformer corresponding to **Figure B.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 B.4**, and demonstrate two separate distinctions in the process. Firstly, that the load model responds similarly between the measurement values and the reported model. Secondly, that the changes and adjustments to the DER model do not impact the response in a way that would misalign the model with the measurements.

[88] 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.

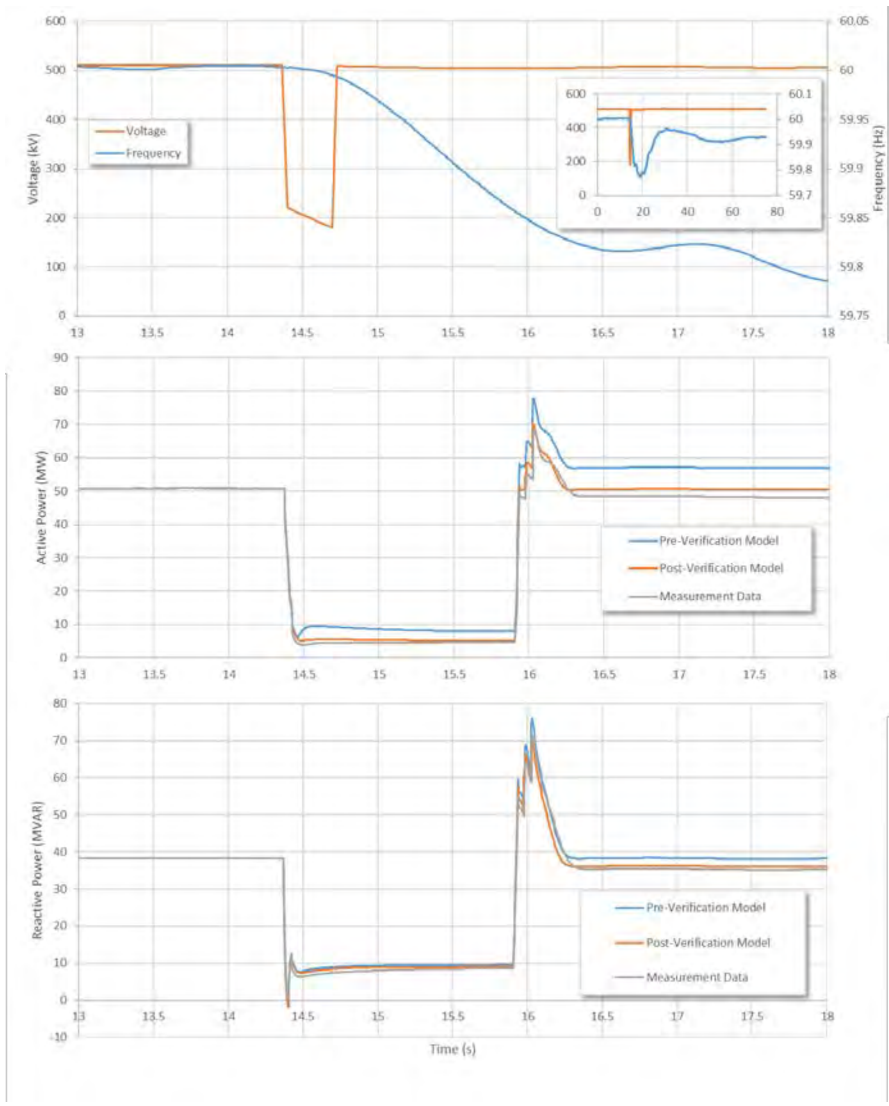


Figure B.3: Voltage, Frequency, Active, and Reactive Power Measurements

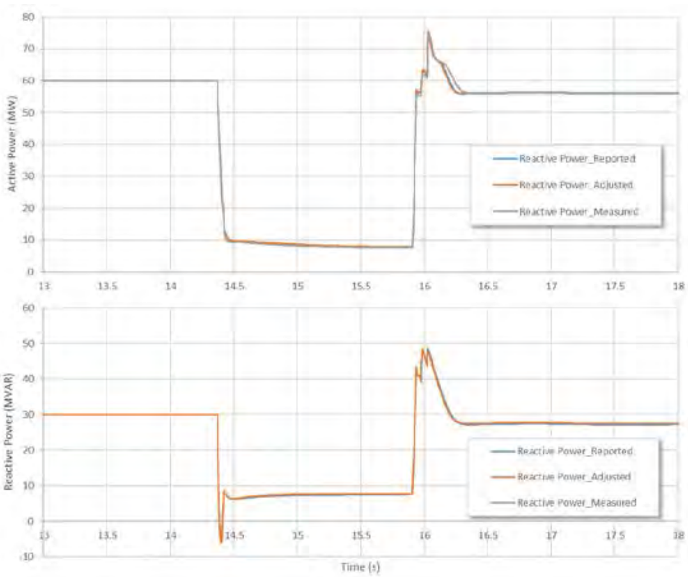


Figure B.4: Active and Reactive Power of Load Model

After demonstrating that the two active power measurements across the transformer were not equivalent, namely that the model had more active power flowing from the system into the distribution bank post disturbance as opposed to the measurements, which actually show a drop in the flow across the transformer after the disturbance. During the fault, very similar characteristics between the model and the measured power across the T-D transformer during the disturbance yet differed primarily in the post-disturbance recovery. Based on how it seems the low voltage ride through settings seem to be too restrictive in the model, the parameters were adjusted as detailed in **Table B.2**.

Table B.2: DER Parameter Changes		
Parameter Name	**~~Previous~~ Pre-Verification Value**	**Post-Verification~~New~~ Value**
Vrfrac	0	0.2
Vfth	0.8	0.4
Vl0	0.44	0.35
Tvl0	0.16	0.75
Tvh0	0.16	0.75

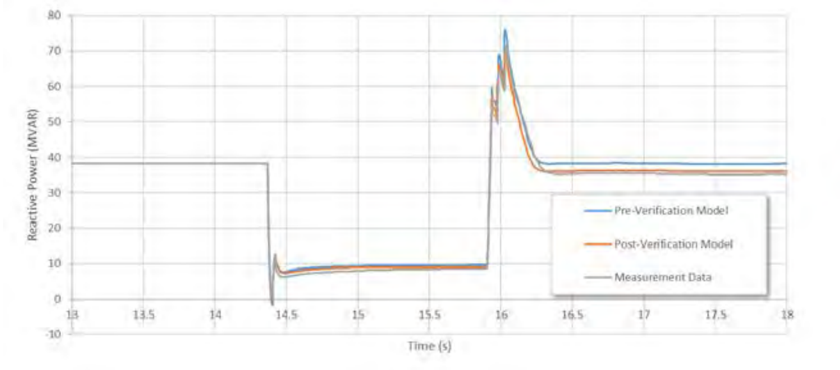


Figure B.5: Active Power of Model versus Measurements after Parameter Adjustment

After the adjustments were made in **Table B.2** and simulating the model response, the active power is looked at closely, reproduced in **Figure B.5**, to determine the effect of the changes. Based on the closeness of fit, the verification process ends and the model is now verified against this particular event's performance. If the TP/PC determines that this verification closeness of fit 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 C: Data Collection Example

Specific types of BPS events have demonstrated a characteristic response in load meters, which has been attributed to DER response;[89] however, a majority of TPs or PCs may not ~~know~~ 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 ~~occurred~~ occurring events. An example of the performance expected can be found in **Figure C.1**, which shows an example of U-DERs responding to a 500kV single-line-to-ground fault in Ontario. More than 30 DER meters recorded interruptions upon the fault and **Figure C.1** highlights seven locations as far as 300km from the fault location (voltage and current waveforms side by side, with nameplate MW indicated). The DERs were all installed under the IEEE 1547-2003; therefore, most of them tripped offline 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 PoC.

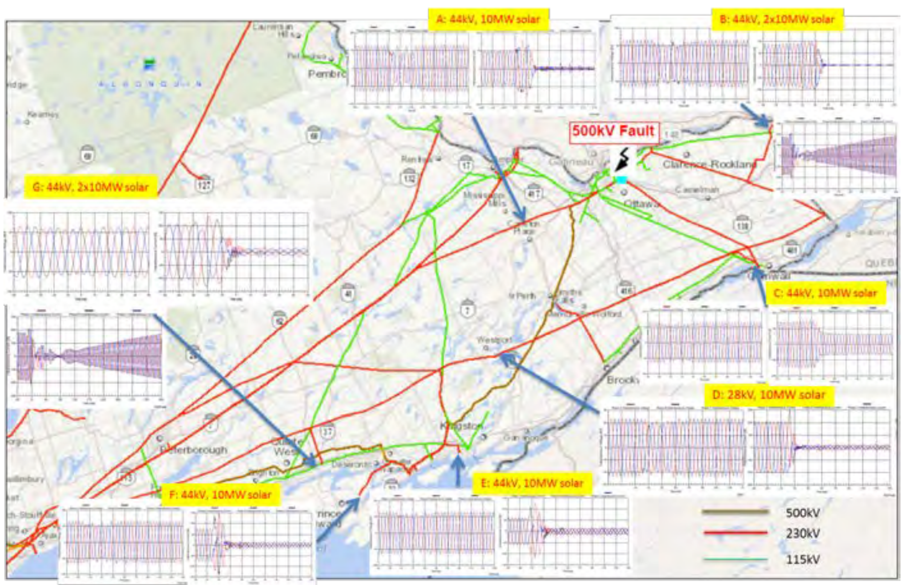
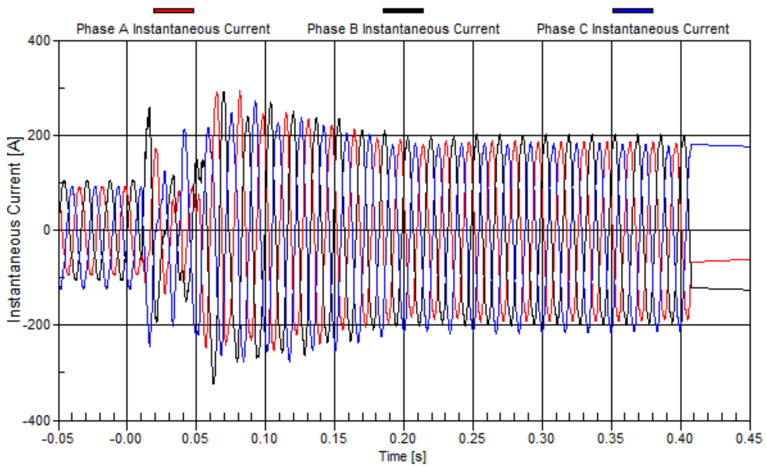


Figure C.1: Solar U-DER Voltage and Current Waveforms for a 500kV Fault

TPs can further verify the tripped loss of DER by using aggregated measurements from revenue meters at substation. **Figure C.2** plots current waveforms from one out of two paralleled 230/44kV step-down transformers at Site B where multiple solar generators are connected through the substation to 44kV feeders. The fault started near 0.0s in **Figure**

[89] https://www.nerc.com/pa/rrm/ea/April_May_2018_Fault_Induced_Solar_PV_Resource_Int/April_May_2018_Solar_PV_Disturbance_Report.pdf

C.2 and was cleared after three cycles (0.05 seconds). Increased net load current through the transformer can be seen after the fault clearing, which suggests most solar DERs could not recover immediately after fault clearing.



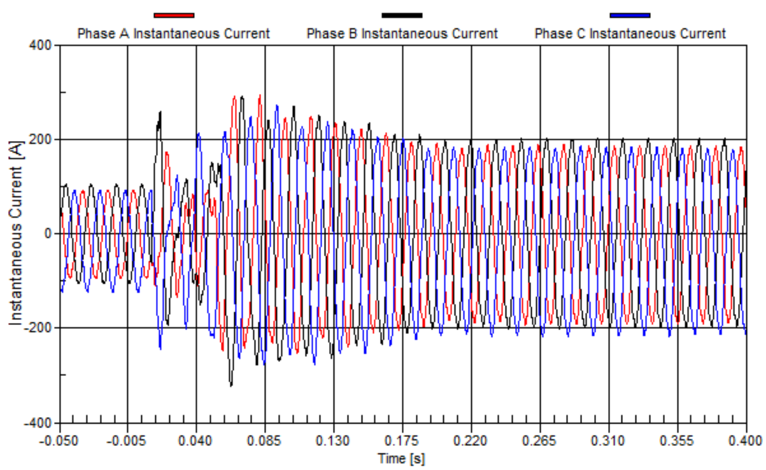


Figure C.2: Current waveforms from 230/44kV transformer at Site B

DER operating logs show various reasons that may initiate DERs 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~~ride through the disturbances if the decisions of ~~gating~~ tripping offline ~~inverter~~ were ~~reasonably~~ delayed.

Figure C.3 compares performances of two 44kV solar plants under a common 500kV single-line-to-ground fault. The two plants connect to the same substation bus but have different control strategies. The inverter on left side (10MW nameplate) stopped operating under voltage sag by design. The one on right side (9MW nameplate), in contrast, was configured to inject reactive current under the same voltage sag. It can be verified from **Figure C.3** that the current waveforms of the two plants were very similar between -25ms and 0ms. However, the controllers made different decisions based on the information from the 25ms: the first solar plant stopped generating at t=0ms while the second one continued current injection during the BPS fault and beyond, even though they were looking at almost identical voltages at the PoCs.

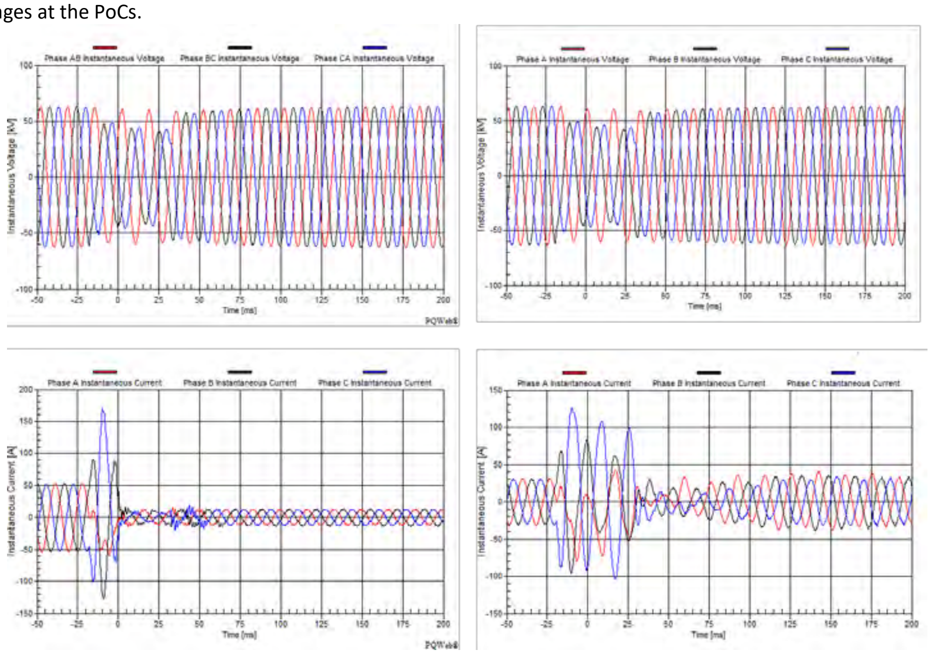


Figure C.3: Comparison of Two Adjacent Solar Plants' Responses to the Same 500kV Fault (top: voltage, bottom: current)

Installation data may suggest the overall majority of DERs are solar generators, but wind turbines 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 C.4** and **Figure C.5** show Type IV and Type III wind plants responses to a common 500kV bus fault, respectively. While the wind plants are connected at different locations and voltage levels (28kV vs. 44kV), both shut down under the BPS fault. **Figure C.6** shows load current increase measured from one out of two paralleled 115kV/44kV step-down transformers as a result of wind generation loss in the 44kV 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 issue is expected to diminish with the new 2018 standard revision, which requires at least 160ms time delay to accommodate transmission fault clearing.

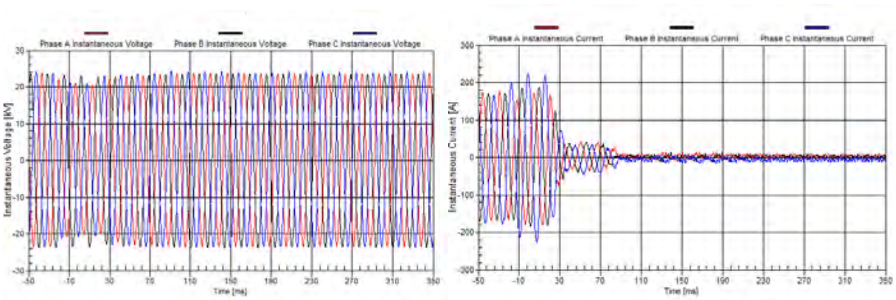


Figure C.4: Type IV Wind Plant (28kV/10MW) Response to 500kV Single-Line-to-Ground Fault

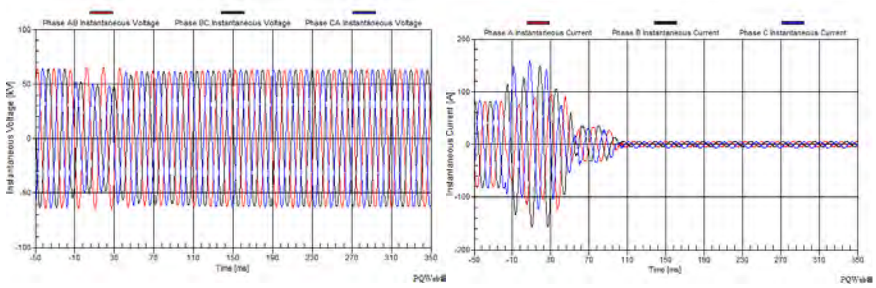


Figure C.5: Type III Wind Plant (44 kV/10 MW) Response to 500kV Single-Line-to-Ground Fault

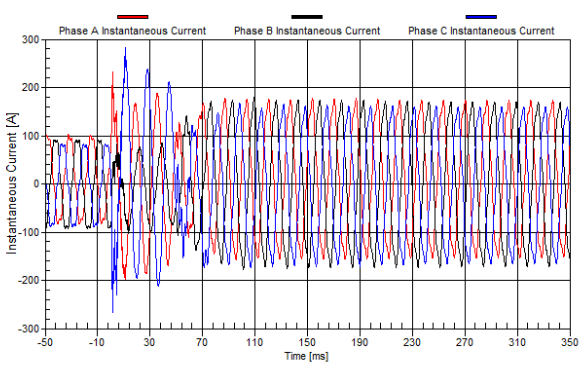


Figure C.6: Load Current Increase at a 115 kV/44 kV Transformer after Loss of Wind Generation

April-May 2018 Disturbances Findings

In the Angeles Forest and Palmdale Roost disturbances, a noticeable amount of net load increase was observed at the time of the disturbances.[90] DERs were verified to be involved in the disturbance using a residential rooftop solar PV unit captured in the Southern California Edison (SCE) 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 behind-the-meter solar PV DERs; however, the availability, resolution, and accuracy of this information was fairly limited at the time of the event analysis. **Figure C.7** shows the CAISO net load for both disturbances. It is challenging to identify exactly[91] the amount of DERs that either momentarily ceased current injection or tripped offline using BA-level net load quantities. Note that these measurements were taken at a system-wide level and represent many T-D interfaces, while the above IESO example is for specific T-D interfaces.

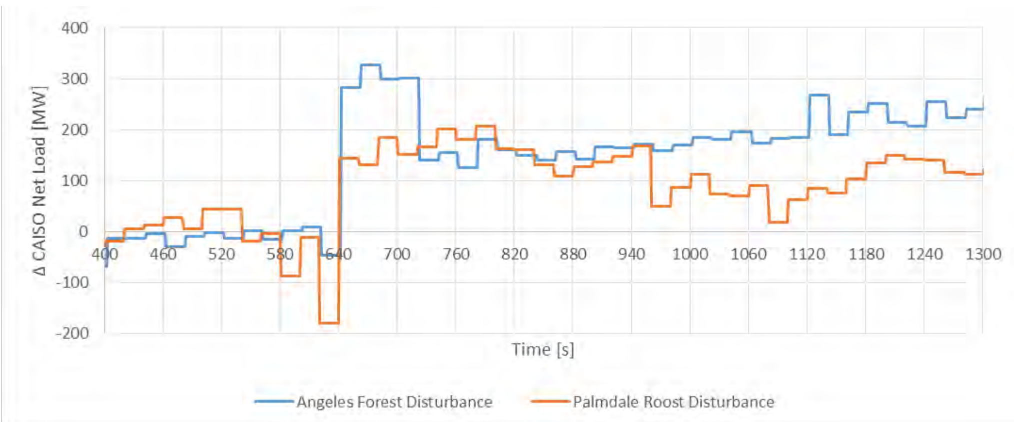


Figure C.7: CAISO Net Load during Angeles Forest and Palmdale Roost Disturbance [Source: CAISO]

SCE also gathered net load data for these disturbances (shown in **Figure C.8**). While an initial spike in net load is 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[92] solar PV in their footprint. However, it does account for the unmetered DERs that are mostly composed of Behind the Meter (BTM)~~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.[93] Therefore, the SCADA point does not differentiate between changes in net load and changes in losses.
- ~~As with all~~Typically for energy management systems (EMSs), the remote terminal units (RTUs) reporting 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)

[90] https://www.nerc.com/pa/rrm/ea/Pages/April-May-2018-Fault-Induced-Solar-PV-Resource-Interruption-Disturbances-Report.aspx
[91] 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.
[92] Generally, generation greater than 1 MW is metered by SCE on the distribution, subtransmission, and transmission system.
[93] Net Load + Losses = Metered Generation + Intertie Imports

Formatted: Heading 6,Appendix Section Header before refreshed values 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 the reasons described above, the spikes in net load were accounted for as calculation errors and 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 when using area-wide net load SCADA points[94]. TPs and PCs, when gathering data for use in verification of DER models, should consider the bullets above when using SCADA or other EMSs when utilizing these points for verification of DER models, especially when utilizing system-wide measurements.

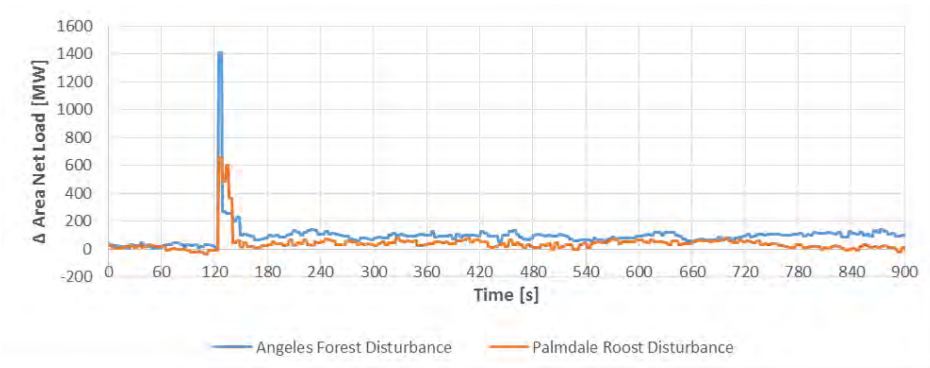


Figure C.8: SCE Area Net Load Response [Source: SCE]

It was determined that monitoring the T-D transformer bank flows using 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 above. **Figure C.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.[95] After that time, the net loading returned back 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 data collection for DER and how to identify or attribute responses in already collected data, especially for higher impact T-D interfaces.

[94] For that matter, SCADA scans are not recommended to determine the total tripping of any IBR resource, including DERs that are IBRs.

[95] 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.

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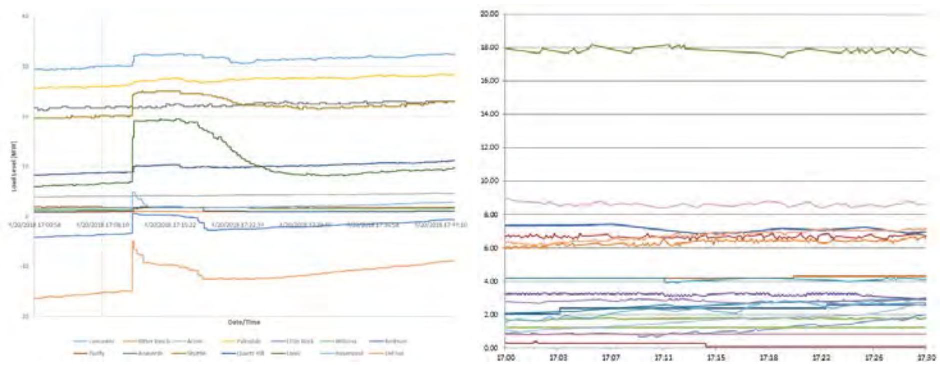

Figure C.9: SCE (left) and PG&E (right) Individual Load SCADA Points

Contributors

NERC gratefully acknowledges the contributions and assistance of the following industry experts in the preparation of this guideline. NERC also would like to acknowledge all the contributions of the NERC System Planning Impacts from Distributed Energy Resources Working Group (SPIDERWG).

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Shahrokh Akhlaghi	Southwest Power Pool
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Irina Green	California ISO
Chester Li	Hydro One Networks, Inc.
Dan Kopin	Utility Services, Inc.
Hassan Ghoudjehbaklou	San Diego Gas and Electric
Parag Mitra	Electric Power Research Institute
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Bob Micek	Tri-State Generation and Transmission Association
Raul Perez	Southern California Edison
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Reliability Guideline	
Instructions	Please use this form to submit comments on the draft Reliability Guideline. Comments must be submitted within the review period below to NERC (reliabilityguidelinecomments@nerc.net) with the words "XXXXXXXXXX" in the subject line. Only comments submitted in this Microsoft Excel format will be accepted. Both general and specific comments should be provided within this form. Comments may be submitted by individuals or organizations. Please provide the requested information in Row 6. If comments are submitted on behalf of multiple organizations, list all organizations in Row 6. Please provide the Industry Segment and Region (if applicable) in Rows 7 and 8 and provide the requested contact information in Rows 9 and 10.
Review Period	

Organization(s)	Page #	Line / Paragraph	Comment	Proposed Change	NERC Response
Orange and Rockland	1	284/285	the reference to DP can be confusing bewteen distribution planner and distrubution provider	consider title change to Data Collectiona and the Distribution Provider to avoid confusion	Change made as proposed
Manitoba Hydro	1	271/1	different that the data	different than the data	Change made as proposed
Manitoba Hydro	5		Page 5 – top of page. There are 6 items bulleted that are supposed to be present for both U-DER and R-DER. However, the Table 1.1 has a smaller subset for R-DER.	Please make the text consistent with the table.	Changes made to Table 1.1
Manitoba Hydro	6		Page 6 -Table 1-1: An example of a recording device is "AMS". We believe this should be AMI – Advanced Metering Infrastructure.	If AMI, smart meters, advanced revenue meters are all synonymous then an explanation should be provided early in the report.	Change made as proposed
Manitoba Hydro	9	Table 1.3, first bullet point under Triggering --> Key Considerations	Table 1.3: we believe that the 88% voltage threshold should be considered as an example not a presciptive setting. We are wondering whether it is benificial to have have an overvoltage trigger setting as well?	We would let entities to decide the trigger thresholds based on their experience.	Added footnote capturing proposed change
Manitoba Hydro	34		Figure 3.2 is blurred and hard to read	To make it easier to read, please consider replacing Figure 3.2 with a high resoution screen capture? For example, you can arrange a high resoluion figure in landscape format in a single page.	Changes made based on comment. Figure size increased.
Manitoba Hydro			In general, the case studies in the appendix are most valuable. Is it possible for the working group to collect a few more practical examples from utilities that have performed DER model validation? Perhaps there are examples from California? We would like to see an initial model compared with field results and an explanation of which parameters were varied to get reasonable results. The example from the IESO was interesting but it wasn't clear how they changed their model to match field results.		Thank you for your comment. At this time, no other entities volunteered examples that the comment requested. No change made.
Thomas Foltz on behalf of American Electric Power	v	90-95	While the Reliability Guideline does include language indicating that "Reliability guidelines are not binding norms or parameters", the language in this section is not as robust as provided in previous Reliability Guidelines, typically within the opening Preamble. Most notable is the absence of language indicating that Reliability Guidelines "are not binding norms or parameters *to the level that compliance to NERC's Reliability Standards are monitored or enforced.* Rather, their incorporation into industry practices is strictly voluntary."	Add Preamble section and provide more robust, customary language used in previous Reliability Guidelines, including language that indicates that Reliability Guidelines are not binding norms or parameters *to the level that compliance to NERC's Reliability Standards are monitored or enforced*, and that rather, their incorporation into industry practices is strictly voluntary.	Preamble added consistent with other NERC Reliability Guidelines
Thomas Foltz on behalf of American Electric Power	N/A	N/A	While AEP notes nothing objectionable within the content of this specific Reliability Guideline, we do have concerns related to both the actual *execution* of the guidance as well as the eventual development of guidance by the SPIDERWG regarding that execution (as noted in footnote 6). AEP would like to take the opportunity to share those concerns related to "next steps", and we hope you would be willing to share with the individuals and teams tasked with developing guidance in that regard. This Reliability Guideline understates the significance of its recommendations related to the revision of existing or new interconnection requirements, requiring large amounts of data from customers to feed aggregate planning models of the BPS. While the "audience" of this Reliability Guideline is presumably NERC registered entities, the content of the Reliability Guideline is centric to U-DERs and R-DERs. As such, the guideline may need to apply-to entities which are *not* NERC-registered entities. This Reliability Guideline makes the incorrect assumption that every entity who owns or operates a system to which DER is connected is a TO or DP. To the contrary, many of these entities with the needed data (such as co-ops and munis) would be outside of NERC's jurisdiction, as they are not all registered entities. As such, it needs to be recognized that access to some of the data would not be available. Related to the above, the DER equipment being connected could potentially be owned by a variety of different entities, for example the retail customer behind its meter or wholesale entity (i.e. co-op or muni utility), so the issue then becomes the **enforcement** of the existing contracts of delivery points. Even with the verbiage already in service agreements, the question then remains; exactly *who* is responsible for both the modeling data itself *and* for making sure the models are appropriately maintained and of proper "fidelity?" While we recognize that this Reliability Guideline neither contains obligations nor is to be used to determine compliance with existing obligations, we would be greatly concerned by any effort to use this Reliability Guideline as a template for actual standards or obligations. Once again, any enforcement by NERC of such future obligations would prove problematic at best, because as previously stated, not all involved parties will be NERC-registered entities. And the questions previously posed, including those related to identifying exactly *who* is responsible for both the modeling data itself *and* for making sure the models are appropriately maintained and of proper "fidelity", would be of even greater concern should such reliability guidance eventually be used to develop NERC obligations. While AEP acknowledges the value of high fidelity aggregate DER models, and agree their pursuit is a worthy objective, we believe the topic is "research-heavy." While TPs and PCs would indeed be participants in the monitoring of the necessary data, they are not themselves research organizations nor are they designed to perform such research.		Thank you for your comments. The NERC SPIDERWG believes that aggregate DER should be represented in planning assessments. Previously published NERC Reliability Guidelines and Technical Reports highlighted the need to model aggregate levels of DERS in planning assessments as well. SPIDERWG has provided this guidance in pursuit of high-fidelity aggregate DER models for those planning assessments and does not anticipate the alteration of standards, compliance, and enforecment on the basis of this Reliability Guideline alone. .
ERCOT	vi	109	typo	should be "...Transmission Planners (TPs) and..."	Change made as proposed
ERCOT	7	450	Table 1.2 - Key Considerations: A consideration I don't see below is AVR type/status. If AVR is in pf control mode vs voltage control mode or in manual mode it will alter the voltage response. AVR/voltage control is handled DP to DP, but being able to know how the U-DER and the aggregate R-DER may make a difference on the ability to ride through system faults. Also not clear if you need Qmax/Qmin for the U-DER or R-DER.		Changes made to text above Table 1.2. Table 1.1. lists "Reactive Power" in the minimum required measurement section.
ERCOT	7	450	Table 1.2 - Accuracy - Should probably detail what "relatively high accuracy" means. 1% is usually meter grade and 3% is relay grade.		Changes to table made based on comment.
ERCOT	7	450	Table 1.2 - Aggregation - There may also be a need to separate aggregation between battery DERs and other DERs based on their operational characteristics.		Added footnote pointing to Chapter 2's section on this topic
ERCOT	9	463	Table 1.3 - Triggering - It may make sense to also include high voltage trigger as high voltage overshoot is a real issue.		Changes made to "Triggering" section.
ERCOT	9	463	typo	Extraneous period at the end of the Duration consideration	Change made as proposed
ERCOT	9	463	Table 1.3 - Aggregation - There may also be a need to separate aggregation between battery DERs and other DERs based on their operational characteristics.		Added text to point to Table 1.2's change on the same comment
ERCOT	11	490	I think there are a few different scenarios here where if DER is solar based, it may be one type of off peak. If DER is another type of fuel, it may be a different off peak scenario.		Changes made based on comment
ERCOT	14	548	Table 2.1 - In addition to the AVR comments above, do you need to also know if there is other interruptible load at the station (UFLS, UVLS, price sensitive load, etc) I know this is steady state but not sure where to put comment.		Added line to Table 3.1
ERCOT	vii	163-164	This bullet point is not clear. What are the other models that would be verified?		Added clarification in bullet

Organization(s)	Page #	Line / Paragraph	Comment	Proposed Change	NERC Response
ERCOT	vii	151-167	It is not clear whether these recommendations are intended to address verification of individual DER sites or aggregate DER behavior observed at the T-D interface.	This section should be more clear that recommendations are focused on DER model verification for aggregate DER model (as seen at the T-D interface) rather than individual DER sites. There should be some recommendation for how to verify aggregate DER response versus aggregate load response and can or should these two components be verified separately.	Changes made as proposed
ERCOT	vi	126-129	If U-DERs are agregated or connected to the same station as R-DER, what is the point of data measurements at the U-DER point of interconnection for model verification purposes? This would only seem to be useful if each DER was explicitly modeled.	Clarification that the measurement point should be dependent on the model practice. If there is any aggregation of R-DER and/or U-DER, it seems that the T-D interface would be the only logical measurement point for model verification.	Added footnote to reference Chapter 1's section on this topic that covers this comment.
ERCOT	viii-ix	206-216	This modeling framework and Figure I.1 have been widely used and promoted in many NERC documents. There is some sense in industry that this is the only appropriate way to represent DER. However, this is only a guideline and not a requirement.	An explicit statement (reminder) should be added to the paragraph at line 215: However, it should be noted that RCs, PCs and TPs may implement alternative ways to represent DER in their respective areas.	Multiple sections in this Reliability Guideline point to the reminder that this document is non-binding. No change made.
ERCOT	x	257-258	"monitoring equipment at the T-D interface would make available data to capture the aggregate behavior of DERs, which can support both DER model verification and load model verification."	Some additional support/discussion of this statement is necessary. Is it possible to verify DER model based on T-D interface measurements or is it only possible to verify a combined response of DER model and load model?	Supporting statements added.
ERCOT	1	303-304	Propose edit for clarity and less abiguity (could be read that DERs are making engineering judgments)	DER model verification starts with having suitable DER data available to make reasonable engineering judgments regarding how to model the aggregate behavior of DERs.	Change made as proposed
ERCOT	2	333-335	When transmission models represent aggregate amounts of DER, PCC monitoring will not be useful for model verifications. I think this section could state that more clearly. Even if U-DERs are modeled explicitly, the value is dependent on the explicit representation of the distribution system in the transmission model that is not likely to be adopted by most TPs/PCs.	Add the following to the end of line 335: "assuming that the necessary portions of the distribution system are explicitly represented within the transmission system model for a specific U-DER."	Changes made to address comment.
ERCOT	3	370-375	Should include a statement about the complication of using T-D measurements to verify DER response separate from load response.		Clarifications made to footnote that contains such statement.
ERCOT	3	388-392	"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."	If suggesting that it is possible and practical to verify aggregate DER models separate from load response, the guideline should provide some actual guidance on how to accomplish this feat.	Changes made based on comment
ERCOT	6	433-437	The purpose of this paragraph is not clear. Is protection device status referring to breaker status or relay information flags to identify that trips are due to over-voltage, under-frequency, etc.?		Added clarification to paragraph.
ERCOT	7	450	Table 1.2 - Accuracy - Shoud the guideline provide actual guidance regarding how data dropouts and other gaps in data collection can be eliminated?		Changes made based on comment.
ERCOT	9	463	Table 1.3 - Triggering - The intent of the statement "In the case, both R-DER and U-DER terminals are expected to have the same as electrical frequency." is not clear.	Suggest replacing with "In the transmission system model, both R-DER and U-DER terminals are expected to have the same as electrical frequency."	Change made as proposed
ERCOT	9	463	Table 1.3 - Duration - 1-2 seconds is too short for the recording window and how would the event to be studied be known ahead of time? Shouldn't the duration be set to capture all relevant events?	Recommend a recording window of at least 30 seconds.	Changes made to address comment.
ERCOT	9	463	Table 1.3 - Accuracy - Should the guideline provide actual guidance regarding how data dropouts and other gaps in data collection can be eliminated?		Changes made based on comment.
ERCOT	9	463	Table 1.3 - Aggregation - this document should highlight and provide guidance for verifying not just differentiations between U-DER and R-DER, but also different technologies/fuel types. How to verify DER models when there is a combination of solar, wind, BESS, diesel, gas?		Added text to point to Table 1.2's change on similar comment
ERCOT	11	476-484	This paragraph does not make sense and needs significant re-write.	Not really even sure what this paragraph is attempting to say.	Changes made based on comment.
ERCOT	11	490	This statement is not very specific.	Would it be more useful to verify minimum or maximum expected DER output levels? Is it important to verify this from the TP perspective or should the TP be considering the extemes of all DER output at 100% capacity and all DER at zero?	Changes made based on comment.
ERCOT	11	486-488	I think these three lines can be simplified as suggested.	The TP should verify DER output levels for the following conditions:	Change not made based on SPIDERWG consensus.
ERCOT	11	496-500	This is really getting into forecasting rather than verification. Load forecasts used in the planning horizon may shift over time (due to economic conditions, weather, etc.) and not reflect what was initially planned. DER forecasts could be similarly affected.	Suggest deleting this paragraph, but if it is deemed necessary, it needs some grammatical work and clarification.	Change made as proposed.
ERCOT	12-13	528-535	Figures 2.1 and 2.2 need more legible axis titles and legends. It is not clear if these are showing DER output at the PCC at the T-D interface, netted with load?	It is not clear what model verification conclusion should be made from this example.	Changes made based on comment.
ERCOT	14	575	typo	Should be "as" instead of "at"	Change made as proposed
ERCOT	14	576	typo	extraneous space before the period	Change made as proposed
ERCOT	14	577-578	typo?	should be "IEEE 1547-2003"?	Changes made as propsed. Changes made based on comment
ERCOT	16	607	typo?	Should refer to figure 2.4?	Change made as proposed
ERCOT	14	686	typo?	Should refer to figure 2.3?	Change made as proposed
ERCOT	14-15	586-596	It would be better if this example provided a numerical conclusion regarding what the measurements actually verify.	It is not clear what modeling this example verifies. A DER with output of 40 MW and 1 MVAr with a station load of 48 MW and 4 MVAr? A DER with zero output and station load of 14 MW and 7 MVAr?	Changes made based on comment
ERCOT	16	604-615	It would be better if this example provided a numerical conclusion regarding what the measurements actually verify.		Changes made based on comment
ERCOT	20	651-656	The paragraph first refers to "verification of the aggregate DER model" and then cites the use of "recorded BPS level events". This does not seem consistent with the use of commisioning tests (referenced in the last sentence) which would seem to be more useful for verifying an individual DER model based on distribution level events/recordings.	Throughout the document, a more clear distinction is needed between verification of aggregate DER models and individual (U-DER) models. Verification of an aggregate model requires a different approach compared to verification of an individual DER model, but these two concepts are often mixed and inter-mingled within the same paragraph leading to confusion. It is suggested that this guideline should focus on verification of aggregate DER models (since aggregate DER models are the more likely representation in transmission system models and verification processes for an individual DER model is not significanly different from verification processes for an individual transmission-connected device).	Moved section identified to more relevant section and added clarity.
ERCOT	20	663	Guidance for how to separate DER response from load response in the verification process is needed.		Changes made in section referenced to address comment.
ERCOT	21	705	Should clarify that DER_A model is designed to represent inverter-based DER. Also, this guideline should acknowledge what applicability it has for verification of non-inverter-based DER. This is a common deficiency of many of the recent DER-related NERC reliability guidelines. They discuss DER in very general terms, but are mostly applicable for inverter-based DER without explicitly acknowledging that limitation or providing additional guidance for addressing non-inverter-based DER.	Modify language as follows: "one of the few current generic models provided for representing inverter-based DER"	Change made as proposed
ERCOT	21	708-709	References to parameterizations for DER aggregations, but this section is supposed to be for "Individual DER Dynamic Model Verification"		Title changed to match content
ERCOT	22	713	Table 3.1 - How much of DER trips during voltage or frequency events? - This row would not seem to be applicable for individual DER - the DER would either ride through the event or not. Further, the Vrfrac parameter is the ratio of DERs that restore output upon voltage recovery and is not associated with frequency.	The table should be modified to address inconsistancies with DER_A parameterization guideline.	Changes made based on comment.
ERCOT	22	716	Is SGIA applicable to distribution-connected generators or only transmission-connected generators?		The SGIA is applicable to those entities that follow FERC rules. Some states have enacted similar requirements for their juristictions. The SGIA has a section that contains the applicability as well.

Organization(s)	Page #	Line / Paragraph	Comment	Proposed Change	NERC Response
ERCOT	22	722-723	It is not clear how measured data at U-DER terminals would allow more accurate aggregations. Also, what is the relavance of accurate aggregations in the section that is supposed to be for "Individual DER Dynamic Model Verification"?	Suggest a more detailed discussion of how measured data at U-DER terminals would allow more accurate aggregations be included in the section covering "Aggregate DERs Dynamic Model Verification"	Changes made based on comment.
ERCOT	22	714-735	It seems that the conclusion of this section is that the SGIA cannot be relied upon to provide measurement data necessary for the PC/TP to verify DER models.	Based on the section title, this section should discuss how model parameters can be verified based on measured data. Instead, it only provides a discussion of how relying on the SGIA may not provide sufficient measurement data for verification. Maybe this section should also provide some guidance on additional ways the PC/TP may obtain appropriate measurement data.	Changes made to address comment.
ERCOT	23-24	749-751	In Figure 3.2, how is it evident that "it is only applicable to collect multiple terminal locations of data when more than a single U-DER installation is modeled at the substation in the aggregation to ensure adequate measurements are available for the TP to verify their models"? What does that mean?		Changes made to address comment.
ERCOT	24	770	Figure 3.2 is very difficult to read and understand. Is this dipicting a one-line with measurement plots as observed at certain locations? Is the 115kV fault location dipicted? Does the load plot represent a specific load, a specific feeder? How does it differ from the transformer loading plots?	Maybe show a simple one-line diagram that can be read with references to larger plots tha could also be more easily read.	Changes made based on comment
ERCOT	24	757-759	Why is reduced current expected during fault? Wouldn't fault current be expected to be delivered through T3 during the fault? Is T3 a 230kV-44kV transformer?		Changes made based on comment. Fault is upstream of the station, so the expected (no DER) response for load is to reduce current as shown in the "Load" portion of the figure. With DER, T3's current increased.
ERCOT	24	761-767	Are T1 & T2 230kV-28kV transformers? Wouldn't a verification require that aggregate model reflect the reduction in DER output or increase in load served from the 230kV station in either a simulation utilizing a playback function or a full system simulation? Showing/discussing that part of the verification process would make this example better. Does this example indicate that the measurements at specific DERs are not really necessary because DER trips (at 28 kV) and no DER trips (at 44kV) can be inferred from the transformer loading plots	Maybe just more clearly state that the increase in observed transformer load current is due to DER tripping (though the solar 5 and solar 6 plots do not seem to indicate a full trip, but certainly a reduction in output).	Changes made based on comment.
ERCOT	27	845	Should refer to DER model verification?	Change section title to "Summary of DER Model Verification". Also, similar modifications should be made in the text body (line 846)	Changes made based on comment.
ERCOT	34	939	typo	There does not appear to be a chapter 4 - should this refer to chater 3 only?	Yes. Change made as proposed.
ERCOT	34	936	typo	Should title be "Hypothetical Dynamic Model Verification Case"?	Change made as proposed.
ERCOT	34	966	typo	induction instead of inductor	Change made as proposed.
ERCOT	36	995	typo	demonted?	Change made to fix typo.
ERCOT	44	1119	Should BTM be defined some place or just spelled out (assume it means behind-the-meter)? This appears to be the only instance where it is used.		Yes. Change made.
ERCOT	4,5	412, 417	Why are some list items in bold and others not?		Should be all not bold. Checked to ensure all not bold.
ERCOT	6	435	typo	becomes	Change made as proposed.
ERCOT	8	450	Post-Processing section needs rewritten - sentence 1	Depending on where the measurement is taken, some post-processing will need to be done to determine if the DER is connected to a point on transmission that is not the normal delivery point.	Change made as proposed.
ERCOT	8	450	Data Format section - sentence 2 - no comma needed		Change made as proposed.
ERCOT	8	452	Needs comma		Change made as proposed.
ERCOT	11	472	typo	initializes	Change made as proposed.
ERCOT	14	557	typo	For example, when coupling..	Change made as proposed.
ERCOT	16	609	typo	were a result of	Change made as proposed.
ERCOT	16	612	typo	verifying	Change made as proposed.
ERCOT	16	612	needs a period after model		Change made as proposed.
ERCOT	21	701	Add a reference to interconnection requirements	...address the modeling practices the entity uses due to interconnection requirements...	Changes made to include reference to interconnection requirements.
ERCOT	21	707	Can the date of installation be requested and that date be translated to a vintage of IEEE 1547? There could be concerns about receiving the correct vintage data, but getting the installation date may be more reliable.		Changes made to Table 3.1 to reference the installation date as a way to answer this question.
ERCOT	26	793	Are there any parameters that should never be changed or tuned?		Changes made based on comment.
ERCOT	34	970	remove were		Changes made to clarify the tenses in the sentence.
ERCOT	38	1017	Change Table B.2 column names to better match the labels in Figure B.5 - Pre-verification and Post-verification		Changes made as proposed.
ERCOT	40	1040	typo	occurring	Change made as proposed.
Exelon	General		Exelon supports the draft Reliability Guideline. As an EEI member Exelon concurs with the comments submitted by EEI.		Thank you for your comment and support for this Reliability Guideline.
EEI	vi	96	General Comments: EEI supports NERC's efforts to address modeling issues surrounding the rapid growth of DER. EEI recognizes that Transmission Planners and Planning Coordinators will, over time, need the level of data identified in this guideline to accurately plan and assess DER impacts on the Reliable Operation of the BES. For this reason, EEI supports this Reliability Guideline as a good template that can be used by companies to develop data gathering process on DERs. We also agree that planners need to continue working closely with stakeholders, rather than just Distribution Providers, to ensure needed data is collected, where and as necessary, to ensure planning models accurately model DER behavior during a wide range of planning scenarios. However, it is also incumbent on NERC to recognize that much of the data identified may not be readily and widely available for some entities at this time and can only be made available through substantial commitments of time and money to both modify, upgrade or in some cases install new systems to collect the type and volume of data needed. EEI also asks NERC to consider that not all companies and regions are equally impacted by DERs at this time, so efforts and investments will vary by region and entity. Therefore, companies will utilize the recommendations contained in this guideline in fundamentally different ways.	Simply asking for realistic expectations, noting that much of what is suggested in this RG will take time and it will be applied differently across the all regions.	Thank you for your comments. The NERC SPIDERWG believes that aggregate DER should be represented in planning assessments, has provided this guidance in pursuit of high-fidelity aggregate DER models for those planning assessments. NERC SPIDERWG understands the time element of many of these recommendations
EEI	vi	109	Correct typo - Transmission Planners (TPs0 to (TPs)	Correct typo	Change made as proposed.
EEI	vii	154 - 157	EEI agrees that the recommendations contained in guidance "is not necessarily more refined than any recommended data required for BPS-connected resources," however, these recommendations do represent a fundamental change for distribution systems and such refinements, while necessary over the long-term, may not be obtainable in the short-term.	Manage expectations	Added footnote to reference the timescale likely involved in this recommendation
EEI	vii	165	The last recommendation needs to be bulleted.	Correct typo	Change made as proposed.
EEI	viii	199	Suggest removing the word "as" – "includes **as** a vast array of event logs."	Consider suggested minor change.	Change made as proposed.
EEI	1	271	Suggest changing "that" to "than" – "aggregate DERs is different **than** the data and information."	Correct typo	Change made as proposed.
EEI	1	283	Data Collection and the Distribution Planner; page 1; line 283: The correct registered entity is "Distribution Provider," not Distribution Planner; please correct.	Correct minor error related to DP meaning.	Change made as proposed.

Organization(s)	Page #	Line / Paragraph	Comment	Proposed Change	NERC Response
PJM				Thank you for the opportunity to provide comments to draft Guideline: NERC Reliability Guideline Model Verification of Aggregate DER Models used in Planning Studies. PJM's concern is specific to the DER data collection by the Transmission Planners and/or Planning Coordinators. The focus to obtain information from non-FERC jurisdictional entities and distribution providers that do not meet the NERC registration criteria, needs to shift from efforts to establish this data requirement through NERC documents, and instead work to convince states to make requirements for their local entities to share this information with Transmission Planners. While we agree with the spirit of the modeling applications, we cannot support the ability to collect this data.	Thank you for the comment. Changes were made based on having requirments for data transfer from DP to TP.
Eversource	3	376	On-site DER developer-owned utility grade relaying may also be available to provide data. These should be programmed to trigger for events appropriately, etc. If NERC has/collaborates on a specific settings guideline this could be passed on to developers.		This Reliability Guideline provides some examples of recordnig type devices and encourages coordination among stakeholders to procure measurements.
Eversource	3	387	Since "PoC" is a defined term in IEEE 1547-2018, does NERC mean "the DER terminals" like IEEE 1547 does, or does it mean something else? (such as the reference point of applicability in IEEE 1547-2018, which could be the PoC (DER terminals), or it could be the location between the end of developer ownership and the beginning of utility ownership.		Changes made based on comment.
Eversource	23	735 / Tabel 3.2	Table 3.2: DER is defined in IEEE 1547 as sources that can provide active power, and therefore including Energy Efficiency and Demand Resources in the table listed as "DER" is misleading, as these are load reduction mechanisms rather than sources of energy.		Changes to the table's footnote based on comment.
ISO New England	vi	109	typo	Change "This guideline provides Transmission Planners (TPs0 to (TPs)	Change made as proposed.
ISO New England	vi	113	Describe who provides the DER data and note that DPs are the only NERC registered entity that can provide this data when facilities are connected to distribution systems.	The first step in DER model verification is collecting data and information regarding actual DER performance (through measurements) to BPS disturbances or other operating 112 conditions. PCs and TPs may typically obtain DER information for facilities 5 MW and above through Small Generator Interconnection Procedures (SGIPs). For facilities connected to distribution systems, the only NERC registered entity that can provide the data is the Distribution Provider.	Change made as proposed.
ISO New England	vii	158	Clarify that DPs (or states) govern most DER interconnection requirements for smaller scale installations. TPs and PCs probably have more control over larger facilities covered by generator interconnection agreements.	TPs, PCs, TOs, and other applicable entities that may need DER information ~~govern DER interconnection requirements~~ should coordinate with DPs for facilities connected to distribution systems to determine the necessary measurement information that would be of use for the purposes of DER modeling and model verification.	Change made as proposed.
ISO New England	vii	163	Clarification needed: This sub-bullet could be misunderstood. What does "other models" mean? Does this mean other DER models, protection models for DER, something else? Do the words "current models" refer to the DER_A model?	Here is a suggested change, **which assumes that** it accurately captures the intent of the sub-bullet: This collaboration should include a procedure where newer DER models, rather than the existing DER models, can be verified with additional data should a more accurate representation be required.	Change made as proposed.
ISO New England	ix	227	Grammar makes the objective of this sentence unclear; make change as shown.	Those model outputs and the measured outputs are compared and if there is a sufficient match based on the TP/PC procedures, then the verification procedure stops.	Change made as proposed.
ISO New England	1	283	Change Distribution Planner to NERC function - Distribution Provider	Data Collection and the Distribution Provider	Change made as proposed.
ISO New England	1	288	Something is wrong with this sentence: "Applicable entities that may govern DER interconnection requirements **states**, upon their review of interconnection requirements for DERs connecting to the DPs footprint, are encouraged to ensure DPs are capable of collecting data for model verification purposes as unverified models have an impact on BPS studies."	Applicable entities that may govern DER interconnection requirements (i.e. states), upon their review of interconnection requirements for DERs connecting to the DPs footprint, are encouraged to ensure DPs are capable of collecting data for model verification purposes as unverified models have an impact on BPS studies.	Change made to address comment.
ISO New England	1	303	In some cases, DERs may not be the appropriate entity to determine aggregate models, it seems it may be the DPs.	DER model verification starts with with applicable entities having suitable data for DER modeling ~~having suitable data available for DERs~~ to make reasonable engineering judgments regarding how to model the aggregate behavior of DERs.	Changes made to address comment.
ISO New England	3	398	Grammar makes this sentence unclear; make change as shown.	...are automatically calculated at initialization to ensure voltage at the terminal end of the composite load model stays within ANSI acceptable ~~voltage~~ continuous service voltage.	Change made as proposed
ISO New England	8	Table 1.2	Grammar: some additional words may be needed to make this sentence more readable and understandable. Topic: 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 it normal delivery point.**	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 it's normal delivery point.	Changes made to address comment.
ISO New England	22	718	Should this be the NERC function - Transmission Service Provider (TSP), if not, then change as shown or use capital letters	And per FERC Order No. 792, metering data is also provided to the transmission ~~service~~ provider.	Change made as proposed
ISO New England	22	730	Note that the SGIA will "apply to" instead of "gather"	In this region, reliance on the SGIA alone will only apply to ~~gather~~ a third of the installed Solar PV DER.	Change made as proposed.
ReliabilityFirst	General report observation		The report jumps back and forth between using P and Q and using MW and MVAR.	Should the report consistently use one or the other, or are readers assume to know that P = MW and Q = MVAR?	Changes made to address comment.
ReliabilityFirst	vi	Line 101-102	This sounds like an aspiration. There are still significant barriers to including DER data into the interconnection-wide cases.	Maybe there needs to be a distinction between one-off study cases to study DER impacts vs. interconnection wide cases.	Changes made based on comment.
ReliabilityFirst	vi	Line 118	Suggest to add TO here. RF has found there is a gap between the DP and LSE that could impact responsibilities associated with DER data collection.	This could be the start of discussions to point the TO towards working collaboratively with the LSEs and DPs in their footprint to get this information.	Changes made based on comment.
ReliabilityFirst	vi	Line 127-128	Per the comment from Line 118, for a majority of these locations, the TO is going to have to request this information from an un-registered entity (i.e. Municipal System, or Rural Electric Co-op).	This could be the start of discussions to point the TO towards working collaboratively with the LSEs and DPs in their footprint to get this information.	Ensured TO was in the list of recommended entities in the recommendation to collaboratively work to gather information.
ReliabilityFirst	vi	Line 136-137	Only focusing on only large disturbances may accidently miss issues associated with the dynamic behavior of load versus generation.	Further emphasize exploration of other methods to be explored outside of large disturbance events. Possible perform a significant audit of the load characteristic before trying to match a performance curve, otherwise the entity may be changing dynamic values when if fact they should be adjusting the composition of the load types.	Changes made based on comment.
ReliabilityFirst	vii	Line 154-155	Consider adding TOs as well.	TOs should work work collaboratively with DPs and other non-registered Load Serving Entities (LSEs). May also require working collaboratively with PUC to enforce or recommend these requirements.	Changes made based on comment.
ReliabilityFirst	vii	Line 156-157	DER data is going to be more difficult to track and obtain than other data related/required for BPS-connected resources. It may be more difficult to aggregate these dispersed resources than accurately one stand-a-lone connection.	Consider removal of this statement.	Change made as proposed
ReliabilityFirst	vii	Line 159	Add LSE with DP reference	DPs and other Load Serving Entities	The registration of a "Load-Serving Entity" no longer exists with FERC accepting the removal of that category of registration. No change made.

Organization(s)	Page #	Line / Paragraph	Comment	Proposed Change	NERC Response
ReliabilityFirst	vii	Line 158-161	Rather than guidance, a SAR is recommended	Suggest that a SAR be created to require the necessary measurement information that would be of use for the purposes of DER modeling and model verification, be collected and provided to the Transmission Operators, Transmission Planners, and Planning Coordinators. If not mandated, it likely that few measuring devices will get installed. Include DPs and Load Serving Entities as part of the SAR.	At this time, SPIDERWG believes that this current guideance will start any measurement device installation or for data to be transferred. The SPIDERWG is currently going through a standards review process that will take this into account for findings of that work product.
ReliabilityFirst	viii	Line 192-193	Further consideration required around the implementation of modeling DERs explicitly.	The recommended practice of modeling gross load and explicitly modeling DER as generation creates barriers to implementation that still need to be resolved. Existing case building practices require the scaling of Transmission Zones to a forecasted load + losses value. There is also a lack of specification for time-of-day and corresponding load composition. Not every TO utilizes coincident load modeling practices.	Thank you for your comment. The NERC SPIDERWG believes that aggregate DER should be represented in planning assessments. Previously published NERC Reliability Guidelines and Technical Reports highlighted the need to model aggregate levels of DERS in planning assessments as well
ReliabilityFirst	viii	Line 202-203	Add some context to this statement.	This might be a good place to add the difference in philosophy regarding long-term planning and near-term/operational planned.	Changes made based on comment.
ReliabilityFirst	ix	Line 213	Additional consideration	Confirm that this representation is feasible in available industry tools like PSS/e.	No change made based on comment. See modeling sections of other SPIDERWG report that confirm: https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability_Guideline_DER_A_Parameterization.pdf
ReliabilityFirst	ix	Line 235-237	Additional consideration	It may be difficult to have a high confidence level for verification efforts in future (5+) year out cases due to the difficulty in predicting the composition of the load (residential, industrial, commercial). It also may be difficult put together an accurate dynamic model for the aggregate load. This may be more applicable for Operation Planning cases (0-2) years out.	Changes made based on comment.
ReliabilityFirst	1	Line 271-272	Add reference to TOs	Consider changing to TOs needing to collaborate with DPs and LSEs	Changes made based on comment.
ReliabilityFirst	1	Line 274-275	Additional consideration	The referenced document does not address how to convert Interconnection-Wide cases to Gross load + explicitly modeled DER. This is a significant shift from NET modeled representation.	This Reliability Guideline references past published Reliability Guidelines that describe this in detail. Changes made based on comment for clarity.
ReliabilityFirst	1	Line 285-286	Correction/wording change	The overwhelming majority of the DPs in the RF footprint are not familiar with load flow or dynamic analysis. These entities may, or may not conduct the interconnection studies, they may be only informed of the results from TPs, PCs, or TOs.	Changes made based on comment.
ReliabilityFirst	1	Line 288-290	Provide additional context for clarification.	Define applicable entities or provide examples	Changes made based on comment.
ReliabilityFirst	2	Footnote 20	Suggest wording change	There could be instances of DERs that are compliant with the referenced standard available prior to 2021. Consider changing 'available' to 'widely available'.	Change made as proposed.
ReliabilityFirst	5	Line 419	Additional consideration	Why is it important for the data collection devices to perform the calculations? With MW and MVAR captured and transmitted, the receiving end can perform the MVA and PF calculation, and less data has to be transmitted.	Changes made based on comment.
ReliabilityFirst	9	Table 1.3 Triggering	Typo correction	have the same as electrical frequency' should be changed to 'have the same electrical frequency'	Change made as proposed.
ReliabilityFirst	22	Line 725	Suggested wording change	Suggest to remove the statement about the data being cumbersome to send. If the TP/PC needs the data, then it should be sent. Strike the “and such data is not cumbersome to send” to the TP/PC.	Change made as proposed.
ReliabilityFirst	23	Line 747	Suggested wording change	Suggest removing "one to many" to make the statement more clear to the reader.	Change made as proposed.
ReliabilityFirst	34	Table B.1 and Figure B.1	Minor correction	Table B.1 and Figure B.1 are not consistent with the placement of "j"	Changes made based on comment
ReliabilityFirst	40	Line 1033	Suggested wording change	TPs and PCs are familiar with model verification when they comply with MOD-33. Suggest removing the statement about TPs and PCs, 'may not know'.	Changes made based on comment.
ReliabilityFirst	41	Line 1055	Add context in wording or footnote	With the reference to three cycles, it may be beneficial to indicate that three cycles is 0.05 seconds since Figure C.2 is shown in terms of seconds.	Changes made based on comment.
ReliabilityFirst	41	Figure C.2	Reformat graph	After 0.40 seconds Figure C.2 change from being AC to DC. Reformat the graph to cut off at 0.4 seconds	Change made as requested.
ReliabilityFirst	41	Line 1065	Suggested wording change	Suggest removing the word "reasonably". It was not unreasonable for there to have been no delay.	Changes made as proposed.
ReliabilityFirst	44	Line 1123	Suggested wording change	Suggest replacing 'As with all' with 'Typically for'.	Change made as proposed
ReliabilityFirst	45	Line 1143	Additional consideration	State more directly that SCADA with 2-4 second scan rates is not the tool for identifying how much IBR dropped out for a couple of seconds.	Change made based on proposed addition.

Organization(s)	Page #	Line / Paragraph	Comment	Proposed Change	NERC Response
EPRI			EPRI	Add a paragraph similar to NERC's 1547-2018 reliability guideline like this one (***additions in bold italics)*** : *Management of the increasing diversity of DER functional settings can become a challenge. Even once DPs and RCs 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 so-called manufacturer-automated profiles (MAPs) that preset certain functional parameters to the values specified in applicable rules (e.g., CA Rule 21, HI Rule 14H, or the default values of a certain IEEE 1547-2018 performance category). To date, these MAPs 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 MAP 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 cornerstone 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.[Footnote 1] 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, which will be used to exchange and store DER settings. Potential use cases of such common file format include:*** ***- 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***	Change made based on proposed addition.

Battery Energy Storage Systems (BESS) and Hybrid Power Plant Modeling and Performance Guideline

Action

Approve

Summary

The Guideline was posted for a 45-day comment period and the IRPWG has responded to comments and made conforming revisions to the guideline. They are seeking approval of the Battery Energy Storage Systems (BESS) and Hybrid Power Plant Modeling and Performance Guideline.

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

Approve the Reliability Guideline

Julia Matevosyan, IRPWG Vice Chair

NERC Reliability and Security Technical Committee Meeting

March 2021

RELIABILITY | RESILIENCE | SECURITY




Background

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

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

Reliability Guideline

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

Milestones

- 12/15/2020 – Reliability and Security Technical Committee accepted the document for a 45-day industry comment period
- 12/18/2020 – The Reliability Guideline posted for comments
- 2/2/2021 – Comment period concluded
- 2/2/2021 - 2/10/2021 – IRPWG made conforming changes to the Reliability Guideline and responded to comments in the comment matrix
- 2/10/2021 – Comment matrix redline and final version of the Reliability Guideline included in the RSTC agenda packet

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NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Request

- The IRPWG requests that the Reliability and Security Technical Committee approve the IRPWG Reliability Guideline: Performance, Modeling, and Simulations of BPS-Connected Battery Energy Storage Systems and Hybrid Power Plants

Questions and Answers

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Reliability Guideline

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

March 2021

RELIABILITY | RESILIENCE | SECURITY




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Preface

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

Reliability | Resilience | Security
Because nearly 400 million citizens in North America are counting on us

The North American BPS is divided into six RE boundaries as shown in the map and corresponding table below. The multicolored area denotes overlap as some load-serving entities participate in one RE 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 bulk power system (BPS) operations, planning, and security. Reliability guidelines provide key practices, guidance, and information on specific issues critical to promote and maintain a highly reliable and secure BPS.

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

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.

- [Reserved]

Executive Summary

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

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

The recommendations in this guideline should apply to all BPS-connected BESSs and hybrid plants, and should not be limited only to Bulk Electric System (BES) facilities. Many newly interconnecting BESS projects and hybrid plants may not meet the BES definition; however, having unified performance and behavior from all BPS-connected inverter-based resources (including BESSs and hybrid plants) is important for reliable operation of the North American BPS. Building off the NERC *Reliability Guideline: Improvements to Interconnection Requirements for BPS-Connected Inverter-Based Resources*,[4] 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. The IEEE P2800 project is currently developing “interconnection capability and performance criteria for inverter-based resources interconnected with transmission and networked sub-transmission systems” that will also apply to BESSs and hybrid power plants.[5] Where any potential overlap exists, the guidance in this reliability guideline should be considered by applicable entities until IEEE P2800 is approved and fully implemented by industry.

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

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

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

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

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

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

High-Level Recommendations

This Reliability Guideline contains detailed recommendations regarding BESS and hybrid power plant performance, modeling, and studies. Industry is strongly encouraged to review the guidance provided, use the technical details and reference materials provided, and adapt the recommendations provided for their specific processes and practices. Table ES.1 provides a set of high-level recommendations (categorized by performance, modeling, and studies), and applicability[6] of the recommendations provided, that encompass all aspects of the guidance contained throughout this Reliability Guideline.

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

#	Recommendation	Applicable Entities
A1	**Applicability:** The recommendations in this guideline should be applied to all BPS-connected BESSs and hybrid plants, and should not be limited to only BES facilities. Many newly interconnecting BESSs and hybrid power plants may not meet the BES definition; however, having unified performance and behavior from all BPS-connected inverter-based resources is important for reliable operation of the North American BPS.	TOs, TPs, PCs, BAs, RCs, GOs, GOPs, developers, equipment manufacturers
P1	**BESS and Hybrid Plant Performance:** GOs of existing or newly interconnecting BESSs and hybrid power plants should closely review the recommended performance characteristics outlined in this Reliability Guideline and adopt these recommendations into existing and new facilities to the extent possible. Newly interconnecting GOs of BESSs and hybrid power plants should work closely with their respective TOs, Balancing Authorities (BAs), Reliability Coordinators (RCs), TPs, and PCs to ensure all entities have an understanding of the operational capabilities and limitations of the facilities being interconnected. 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 BESSs and hybrid power plants. TPs and PCs should ensure that their modeling requirements include clear specifications for BESSs and hybrid power plants. TPs and PCs should also ensure that their study processes and practices are updated and improved to consider the unique operational capabilities of those facilities.	TOs, TPs, PCs
P3	**Unique Operational Capabilities of BESSs and Hybrid Power Plants:** All applicable entities should consider the detailed guidance contained in this guideline and fully utilize the operational capabilities of these new technologies to support reliable operation of the BPS. Capabilities such as grid forming technology, operation in low short-circuit networks, ability to provide primary and fast frequency response, and other functions more readily available in these new technologies should be fully utilized (as needed) and are essential reliability services for the BPS.	TOs, TPs, PCs, BAs, RCs, GOs, GOPs, developers, equipment manufacturers

[6] 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 BESSs 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. Any modifications to equipment settings that have an impact on the electrical performance of the equipment should be studied by the TP and PC 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 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"[7] 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 processes for both interconnection studies and annual planning studies to ensure they are appropriate for a BPS with significantly more BESSs and hybrid power plants. Determination of stressed operating conditions, selection of study assumptions, inclusion of various modeling practices, and determination of appropriate dispatch conditions are just a few areas where close attention will be needed by TPs and PCs to ensure their study approaches align with the new technologies.	TPs, PCs
S2	**Expansion of Study Conditions:** The variability and uncertainty of renewable energy resources has led TPs and PCs to study different expected operating conditions than were previously used for planning assessments. BESSs and hybrid plants may help address some of the operational variability; however, developing suitable and reasonable study assumptions will become a significant challenge for future planning studies. TPs and PCs may need to expand the set of study conditions used for future planning assessments as the most severe operating conditions may change over time.	TPs, PCs

[7] "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.

Introduction

The North American generation mix like many areas around the world is trending towards increasing amounts of inverter-based resources, most predominantly wind and solar PV resources. According to the U.S. Energy Information Administration (EIA) Annual Energy Outlook 2020,[8] wind power capacity in the United States more than doubled in the past decade (39.6 GW in 2010 to 107.4 GW in 2019) and solar generation multiplied by 25x from 2.7 GW in 2010 to 67.7 GW in 2019. Wind and solar generation supplied nearly 7.2% and 2.7% of U.S. energy in 2019, respectively. The EIA and many other organizations have projected continued rapid growth of both technologies over the next several decades. This rapid evolution at both the BPS and distribution system challenges conventional planning and operating practices yet also poses benefits to BPS planning, operations, and design. One of the primary challenges is the variability and uncertainty of renewable energy resources, which leads to additional variability and uncertainty in the planning and operations horizons. The need for flexibility coupled with favorable economics has therefore led to an influx of BPS-connected energy storage projects and hybrid power plants using energy storage.[9]

Areas across North America are also seeking low-carbon power systems. For example, California requires[10] by the end of 2045 that eligible renewable energy resources and zero-carbon resources supply 100% of retail sales of electric energy to California end-use customers and 100% of electric energy procured to serve all state agencies. As such, the California Public Utilities Commission has seen a surge of new energy storage contracts, achieved its 2020 energy storage goal of 1,325 MW ahead of time,[11] and is projected to have 55,000 MW of new storage by 2045.[12] At the same time, the risk and impact of wildfires in the region is leading California utilities, policymakers, and end-use customers toward more close consideration for grid resilience and flexibility. Energy storage systems, particularly battery energy storage systems (BESSs), and BESSs coupled with inverter-based resources to create hybrid power plants are providing short-term energy and reliability services including ramping and variability control, voltage and frequency regulation, operation in low short-circuit strength conditions, and other features.

Historically, BESSs have not been a significant factor in planning and operating the BPS; however, interconnection requests and projects being constructed today have scaled up to match the size of solar PV and wind plants. For example, the Gateway Project in the San Diego Gas and Electric area consists of a 250 MW BESS providing energy and ancillary services in the California Independent System Operator (CAISO) market.[13] California recently approved a proposed 1,500 MW battery at Moss Landing.[14] Southern California Edison currently has several hundred megawatts of BESSs deployed in their region with much more in their

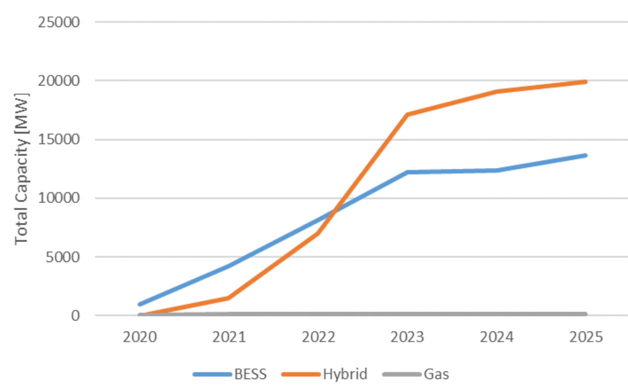

Figure I.1

: Review of CAISO Interconnection Queue for Hybrid Resources and BESSs

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

[9] 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.

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

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

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

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

[14] 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/

interconnection queue.[15] Figure I.1 shows a cursory review of the CAISO interconnection queue (captured in early 2020), where most new interconnection requests are either stand-alone BESSs or hybrid plants consisting mainly of solar PV or wind combined with a BESS component. Elsewhere, in ERCOT over 1600 MW of BESSs are expected to be in-service by end of 2021.[16] These types of interconnection requests are observed across North America, and these newly connecting resources will need to operate reliably to provide essential reliability services, be modeled appropriately, and also be studied as part of the interconnection study process.

Generation interconnection queues are currently inundated with requests for new interconnections of BESSs and hybrid power plants. TPs and PCs need the capabilities to accurately model and study these resources in the interconnection studies and annual planning processes. While early BESSs were primarily proposed for energy arbitrage and mitigating renewable resource variability, there has been more recent interest in installing BESSs for broader services as a generating resource or even as a source of transmission services such as voltage support under "storage as transmission facility"[17] programs. Therefore, it is imperative to have clear guidance on how BESSs and hybrid power plants should perform when connected to the BPS, and also to have recommended practices for modeling and studying BESSs and hybrid power plants for power flow, stability, short-circuit, and electromagnetic transient (EMT) studies. These types of modeling practices and studies are the primary focus of this guideline.[18]

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

Fundamentals of Energy Storage Systems

Energy storage can take many different forms, and some are synchronously connected to the grid while others are connected through a power electronics interface (i.e., inverter-based). Examples of different energy storage technologies include, but are not limited to, the following:[19]

- **Battery Energy Storage:** There are many types of battery energy storage systems (BESSs) – lithium-ion, nickel-cadmium, sodium sulfur, redox flow, and other types of batteries.[20] Batteries convert stored chemical energy to direct current (dc) electrical energy, and vice versa. Power electronic converters (i.e., inverters) are used to connect the battery to the alternating current (ac) power grid.

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

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

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15 https://www.edison.com/home/innovation/energy-storage.html

16 http://www.ercot.com/content/wcm/lists/197386/Capacity_Changes_by_Fuel_Type_Charts_October_2020.xlsx

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

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

19 https://energystorage.org/why-energy-storage/technologies/

20 https://energystorage.org/why-energy-storage/technologies/solid-electrode-batteries/

- **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.[21]

- **Thermal Energy Storage:** Thermal energy storage involves heating or cooling a material with a high heat capacity and recovering the energy later using the thermal gradient between the thermal storage medium and the ambient conditions. For example, electric energy could be used to heat volcanic stones, which can then be converted back to electric energy using a steam turbine.[22] Concentrated solar plants use molten salt as thermal storage medium and steam turbines to convert heat to electric energy.

- **Compressed Air Energy Storage:** Compressed air storage stores energy in the form of pressurized air in a geological feature or other facility. Energy can be delivered back to the grid at a later time, usually by heating the pressurized air and sending it through a turbine to generate power.

- **Supercapacitors:** Supercapacitors are high-power electrostatic devices with fast charging and discharging capability (order of 1-10 seconds) and low energy density. There are no chemical reactions occurring during charging and discharging, which can result in low maintenance costs, long lifetimes, and high efficiency. These devices are scalable, but their fast response can generally not be sustained due to the low energy density.

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

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

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

Fundamentals of Hybrid Plants with BESS

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

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

There are many types of hybrid power plants that combine synchronous generation, inverter-based generation, and energy storage systems;[23] 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

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

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

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

technologies.[24] Due to this fact, this guideline focuses 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 impacts how the resource interacts with the BPS, its ability to provide essential reliability services, how it is modeled, and how it is studied. Hybrid plants can be classified as either of the following:

- **AC-Coupled Hybrid Plants:** An ac-coupled hybrid power plant couples each form of generation or storage at a common collection bus after it has been converted from dc to ac at each individual inverter. **Figure I.3**2 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.3** shows a simple illustration of one possible configuration of a dc-coupled hybrid power plant, where the energy storage component is coupled through a dc-dc converter on the dc side. The dc-ac inverter can be unidirectional where the BESS can only be charged from the renewable resource or bi-directional where the BESS can also be charged from the BPS (depending on interconnection requirements and agreements).[25] There are multiple different possible configurations for dc-coupled facilities, particularly on the dc-side between the generating resource, the BESS, and ways they connect through the ac-dc inverter.[26]

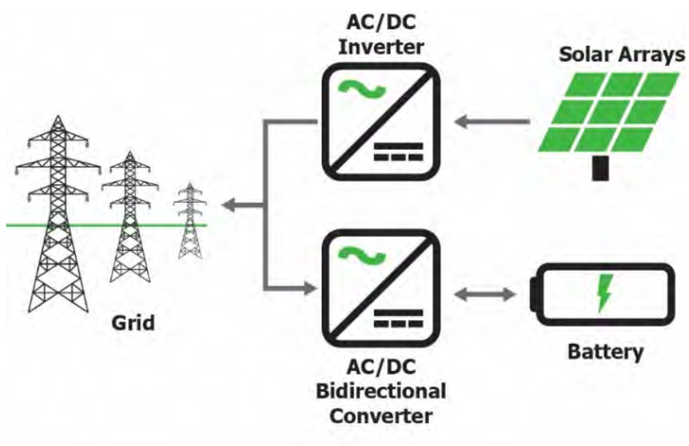

Figure I.2: Illustration of AC-Coupled Hybrid Plant

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

[25] 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

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

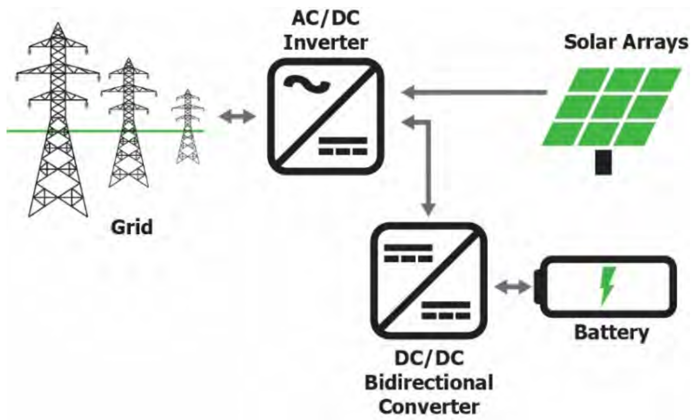

Figure I.3: Illustration of DC-Coupled Hybrid Plant

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

Hybrid plants combine many of the benefits of stand-alone BESSs with renewable energy generating resources, including but not limited to the following:[27]

- **Cost Efficiencies:** Integrating different technologies at the same location enables a developer to save on shared electrical, controls, and communications equipment; simplifies siting; allows for shared personnel; improves maintenance schedules; reduces electrical losses associated with ac/dc conversion efficiency (i.e., dc-coupled); and saves on other relevant operational costs.
- **Reduced Interconnection Costs:** In some cases, adding a battery that can charge and discharge on command can reduce interconnection costs for a renewable generator by avoiding overloads on existing transmission equipment or addressing reliability needs that may have required new transmission equipment.
- **Energy Arbitrage:** The storage element in a hybrid plant can be used to charge during low-priced hours and discharge during high-priced hours, shifting energy production to those hours where energy is needed. Current arbitrage for hybrids (and BESSs) is on the order of hours and days; future technologies may be able to further shift energy storage and production based on system needs.
- **Excess Energy Harvesting:** Hybrid plants have the added benefit of being able to capture any excess solar or wind production that would otherwise be lost or "clipped" (e.g., due to curtailment or oversizing of PV panels compared to inverter size). Capturing excess energy increases plant capacity factor, enabling it to continue operating when the generating resource output decreases.
- **Frequency Response Capability:** 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 fast frequency response.[28] The energy storage component can initially

[27] The benefits noted are also generally applicable to stand-alone energy storage devices such as BESSs; the benefits noted here focus on how addition of a BESS to a traditional renewable energy generating project can improve the operational capabilities and flexibility of the resource.
[28] 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 fast frequency response until the combustion turbine is turned on to sustain the provided response.

charge or discharge rapidly, delivering initial performance of fast frequency response, 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[29] are differentiating co-located power plants from hybrid plants due to their key differences. Co-located power plants can be defined as:

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

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

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

Chapter 1: BPS-Connected BESS and Hybrid Plant Performance

BESSs and hybrid plants have similar recommended performance to other BPS-connected inverter-based resources (e.g., wind and solar PV plants). However, there are unique operational and technological differences that need to be considered when describing the recommended performance for these facilities. The NERC *Reliability Guideline: BPS-Connected Inverter-Based Resource Performance*[30] provided a foundation of recommended performance for BPS-connected inverter-based resources, including BESSs and hybrid plants; however, it did not go into the technical details for these resources. This chapter describes in more depth the specific technological considerations that should be made when describing the recommended performance for these resources.

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

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

Recommended Performance and Considerations for BESS Facilities

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

Table 1.1: High Level Considerations for BESS Performance

Category	Specifications and Comparison with BPS-Connected Inverter-Based Generators
Momentary Cessation	No significant differences from other BPS-connected inverter-based generating resources; momentary cessation should not be used to greatest possible extent[31] 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[32] 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.

[30] https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Inverter-Based_Resource_Performance_Guideline.pdf
[31] 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.
[32] 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.

Table 1.1: High Level Considerations for BESS Performance

Category	Specifications and Comparison with BPS-Connected Inverter-Based Generators
Active Power-Frequency Controls	Active power-frequency controls can be extended to the charging region of operation for BESSs. The conventional droop characteristic can be used in both discharging and charging modes. Further, a droop gain[33] 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[34] of active power-frequency control to support the BPS should be coordinated with system needs. The fast response of BESSs to frequency deviations can provide reliability benefits. Consistent with FERC Order 842, there should be no requirement for BESS resources to provide frequency response if the 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.
Fast Frequency Response (FFR)	BESSs are well-positioned for providing FFR to systems with high rate-of-change-of-frequency (ROCOF) due to not having any rotational components (similar to a solar PV facility). The need for FFR is based on each specific Interconnection's need.[35] Sustained forms of FFR help arrest fast frequency excursions but also help overall frequency control. BESSs are likely to be able to provide sustained FFR within their SOC constraints. With the ability for BESSs to rapidly change MW output across their full charge and discharge ranges (within SOC limits), BPS voltage fluctuations should be closely monitored especially on systems with lower short-circuit ratios.
Reactive Power-Voltage Control	BESSs should be configured to provide dynamic voltage control during both discharging and charging operations to support BPS voltages during normal and abnormal conditions. TOPs should provide a voltage schedule (i.e., a voltage set point and tolerance) to all BESSs, applicable to both operating modes.
Reactive Current-Voltage Control	No significant difference from other BPS-connected inverter-based generating resources. BESSs should be configured to provide dynamic voltage support during large disturbances both while charging and discharging.
Reactive Power at No Active Power Output	No significant difference from other BPS-connected inverter-based generating resources.
Inverter Current Injection during Fault Conditions	BESSs should be configured to provide fault current contribution during large disturbance events that can support legacy BPS protection and stability.[36] Inverter limits will need to be met, as with all inverter-based resources; however, SOC may not be an issue for providing fault current for BESSs since faults are typically cleared in fractions of a second. Additionally, limits on dc voltage magnitude can apply.

[33] Droop should be set using the same base for both charging and discharging mode of operation (e.g., rated active power, P_{max}), so that the same rate of response is provided regardless of charging or discharging.
[34] 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.
[35] 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
[36] Large disturbance fault current contribution from inverter-based resources can help ensure BPS protection schemes operate appropriately by ensuring they have appropriate voltage-current relationships of magnitude and phase angles (i.e., appropriate positive and negative sequence current injection).

Table 1.1: High Level Considerations for BESS Performance	
Category	**Specifications and Comparison with BPS-Connected Inverter-Based Generators**
Return to Service Following Tripping	BESSs should return to service following any tripping or other off-line operation by operating at the origin (no significant exchange of active or reactive power with the BPS), and then ramp back to the expected power output. This is a function of plant settings and interconnection requirements set by the BA or TO.
Balancing	No significant difference from other BPS-connected inverter-based generating resources. The capability to provide balancing services for the BPS should be available from all BESSs. BAs, TPs, PCs, and RCs should ensure requirements are in place for appropriate balancing of the BPS.
Monitoring	No significant difference from other BPS-connected inverter-based generating resources.
Operation in Low Short-Circuit Strength Systems	No significant difference from other BPS-connected inverter-based generating resources. BESSs should utilize grid forming operation, as appropriate (see below), to support BPS stability and reliability in low short-circuit strength operating conditions.
Grid Forming	BESSs have the unique capabilities to effectively deploy grid forming technology to help improve BPS reliability in the future of high penetration of inverter-based resources. Key aspects that enable this functionality include availability of an energy buffer to be deployed for imbalances in generation and load, low communication latency between different layers of controllers, and robust dc voltage that enables synthesis of an ac voltage for a wide variety of system conditions. In grids where system strength and other stability issues are of concern, BESSs may be required to have this capability to support reliable operation of the BPS. TPs and PCs should develop interconnection requirements and new practices, as needed, to integrate the concepts of grid forming technology into the planning processes.
Fault Ride-Through Capability	No significant difference from other BPS-connected inverter-based generating resources. BESSs should have the same capability to ride through fault events on the BPS, when point of measurement (POM) voltage and frequency is within the curves specified in the latest effective version of PRC-024.[37] This applies to both charging and discharging modes; unexpected tripping of generation or load resources on the BPS will degrade system stability and adversely impact BPS reliability. Ride-through capability is a fundamental need for all BPS-connected resources such that planning studies can identify any expected risks. However, the behavior during ride-through while discharging and charging may be different.
System Restoration and Blackstart Capability	BESSs may have the ability to form and sustain their own electrical island if they are to be designated as part of a blackstart cranking path. This may require new control topologies or modifications to settings that enable this functionality. Blackstart conditions may cause large power and voltage swings that must be reliably controlled and withstood by all blackstart resources (i.e., operation under low short circuit grid conditions). For BESSs to operate as a blackstart resource, assurance of energy availability as well as designed energy rating that ensures energy availability for the entire period of restoration activities is required. At this time, it is unlikely that most legacy BESSs can support system restoration activities as a stand-alone resource; however, they may be used to enable start-up of subsequent solar PV, wind, or synchronous machine plants.

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

Table 1.1: High Level Considerations for BESS Performance	
Category	**Specifications and Comparison with BPS-Connected Inverter-Based Generators**
Protection Settings	No significant difference from other BPS-connected inverter-based generating resources.
State of Charge *(new)*	The SOC of a BESS affects the ability of the BESS to provide energy or other essential reliability services to the BPS at any given time.[38] In many cases, the BESS may have SOC limits that are tighter than 0–100%[39] for battery lifespan and other equipment and performance considerations. SOC limits affect the ability of the BESS to operate as expected, and any SOC limits will override any other ability of the BESS to provide essential reliability services (ERSs) or energy to the BPS. These limits and how they affect BESS operation should be defined by the equipment manufacturers and plant developer, agreed upon by the GO, and provided to the BA, TOP, RC, TP and PC.
Oscillation Damping Support	BESSs can have the capability of providing damping support similarly to synchronous generators and HVDC/FACTS facilities. BPS-connected inverter-based resources could also provide damping support. A major difference from other BPS-connected inverter-based resources is that BESSs can operate in the charging mode in addition to the discharging mode, which provide greater capabilities of damping support.

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

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

- **Momentary Cessation:** To the greatest possible extent,[40] BESSs should not use momentary cessation as a form of large disturbance behavior when connected to the BPS. Any existing BESSs using momentary cessation should eliminate its use to the extent possible, and its use for newly interconnecting BESSs should be disallowed by TOs in their interconnection requirements. Sufficiently fast dynamic active and reactive current controls are more suitable.[41] If voltage at the POM is outside the curves specified in the latest effective version of PRC-024, then momentary cessation may be used to avoid tripping of the BESS. However, inside the curves, momentary cessation should not be used, subject to limitations for legacy equipment. This recommendation applies for both charging and discharging operation.
- **Phase Jump Immunity:** Similar to other inverter-based resources, BESSs should be able to withstand all expected phase jumps on the BPS; this applies during both charging and discharging operation. Efforts such as P2800 may help standardize expected thresholds for newly interconnecting inverters to be able withstand in terms of phase jump immunity. In the meantime, the TO (in coordination with their TP and PC) should clearly specify what this expectation is so that newly interconnecting projects can test their performance against worst-case expected phase jumps during grid events.
- **Reactive Current-Voltage Control (Large Disturbances):** Fundamentally, there are no significant differences between BESSs and other BPS-connected inverter-based resources with respect to reactive current-voltage control during large disturbances. BESS inverters should maintain stability, adhere to inverter current limits, and provide fast dynamic response to BPS fault events in both charging and discharging modes. Transitions from charging to discharging (e.g., caused by active power-frequency controls) during large disturbances should not impede the BESS from dynamically supporting BPS voltage and reactive current injection. Studies should ensure stable performance for charging and discharging.

[38] https://www.nrel.gov/docs/fy19osti/74426.pdf
[39] Or the values 0% and 100% can simply be defined as the normally allowable range of operation.
[40] 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.
[41] In rare cases, momentary cessation may be admissible based on reliability studies performed by the TP and PC on a case-by-case basis.

- **Reactive Power at No Active Power Output:** BESSs should have capability to provide dynamic reactive power to support BPS voltage while not discharging or charging active power. This is one of the benefits of inverter-based technology and can be utilized by grid operators to help regulate BPS voltages. Every BESS should have the capability to perform such operation, and the actual use of such capability should be coordinated with the TOP and RC regarding any voltage regulation requirements and scheduled voltage ranges.
- **Return to Service Following Tripping:** BESSs should adhere to any requirements set forth by its respective BA. In general, following any tripping or other off-line operation, BESSs should return to service starting at their origin point on the capability curve (i.e., operation at no active or reactive power loading) and then ramp to their expected operating point based on recommendations or requirements provided by the BA (or TO in their interconnection requirements).
- **Balancing:** The capability to provide balancing services to the BA for the purposes of ensuring BPS reliability should be available from all BESSs. BAs, TPs, PCs, and other applicable entities should understand what services are being provided from BESSs; however, the capability to providing balancing services to the BA should be available from all BESSs.
- **Monitoring:** BESSs should be equipped with equipment that provides the functionality of a digital fault recorder (DFR), dynamic disturbance recorder (DDR), sequence of events recorder (SER), harmonics recorder, and battery management system (BMS)[42] 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 will operate stably in its electrical environment and in any of its operating modes. For example, if the short-circuit strength is low, operation of the hybrid resource should be studied in detail by the TP and PC using EMT simulations, as appropriate. Studies should also be conducted to ensure that no instability modes exist at higher frequencies. In addition, the ability of newly interconnecting BESSs to operate with grid forming technology[43] (described below) enable BESSs to operate in very low short-circuit strength networks and further provide BPS support beyond other grid-following inverter-based resources. Refer to recommendations from NERC *Reliability Guideline: BPS-Connected Inverter-Based Resource Performance* as well as NERC *Reliability Guideline: Integrating Inverter-Based Resources into Low Short Circuit Strength Systems*.[44]
- **Fault Ride-Through Capability:** BESSs, like other BPS-connected inverter-based resources, should have the capability to ride through voltage and frequency disturbances when RMS voltage at the POM is within the curves of the latest effective version of PRC-024, subject to limitations for legacy equipment. Ride-through performance requirements should apply to both charging and discharging modes, since unexpected tripping of any generation or load resources on the BPS will degrade system stability and adversely impact BPS reliability. Ride-through capability is a fundamental need for all BPS-connected resources such that planning studies can identify any expected risks.
- **Protection Settings:** Appropriate protections should be in place to operate BESS facilities safely and reliably when connected to the BPS. To ensure proper site coordination with the interconnecting TO, protection settings should be clearly documented and provided to the TO for approval by the BESS owner. Additionally,

[42] 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).

[43] 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.

[44] 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

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.[45]

Refer to the recommendations outlined in NERC *Reliability Guideline: BPS-Connected Inverter-Based Resource Performance*[46] for more details on each of the aforementioned subjects. The following sub-sections outline the additional topics from **Table 1.1** that warrant additional details and where BESSs have specific considerations that need to be taken.

Capability Curve

BESSs are generally four-quadrant devices that extend into the charging region. BESS inverters may be nearly symmetrical[47] (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 the capture the gross ratings as well as net rating of the facility that accounts for station service, losses, and other factors. Capability curves for the overall BESS should be provided by the GO to the TO, TP, PC, TOP, and RC to ensure sufficient understanding of the capabilities of the BESS to provide reactive power under varying active power outputs.

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[45] 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

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

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

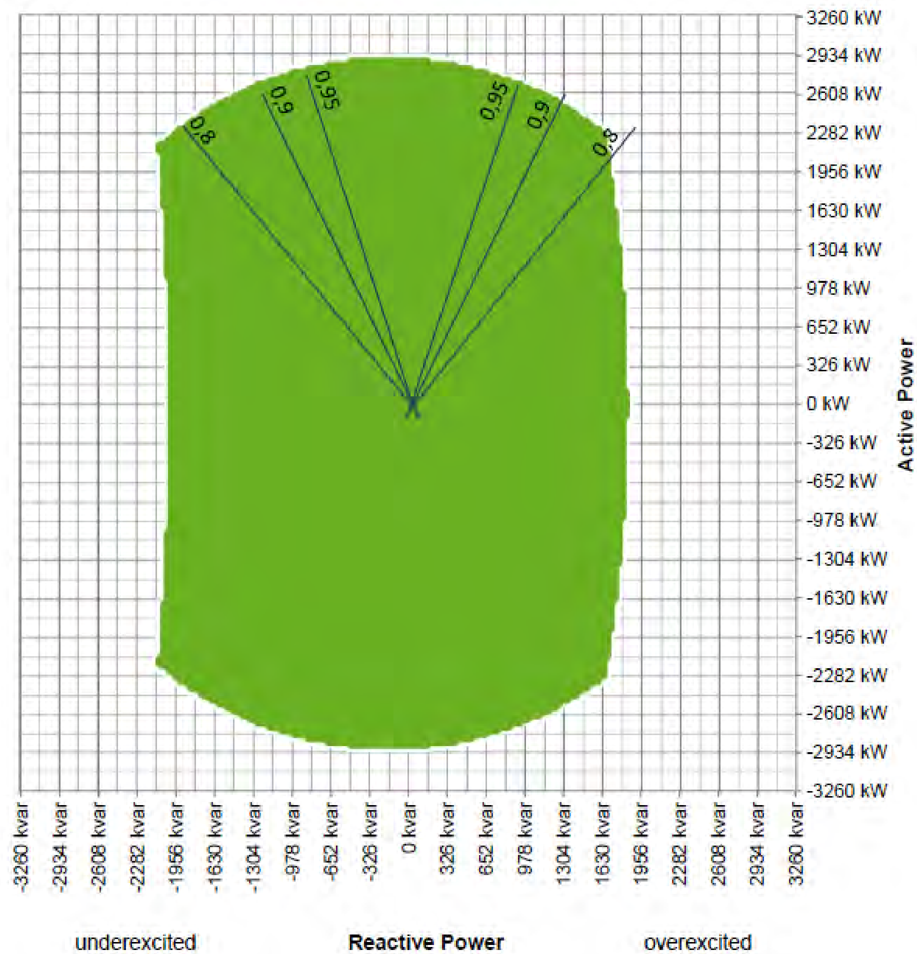

Figure 1.1: Example of 2.7 MVA BESS Capability Curve [Source: SMA America]

Active Power-Frequency Control

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

Fast Frequency Response

As the instantaneous penetration of inverter-based resources continues to increase, on-line synchronous inertia may decrease and rate-of-change of frequency (ROCOF) may continue to increase. High ROCOF systems may be faced with the need for faster-responding resources to ensure that unexpected underfrequency load shedding (UFLS) operations do not occur.[48]

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

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

Many different simulations can be performed to show the benefits of utilizing BESSs for improving frequency response, particularly improving the nadir of system frequency following a large loss of generation. **Figure 1.2** illustrates one study demonstrating these affects. The blue trace shows the response following a large generation loss for a synchronous-based system. The red plot shows the same system (with same amount of reserves) with the synchronous generation replaced with BESSs (with one option of frequency control enabled). The green plots show the system with BESSs with a different frequency control logic and tuned appropriately. The system dominated by synchronous machines exhibits an initial inertial response followed by a slower turbine-governor response. On the other hand, while the BESS system does not have physical inertia like a synchronous machine, its controls can be tuned to provide a suitably fast injection of energy such that the initial ROCOF remains nearly the same (or even improved) and the frequency nadir is significantly improved. Note that voltages should be monitored closely as high-speed active power responses can cause high-speed voltage fluctuations, especially in low short-circuit-ratio conditions.

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

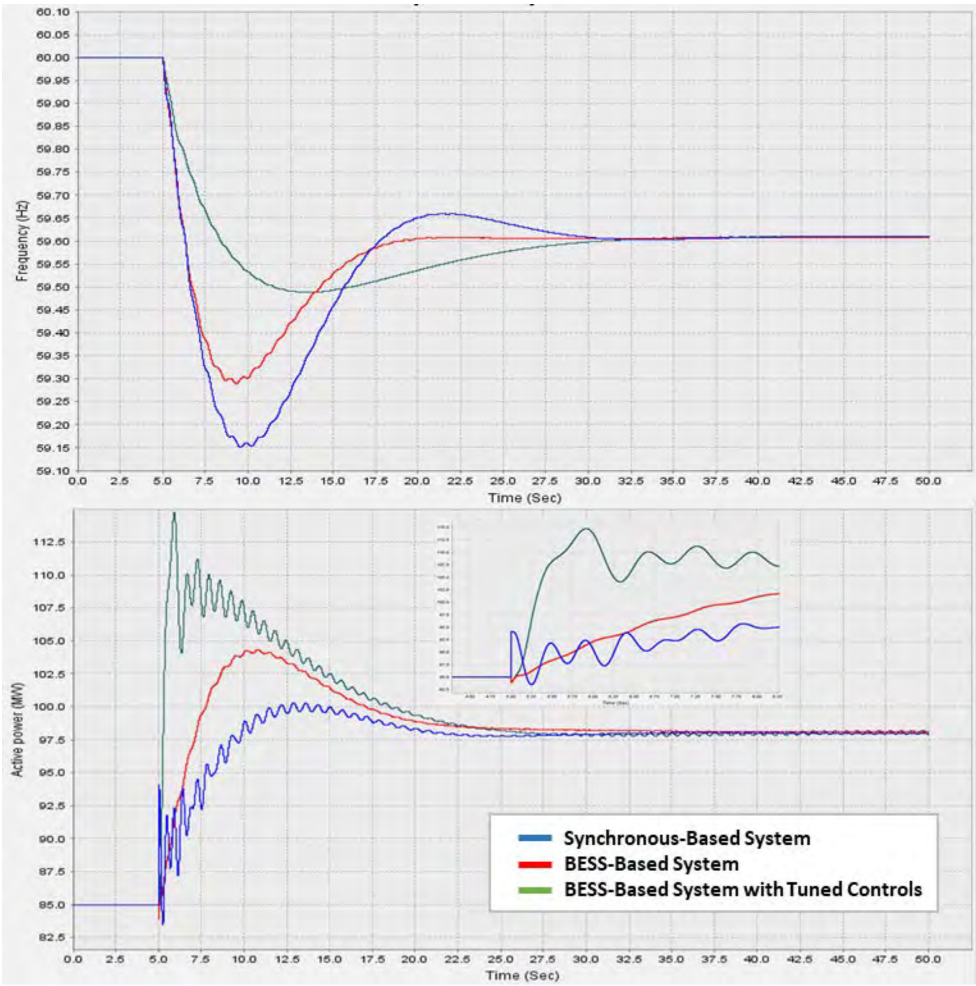

Figure 1.2: Demonstration of Impacts of a BESS on Frequency Response [Source: EPRI]

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

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

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

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

Inverter Current Injection during Fault Conditions

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

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

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

Grid Forming

Most commercially available inverters currently require an external source to provide a reference voltage to which the inverter phase-locks. These inverters are termed "grid-following".[49] 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").[50] While there is currently no standard industry definition for grid forming technology, a broad definition can be:

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

Four key aspects that enable achieving this operation mode are:

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

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

[49] 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.

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

Tesla's Grid Forming + Grid Following Philosophy

Tesla BESSs are currently utilizing a concept of "grid forming + grid following" where the BESS is able to provide both functionalities based on BPS reliability needs. When the BESS is operating in virtual machine mode, the dynamics of a virtual synchronous condenser are added to the output of the current-source inverter (see **Figure 1.3**). 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 sub-cycle phase response, voltage stability, and fast fault current injection that helps in smooth transitions between different operating states. With such a hybrid approach, the BESS remains responsive to active and reactive power dispatch commands while providing essential reliability services to the BPS during dynamic grid events. While there are many possible ways to accomplish grid forming capabilities, Tesla has implemented this feature into its products in an effort to support BPS operation with decreased inertia and overall system strength.

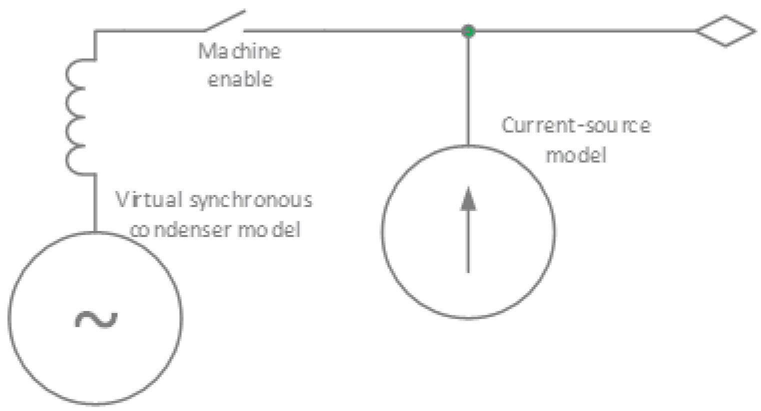

Figure 1.3: Concept of Tesla "Grid Forming + Grid Following" Mode [Source: Tesla]

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:

- Generate its own voltage and seamlessly synchronize to other portions of the BPS.
- Stably operate during large frequency, voltage, and power swings, and reliably operate in low short-circuit strength networks. Detailed EMT studies demonstrating the ability to operate under these conditions should be conducted.
- Provide sufficient inrush current to energize transformers and transmission lines and start electric motors. Note that BESSs, like other inverter-based resources, have limited ability to provide high levels of inrush current. This necessitates the need to coordinate the BESS resource with the blackstart load.
- Have assurance that the BESS will be available immediately after a large-scale outage requiring system restoration activities. BESSs will need to demonstrate to their RC and TOP they can be available at any point in time to be considered as a blackstart resource.

- Have sufficient energy to remain on-line and operational for the time required to ensure blackstart plans can be fully executed.[51] Therefore, BESS energy ratings should be designed to achieve the required time frames. And their states of charge should be maintained above a limit to ensure enough energy is available for blackstart purposes.
- Be able to quickly respond to and control fluctuations in system voltage and frequency.
- Be able to start rapidly to minimize system restoration times.
- Have redundancy to self-start in the event of any failures within the facility.
- In order to ensure proper integration into the overall system blackstart scheme and coordination between resources via appropriate engineering studies, all control design, settings, configurable parameters, and accurate models should be made available to the BA, TP, PC, TOP, and RC.
- Have remote startup and operational control capabilities to avoid requiring dispatch of personnel to the field.

State of Charge

SOC represents the present level of charge of an electric battery relative to its capacity, within the range of fully discharged (0%) to fully charged (100%). Refer to the description of FERC Order No. 841 in Appendix A. The SOC of a BESS affects the ability of the BESS to provide energy or other essential reliability services to the BPS at any given time.[52] In many cases, the BESS may have SOC limits that are tighter than 0–100% for battery lifespan and other equipment and performance considerations. Alternatively, 0% and 100% may be defined as the normal range of operation, ignoring the extreme-but-not-recommended charge and discharge levels.

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

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

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

[51] 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
[52] https://www.nrel.gov/docs/fy19osti/74426.pdf

providing two services: peak shaving (charging in morning and discharging at night) and transmission line congestion management around a set of wind power plants. The magnitude and duration of any other service provided by the BESS (such as voltage control or frequency support capability) revolves around the two primary services. **Figure 1.4** 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.

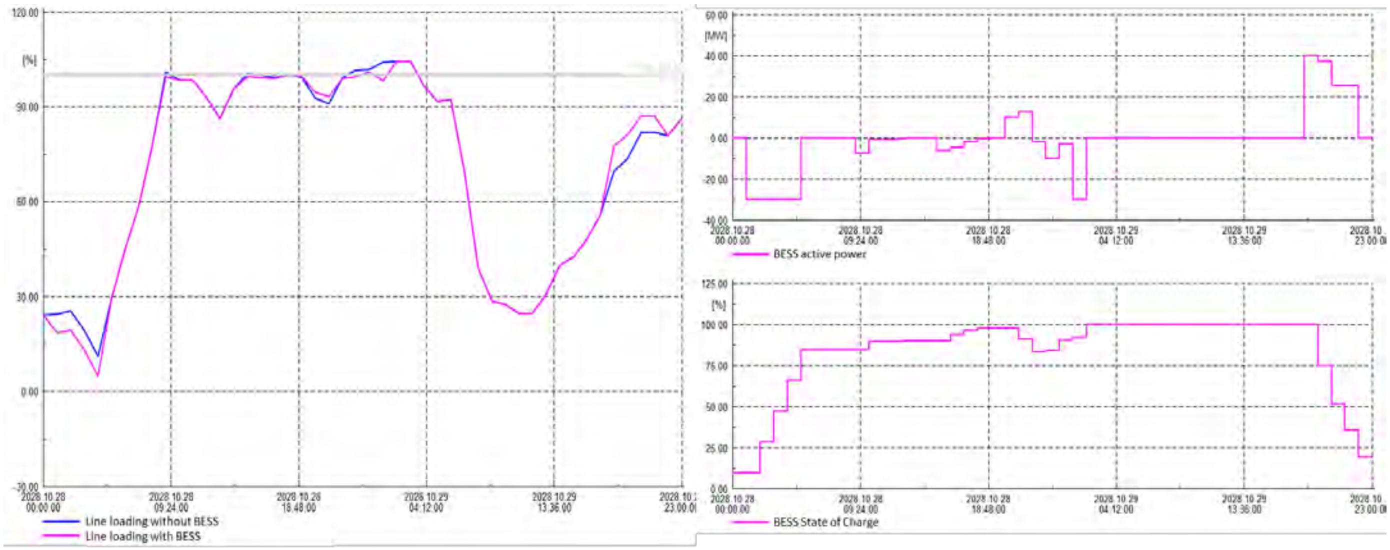

Figure 1.4: Example Time Series of BESS State of Charge [Source: EPRI]

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 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 high renewable output condition and could lead to insufficient damping support required to maintain stability for high power long distance power transfer during and after large disturbances. Currently, renewable generation resources are not required to provide damping support in ERCOT, and synchronous condensers typically are not equipped with PSS. A study conducted by ERCOT in 2019 identified oscillatory responses around 1.8 Hz between synchronous condensers in the Panhandle area and other synchronous generators far away from the Panhandle region under a high renewable generation penetration condition with large power transfers to electrically distant load centers.[53]

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

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

Recommended Performance and Considerations for Hybrid Plants

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

DC-Coupled Hybrid Plants

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

- Momentary cessation
- Phase jump immunity
- Reactive current-voltage control during large disturbances
- Reactive power at no active power output
- Return to service following tripping
- Inverter current injection during fault conditions
- Balancing
- Monitoring
- Operation in low short-circuit strength systems
- Fault ride-through capability
- System Restoration and Black Start Capability
- Grid forming[54]
- Protection settings

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

- State of Charge
- Damping support

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

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

AC-Coupled Hybrid Plants

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

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

Category	Comparison with BPS-Connected Inverter-Based Generators
Momentary Cessation	No significant differences from other BPS-connected inverter-based generating resources; for BESS part of the hybrid, momentary cessation should not be used to the greatest possible extent[55] during charging and discharging operation.
Phase Jump Immunity	No significant difference from other BPS-connected inverter-based generating resources.
Capability Curve	The overall composite capability curve of a hybrid plant is the aggregation of the individual capability curves of the generating resources and BESSs plus any other reactive devices and less any losses within the facility, as measured at the plant POI. The capability curve extends into the BESS charging region to create a four-quadrant capability curve. The curve is not symmetrical for injection and withdrawal. On the injection side, the capability curve will be equal to the sum of capability curves of a generator and capability curve of BEES during discharging. On the withdrawal side capability will be equal to BEES capability curve, when charging. Note that interconnection requirements may not allow the full use of hybrid resource capability depending on how the BESS can charge and discharge with the generating component and with the grid.

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

Table 1.2: High Level Considerations for AC-Coupled Hybrid Plant Performance	
Category	**Comparison with BPS-Connected Inverter-Based Generators**
Active Power-Frequency Controls	No significant difference from other BPS-connected inverter-based generating resources and BESS. The conventional droop characteristic can be used in both generating and charging modes of the hybrid. Active power-frequency control capability may be limited by total active power injection and/or withdrawal limit of the hybrid plant at POI that may be set lower than the sum of active power ratings of the individual resources within the hybrid plant. Due to the presence of the BESS, a hybrid plant can also have the capability of providing frequency response for under frequency conditions, subject to the SOC and set point limits outlined in FERC Order 842.
Fast Frequency Response (FFR)	FFR capability will depend on the resources making up the hybrid plant. BESSs are well-positioned for providing FFR to systems with high rate-of-change-of-frequency (ROCOF) due to not having any rotational components (similar to a solar PV facility). However, if BESS is combined with wind generation facility coordination between resources within the hybrid may be needed to achieve sustained FFR. Additionally, hybrid plant FFR capability may be limited to total active power injection and/or withdrawal limit of the hybrid plant. The need for FFR is based on each specific Interconnection's need.[56] Sustained forms of FFR help arrest fast frequency excursions but also help overall frequency control. BESSs are likely to be able to provide sustained FFR within their 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 that service can be procured by the BA.
Reactive Power-Voltage Control (Small Disturbance)	No significant difference from other BPS-connected inverter-based generating resources. The dynamic voltage support capability of a hybrid is a combination of capability of the generating resource(s) and BESS(s), which are part of the hybrid. BESSs portion of the hybrid have the capability to provide dynamic voltage control during both discharging and charging operations. Note that system specific requirements may not necessitate the use of the full equipment capability of the hybrid plant. TOPs should provide a voltage schedule (i.e., a voltage set point and tolerance) to the hybrid that can apply to both operating modes (injection and withdrawal).
Reactive Current-Voltage Control (Large Disturbance)	No significant difference from other BPS-connected inverter-based generating resources. BESS portion of the hybrid can be configured to provide dynamic voltage support during large disturbances both while charging and discharging.
Reactive Power at No Active Power Output	No significant difference from other BPS-connected inverter-based generating resources.[57]
Inverter Current Injection during Fault Conditions	No significant difference from stand-alone BPS-connected inverter-based generating resources and BESS.

[56] 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

[57] 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.

Table 1.2: High Level Considerations for AC-Coupled Hybrid Plant Performance	
Category	**Comparison with BPS-Connected Inverter-Based Generators**
Return to Service Following Tripping	No significant difference from other BPS-connected inverter-based generating resources. Hybrid plant should return to service following any tripping or other off-line operation by operating at the origin (no significant exchange of active or reactive power with the BPS), and then ramp back to the expected set point values, as applicable. This is a function of settings and any requirements set forth by the BA (or TO in their interconnection requirements).
Balancing	No significant difference from other BPS-connected inverter-based generating resources.
Monitoring	No significant difference from other BPS-connected inverter-based generating resources.
Operation in Low Short-Circuit Strength Systems	No significant difference from other BPS-connected inverter-based generating resources.
Grid Forming	BESSs portion of a hybrid plant have the unique capabilities to effectively deploy grid forming technology to help improve BPS reliability in the future of high penetration of inverter-based resources. Newly interconnecting hybrid plants should consider using grid forming technology to support the BPS under these future conditions.
Fault Ride-Through Capability	No significant difference from other BPS-connected inverter-based generating resources. A hybrid plant should have the same capability to ride through fault events on the BPS, when point of measurement (POM) voltage is within the curves specified in the latest effective version of PRC-024, subject to limitations of legacy equipment. For the BESS part of the hybrid this applies to both charging and discharging modes. Unexpected tripping of generation or load resources on the BPS will degrade system stability and adversely impact BPS reliability. Ride-through capability is a fundamental need for all BPS-connected resources such that planning studies can identify any expected risks.
System Restoration and Blackstart Capability	Hybrid plants may have the ability to form and sustain their own electrical island if they are a part of a blackstart cranking path. This may require new controls topologies or modifications to settings that enable this functionality. Blackstart conditions may cause large power and voltage swings that must be reliably controlled and withstood by all blackstart resources (i.e., operation under low short circuit grid conditions). For the hybrid to operate as a blackstart resource, assurance of energy availability is needed as well as designed energy rating that ensures energy availability for the entire period of restoration activities. At this time, it is unlikely that most legacy hybrid plants can support system restoration activities as a stand-alone resource; however, they may be used to enable start-up of subsequent solar PV, wind, or synchronous machine plants and accommodate fluctuations in supply and demand.
Protection Settings	No significant difference from other BPS-connected inverter-based generating resources.
Power Quality	No significant difference from other BPS-connected inverter-based generating resources.

Table 1.2: High Level Considerations for AC-Coupled Hybrid Plant Performance	
Category	**Comparison with BPS-Connected Inverter-Based Generators**
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 essential reliability services to the BPS at any given time.[58] These limits and how they affect BESS operation should be defined by the hybrid owner and provided to the BA, TOP, RC, TP and PC. BESS's SOC will be optimized by the hybrid plant controller in coordination with other parts of the hybrid (wind or solar), based on irradiance and/or wind conditions, market prices, energy and ESR obligations of the hybrid. In addition, the manner in which the BESS would charge is to be communicated by the GO. Here, system loading conditions and generation from other parts of the hybrid plant will play a role. For example, in a wind-BESS hybrid plant during low load high renewable scenarios, the BESS may be charged directly from the wind output. In this scenario, the hybrid plant will not appear as a load on the system. Alternatively, the plant may be directed to charge from the network in order to increase the loading on the system to satisfy stability considerations.
Operational Limits *(new)*	Based on economics or design considerations, BESS portion of the hybrid may be operated to only charge from other wind and/or solar part of the hybrid or to charge from the grid as well. This information should be provided by the hybrid owner to the BA, TOP, RC, TP and PC. Hybrid plant owners may choose to limit injection/withdrawal at the POI to a level that is lower than actual capability of the hybrid. This information should be provided by the hybrid owner to the BA, TOP, RC, TP and PC. Where such limit exists, the studies as well as voltage support and frequency support requirements may apply only up to the limits.
Damping Support	BESSs can have the capability of providing oscillation damping support, similar to synchronous gnerators, HVDC/FACTS facilities, and other BPS-connected inverter-based resources. BESSs can operate in the both charging and discharging mode, which provides greater capabilities for damping support.

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

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

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

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

- System restoration and blackstart capability
- Grid forming[59]
- Protection settings
- Damping support

Refer to the recommendations outlined in NERC *Reliability Guideline: BPS-Connected Inverter-Based Resource Performance*[60] for more details on each of the aforementioned subjects. The following sub-sections outline the additional topics from **Table 1.2** that warrant additional details and where AC-Coupled hybrids have specific considerations that need to be taken.

Capability Curve

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

[59] 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.

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

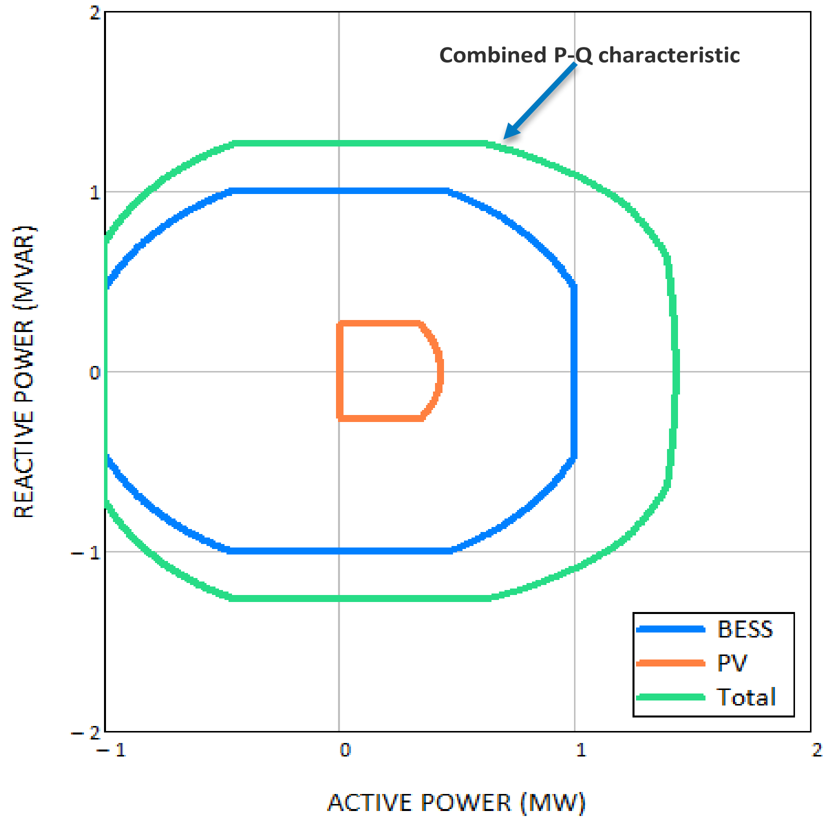

Figure 1.5: Example of AC-Coupled Solar PV + BESS Hybrid Plant Capability Curve [Source: NREL]

Active Power-Frequency Control

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

Fast Frequency Response

BESSs and solar PV have the capability of providing FFR to rapid changes in frequency disturbances on the BPS. Since there are no rotational elements, the active power output is predominantly driven by the controls that are programmed into the inverter. Wind generating resources can provide FFR through tapping into kinetic energy of rotating mass of a wind turbine.[61] Such response, however, cannot be sustained. To obtain sustained fast frequency response from hybrid plants containing wind/solar PV generating resources along with BESS the FFR capability of the AC-coupled hybrid plant is equal to combined capability of all resources that are part of the hybrid plant. The resources within the hybrid can be coordinated to optimize total FFR and achieve required sustain time. The overall capability may be limited by total active power injection and/or withdrawal limit of the hybrid plant that may be set lower than actual capability of the plant.

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

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

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

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

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

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

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

State of Charge

SOC considerations for the BESS portion of the ac-coupled hybrid plant are similar to those of a stand-alone BESS discussed above. The SOC of a BESS portion of the hybrid may affect the ability of the BESS to provide energy or other essential reliability services to the BPS at any given time.[62] These limits and how they affect BESS operation should

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

be defined by the hybrid owner and provided to the BA, TOP, RC, TP and PC. BESS's SOC will be optimized by the hybrid plant controller in coordination with other parts of the hybrid (wind or solar), based on irradiance and/or wind conditions, market prices, energy and ESR obligations of the hybrid.

Operational Limits

Based on economics or design considerations, the BESS portion of a hybrid plant may be operated to only charge from the generating component or to charge from the grid as well. Technical, economic, and policy considerations will dictate whether the hybrid plant charges from the grid or only from the generating component.[63] 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. Characteristic of charging and any operational limitations should be provided by the hybrid plant owner to the BA, TOP, RC, TP and PC.

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

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

Chapter 2: BESS and Hybrid Plant Power Flow Modeling

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

BESS Power Flow Modeling

As mentioned, the power flow representation for a BPS-connected BESS is similar to other types of BPS-connected inverter-based resources. **Figure 2.1** shows a generic[64] power flow model for a BPS-connected BESS facility. The power flow representation of a BPS-connected BESS facility will include the following components:

1. **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.
2. **Substation Transformer:** Any substation transformers[65] (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.
3. **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.
4. **Equivalent Pad-Mounted Transformer:** Each of the inverters interfacing the battery systems with the ac electrical network will include a pad-mounted transformer. An equivalent pad-mounted transformer is typically modeled, which is scaled to an appropriate size to match the overall MVA rating of the aggregate inverters at the BESS facility.
5. **Equivalent BESS:** An equivalent BESS generating resource is modeled to represent the aggregate amount of inverter-interfaced BESSs installed at the facility. The capability is scaled to match the overall capability of aggregate inverters. The equivalent BESS is modeled as a generator in the power flow, and appropriate voltage control settings (and other applicable control settings) should be specified in the model. In situations where different inverter types (e.g., make and model of inverter) are used[66] within the BESS, each different inverter type is typically separately aggregated. GOs should consult with their TP and PC for recommended modeling practices.
6. **Shunt Compensation and Reactive Devices:** The plant may include shunt reactive devices to meet reactive capability and voltage requirements defined by the TO and TOP. These may include shunt capacitors and reactors, FACTS devices, or synchronous condensers, as applicable. If these devices are installed, they should be modeled appropriately. **Figure 2.1** also denotes that these installations could even be located at the POI, within the boundary of the GO and GOP, and those devices should also be modeled appropriately.
7. **Plant Loads:** The plant may include a small load to represent station service load, as deemed necessary based on the TP and PC modeling requirements. Auxiliary loads supplied by the dc bus are generally not modeled.

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[64] 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.
[65] Some BESSs may have more than one substation transformer, and each should be explicitly modeled.
[66] This occurs more frequently in inverter-based generating resources, either installed in different phases or often in large facilities.

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

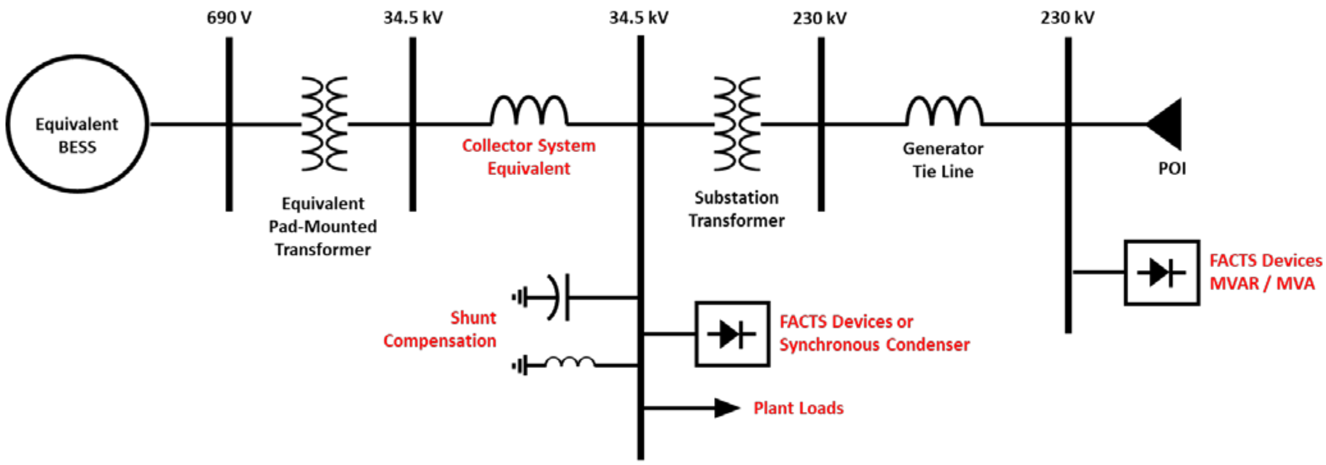

Figure 2.1: Generic Power Flow Model Example for BESS

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

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

Hybrid Power Flow Modeling

The configuration of hybrid plants will likely vary more than BESS facilities, based on the size of the plant, the type of technologies used, and the overall layout of the facility. Regardless, each hybrid plant should be modeled according to the expected[67] or actual facilities installed in the field. Further, hybrid plants may be modeled differently depending on whether they are ac-coupled or dc-coupled facilities. GOs should consult with their TP and PC to determine the appropriate modeling approach based on whether the facility is ac-coupled or dc-coupled.

AC-Coupled Hybrid Plant Power Flow Modeling

Figure 2.2 illustrates a generic model representation for an example[68] ac-coupled hybrid plant. Since the BESS and the generating resource are connected through the ac network, then each component should be represented accordingly, as shown in **Figure 2.2**. An equivalent BESS generation and equivalent pad-mounted transformer should

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

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

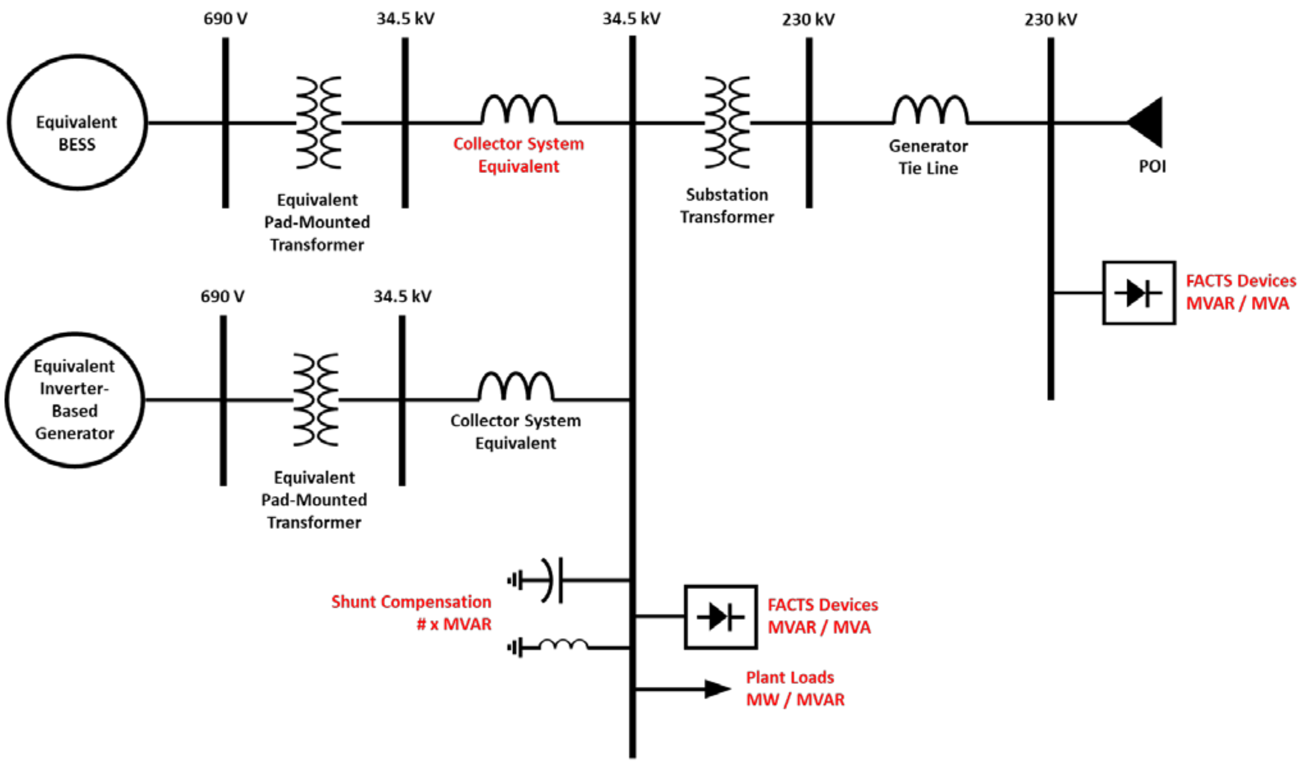

Figure 2.2: Generic Power Flow Model Example for AC-Coupled Hybrid Power Plants

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

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

output of the overall facility may not. Therefore, it is important to understand what the maximum operational output of the plant will be. Most power flow software today does not have a way to represent this limit, but the software industry should pursue the ability to explicitly model both the BESS and the generator within an overall plant model with its own limitations. In the meantime, BAs, TOPs, RCs, TPs, PCs, and GOs should develop a standardized way of documenting and communicating such limits.

- **BESS Charging from BPS or from Generating Resource:** Depending on the interconnection agreement, the hybrid plant may or may not be able to charge from the BPS. If allowed, the BESS may be able to charge power from the BPS with the generating unit dispatched off. If not allowed, the BESS will only charge using energy produced by the generating component of the plant. Most power flow software today does not have 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.[69]

The WECC Renewable Energy Modeling Task Force (REMTF) has developed recommendations for software vendors to improve the capability for modeling BESSs and hybrid plants,[70] 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.

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

[70] 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

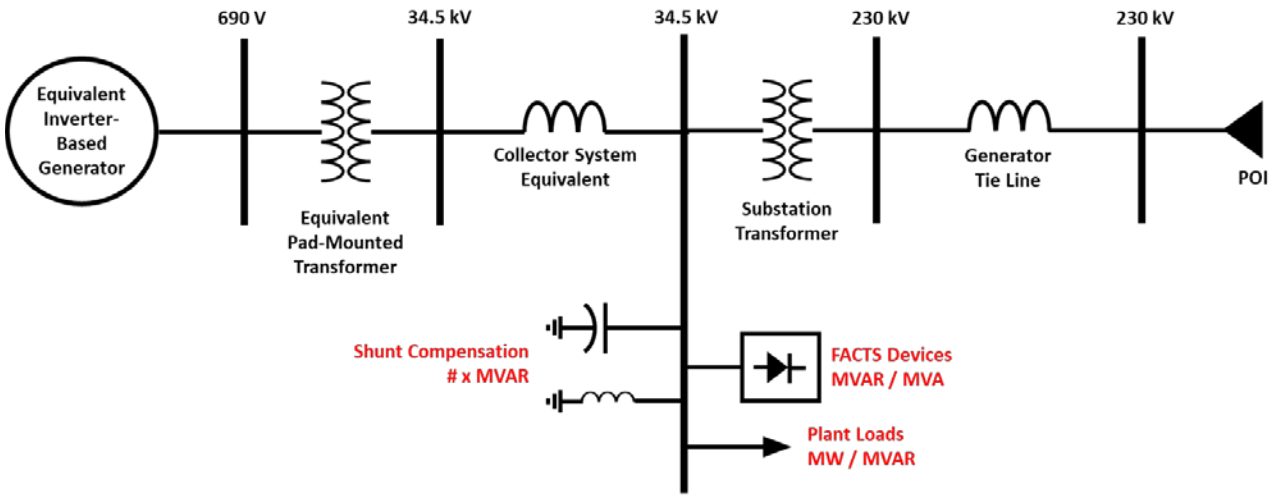

Figure 2.3: Generic Power Flow Model for DC-Coupled Hybrid Power Plants

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.

Chapter 3: BESS and Hybrid Plant Dynamics Modeling

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

Use of Standardized, User-Defined, and EMT Models

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

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

As BESSs and hybrid plants continue to interconnect to the BPS, it imperative that these resources are studied appropriately using accurate models. TPs and PCs will weigh these considerations against their modeling practices and capabilities, and determine appropriate modeling requirements for existing and newly interconnecting generating resources. 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,[71] and all TPs and PCs are encouraged to strengthen their requirements particularly in the area of BESS and hybrid plant modeling. These quality tests can be applied to standardized library models, to user-defined models, as well as to EMT models. The goal of these tests is to give the TP and PC assurance that the model being used reasonably represents the equipment in the field and meets the expected performance specifications established by the TO in their interconnection requirements. Examples of model quality tests used for inverter-based resources that should also be applied to BESSs and hybrid plants include, but are not limited to, the following:

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

BESS Dynamic Modeling

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

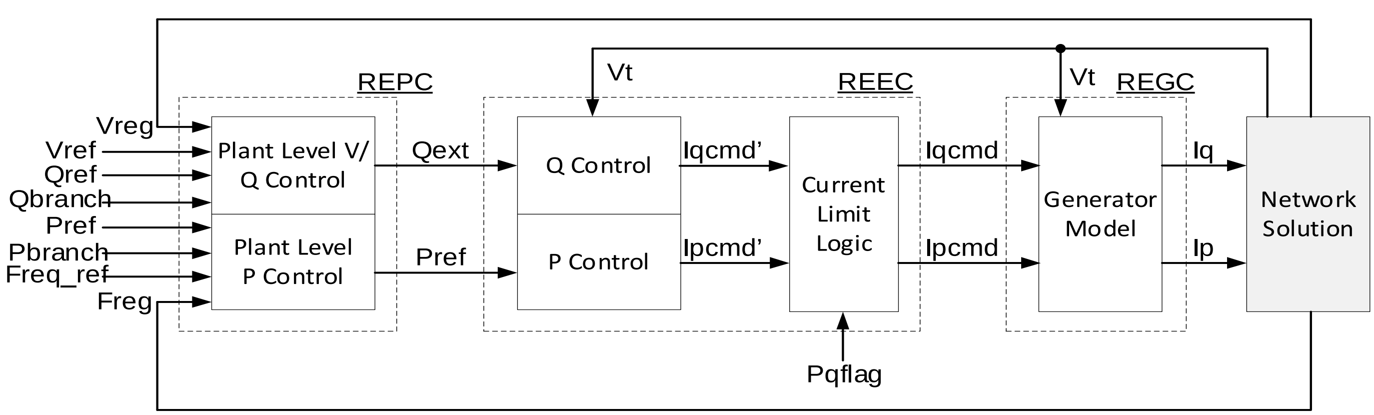

Figure 3. 1: Block Diagrams of Different Modules of the WECC Generic Models[72]

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

- **REGC (REGC_*)[73] Module:** Used to represent the converter (inverter) interface with the grid. It processes the real and reactive current command and outputs of real and reactive current injection into the grid model.
- **REEC (REEC_C/REEC_D)[74] Module:** Used to represent the electrical controls of the inverters. It acts on the active and reactive power reference from the REPC module, with feedback of terminal voltage and generator power output, and gives real and reactive current commands to the REGC module.
- **REPC (REPC_*) Module:** Used to represent the plant controller. It processes voltage and reactive power output to emulate volt/var control at the plant level. It also processes frequency and active power output to emulate active power control. This module gives active reactive power commands to the REEC module.

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

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

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

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

Scaling for BESS Plant Size and Reactive Capability

Model parameters are expressed in per unit of the generator MVA base except in repc_b. The specification of MVA base is implementation-dependent.[75] To scale the dynamic model to the size of the plant, the generator MVA base parameter must be adjusted. It should be set to sum of the individual inverter MVA rating. The active and reactive range are expressed in per unit on the scaled MVA base. The MVA base for REPC_B model is always the system MVA base in GE PSLF; Siemens PTI PSS/e implementation allows a different MVA base to be specified. The per unit parameters of REPC_B model should be expressed on the MVA base used.

Reactive Power / Voltage Controls Options

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

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

[73] 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).
[74] REEC_D and REPC_B model descriptions: https://www.wecc.org/Administrative/Memo_RES_Modeling_Updates_083120_Rev17_Clean.pdf
[75] For example, in the PSLF implementation, if MVA base is zero in reec_* or repc_*, then the MVA base entered for the regc applies to those models as well. The user may specify a different MVA, if desired. In the PSSE implementation, the MVA base is set in the power flow model.

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

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

Various combinations of plant-level and inverter-level reactive control are possible by setting the appropriate parameters and switches. **Table 3.2** shows a list of control options and respective models and switch that would be involved. Additional variations[76] of flag settings are not shown in **Table 3.2** since they are not likely to be used for BESS operation.

Table 3.2: Reactive Power Control Options for BESS Generic Models

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

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

Active power control options

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

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

The BESS is expected to provide frequency response in both upward and downward directions. The no response and down only options are greyed out because they are unlikely to be approved by the transmission planning entity (assuming interconnection requirements are fully utilizing the bi-direction capabilities of BESS technology). In the WECC recommended modeling enhancement for hybrid power plants,[77] the base load flag in the power flow model could override the frqflag setting in the dynamic model. The frqflag/ddn/dup are meant to reflect the inverter capability while base load flag represents the availability of the operational headroom. It is important to set base load flag to 0 for BESS generators regulating frequency.

[76] 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.
[77] WECC White Paper on Modeling Hybrid Power Plant of Renewable Energy and Battery Energy Storage System https://www.wecc.org/_layouts/15/WopiFrame.aspx?sourcedoc=/Administrative/WECC%20White%20Paper%20on%20modeling%20hybrid%20solar-battery.pdf

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

*BaseLoad flag is set in the power flow model.

Current Limit Logic

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

State of Charge

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

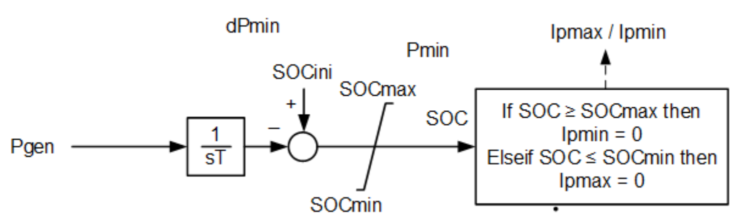

Figure 3.2: Block Diagram of the Charging/Discharging Mechanism of the BESS

Representation of Voltage and Frequency Protection

Frequency and voltage ride-through are needed for transmission-connected solar PV plants. Because they are simplified, the generic models may not be suitable to fully assess compliance with the voltage and frequency ride-through requirement. Voltage ride-through is engineered as part of the plant design and needs far more sophisticated modeling detail than is possible to capture in a positive-sequence simulation environment. It is best to use a standardized (existing) protection model with voltage and frequency thresholds and time delays to show the minimum disturbance tolerance requirement that applies to the plant. Also, the frequency calculations in a positive-sequence simulation tool is not accurate during or immediately following a fault nearby. It is best to use the frequency protection relay model in a monitor-only mode and always have some time delay (e.g., at least 50 ms) associated with any under- and over-frequency trip settings.[78]

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

Hybrid Plant Dynamics Modeling

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

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

AC-Coupled Hybrid Modeling

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

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

Functionality	GE PSLF Module	Siemens PTI Module
BESS Grid Interface	regc_*	REGC*
BESS Electrical Controller	reec_c or reec_d	REECC1 or REECD1
Plant-Level Controller	repc_b[79]	PLNTBU1
Auxiliary Controller		REAX4BU1 or REAX3BU1
Voltage/Frequency Protection	lhvrt/lhfrt	VRGTPA/FRQTPA
Non-BESS Generation Component of Hybrid Facility	Use appropriate modules for the generation type (i.e., applicable models for wind, solar, synchronous generation, etc.)	

Reactive Power Control

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

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

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

Active Power Control

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

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

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

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

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

DC-Coupled Hybrid Modeling

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

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

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

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

Electromagnetic Transient Modeling for BESSs and Hybrid Plants

Recommendations pertaining to EMT modeling of BESSs and hybrid power plants are very similar to those that have previously been put forth in NERC Reliability Guidelines.[80] All TPs and PCs should establish EMT modeling requirements for all newly interconnecting BESSs and hybrid plants. GOs should coordinate with equipment manufacturers and any other entities (e.g., consultants developing the models) to ensure the model represents the expected topologies, controls, and settings of the plant seeking interconnections and to ensure that the models are updated after commissioning to represent the as-built settings of the facility. TPs and PCs should collect sufficient data and supplementary information from the GO to ensure that the as-built settings match the model.

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

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

Chapter 4: BESS and Hybrid Plant Short Circuit Modeling

BESSs and hybrid plants should be modeled in short-circuit programs during the interconnection process and during ongoing planning, design, and protection setting activities. TPs, PCs, TOs, and other entities should develop or enhance modeling practices for BESSs and hybrid plants as new capabilities and features within existing tools become available. At a high-level, the recommendations for modeling BESSs and hybrid plants are the same as for modeling other full-converter inverter-based generating resources (e.g., Type 4 wind, solar PV, voltage source converter HVDC, and other FACTS devices).[81] The modeling practices described in this chapter should help industry develop standardized approaches for modeling BESSs and hybrid plants, similar to other inverter-based resources, that capture the key performance characteristics, appropriately represent equipment ratings, and capture other nuances[82] involved with modeling each specific facility.

BESS Short Circuit Modeling

The IEEE Power System Relaying and Control (PSRC) Committee Working Group C24 led the development of state-of-the-art inverter-based resource short-circuit modeling practices, and recently published *Technical Report #78: Modification of Commercial Fault Calculation Programs for Wind Turbine Generators*.[83] This report advises industry on necessary modifications to commercial short-circuit programs to allow accurate modeling of wind turbine generators and wind power plants. While the report does not specifically discuss modeling solar PV, BESS, or other inverter-based resources, the recommendations for modeling Type 4, full-converter wind resources also apply to solar PV and BESS facilities. Presently, the software vendors for commercial short-circuit programs have incorporated the new modeling approach of representing voltage-dependent current sources into their respective programs.[84] TOs, TPs, and PCs should coordinate to ensure that modeling requirements are reflective of these new capabilities, and that well-defined specifications are in place to collect all necessary short-circuit modeling information from the GO. GOs can work with their inverter manufacturer to gather the necessary information to meet the modeling requirements.

In general, inverters are voltage-dependent current sources, meaning the amount of active and reactive current injected by the inverter during a fault is dependent on its terminal voltage. Inverter control logic dictates the voltage dependency (e.g., K-factor or closed-loop response) and is typically non-linear. As with wind and solar PV resources, the fault current from a BESS also depends on the pre-fault current. Particularly for BESSs, it also depends on whether the BESS is charging or discharging prior to the fault. BESS fault current is relatively independent of BESS SOC since the SOC does not modify any control loops or affect inverter overload current capability.[85]

The IEEE PSRC WG C24 report recommends that fault current injection information be provided for inverter-based resources in a tabular form (see **Table 4 1** as an example). These tables should be provided for different fault types as specified by the TO, TP, and PC. Further, inverter controls may take time to reach a steady-state fault current levels so the report recommends that fault current data be provided for various time instants after fault initiation (e.g., 1, 3 and 5 cycles). If the resource provides unbalanced fault currents for unbalanced faults, then additional tables will be needed for the negative sequence current contribution. Particularly for BESSs, different set of tables should be provided for BESS in charging and discharging operation. Most TPs and PCs prefer data provided in sequence domain (positive, negative, and zero) rather than in phase domain. Again, TOs, TPs, and PCs should ensure their modeling

[81] 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
[82] Such as capturing different control algorithms and any additional short-circuit current from BESSs due to additional energy on the dc bus.
[83] 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
[84] 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.
[85] BESS SOC is closely managed and not expected to be operated near the edge of its charge or discharge limit during normal operation.

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

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

Table 4 1: Example Positive Sequence Fault Current from BESS

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

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

Hybrid Plant Short Circuit Modeling

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

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

Chapter 5: Studies for BESS and Hybrid Plants

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

Interconnection Studies

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

Interconnection studies should incorporate appropriate steady-state and dynamic ratings of all equipment, any material modifications to 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 dynamic services from BESSs and hybrid plants from being provided to the BPS. Short-circuit studies will also be needed in order to ensure appropriate breaker duty ratings, protective relay settings, and sufficient and appropriate fault currents. EMT studies may also be needed based on specific-system conditions at the point of interconnection (e.g., control interactions or control instability in low short circuit strength areas). All reliability studies should use models that have been validated and rigorously verified by the TP and PC to be appropriate for the type of study being conducted.

Table 5.1 provides a list of example scenarios possibly studied during the interconnection process and considerations for each. This list is not exhaustive nor is it necessary for every interconnection study. TPs and PCs should consider the full extent of possible BESS and hybrid plant modes of operation based on the local interconnection requirements or market rules and perform reliability studies to ensure reliable operation of the BPS under all expected operating conditions. For example, hybrid plants may or may not be allowed to charge from the BPS depending on local requirements. These considerations will need to be made by TPs and PCs as they develop their study approaches. In general, BESSs and hybrid plants will follow directives from the BA and RC based on system reliability needs and market incentives, where applicable, and TPs and PCs can use this assumption when determining appropriate charge and discharge assumptions. For example, in a market environment, the battery will typically discharge during periods of high power prices and charge during times of low power prices. Generally, the price of power will be higher during peak demand and lower during low demand or high renewable output conditions.[86] Table 5.1 was constructed with these assumptions in mind, with exceptions noted.

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

Table 5. 1: Potential BESS and Hybrid Plant Study Dispatch Scenarios			
System Conditions	**Plant Type**	**Plant Dispatch**	**Considerations**
Peak net demand	BESS	Fully discharging	This is a feasible scenario.
		Fully charging	Depending on market mechanisms and system rules, this scenario may not be feasible. However, there may be situations where this is a feasible scenario. For example, in a system that has a lot of wind generation, if there is high wind output at peak load a BESS may be charging to prepare for a time later in the day when the wind is expected to die down. Another feasible scenario would be when a BESS is charging right before peak load, when the system is "near" peak.
	Hybrid	Maximum plant output	This is a feasible scenario. This scenario could be achieved by a combination of maximum renewable generation output and/or maximum battery output to achieve the maximum facility rating as limited by the power plant controller.
		Maximum renewable generation output with battery fully charging	This may be a feasible scenario. Though it is unlikely to stress the system, this scenario could stress the plant and may need to be studied in transient simulations.
		No or low renewable generation output with battery fully discharging	This is a feasible scenario. The BESS component injects power at its maximum capability with some or no contributions from the generating component.
		No or low renewable generation output with battery fully charging from the grid	Similar to BESS fully charging scenario, as described above. Depending on interconnection requirements and market rules, this scenario may not be feasible. However, there may be situations where this is a feasible scenario depending on localized transmission constraints.
Off-peak (low) net demand	BESS	Fully discharging	This is an unlikely scenario, but it is possible an area could have a high price, due to nearby constraints, so it could need to be studied.
		Fully charging	This is a feasible scenario.
	Hybrid	Maximum plant output	This is a feasible scenario. This scenario could be achieved by maximum renewable generation output that is sustained for a period long enough that the battery is no longer able to charge.
		Maximum renewable generation output with maximum battery charging	This may be a feasible scenario. Though it is unlikely to stress the system, this scenario could stress the plant and may need to be studied in transient simulations.
		No or low renewable generation output with battery fully discharging	This is unlikely to be feasible, but may be a feasible scenario for ac-coupled hybrids in some situations depending on localized transmission constraints.

Table 5. 1: Potential BESS and Hybrid Plant Study Dispatch Scenarios

System Conditions	Plant Type	Plant Dispatch	Considerations
		No or low renewable generation output with battery fully charging from the grid	This may be a feasible scenario depending on interconnection requirements, market rules, and plant design. Solar investment tax credit rules may incent hybrids to not charge from the grid during the first five years of operation, but it may be feasible starting in year six.
High system-wide renewable generation output	BESS	Fully discharging	This is an unlikely yet possible scenario.
		Fully charging	This is a feasible scenario.
	Hybrid	Maximum plant output	This is a feasible scenario.
		Maximum renewable generation output with maximum battery charging	This may be a feasible scenario. Though it is unlikely to stress the system, this scenario could stress the plant and may need to be studied in transient simulations.
Changes in dispatch	BESS	Variable	BESS transitions between charging and discharging should be tested in both steady-state and dynamic simulations. TPs and PCs should test that the model matches required ramping requirements (as applicable) and ensure that change in power dispatch do not adversely affect BPS reliability (e.g., power quality, flicker, voltage deviations, successive operation[87] of voltage control devices).

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

Hybrid Additions – Needed Studies

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

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

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

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

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

Process/ Study	AC-Coupled or DC-Coupled with New/Modified Inverter	DC-Coupled with Existing Inverter and Grid Charging	DC-Coupled without Grid Charging (no inverter changes)
Registration with and Notification to the TP/PC	Needed	Needed	Needed
Steady-State Power Flow Study	Needed if the maximum plant active power injection or withdrawal capability changes or if the operational characteristics change; not needed otherwise	Needed to study charging mode	May be needed to study different operating conditions
Short-Circuit Study	Needed	Not needed	Not needed
Stability Study[88]	Needed	Needed to study charging mode	May be needed to study different operating conditions

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

Transmission Planning Assessment Studies

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

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

to closely consider the duration of the outage and the energy available from BESSs and hybrid plants to support the BPS post-contingency.[89] Refer back to **Table 5. 1** as a reference for study scenarios to begin these conversations.

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

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

Blackstart Study Considerations

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

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

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

CAISO BESS and Hybrid Study Approach Example

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

CAISO Generation Interconnection Study

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

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

Table 5.3 shows the different assumptions that are used for the studies conducted. The purpose of the reliability assessment is to define the boundaries of operation. Mitigation of a potential problem is usually through generation re-dispatch (congestion management) or RAS actions. 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[90]	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[91]	Max charging[92]	Max charging	Max discharging	Max charging
Other Renewable	Pmax	Pmax	Pmax	Pmax	Pmax
Thermal Generation	Pmax	As needed to balance load	As needed to balance load	As needed to balance load	As needed to balance load
Hydro Generation	Based on historical data	Based on historical data	Based on historical data	Based on historical data	Based on historical data
Import Levels	Historical max flows adjusted to accommodate output from renewable generation as needed				

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

90 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.
91 Maximum steady-state positive output associated with the maximum net output in the Interconnection Request
92 Maximum steady-state negative output for re-charging of the energy storage facility

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

The CAISO also performs deliverability assessments[93] as part of the interconnection study process. This includes a deliverability assessment at peak demand for resource adequacy purposes as well as a delivery assessment at off-peak demand to evaluate potential curtailment of intermittent resources (i.e., wind and solar). Table 5.4 shows the assumptions used in these deliverability assessments.

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

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

CAISO Transmission Planning Study

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

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

Appendix A: Relevant FERC Orders to BESSs and Hybrids

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

- **Electric Storage Resource (FERC Definition):**[94] 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[95] (February 15, 2018), FERC required Regional Transmission Organizations (RTOs) and Independent System Operators (ISOs) under its jurisdiction to establish participation models that recognize the physical and operational characteristics of electric storage resources. Each participation model, per the Order, must "ensure that a resource using the participation model for electric storage resources is eligible to provide all capacity, energy, and ancillary services that it is technically capable of providing in the RTO/ISO markets" and "account for the physical and operational characteristics of electric storage resources through bidding parameters or other means." These ancillary services may include blackstart service, primary frequency response service, reactive power service, frequency regulation, or any other services defined by the RTO/ISO.

The Commission gave flexibility to both transmission providers, in determining telemetry requirements, as well as to electric storage resources, in managing 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 IRPWG; rather, they are provided here only as a reference.

Table A.1: FERC Participation Model Parameters

Physical or Operational Characteristic	Definition
State of Charge (SOC)	The amount of energy stored in proportion to the limit on the amount of energy that can be stored, typically expressed as a percentage. It represents the forecasted starting State of Charge for the market interval being offered into.
Maximum State of Charge (SOC_{max})	A State of Charge value that should not be exceeded (i.e., gone above) when a resource using the participation model for electric storage resources is receiving electric energy from the grid (e.g., 95% State of Charge).[96]
Minimum State of Charge	A State of Charge value that should not be exceeded (i.e., gone below) when a resource using the participation model for electric storage resources is injecting electric energy to the grid (e.g., 5% State of Charge).

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

Table A.1: FERC Participation Model Parameters	
Physical or Operational Characteristic	**Definition**
Maximum Charge Limit	The maximum MW quantity of electric energy [power][97] that a resource using the participation model for electric storage resources can receive from the grid.
Maximum Discharge Limit	The maximum MW quantity that a resource using the participation model for electric storage resources can inject to the grid.
Minimum Charge Time	The shortest duration that a resource using the participation model for electric storage resources is able to be dispatched by the RTO/ISO to receive electric energy from the grid (e.g., one hour).
Maximum Charge Time	The maximum duration that a resource using the participation model for electric storage resources is able to be dispatched by the RTO/ISO to receive electric energy from the grid (e.g., four hours).
Minimum Run* Time	The minimum amount of time that a resource using the participation model for electric storage resources is able to inject electric energy to the grid (e.g., one hour).
Maximum Run Time	The maximum amount of time that a resource using the participation model for electric storage resources is able to inject electric energy to the grid (e.g., four hours).
Minimum Discharge Limit	The minimum MW output level that a resource using the participation model for electric storage resources can inject onto the grid.
Minimum Charge Limit	The minimum MW level that a resource using the participation model for electric storage resources can receive from the grid.
Discharge Ramp Rate	The speed at which a resource using the participation model for electric storage resources can move from zero output to its Maximum Discharge Limit.
Charge Ramp Rate	The speed at which a resource using the participation model for electric storage resources can move from zero output to its Maximum Charge Limit.

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

FERC Order No. 842

In Order No. 842[98] (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.[99] 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:

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

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

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

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

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

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

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

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

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

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

FERC Order No. 845

In Order No. 845[100] (April 19, 2018), the Commission clarified that "in certain situations, electric storage resources can function as a generating facility, a transmission asset, or both." The Commission made clear that electric storage resources under its jurisdiction greater than 20 MW had the option to interconnect pursuant to the Large Generator Interconnection Procedures (LGIP) and Large Generator Interconnection Agreement (LGIA), "so long as they meet the threshold requirements as stated in those documents." In the event the LGIA does not accommodate for the load characteristics of electric storage resources, transmission providers may enter into non-conforming LGIAs.

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

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

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

FERC Order No. 845-A

In Order No. 845-A[101] (February 21, 2019), the Commission reiterated that Order No. 845 allows electric storage resources to interconnect pursuant to the LGIP and LGIA, but declined to impose requirements on how transmission providers study the load characteristics of electric storage resources. Instead, the Commission clarified that transmission providers "have the flexibility to address the load characteristics of electric storage resources" within studies, including studies of electric storage resource load characteristics and studies of the upgrades required to accommodate electric storage resource load characteristics. Further, the Commission stated that transmission providers may enter into non-conforming LGIAs "when necessary" in order to accommodate a particular electric storage resource.

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

Contribution

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

Name	Entity
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Organization(s)	Page #	Line / Paragrap	Comment	Proposed Change	NERC Response
PJM	vii	Recommendation A1	PJM agrees philosophically with the intent. Jurisdictional limitations to non-BES make this challenging, but agree that a uniform set of specifications should be adopted by all interconnected entities.	uniform set of specifications	Edits made based on comment.
PJM	vii	Recommendation M1	MOD-033 is the process that TPs have to verify models match facility behavior. PJMS's process uses PMU measurements for this effort, which limits what facilities can afford to install this monitoring capability. PJM agrees the burden lies with the GOs, developers, manufacturers to develop modeling for use in simulation software that properly mimics expected actual performance of a facility. Commissioning testing would be verified through MOD-026 and MOD-027 submittals. Due to the 10 year gap between submittals, TPs will wait a long time to experience benefits from any recommendations. Also, similar to A1, MOD-026 and MOD-027 jurisdiction is at 100 MVA.	Implementation plan to shorten time period between submittals and/or updated submittals.	Edits made based on comment.
PJM	vii	Recommendation M2	Similar to M1: PJM agrees the burden lies with the GOs, developers, manufacturers to develop modeling for use in simulation software that properly mimics expected actual performance of a facility. MOD-026, MOD-027, MOD-033 provide for model validation & verification.		Thank you for your comment.
PJM	viii	Recommendation M3	PJM agrees. It makes more sense to require proper modeling be available upon interconnection before allowing new technologies to interconnect and then scramble to develop after the fact. This would properly place the burden on manufacturers and developers to have this in place before connecting. Workarounds or ignoring modeling shortcomings is not in the direction of goodness from a system reliability perspective. Otherwise what is the incentive? PJM agrees that software vendors should add model validation (data screening).		Thank you for your comment.
PJM	viii	Recommendation S1	PJM agrees with the key factors for the planning studies with the large penetration of BESSs and hybrid power plants.		Thank you for your comment.
PJM	viii	Recommendation S2	PJM agrees developing appropriate study assumptions will be a significant challenge. Along with study assumption, we think developing efficient and effective study process & methodology is challenging and important. For example in stability study system wide level study may need different approach from a plant level study. It would be beneficial if more detailed technical guidelines are available for study methodology especially related to EMT simulation and hybrid simulation which is pretty new in conventional TPs and PCs planning stability studies.	It would be beneficial if more detailed technical guidelines are available for study methodology especially related to EMT simulation and hybrid simulation which is pretty new in conventional TPs and PCs planning stability studies.	IRPWG is working on a Reliability Guideline specifically focused on EMT modeling and studies, expected to be published this year.
AEP	N/A	N/A	While AEP appreciates the diligent efforts of all those who were involved in developing the content within this proposed Reliability Guideline, we do not believe it is beneficial, or even necessary, for a number of reasons. In short, it provides a very generalized guidance approach for a very nuanced and technical topic, and does not take into account the technology being used or its application. The result is not correct in a technical sense, nor is it beneficial by suggesting a one-size-fits-all approach for the topic. Just as different fuel generation types require unique technological solutions, so also do energy storage technologies and their unique chemistries, whose own solutions must be studied individually and not over-generalized in any way. Another example of this over-generalization, is that the language in the Reliability Guideline does not consider whether the assets themselves are Generation assets or Transmission assets, which often needs to be taken into consideration when specific solutions are needed. We are also concerned by the timing of this Reliability Guideline with that of the eventual adoption of IEEE Standard 2800. The RTOs are at the forefront of this topic, and have already established guidance of their own which entities are following, which will be further shaped by this IEEE standard. The authors of this Reliability Guideline seek to meet a presumed need of filling the gap between the present time and the eventual adoption of this IEEE standard, and on page 1 states "TOs, TPs, and PCs are strongly encouraged to improve their interconnection requirements and study processes by adopting and integrating the recommended performance characteristics outlined in this guideline." The duration of this perceived time gap however will likely be extremely short, as IEEE 2800 is in its final development phase and will soon be adopted. Since IEEE 2800 would supersede any guidance provided in this Reliability Guideline, and given that the standard is in the final review phase, we do not believe the guidance within this Reliability Guideline would be beneficial. While AEP appreciates efforts of the drafters in developing this proposed Reliability Guideline, for the reasons provided, we do not see a reliability benefit in developing and issuing additional, generic guidance in the form of this NERC Reliability Guideline.		Thank you for your comment. IRPWG membership believes this guideline provides significant value to industry, particularly in the interim until IEEE P2800 is approved and fully implemented. It is likely that this will take at least a couple years for full implementation, and IRPWG believes this guideline provides useful recommendations for all involved entities regarding the performance, modeling, and studies needed to realibly integrate these emerging and relatively new technologies. As with other IRPWG guidelines, this guideline provides a framework that entities can use to establish their own requirements and practices. The guideline also covers capabilities and recommended performance characteristics but each TP, PC, RC, TOP, and BA will need to leverage those capabilities as needed for their specific system. The guideline does not address BESS/hybrids as generation versus transmission assets as this is considered by IRPWG to be a market-related issue regarding cost recovery. Lastly, multiple ISO/RTOs have stated that they are actively integrating the recommendations from this guideline (and other IRPWG guidelines) into their practices and procedures and find value in the material being presented to industry.

Organization(s)	Page #	Line / Paragraph	Comment	Proposed Change	NERC Response
AEP	v	109-120	While the Reliability Guideline does include language indicating that "Reliability guidelines are not binding norms or parameters", the language in this section is not as robust as provided in previous Reliability Guidelines, typically within the opening Preamble. Most notable is the absence of language indicating that Reliability Guidelines "are not binding norms or parameters *to the level that compliance to NERC's Reliability Standards are monitored or enforced.* Rather, their incorporation into industry practices is strictly voluntary."	Add Preamble section and provide more robust, customary language used in previous Reliability Guidelines, including language that indicates that Reliability Guidelines are not binding norms or parameters *to the level that compliance to NERC's Reliability Standards are monitored or enforced*, and that rather, their incorporation into industry practices is strictly voluntary.	Preamble in current draft matches the new Preamble being used for all Reliability and Security Guidelines.
AEP	N/A	N/A	The announcement of the comment period on this Reliability Guideline states "The performance characteristics should be considered by all Generator Owners and developers seeking interconnection to the BPS, and Transmission Owners, Transmission Planner, and Planning Coordinators should consider adopting these recommendations in the interconnection requirements per NERC FAC-001 and FAC-002 standards." However, this encouragement's reference to these two FAC standards is not explicitly given within the Reliability Guideline as FAC-001 itself is not mentioned, and as FAC-002 is only mentioned within the "Hybrid Additions – Needed Studies" section within "Chapter 5: Studies for BESS and Hybrid Plants."		Edits made based on comment.
EPRI	vii	P3	Provision of primary and fast frequency response is not necessarily a new capability for any IBRs	Suggest to delete the word New at the starting of the sentence	Change made.
EPRI	vii	P3	Suggest to add the words 'as needed' in parentheses after 'should be fully utilized'	Suggest to add the words 'as needed' in parentheses after 'should be fully utilized'	Change made.
EPRI	vii	M1	How would an exact match of controls be defined/verified? Also, not having an exact match does not necessarily mean that a model is bad.	Suggest to replace the word 'match' with 'accurately and precisely represent'	Change made.
EPRI	vii	M2	M1 and M2 can possibly be merged together	M1 and M2 can possibly be merged together	Change made.
EPRI	vii	M2	When mentioning standardized library models and detailed user defined models, it may not be automatically apparent that this refers to positive sequence models.	Suggest that it might beneficial to clarify that standardized library models and detailed user defined models relate to positive sequence models	Change made.
EPRI	xiii	Frequency response capability	An economic reason has been provided for inability of wind or solar to provide under frequency response. However, no counter reason is provided to justify how adding energy storage will serve economic benefit. From a technology standpoint, even a wind and solar PV can provide frequency response	Suggest to add few statements which justify the economic reason of adding storage to provide frequency response from a renewable hybrid plant.	Edits made based on comment.
EPRI	xiii	Frequency response capability	Footnote 25 explains the aspect of adding BESS to synchronous machine plant. The key point being that the combustion turbine is not a spinning reserve. However, in the main body of the text, this is not clear. For example, suppose there is an online synchronous machine, it can by default provide fast frequency response. it does not need a storage element to do so. Additionally, what if the storage element is itself a flywheel? Further, rapid charge discharge at the terminals of an online synchronous machine can be destabilizing.	A bit of re-wording is required here. I can help to re-word this paragraph.	Edits made based on comment.
EPRI	1	footnote 29	replace the word generation with absorbtion or consumption	replace the word generation with absorbtion or consumption	Change made.
EPRI	7	Figure 1.2	This figure is misplaced. The figure shows the capability of a hybrid plant and may be better to be moved to the hybrid plant section	Suggest to move figure to page 19	Change made.
EPRI	25	1001	If not allowed to charge from the grid, how does the system operator ensure that ac coupled hybrid is charging from generating resource? By monitoring power output of both generating resouce and at POC?	A footnote on this may be beneficial.	Edits made based on comment.
EPRI	25	1002	Power flow software can be configured in any way by the user to represent different modes of BESS charging. So it is incorrect to say that power flow software does not have a way to represent.	Suggest to include the word 'automatically' or 'inherent' before 'way to represent'	Edits made based on comment.
EPRI	25	1020	In order to make it explicitly clear, suggest to add the words 'required to be' before 'modeled'	In order to make it explicitly clear, suggest to add the words 'required to be' before 'modeled'	Edits made based on comment.
EPRI	26	Frequency response	Not only the active power limits, but even the values of 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.	Suggest to add 'droop gains' in addition to active power limits. A footnote reference to the DER_A data collection guideline may be beneficial as we had provided an example parameterization in that document	Edits made based on comment.
EPRI	27	1075	Not just the aspect of using an appropriate model, but also appropriate parameterization of the model is important	Suggest to add the words 'and suitably parameterized' after 'appropriate'	Change made.

Organization(s)	Page #	Line / Paragrap	Comment	Proposed Change	NERC Response
EPRI		395	In many instanaces the manufacturer has altered SOC limits post installation, lately due to safety concerns and they are the party that determines these limits	State of Charge (new) – Change last sentence to “These limits and how they affect BESS operation need to be defined by the manufacturer, agreed upon by the owner and provided to the BA, TOP, TP and PC	Edits made based on comment.
EPRI		435	Hisorically there have been instances where Battery Management System (BMS) based calculations and associated reported metrics such as state of health (SOH) and SOC were proven incorrect. Allowing access to relavent data and associated independent verification could alllow for assured operating paramters and corrections of BMS calculations if determined incorrect	Change to: Monitoring: BESSs should be equipped with digital fault recorder (DFR), dynamic disturbance recorder (DDR), sequence of events recorder (SER), and harmonics recorder capability. In addition, data internal to the battery system should be made accessible to the operator for independent evaluation (if deemed necessary) to verify accuracy of reported metrics, assess operational issues and correct any apparent BMS miscalculations	Change made.
EPRI		663	same comment as 395		Change made.
EPRI		1431	General Comment: A BESS internal firmware revision to the Battery Management System (BMS) may be considered a material modification and require further study. The developer of the firmware should be able to demonstrate whether the firmware revision does or does not require further study or other interconnection validation or testing	Change to: When a BESS component is added to an existing generating facility or BMS firmware of an existing BESS is changed/updated, additional interconnection studies may be required per the latest version of the NERC FAC-002 Reliability Standards as this would constitute a material modification of the existing facility.	Change made.
EPRI		682	typo	Change “tigher” to “tighter”	Change made.
EPRI		1403	General Comment: A BESS internal firmware revision to the Battery Management System (BMS) may be considered a material modification and require further study. The developer of the firmware should be able to demonstrate whether the firmware revision does or does not require further study or other interconnection validation or testing	change to: Interconnection studies should incorporate appropriate steady-state and dynamic ratings of all equipment, any material modifications to battery management system firmware or site controls, and identify the most-limiting elements that establish any system operating limits.	Change made.
Manitoba Hydro	16/63	11	The abbreviation SOC provided without defining it (instead it was first defined in page 18/63)	define the abbreviation "state of charge (SOC)" in page 16/63 or rearrange the table to have state of charge to become the first category in Table 1.1	Change made.
Manitoba Hydro	18/63	411/	TP or PC will be in a better position to specify the worst case expected phase jump than TO for new interconnection projects		Edits made based on comment.
Manitoba Hydro	23/63		No legend provided in Figure 1.3. It is not clear what is represented in those curves unless we read the previous paragraph.	recommend to include a legend	Change made.
ReliabilityFirst	vii	173 - M2	Add a line stating black box models are not acceptable.	Add Line - "TP and PC modeling requirements should state that if a user defined model is provided by the GO, it must include uncompiled code and a block diagram."	TPs and PCs may allow black box models based on their specific modeling practices. This is ultimately up to the TP and PC to determine; however, must also fulfill requirements set by the MOD-032 Designee in creating interconnection-wide base cases.
ReliabilityFirst	viii	173-M3	"real-code" is not defined in the document	Add a footnote to "real-code" to define this term.	Change made.
ReliabilityFirst	11	618	Reference PRC-026-1 Relay Performance During Stable Power Swings	Add a footnote with a link to NERC PRC-026-1.	IRPWG does not believe it suitabel to reference PRC-026 in this context, particularly related to inverter-based resources during blackstart conditions.
ReliabilityFirst	27	1082	User defined models supplied are often black box models with compiled code. This causes issues during the interconnection case building process when a case doesn't initialize and it is impossible to trouble shoot the model. Power flow software is constantly advancing their versions, so compiled code may not work when the industry moves to new versions.	Add Line - "User written models are only considered acceptable when provided with uncompiled code and a block diagram."	TPs and PCs may allow black box models based on their specific modeling practices. This is ultimately up to the TP and PC to determine; however, must also fulfill requirements set by the MOD-032 Designee in creating interconnection-wide base cases.
ReliabilityFirst	27	1097	Currently, resources are connecting without first meeting certain modeling requirements.	Add Line - "Generating resources should not be allowed to interconnect without first meeting all modeling requirements of the TPs and PCs."	Change made.

Organization(s)	Page #	Line / Paragrap	Comment	Proposed Change	NERC Response
ReliabilityFirst	42	1529	Due to the increase of inverter-based resources and the associated complexities with operations with the addition of RASs, it may be beneficial to add some additional verbiage about RAS coordination and review from a interconnection and study process aspect.	Add line - "Careful consideration should be made during the interconnection process regarding facilities with planned RASs. As the number of RASs increases on the BPS, the need for a comprehensive system review should be considered periodically.	Edits made based on comment.
ReliabilityFirst	General	General	While the document is mostly about modeling, please consider the development of future guidance documents about day-ahead and short-term operational studies. There are presently unknown questions surrounding BESSs and hybrid power plants availability and capability regarding generation redispatch for real-time or contingency events.	Potential future guideline document or discussion	Thank you for the comment; IRPWG will consider this topic.
TVA	xiii	318	Caption for Figure I.4 needs to be on same page as figure.	Move caption.	Change made.
TVA	2, 17	395, 764	Table 1.1, Category: Reactive Power at No Active Power Output states, "No significant difference from other inverter-based generating resources." This does not align with present draft of IEEE P2800 for Type 3 WTGs which are allowed zero reactive capability at zero active power. Similar issue in Table 1.2	Suggest adding Type 3 WTG exclusion or reiterate Line 543: "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."	Edits made based on comment.
TVA	6	473	Caption for Figure 1.1 references a 5.3 MVA BESS capability curve, but the curve shown appears to be for a 2.9 MVA BESS.	Revise caption to reflect 2.9 MVA BESS.	Figure correct; confirmed with OEM.
WEC Energy Group	5	453-456	A specific reference to the PRC-027 coordination standard should be made.		Change made.
EEI	vi	126	General Comments: The Reliability Guideline addresses the emerging issue of the rapid increase in the use of battery energy storage systems and hybrid power plants and their potential impact on registered entities across all regions. This is an important issue to be addressed. As noted in this guideline, IEEE P2800 project, which is moving toward completion, will also address “interconnection capability and performance criteria for inverter-based resources interconnected with transmission and networked sub-transmission systems that will also apply to BESSs and hybrid power plants.” (see Line 153 – 155). EEI recommends that NERC ensures this guideline aligns with IEEE standard to prevent confusion within the industry.	EEI recommends that NERC ensures this guideline aligns with IEEE 2800 standard to prevent confusion within the industry.	IRPWG includes many members (and sub-group leads) of the IEEE P2800 effort, and believes the reliability guidelines serves as a useful bridge strategy until full adoption of the IEEE standard. IRPWG does not see any significant areas of conflict between this guideline and the draft standard.
EEI	vii	173	(Applicable Entities section of Table ES.1) –References made to developers and equipment manufacturers under the Applicable Entities section of Table ES.1 could be misinterpreted as an obligation. While developers and equipment manufacturers have important information that could aide NERC registered entities, their obligations are different and should not be included in an Applicability Section of a NERC Reliability Guideline. To resolve this issue, consideration should be given to adding an additional column to identify those entities that have ancillary obligations outside of NERC authority or oversight.	Consideration should be given to adding an additional column to identify those entities that have ancillary obligations outside of NERC authority or oversight.	Footnote added for clarity; IRPWG believes a single applicability column is suitable for this guideline since it provides recommendations to specific entities. As mentioned in the Preamble, guidelines to do not create bindings norms and do not carry any other obligations.
EEI	vii	173	P1 –The following modifications are suggested to better clarify entity obligations and responsibilities. While equipment manufacturers and developers generally have useful and often relevant information on equipment performance, it is the owner of the facility who is responsible for the performance of their equipment once the equipment has been installed: BESS and Hybrid Plant Performance: GOs of existing or newly interconnecting BESSs and hybrid power plants should closely review the recommended performance characteristics outlined in this Reliability Guideline and adopt these recommendations into their existing and new facilities to the extent possible. Newly interconnecting GOs of BESSs and hybrid power plants should work closely with their respective TOs, Balancing Authorities (BAs), Reliability Coordinators (RCs), TPs, and PCs to ensure all entities have an understanding of the operational capabilities and limitations of the facilities being interconnected.	Suggest modifying Section P1 of Table to remove Equipment manufacturers and developers for the reasons provided in our comments.	Edits made based on comment.
EEI	vii	173	M1 The following modification are suggested to better clarify entity responsibilities: **Models Matching As-Built Controls, Settings, and Performance: Responsible GOs** should (**utilizing the expertise of their resource manufacturer**) ensure that the **data supplied to their TP and PC, for the development of** models used to represent **their** BESSs and hybrid power plants; match the controls, settings, and performance of **their** equipment, **as** installed. **GOs should be prepared to assist the responsible TP and PC during** the commissioning process **to ensure system models accurately reflect the performance of their BESS and/or hybrid power plant.**	EEI suggests the modifications shown in bold to better clarify entity responsibilities.	Edits made based on comment.

Organization(s)	Page #	Line / Paragraph	Comment	Proposed Change	NERC Response
EEI	vii	173	M2 – The following suggested modifications to this section are offered to better clarify the responsibilities under this section of Table ES.1: **Use of Appropriate Models**: All BESS and hybrid power plant GOs **(and associated** developers, and equipment manufacturers, **where needed) should make themselves available to assist TPs and PCs to** ensure that the dynamic models used to represent **their** facility **accurately** represent the dynamic response and behavior of **their** resource, **as** installed. This may include representation using standardized library models, detailed user-defined models, as well as electromagnetic transient (EMT) models. All TPs and PCs should ensure their modeling requirements and processes clearly define the types of models that are acceptable, the level of detail expected for each model, and benchmarking between models required during the planning study process.	EEI suggests modifying M2 to better clarify the responsibilities.	IRPWG used part of this edit; however, the language as originally written has the appropriate intent that the GO, developer, and equipment manufacturer need to be responsible for developing an accurate model meeting TP and PC requirements.
EEI	ix	208	The footnote link (10) appears to be broken. This needs to be fixed.	Fix broken link for footnote 10.	Edits made based on comment.
EEI	5	435 through 436	The monitoring requirements identified in this Reliability Guideline are impractical and possibly unenforceable. The equipment identified is costly and, unless mandated within the responsible entity's interconnection agreement, there would be no obligation to provide such capability. EEI suggests the following as an alternative approach to address this need: **Monitoring:** Whenever technically feasible BESSs **owners** should **work with the responsible TO, TP and PC to ensure that equipment is installed that provides the functionality of a** digital fault recorder (DFR), dynamic disturbance recorder (DDR), sequence of events recorder (SER), and harmonics recorder. **If this capability is not embedded in the BESS control system, or controls package provided with the resource, the TO should be consulted to assist in finding alternatives that meet the needs as specified by the responsible TP and PC. (Specifications should be provided to assist the BESS owner.)**	EEI suggests making modifications to the monitoring section to provide more practical solutions for the industry.	The language provided in the guideline aligns with the future P2800 requirements; however, some of the recommended changes proposed here were incorprated into the guideline language.
EEI	5	453 through 456	The protection setting requirements identified do not adequately identify the responsibilities and obligations for BESS owners as it relates to the responsible TO. EEI suggests the following alternative approach to address this issue: **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 system,** protection settings should be documented and provided **to the responsible interconnection TO for approval. Additionally, BESS owners should provide** protection settings to the responsible TP, PC, TOP, RC, and BA to ensure all entities are aware of expected performance of the 456 BESS during planning and operations horizons.	EEI suggests making the proposed modifications to better capture the responsibilities of the responsible TO.	Change made.
EEI	14 and 17	735 and 764	Monitoring requirements should be harmonized with our suggested changes as provided under Line 435 – 436.	EEI suggests that monitoring obligations should be harmonized throughout the Guideline.	Updated aforementioned section, and this section points to that section for further guidance. See above comment regarding change made.
EEI	15	740	Protection setting comments for this section should be harmonized with our suggested changes as provided under Line 453 – 456.	EEI suggests that protection setting obligations should be harmonized throughout the Guideline.	Updated aforementioned section, and this section points to that section for further guidance. See above comment regarding change made.

Standards authorization Request (SAR) to revise TPL-001-5.1

Action
Endorse

Summary
Considering current trends, the NERC SPIDERWG and NERC Inverter-Based Resource Performance Working Group (IRPWG) independently undertook review of the TPL-001 standard for considering DERs and BPS-connected IBRs, respectively. These reviews are captured in the following RSTC-approved white papers:

SPIDERWG: Assessment of DER impacts on NERC Reliability Standard TPL-001 (here)
IRPTF/IRPWG: IRPTF Review of NERC Reliability Standards – March 2020 (here)

This SAR proposes to update TPL-001-5.1 to address the issues identified in both white papers. The SPIDERWG is seeking endorsement of the SAR.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

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.

<table>
<tr><th colspan="4">Requested information</th></tr>
<tr><td>SAR Title:</td><td colspan="3">TPL-001-5.1 Transmission System Planning Performance Requirements</td></tr>
<tr><td>Date Submitted:</td><td colspan="3">Mm/dd/2020</td></tr>
<tr><td colspan="4">SAR Requester</td></tr>
<tr><td>Name:</td><td colspan="3">Kun Zhu, MISO (NERC SPIDERWG Chair)
Bill Quaintance, Duke Energy Progress (NERC SPIDERWG Vice-Chair)</td></tr>
<tr><td>Organization:</td><td colspan="3">NERC System Planning Impacts from DERs Working Group (SPIDERWG)</td></tr>
<tr><td>Telephone:</td><td>Kun – 317-249-5789
Bill – 919-546-4810</td><td>Email:</td><td>kzhu@misoenergy.org
william.quaintance@duke-energy.com</td></tr>
<tr><td colspan="4">SAR Type (Check as many as apply)</td></tr>
<tr><td colspan="2">☐ New Standard
☒ Revision to Existing Standard
☒ Add, Modify or Retire a Glossary Term
☐ Withdraw/retire an Existing Standard</td><td colspan="2">☐ Imminent Action/ Confidential Issue (SPM Section 10)
☐ Variance development or revision
☐ Other (Please specify)</td></tr>
<tr><td colspan="4">Justification for this proposed standard development project (Check all that apply to help NERC prioritize development)</td></tr>
<tr><td colspan="2">☐ Regulatory Initiation
☒ Emerging Risk (Reliability Issues Steering Committee) Identified
☐ Reliability Standard Development Plan</td><td colspan="2">☒ NERC Standing Committee Identified
☐ Enhanced Periodic Review Initiated
☒ Industry Stakeholder Identified</td></tr>
<tr><td colspan="4">Industry Need (What Bulk Electric System (BES) reliability benefit does the proposed project provide?):</td></tr>
<tr><td colspan="4">Many areas of the North American bulk power system (BPS) are experiencing a transition towards increasing penetrations of distributed energy resources (DERs) in addition to BPS-connected inverter-based resources (IBRs). NERC Reliability Standard TPL-001-5.1[1] was developed under a paradigm of predominantly BPS-connected generation, particularly synchronous generation, when penetrations of DERs and BPS-connected IBRs were significantly lower than current and future projections.</td></tr>
</table>

[1] The scope of recent modifications to TPL-001-5 did not include considering the impacts of DER on BPS planning.

Requested information
Considering current trends, the NERC SPIDERWG and NERC Inverter-Based Resource Performance Task Force (IRPTF)[2] independently undertook review of the TPL-001 standard for considering DERs and BPS-connected IBRs, respectively. These reviews are captured in the following RSTC-approved white papers: • SPIDERWG: Assessment of DER impacts on NERC Reliability Standard TPL-001 (here) • IRPTF/IRPWG: IRPTF Review of NERC Reliability Standards – March 2020 (here) This SAR proposes to update TPL-001-5.1 to address the issues identified in both white papers. TPL-001-5.1 does not currently require Planning Coordinators and Transmission Planners to complete Planning Assessments with adequate representation of the dynamic behavior of DERs or BPS-connected IBRs. As the penetration of DERs and BPS-connected IBRs increases, Planning Assessments must include representation of DER and IBR behavior that will impact Transmission System performance to ensure the accuracy of evaluations. NERC's "Lesson Learned: Single Phase Fault Precipitates Loss of Generation and Load", evaluating a 2019 frequency event exacerbated by the unexpected reduction of 725 MW of IBR output and the unexpected loss of 350 MW of DER, highlights the critical importance of accurate Transmission System Planning Assessments.[3] In July 2020, a significant scale of solar PV facilities across a large geographic area in Southern CA reduced about 1000 MW output due to disturbance on bulk power system[4]. Subsequent event analysis revealed that it was the consequence of momentary cessation and slow recovery of power. Standards enhancement has been one of the recommendations after the event analysis to ensure reliable operation of the bulk power system. In general, the impact of DERs on BES should be included in planning assessments. Any choice to exclude the consideration of DERs should be accompanied by a technical rationale and justification.
Purpose or Goal (How does this proposed project provide the reliability-related benefit described above?):
The purpose of this SAR is to revise requirements to provide clarity or, in some cases, expand the scope of requirements when considering the performance of DERs and IBRs to ensure the accuracy of Transmission System Planning Assessments.
Project Scope (Define the parameters of the proposed project):
As identified by SPIDERWG and IRPTF, the following sections of TPL-001-5.1 should be revised to ensure the accuracy of Transmission System Planning Assessments:

[2] The IRPTF has subsequently become the NERC Inverter-Based Resource Performance Working Group (IRPWG) under the NERC Reliability and Security Technical Committee (RSTC).

[3] https://www.nerc.com/pa/rrm/ea/Lessons%20Learned%20Document%20Library/LL20201001_Single_Phase_Fault_Precipitates_Loss_of_Generation_and_Load.pdf

[4] https://www.nerc.com/pa/rrm/ea/Pages/July_2020_San_Fernando_Disturbance_Report.aspx

Requested information
a. R2.1 and R2.2, the use of phrase "System peak Load" b. R3.3.1.1 and R4.3.1.2, the "tripping of generators" in steady state and stability contingency analysis should include tripping of DER c. R3.3.1.1 and R4.3.1.2, the use of the term "GSU transformer" d. R4.1.1 and 4.1.2, the stability performance criteria only applicable to synchronous generators e. R4.3.2, the list of dynamic control devices should include power plant controller and inverter controls so that the expected automatic operation of DER (e.g., DER tripping, dynamic voltage and frequency controls, momentary cessation, etc.) can be considered in stability analyses.
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):
A detailed description of each Project Scope item is given below: a. R2.1 and R2.2, the use of phrase "System peak Load" (*NERC SPIDERWG white paper recommendation*) With increased penetration of DER, the load that transmission system supplies is the net load (net load = gross load – DER output) as seen at the T-D interface, which might reach its peak during operating conditions that are not at the peak gross load hour. Therefore, the most stressed load driven condition of the overall transmission system should be defined by net load rather than gross load. The term "System peak Load" in the standard may be interpreted as System peak gross load. The SDT should consider adding the terms "Gross Load" and "Net Load" to the NERC Glossary of Terms and updating the term "System peak Load" in the standard to "System peak net Load". In addition, a high gross load hour may be the most stressed load driven condition for contingencies that may trip large amounts of DER. High system peak gross load may be studied as additional scenarios as required by current standard under R2.1.3. b. R3.3.1.1 and R4.3.1.2, the "tripping of generators" in steady state and stability contingency analysis should include tripping of DER (*NERC SPIDERWG white paper recommendation*) The terms "generators" in Sub-requirements 3.3.1.1 and 4.3.1.2 should be clarified. DERs should be tripped where simulations show bus voltages that are less than known or assumed minimum DER steady-state or ride-through voltage limits. It is also recommended to include in the assessment any assumptions made in estimating DER bus voltage.

[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.

Requested information
c. R3.3.1.1 and R4.3.1.2, the use of the term "GSU transformer" (*NERC IRPTF white paper recommendation*) The term GSU can also be confusing to GOs of IBR facilities because they will often refer to the transformer that steps the voltage up from the individual inverter (e.g., 600 V) to the collector system voltage (e.g., 34.5 kV). In this case, there is usually another transformer (i.e., the Main Power Transformer) to step the voltage up from the collector system voltage to transmission system voltage. The intention was to refer to transmission system voltages at the high-side of the substation transformer (i.e., point of interconnection) for known or assumed generator low voltage ride-through capability. Therefore, the language in these sub-requirements should be modified to provide clarity for inverter-based resources. For the inverter based resource that is connected to the distribution system, this transformer can mean the one connected to the sub-transmission system depending on the low voltage ride through reference. d. R4.1.1and 4.1.2, the stability performance criteria only applicable to synchronous generators (*recommendation from both white papers*) For example, the language referring to "pulls out of synchronism" is only relevant to synchronous generation and is not applicable to inverter-based generation (including inverter-based DER). Large amounts of DER tripping on low/high voltage/frequency conditions can adversely affect BPS performance and may pose a risk to system instability for conditions such as cascading, voltage instability, or uncontrolled islanding if not properly studied and identified ahead of real-time operations. e. R4.3.2, the list of dynamic control devices should include power plant controller and inverter controls so that the expected automatic operation of DER (e.g., DER tripping, dynamic voltage and frequency controls, momentary cessation, etc.) can be considered in stability analyses. (*recommendation from both white papers*) Sub-requirement 4.3.2 specifies that stability studies must "simulate the expected automatic operation of existing and planned devices designed to provide dynamic control of electrical system quantities when such devices impact the study area." It then contains a list of example devices that have dynamic behavior. Not included in this list are power plant controllers and inverter controls, which often dominate the dynamic response of IBRs. While the sub-requirement does not preclude the simulation of plant-level controllers and inverter controls, it would add clarity if they were added to the list. DERs should be tripped where simulations show load bus voltages that are less than known or assumed minimum DER ride-through voltage limits. It is also recommended to include in the assessment any assumptions made in estimating DER bus voltage. The existing language does not preclude consideration of DER. R1 specifies that the "System models" for the "Planning Assessment" discussed in R4 must: "Use data consistent with that provided in accordance with

Requested information
the MOD-032 standard, supplemented by other sources as needed" and "System models shall represent: …1.1.5 Resources (supply or demand side) required for Load." Thus, R4 does not preclude the consideration of DER by the PC and TP. After all, (1) under MOD-032-1, the PC and TP may already request DER data "necessary for modeling purposes" and (2) DER is a "demand side" resource increasingly required for serving load. R1.1.5 uses the term "Resources" when specifying inclusion of demand side resources, but R4.3 used the term "generators" which is not a defined term in the NERC Glossary. Therefore, it is not clear whether it includes DERs. Terminology and consideration for DER should be addressed by language modifications to bring clarity to the requirements. Requirement R4.3.2 should include DER's dynamic controls, if any, such as DER tripping, dynamic reactive support, active power-frequency control, etc.
Cost Impact Assessment, if known (Provide a paragraph describing the potential cost impacts associated with the proposed project):
Although the cost impact is unknown, costs to Planning Coordinators and Transmission Planners may increase as Transmission System Planning Assessments reflect additional dynamic components and controls.
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 will impact Transmission System Planning Assessments, not any specific 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):
Planning Coordinators and Transmission Planners, i.e. the applicable entities for this standard. Distribution Providers and Generator Owners, i.e. not an applicable entity to this standard, but would be useful to include.
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.
This SAR is the outcome of the following white papers that were both developed by NERC technical sub-groups under the RSTC. • SPIDERWG: Assessment of DER impacts on NERC Reliability Standard TPL-001 (here) • IRPTF/IRPWG: IRPTF Review of NERC Reliability Standards – March 2020 (here) Both deliverables, and the key findings and recommendations contained within, were thoroughly reviewed and approved by the RSTC.

[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
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)?
No
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.
Among all the issues identified in the NERC SPIDERWG and NERC IRPTF white papers, the ones included in this SAR cannot be addressed by any alternatives. Standard language change will ensure DER impacts being considered appropriately. NERC SPIDERWG will prepare a Reliability Guideline to address the rest of the findings from their white paper.

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

Market Interface Principles	
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	None

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

Wildfire Mitigation Guide

Action
Information

Summary
As stated in the 2019 ERO Reliability Risk Priorities Report; Risk Profile #2, wildfires are extreme natural events that can impact the equipment, resources, or infrastructure required to operate the bulk power system. In recent years, wildfires have wrought havoc throughout the Western Interconnection but changing weather conditions increase the opportunities for wildfires to ignite and propagate throughout North America. Electric infrastructure and equipment can: (1) cause ignitions that could lead to wildfires, and (2) be impacted by wildfires. The electric industry should consider having plans and operational strategies in-place to address and mitigate the risks to reliability that wildfires pose. This document is intended to serve as a resource for utilities in high fire-threat areas that want to proactively develop wildfire mitigation plans to maintain and promote the reliability and resilience of the electric grid. The reference guide is posted on the NERC website at https://nerc.com/comm/RSTC/Documents/Wildfire%20Mitigation%20Reference%20Guide_January_2021.pdf.

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NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Wildfire Mitigation Reference Guide

Al McMeekin, Senior Technical Advisor, NERC
Reliability and Security Technical Committee
March 2, 2021

RELIABILITY | RESILIENCE | SECURITY




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RELIABILITY CORPORATION

The 5 W's

- Who
- What
- When
- Where
- Why

Resources and Research

- Wildfire and Bushfire Mitigation Plans
- Organizations
  - State and Federal Agencies
  - Associations, Forums, Councils
- Websites and Publications
- Webinars and Conferences
- Research and Development
  - EPRI
  - Texas A&M University
  - Department of Energy (DOE) National Laboratories

Information

- Wildfire Mitigation Reference Guide
- Al McMeekin, Senior Technical Advisor
  - al.mcmeekin@nerc.net or 404-446-9675
- Steve Ashbaker, Reliability Initiative Director
  - sashbaker@wecc.org or 801-883-6840
- Scott Rowley, Reliability Specialist
  - srowley@wecc.org or 801-819-7643

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Questions and Answers

North American Generator Forum RSTC Update

Allen D. Schriver, P.E.
Senior Manager NERC Reliability Compliance
NextEra Energy
and
COO North American Generator Forum
Allen.Schriver@nexteraenergy.com
March 2, 2021

NAGF Mission

The NAGF mission is to promote the safe, reliable operation of the generator segment of the bulk electric system through generator owner and operator collaboration with grid operators and regulators.

Agenda

- NAGF Annual Meeting
- NERC Standard Projects
- Supply Chain
- NAGF Website
- IRPWG/IEEE P2800

NERC Standard Drafting Teams

- NAGF Annual Meeting
  - The NAGF 10th Annual Meeting was conducted virtually over October 13, 14 and 15, 2020. Attendance averaged about 90 participants per day and the speaker line up was robust and diverse. Mark Lauby and Jason Blake provided Keynote addresses, Manny Cancel provided an E-ISAC update and representatives from NERC, SERC, ReliabilityFirst, and member companies provided presentations on topics relevant to the generator community

- NERC Standards Projects
  - The NAGF is actively engaged in the following NERC Projects to help ensure the generator sector perspective is heard and understood:
    - NERC Project 2019-04: Modifications to PRC-005-6
    - NERC Project 2019-06: Cold Weather

NAGF Collaboration With NATF

- Supply Chain
  - On December 22, 2020, the NAGF participated in the NERC conference call for Trade Organizations/Forum regarding the NERC Level 2 Alert – Supply Chain compromises by Advances Persistent Threat Actor. The NAGF shared this information with membership accordingly.

- NAGF Website
  - The NAGF is moving forward with the redesign of its existing NAGF public and members-only websites to provide a single website with the capabilities to support and sustain the future growth of the organization. The public section of the new website is 90% complete; workflow design, discussion board functionality, and content layout for the members-only section along with event registration/on-line payment functions are currently under development. It is anticipated that beta testing will commence in January 2021.

NAGF

- IRPWG/IEEE P2800
  - Reliability Guideline: EMT Modeling and Simulations
    - Goal: Provide industry with clear guidance and recommendations for use of EMT models and performing EMT simulations.
  - Reliability Guideline: BESS and Hybrid Plant Performance, Modeling, Studies
    - Goal: Provide industry with clear guidance and recommendations for BESS and hybrid plant performance, modeling, and studies.
  - Working on Whitepaper: Using BPS-Connected Inverter-Based Resources and Hybrid Plant Capabilities for Frequency Response

Q & A

NAGF

the power to make a difference

Thank you!

www.GeneratorForum.org

To: NERC Reliability and Security Technical Committee (RSTC)

From: Roman Carter (Director-Peer Reviews, Assistance, Training and Knowledge Management)

Date: February 03, 2021

Subject: NATF Periodic Report to the NERC RSTC – March, 2021

Attachments: NATF External Newsletter (January 2021)

The NATF interfaces with the industry as well as regulatory agencies on key reliability, resiliency, security, and safety topics to promote collaboration, alignment, and continuous improvement, while reducing duplication of effort. Some examples are highlighted below and in the attached January NATF external newsletter, which is also available on our public website: www.natf.net/news/newsletters

Response to COVID-19 Challenges

The NATF continues to work with members and industry partners on responding to the pandemic. A successful collaboration recently with NERC, the U.S. Department of Energy (DOE), and the Federal Energy Regulatory Commission produced version 4 of an epidemic/pandemic resource plan. As noted in the newsletter, version 4 of the resource plan was issued in January and included updates such as use of (burn rate) personal protective equipment (PPE), a tertiary control center strategy, and configuration options for control centers and offices space. The NATF, NERC, and FERC are also in the planning stages of scheduling an industry webinar in the coming weeks to share the information from the pandemic resource plan.

NERC Alert Regarding Supply Chain Compromises by Advanced Persistent Threat Actor

The NATF conducted a well-attended member webinar on December 29, 2020, to socialize the alert; highlight key points of emphasis as discussed in a meeting of NATF, NERC, and E-ISAC senior leadership; enable member sharing of approaches to address the risk; and solicit questions.

DOE Prohibition Order

The NATF is coordinating with its members regarding the “Prohibition Order Securing Critical Defense Facilities” issued by U.S. Secretary of Energy Dan Brouillette on December 17, 2020. On February 2, 2021, we conducted a second special webinar for members to share their response actions and approaches to this order.

NATF-NERC Leadership Meetings

NATF and NERC leadership meet periodically to discuss collaborative work and industry topics. Our most recent call occurred on January 21. Agenda topics included facility ratings, grid security emergencies, and supply chain.

Facility Ratings

NATF staff is communicating with NERC leadership, the Compliance and Certification Committee, and the Reliability and Security Technical Committee regarding facility ratings to help reduce any potential duplication of effort. In addition, as reported in December 2020, the NATF has conducted an initial baseline survey of member implementation status of key practices in the "NATF Facility Ratings Practices Document," published in June 2020, and is preparing reports for its members. Periodic, high-level summary reports on NATF member overall implementation status will be provided to NERC and the regions (ERO) approximately every six months, with the first report expected towards the end of the first quarter of 2021. The NATF is presently conducting its second round of data collection on implementation status with its members. See more about NATF work in the attached newsletter.

NATF Supply Chain Efforts

NATF supply chain efforts continue to align industry entities and suppliers on criteria and information needed for entities to assess a supplier's cyber security risk posture and facilitate mutual risk mitigation, assist entities with methods to conduct supplier risk evaluations, work with other organizations on potential ways to mitigate risk—such as the October 22 webinar on "Managing Compromise of Network Interface Cards," and align with other supply chain cyber security efforts.

As noted in the attached newsletter, the NATF is leading the Industry Organizations Team in its annual review process of the NATF Criteria and Questionnaire with inputs from industry, suppliers, third-party assessors, and others (e.g., the World Economic Forum) and hosted a second webinar designed for suppliers ("Suppliers: Responding to Requests for Cyber Security Information") on January 12.

North American Transmission Forum External Newsletter

January 2021

Epidemic/Pandemic Resource Supplemented with Safety and Work-Environment Considerations

The *Epidemic/Pandemic Response Plan Resource* has recently been updated to include information on personal protective equipment use, a tertiary control center strategy, and configuration options for control centers and office space.

The resource—which focuses on planning/preparedness, response, and recovery activities for a severe epidemic/pandemic—was jointly developed by the NATF, the North American Electric Reliability Corporation, the U.S. Department of Energy, and the Federal Energy Regulatory Commission to help utilities create, update, or formalize their epidemic/pandemic plans in response to the COVID-19 pandemic.

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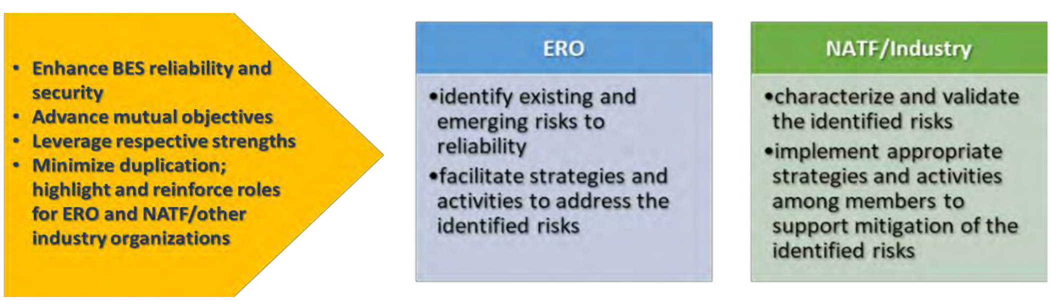
NATF-SERC-RF Pilot Collaborations on Supply Chain Risk Mitigation and Facility Ratings

In April 2019, the NATF and NERC executed an updated memorandum of understanding to advance mutual objectives, leverage respective strengths, and minimize duplication of effort. Upon agreement among NERC, the NATF, and regional entity CEOs, two initial topics (facility ratings and supply chain risk mitigation) were selected to pilot a collaboration approach with two of the Regional Entities—ReliabilityFirst (RF) and SERC. These pilot collaborations aim to highlight and reinforce the following roles for the ERO and the NATF and other industry organizations, consistent with the NERC-NATF MOU:



The pilot collaborations will also help to develop a repeatable approach for collaboration between the NATF and the ERO Enterprise.

Facility Ratings

A team of subject-matter experts (SMEs) from NATF member companies developed and published the "NATF Facility Ratings Practices Document" in mid-2020. These practices can help ensure that facility ratings are developed using the entity's facility ratings methodology, equipment and facilities are built and maintained in the field to ensure ratings are accurate, and ratings for equipment and facilities are documented and communicated. The NATF practice document provides a guide to members for establishing a sustainable process for developing and maintaining accurate facility ratings. The NATF facility ratings practices were compared against a facility ratings problem statement created by the ERO in November 2019 to ensure the practices developed by the NATF membership address the issues and align with the controls identified by the ERO Enterprise.

The NATF is working with its members to socialize and review member implementation of the NATF facility ratings practices. Periodic, high-level summary reports on NATF member overall implementation status will be provided to NERC and the regions (ERO) approximately every six months, with the first report expected towards the end of the first quarter of 2021.

In addition, NATF staff is communicating with NERC leadership, the Compliance and Certification Committee, and the Reliability and Security Technical Committee regarding facility ratings to help reduce any potential duplication of effort.

Supply Chain Risk Mitigation

For the collaboration on supply chain entity risk mitigation, the NATF, RF, and SERC had planned to develop and conduct a workshop for registered entity security professionals and SMEs in each of the two regions on mitigation practices that entities can employ on their systems, equipment, and networks as an additional line of defense to augment the supply chain risk assessment and procurement practices that are focused on addressing risks at the source. Plans for the face-to-face workshops were postponed due to pandemic restrictions on travel and gatherings. In the interim, the NATF, RF, and SERC collaborated to conduct an industry-wide special webinar on “Identifying and Managing Potential Compromise of Network Interface Cards” on October 22, 2020. The webinar featured presentations from the NATF, RF, SERC, NERC, FERC, and NATF member-company SMEs on the following topics:

- Overview of NATF-ERO Collaboration Pilot
- NATF Supplier Cyber Security Assessment Model – How Entity Mitigation Fits In
- NERC/FERC Joint Staff White Paper on Supply Chain Vendor Identification
- Regional Entity Perspectives on Responding to Supply Chain Compromise Risk
- NATF Member SME Perspectives/Experiences with Supply Chain Compromise Mitigation

Slides from the webinar are posted here on the NATF public site.

The NATF will continue to work with RF and SERC to explore options for future regional workshops or special webinars on entity mitigation of supply chain risks.

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NATF Begins Annual Revision Process for Supply Chain Criteria and Questionnaire

This month, the NATF is beginning the annual revision process for the NATF “Energy Sector Supply Chain Risk Questionnaire” (Questionnaire) and the “NATF Cyber Security Criteria for Suppliers” (Criteria). The Criteria and the Questionnaire are living documents that are being revised pursuant to the "Revision Process for the Energy Sector Supply Chain Risk Questionnaire and NATF Cyber Security Criteria for Suppliers," which is available on the

NATF public website. This process provides for an annual revision cycle as well as for additional revisions throughout the year, as necessary.

For the annual revision process, the Criteria and Questionnaire Revision Team will consider inputs through January and February, and proposed changes will be posted for industry comments in early March. Many inputs have already been received, including inputs from the World Economic Forum.

To facilitate alignment on criteria and questions, however, the review team would benefit from receiving inputs for modifications from across the electric and gas industries, including from suppliers and third-party assessors. Some entities are using a different questionnaire or criteria, and the review team is requesting these entities provide differences so the NATF Criteria and Questionnaire can more closely meet their needs. Entities will always have unique questions for suppliers, but creating significant alignment is enabling industry and suppliers to work together to identify and mitigate potential areas of risk.

Background

The Criteria and Questionnaire are tools that were developed by industry entities, suppliers, and third-party assessors for industry-wide use to drive consistency of information obtained from suppliers of bulk power system hardware, software, and services. They provide criteria to evaluate a supplier's supply chain cyber security posture and specific questions to obtain information on the criteria. The vision for these resources is as follows:

- Align on criteria and information needed to evaluate a supplier's cyber security risks.
- Provide transparency to suppliers to enable suppliers to be prepared to provide entities with information.
- Provide alignment to current security frameworks and other resources to provide assurances for the accuracy of supplier information (e.g., SOC2, ISO27001, etc.).
- Encourage entity/supplier discussions for risk mitigation.
- Align with other industry efforts.

The Criteria and Questionnaire will continue to evolve in response to the current cyber security climate facing industry. The NATF Criteria was first posted in 2019 and revised with inputs from industry organizations and suppliers in 2020, and the Questionnaire was first released in 2020. Since these releases just six months ago, the U.S. Department of Energy issued the "Prohibition Order Securing Critical Defense Facilities" on December 17, 2020, and entities have been evolving cross-functional processes that address not only supply chain cyber security but a supplier's overall cyber security risk posture, including both IT and OT.

Learn more at https://www.natf.net/industry-initiatives/supply-chain-industry-coordination.

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Protection System Misoperations Analysis Annual Report

The NATF Protection System Misoperations Analysis Initiative began in 2015. The NATF collects Misoperations data, produces metrics the NATF and individual members use to assess improvement efforts, and provides detailed information that the System Protection Practices Group and members can use to address specific causes of Misoperations. The Misoperations Analysis Working Group prepares member-specific protection system performance metrics that are included in the annual NATF Reliability Performance Reports and prepares a Protection System Misoperation Annual Report to analyze Misoperation categories, causes, and sub-causes and provide recommendations to the System Protection Practices Group and members.

The annual report provides detailed cause analysis protection scheme type. This arrangement, when combined with special analysis of hardware-related and communications-related Misoperations, supports recommendations that are actionable, realistic, effective, and linked to existing NATF practices and Principles of Operating Excellence.

In addition, the 2020 report provides the NATF overall and regional Misoperations rate for three-year time periods, plus assessments of the changes of Misoperation categories and involved relay technologies over the same periods.

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Redacted Operating Experience Reports

Since our last newsletter, we have posted two reports to the "Documents" section of our public site for members and other utilities to use internally and share with their contractors to help improve safety, reliability, and resiliency.

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For more information about the NATF, please visit www.natf.net.