NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

# Agenda
# Reliability and Security Technical Committee

**December 15, 2021** | 11:00 a.m.–4:30 p.m. Eastern Time
Virtual Meeting via WebEx

**Attendee WebEx Link:** Join Meeting

**Call to Order**

**NERC Antitrust Compliance Guidelines and Public Announcement***

**Introductions and Chair's Remarks**

**Agenda**

1. **Energy Reliability Assessments Task Force (ERATF) Recommendations* – Information –** Peter Brandien, ERATF Chair | Jim Piro, Sponsor

   The ERATF is assessing risks associated with unassured energy supplies, including the timing and inconsistent output from variable renewable energy resources, fuel location, and volatility in forecasted load, which can result in insufficient amounts of energy on the system to serve electrical demand. The ERATF is providing an update of their work including a draft SAR for RSTC review as well as a plan to gather industry input for development of a final SAR for RSTC endorsement in March, 2022.

2. **Reliability Guideline: Cyber Intrusion Guide for the System Operator* - Accept to Post for 45-day Comment Period –** Jimmy Hartmann, RTOS Chair | Todd Lucas, Sponsor

   As part of the three-year review cycle for Reliability Guidelines, the *Reliability Guideline: Cyber Intrusion Guide for the System Operator* was reviewed and updated. The update includes the additions of specific metrics to facilitate determining the effectiveness of the guideline per the FERC Order. The RTOS is seeking RSTC acceptance to post the guideline for a 45-day comment period.

3. **GMD Monitoring Reference Document* – Accept to Post for 45-day Comment Period –** Jimmy Hartmann, RTOS Chair | Todd Lucas, Sponsor

   As part of the three-year review cycle for Reference Documents, the GMD Monitoring Reference Document was reviewed and updated. The RTOS is seeking RSTC acceptance to post the guideline for a 45-day comment period.

4. **Resources Subcommittee (RS) Reporting ACE Definition SAR* – Endorse –** Greg Park, RS Chair | Rich Hydzik, Sponsor

   The current definition of Reporting ACE has a conflict with the Western Interconnection's Automatic Time Error Correction (ATEC) process and does not allow other Interconnections to pursue ATEC. Additionally, there could be some confusion in that the terms ACE and Reporting ACE are both used throughout the standards. The RS has a revised draft of the Reporting ACE definition that accommodates any Interconnection that has an approved ATEC process. The

revised definition is also shortened to remove verbiage that duplicates obligations in the BAL standards. Having duplicative language adds complexity to future changes to the applicable BAL standards. The RS is seeking RSTC endorsement of the SAR and subsequent submittal to the Standards Committee for action.

5. **White Paper: Grid Forming Technology, Bulk Power System Reliability Considerations* – Approve** - Julia Matevoysan, IRPWG Vice Chair | Jody Green, Sponsor

   As inverter-based resources (IBRs) penetrations continue to grow across North America, grid dynamics and controls strategies have also adapted and advanced over the recent years. One such technology that is now gaining momentum is grid forming (GFM) inverter technology. GFM inverters have been widely researched in battery energy storage systems (BESS), wind power plants, solar photovoltaic (PV) plants, and hybrid plants. Further, there are several installed projects where GFM functions have been successfully tested, including extremely fast power injection in the inertial timeframe in response to frequency events, islanded operation capability without synchronous generation, blackstart capability, and operation in parallel with grid following (GFL) resources and synchronous machines. Widespread understanding of GFM controls and their impacts to bulk power system performance is still in the early stages; however, the technology shows significant promise. The IRPWG has developed a White Paper with recommendations on this subject and is seeking RSTC approval.

6. **White Paper: BPS-Connected IBR and Hybrid Plant Capabilities for Frequency Response* — Approve** - Julia Matevoysan, IRPWG Vice Chair | Jody Green, Sponsor

   The Federal Energy Regulatory Commission (FERC) issued Order No. 842 in 2018, amending the pro forma Large Generator Interconnection Agreement (LGIA) and Small Generator Interconnection Agreement (SGIA) to require all "newly interconnecting large and small generating facilities, both synchronous and non-synchronous, to install, maintain, and operate equipment capable of providing primary frequency response (PFR) as a condition of interconnection." On the same subject, NERC recently published a white paper, *Fast Frequency Response Concepts and Bulk Power System Reliability Needs*, in March 2020 describing the interrelationships between primary frequency response (PFR) and fast frequency response (FFR). This work extends on the FERC Order NO. 842 and the NERC white paper and recommends leveraging PFR and FFR capabilities from inverter-based resources to the extent possible to support BPS frequency as an essential reliability service. The IRPWG has developed a White Paper with recommendations on this subject and is seeking RSTC approval.

**LUNCH BREAK – 20 MINS**

7. **TPL-001-5 SAR for BPS-Connected IBRs* – Endorse** - Julia Matevoysan, IRPWG Vice Chair | Jody Green, Sponsor

   The NERC IRPWG (formerly IRPTF) undertook a complete review of the NERC Reliability Standards in the context of increasing levels of BPS-connected inverter-based resources and published a white paper on the outcomes and recommendations of this review in March 2020. The review was approved by the NERC Planning Committee and served as the technical justification for future standards revision efforts. Based on the outcome of the review, it was determined that the TPL-001-4/5 needed clarifications "to address terminology throughout the standard that is unclear with regards to inverter-based resources" the next time the standard is revised. The IRPWG brought a SAR to the RSTC in March 2021 which was not endorsed. The IRPWG sought and

received feedback from RSTC members and addressed the comments and made conforming revisions to the SAR. The IRPWG is seeking endorsement of the proposed SAR and subsequent submittal to the Standards Committee for action.

8. **TPL-001-5 SAR for BPS-Connected IBRs* – Endorse** - Kun Zhu, SPIDERWG Chair | Wayne Guttormson, Sponsor

   The NERC SPIDERWG undertook a review of the TPL-001 standard considering the potential impact of DERs. This review is captured in the following RSTC-approved white paper and serves as the technical justification for the revisions suggested in this SAR:

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

   This SAR proposes to update TPL-001-5.1 to address some of the issues identified in the white paper. The SPIDERWG brought a SAR to the RSTC in March 2021 which was not endorsed. The SPIDERWG sought and received feedback from RSTC members and addressed the comments and made conforming revisions to the SAR. The SPIDERWG is seeking endorsement of the proposed SAR and subsequent submittal to the Standards Committee for action.

9. **MOD-032 SAR* – Endorse** - Kun Zhu, SPIDERWG Chair | Wayne Guttormson, Sponsor

   The original MOD-032 SAR was endorsed by the NERC Planning Committee (PC) in 2020 after reviewing its technical content. The NERC Standards Committee (SC) formed a SAR drafting team (SDT) which deemed the SAR flexible enough for future SDT work. The SAR was posted for industry comments. The SC subsequently rejected the SAR due to "insufficient support" and the SDT dismissed. The SPIDERWG believes a reliability gap still exists. The RSTC Executive Committee approved the SPIDERWG to revise the SAR. The SPIDERWG updated the SAR and developed a clarifying document for industry. The ISO/RTO Council has also written a letter of support (included in the agenda package) of the SPIDERWG efforts to develop mandatory provisions to compel Distribution Providers to provide Distributed Energy Resource (DER) data to reliability entities in support of accurate and comprehensive reliability studies, specifically SPIDERWG's request to revive the SAR for Project 2020-01: Modifications to MOD-032: Data for Power System Modeling and Analysis. The SPIDERWG is resubmitting the SAR for RSTC endorsement and subsequent SC action.

10. **White Paper: Survey of DER Modeling Practices* – Approve** - Kun Zhu, SPIDERWG Chair | Wayne Guttormson, Sponsor

    The SPIDERWG sought RSTC reviewers for the draft white paper at the September RSTC meeting. Based on reviewer comments, the white paper was updated to revise recommendations and to further clarify the scope of the survey data (within SPIDERWG members) throughout the document. The SPIDERWG is seeking RSTC approval of the revised white paper.

11. **Reliability Guideline: Recommended Approaches for UFLS Program Design with Increasing Penetrations of DERs* – Approve** - Kun Zhu, SPIDERWG Chair | Wayne Guttormson, Sponsor

    The *Reliability Guideline: Recommended Approaches for UFLS Program Design with Increasing Penetrations of DERs* was posted for a 45-day comment period. The SPIDERWG reviewed the comments received and made conforming revisions to the guideline. The SPIDERWG also included metrics to help assess the effectiveness of the guideline and is seeking RSTC approval of the revised guideline.

**BREAK – 10 MINS**

12. **Facility Ratings Task Force (FRTF) Scope and Next Steps* – Approve –** Greg Stone, FRTF Co-Chair

    The FRTF has developed a revised Scope document that includes a change in reporting structure. Rather than be a joint CCC/RSTC Task Force, the draft scope recommends the FRTF report to the RSTC. Transition of the FRTF to RSTC oversight continues to provide focus and technical expertise on Facility Ratings, including reliability risk to the grid, technical analysis and additional industry perspectives in problem statement definition. The FRTF also recommends adding additional technical expertise from the industry to the group for more robust discussion. The FRTF is seeking approval of the revised scope document.

13. **Security Working Group (SWG)* – Update -** Brent Sessions, SWG | Christine Hasha, Sponsor

    The SWG will provide an update on its current work plan activities as well as the survey results for the Assessing Cyber Risk Team and NIST partnership survey.

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

    a. North American Generator Forum – Allen Schriver

    b. North American Transmission Forum – Roman Carter

15. **TOCC Field Test Update* – Information –** Marisa Hecht, NERC Staff

    During the September RSTC meeting, the RSTC was presented with information regarding a proposed CIP-002 Transmission Owner Control Centers (TOCCs) Field Test. The Field Test document was sent to RSTC members for a comment period ending on Thursday, September 30, 2021. Comments were considered and incorporated into the TOCC Field Test document. The RSTC endorsed the Field Test document which was then approved by the Standards Committee (SC) for implementation. This agenda item will address the implementation of the Field Test for oversight by the RSTC.

16. **RSTC 2022 Calendar Review –** Stephen Crutchfield

| 2022 Meeting Dates | Time | Location | Hotel |
|---|---|---|---|
| March 8, 2022<br>March 9, 2022 | Please reserve entirety of both days | TBD | TBD |
| June 7, 2022<br>June 8, 2022 | Please reserve entirety of both days | TBD | TBD |
| September 13, 2022<br>September 14, 2022 | Please reserve entirety of both days | Atlanta | Grand Hyatt Buckhead |
| December 14, 2022<br>December 15, 2022 | Please reserve entirety of both days | TBD | TBD |

17. **Chair's Closing Remarks and Adjournment**

*Background materials included.

# Antitrust Compliance Guidelines

## I. General

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

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

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

## II. Prohibited Activities

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

- Discussions involving pricing information, especially margin (profit) and internal cost information and participants' expectations as to their future prices or internal costs.
- Discussions of a participant's marketing strategies.
- Discussions regarding how customers and geographical areas are to be divided among competitors.
- Discussions concerning the exclusion of competitors from markets.
- Discussions concerning boycotting or group refusals to deal with competitors, vendors or suppliers.

- Any other matters that do not clearly fall within these guidelines should be reviewed with NERC's General Counsel before being discussed.

## III. Activities That Are Permitted

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

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

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

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

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

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

**RSTC Meetings – Governance Management**

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

1. For each topic, the Chair will introduce the topic and allow for discussion.
2. At the conclusion of the discussion, the Chair will state the primary motion, and ask for first/second.
3. The Chair will then call for any additional discussion.
   - During such 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.
4. 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 Steps 3 and 4.

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.

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# Types of Documents

### *Reliability & Security Guidelines*

- *Formulated from best and/or optimal practices*
- *Suggested approaches or behaviors*
- *"HOW" certain objectives can be met*
- *Recommendations for how objectives "could" or "should" be accomplished*

### *Reference Documents, Whitepapers and Technical Reports*

- *Documented technical concepts*
- *Definitions of technical terms*
- *Defined methods or approaches*
- *Can be used as justification to support "WHY" certain practices are needed*

### *Implementation Guidance*

- *Provides examples or approaches for "HOW" Registered Entities could demonstrate compliance with Reliability Standard requirements.*
- *Used in Compliance Monitoring and Enforcement activities*

Submitted to ERO

### *Standard Authorization Request*

- *Defines scope, reliability benefit, and technical justification for a new or modified Reliability Standard or definition.*
- *Identifies "WHAT" requirements are needed to ensure the reliable operation of the BPS*

Submitted to SC

### Reliability Assessment Reports

- Independent and objective evaluations of BPS reliability conducted by the ERO
- Subgroup used to gain industry perspectives, expertise, and validation
- Requires BOT approval

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# Types of Documents: Member Considerations

| *Reliability & Security Guidelines* | *Reference Documents, Whitepapers and Technical Reports* | *Implementation Guidance* | *Standard Authorization Request* |
|---|---|---|---|
| • *ACCEPT for public comment*<br>  • *Is guidance needed on this topic?*<br>  • *Are there major flaws?*<br>• *APPROVE*<br>  • *Has the public and committee comments been sufficiently addressed?*<br>  • *Do you agree with the recommended guidance?* | • *APPROVE*<br>  • *Does it provide sufficient detail to support technical, security, and engineering SMEs?*<br>  • *Has it been peer reviewed and supported by a technical subgroup?*<br>  • *Is it foundational and/or conceptual*<br>  • *Does it contain specific recommendations?* | • *ENDORSE*<br>  • *Does it provide examples or approaches on how to implement a Reliability Standard?*<br>  • *Does it meet the expectations identified in the Implementation Guidance Development and Review Aid?* | • *ENDORSE*<br>  • *Is the SAR form complete?*<br>  • *Does it contain technical justification?* |

**Reliability Assessment Reports**

- ENDORSE
  - Is there general agreement with findings and recommendations?
  - Was the process followed?

# RSTC Actions

- **Approve:** The RSTC has reviewed the deliverable and supports the content and development process, including any recommendations.
- **Accept:** The RSTC has reviewed the deliverable and supports the development process used to complete the deliverable.
- **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.
- **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.

# Technical Justification for an Energy Assurance Standard Authorization Request

## Action

Request for RSTC reviewers.

## Summary

The NERC Energy Reliability Assessment Task Force (ERATF) prepared a technical paper documenting the analysis from an energy assurance industry survey and a NERC Standards gap review pertaining to risks associated with unassured energy supplies.

The survey consisted of 18 core questions based on the 11 questions formulated in the Energy Assurance white paper. The survey was distributed to sub-groups of the Reliability and Security Technical Committee (RSTC) and ISO/RTOs to gather feedback on energy assurance for three focus areas: 1) Energy Adequacy and Flexibility for Evolving Resource Mix, 2) Natural Gas Delivery Assurance, and 3) Metrics, Procedures & Analysis. The survey sought to examine how stakeholders are evaluating energy constraint issues and fuel availability issues. The original 11 questions from the whitepaper were modified slightly for the purpose of the survey in order to seek out answers to more specific, tactical questions which would inform the ERATF's recommendations.

In addition, through three sub-teams, the task force reviewed whether existing NERC Reliability Standards address aspects pertaining to energy (required to make electricity) assurance and identify any gaps. One team reviewed the operations planning time frame, and a second team assessed at the mid- and long-term planning time frame. The ERATF identified Reliability Standards appear to contain an implicit assumption regarding fuel availability and do not appear to address energy assurance. Changes in a transforming resource mix may call this assumption into question and the ERATF determined that ascertaining energy assurance may benefit from an energy assessment and monitoring fuel availability and deliverability.

The resulting analysis provides a recommendation to consider preparation of a Standards Authorization Request (SAR) pertaining to assessments for energy adequacy. A conceptual SAR, as well as the accompanying technical justification are included for illustration.

## Introduction

The Energy Reliability Assessment Task Force (ERATF) was formed to assess risks associated with unassured energy supplies. The task force was created to provide a formal process to analyze and collaborate with stakeholders addressing the issues identified in the *Ensuring Energy Adequacy with Energy-Constrained Resources*[1] whitepaper. This whitepaper identified energy sufficiency concerns related to operations, operations planning, and mid to long-term planning time frames.

Based on the eleven questions formulated in the whitepaper, the task force created a survey questionnaire. The survey was distributed it to sub-groups of the Reliability and Security Technical Committee (RSTC) and ISO/RTOs to gather feedback on energy assurance for three focus areas: Energy Adequacy and Flexibility for Evolving Resource Mix, Natural Gas Delivery Assurance, and Metrics, Procedures & Analysis. The goal of the survey was to better understanding how stakeholders are evaluating their energy constraint issues and, by extension, fuel availability issues. The original 11 questions from the whitepaper were modified slightly for the purpose of survey in order to seek out answers to more specific, tactical questions which would inform the ERATF's recommendations. For example, sub-questions were added to understand how specific assessment input assumptions were developed and how the impact of varying those assumptions was assessed.

The survey questionnaire had 18 core questions and 12 responses were received from NERC stakeholder groups, Independent System Operators, and individual utilities. These responses provided a tremendous volume of information (over 500 answers) to help evaluate the energy constraint issues (Appendix A).

## NERC ERATF Energy Assessment Survey

In September 2021, the NERC ERATF formed a sub-group of volunteers to review all the survey responses and identify recommendations. The rigor and thoroughness of the responses was excellent and it is clear entities "put a lot of work" into their responses. On October 18, this sub-group presented high-level summaries of the responses to the eighteen questions and higher-level, generalized responses as described below:

- Across many of the responses, it was not always clear if entities were addressing current practices for "capacity" assessments or "energy" assessments. Many entities responded that they modify capacity assessments with higher forced outage rates and extreme scenarios to develop to assess evaluate a range of operating conditions. But based on the responses energy assessments are not well defined and not being perform consistently across industry.
- The survey demonstrated differences in how energy assessments are performed in the three time frames (operations, operational planning, mid/long term planning).
- Unclear what operating entities do with low likelihood, high impact energy assessment results. Some provide the results publically to stakeholders for awareness, yet most do not. For predicted energy deficiencies in the operational planning timeframe of 1-3 days, almost all entities do schedule additional capacity. Most do not provide energy assessments reflective of low likelihood, high impact events in seasonal assessments. Some respondents mentioned review of

[1] Energy_Assurance_White_Paper (nerc.com)

extreme contingencies in the longer-term planning timeframe yet it is unclear if any planning actions are taken:

- Most of the responses were focused on extreme weather scenarios. Very few comments on the evaluation criteria included other potential failure modes, including cyber-attacks or other disruptions that could impact energy assurance, specifically cyber-attacks impacting the fuel supply chain.
- Many entities use history looking back 30 years to develop planning forecasts. Yet others responded that *"…the world climate and social policies (heating & transportation electrification) are changing fast…"* and entities should focus and forecast the future based predicted future events more so than history, including worse case extreme weather.

- Many responded that developing forecasts and assumptions for the mid- and long-term assessments is very difficult and it is challenging to assign levels of confidence in those forecasted assumptions. As an example, it is hard to forecast fuel replenishment or renewable production in the 6-12 month timeframe and more challenging in the long-term planning timeframe.
- Some entities responded that, in the future, the worst conditions could be in the fall or spring seasons with low renewable generation rather than heat wave peak conditions, if those peak conditions also included high renewable generation.
- Some entities responded that there are regional differences that may result or define different energy assessment reliability issues. More specifically, some operating entities have wider ranges in peak loads for extreme temperatures, some have significant fuel risks, some have extreme storm risks, some have significant forest fire risks, and some have drought risks. The reliability implications can vary regionally and therefore risks can vary regionally. Yet most responded it is commonly important across all of NERC industry to *"…develop common and consistent energy assessment methods…"*
- A few responded on the need to assess sufficient energy flexibility including dispatch energy, reserves, and regulation.
- Some offered transitioning from capacity adequacy to energy assurance can initially be performed by considering more conservative assumptions with fuel, wind, and solar, modeling higher probabilities of derates and extreme weather but more sophisticated techniques need to be developed.
- Some entities offered that based on the February 2021 extreme cold weather events it is clear that extreme peaks can be coincident with loss of fuel.
- Many respondents indicated that energy assessments should be performed throughout the year, not just during peak conditions, to capture the risk for fuel unavailability.
- Classic forced outage rate measurements such as Effective Force Outage Rates – Demand (EFORD) metrics and Unforced Capacity (UCAP) constructs are not great for assessing renewable energy assurance, as they assume a randomness to failures, rather than a coincidence. Many existing capacity valuation constructs, especially for longer term resource adequacy does not value

capacity that might support energy deficits resulting from multi-day loss of resources such as loss of fuel for over a week; especially for common mode loss of regional fuel.

- Some entities offered a significant issue in the planning horizon is assumptions regarding retirements of legacy fossil flexible resources with flexibility.
- Developing mid- to long-term assumptions is very important. For example, *"what to assume for non-ICAP imports"* or *"what to assume for fuel replenishment"* in seasonal timeframes.
- Some use 90-10 for extreme scenario assessments, others do something different.

<u>NERC Reliability Standards Review</u>

A set of sub teams of the ERATF were formed to review of the existing NERC Reliability Standards from the viewpoint of energy (required to make electricity) assurance and identify any gaps. The perspective of this review was addressing the assumption Reliability Standards may have that energy is always available. This assumption is now under review with the new resource mix, and may not be always true without having performed an energy assessment and without monitoring the resources ability to deliver. One team reviewed the operations planning time frame, and a second team assessed at the mid- and long-term planning time frame.

The comments from the operations planning sub team were the following observations:

1. The existing Reliability Standards do not explicitly define or require energy assessments.
2. A number of the Standards depend on resources to deliver energy to adhere to the requirements, such as operating within system operating limits (SOL) and interconnection reliability operating limits (IROLs), contingency reserves to regulate the system, and energy characteristics such as large ramps that may constrict or be limited by available energy. The timing of deploying energy resources to meet the demand is crucial.
3. There is little understanding of critical infrastructure interdependencies and the potential impacts on power generation.
4. Currently, there are insufficient tools to model and forecast wind, solar, etc. for energy assessments. Also mentioned was to consider power system modeling to create more accurate predictive tools, and include dynamic modeling of the gas system.
5. As the majority of fuel infrastructure exists beyond a single area, there is a need to understand and model the fuel infrastructure on a larger basis (e.g. affects from events outside of a specific area that can have impact on that area), so the impacts can be understood.
6. Considering that NERC Standards that require the use of generation assume that fuel is available, situational awareness was mentioned. The Emergency Operations (EOP) and Transmission Operations (TOP) Reliability Standards, and transmission operational requirements should require energy assessments. With the current Reliability Standards, it can an adequate analysis of the transmission system has been conducted and while still not meeting the energy requirements needed for the Reliable Operations of the bulk power system. Are the standards assuming that there is adequate situational awareness, and can maintain the energy supply? There is an 'energy' aspect of situational awareness that is missing from the current set of Reliability Standards.

7. Consider moving some elements of the NERC Reliability and Security guidelines[2] into NERC's Reliability Standards.

The comments and recommendations from the mid/long term planning sub team include the following observations:

1. The existing Reliability Standards do not explicitly require energy assessments. In a new or revised standard consider the following attributes:
    a. Add requirement(s) for extreme weather or environmental[3] events.
    b. Determine how much time is required to recover and prepare for the next stress event.
    c. Create an approach to support assessments of the impact of decarbonization goals.
    d. Consider the risk to gas supply disruption, such as natural gas being unavailable due to high demand.
    e. Ensure that there is adequate coordination between the operations and planning teams.
    f. When writing transmission planning studies, consider including other transmission equipment along with transformers.
    g. Studies need to account for additional characteristics, e.g. ramp rate, start/stop of units.
    h. Consideration is needed for 'dynamic load model' studies.
2. It was noted that the TPL standards are potentially the most appropriate location to add an energy assurance requirement, or a new class of Standards would need to be created.

<u>Recommendations</u>

Based on the review of the questionnaire and the NERC Standards gap review, sub-teams #1 and #2 are recommending that a Standards Authorization Request (SAR) be submitted. Energy assessments must be required within the NERC Standards considering the following:

- Define terms e.g. energy assessment, fuel, fuel assurance, etc.
- For energy assessments, metrics and observations should be compared to targets or predefined criteria. Results should be in terms of the impact to the Bulk Power System.
- Energy assessments should be required to include the appropriate assumptions and scenarios that account for but not limited to: time-coupled restrictions on the availability of fuel, the impact of energy storage and other flexible resources, the logistical constraints of the associated fuel delivery supply chains, common mode outages not connected to fuel supply, coincident outages of multiple independent resources, outage duration based on failure modes, and intermittent resources need to account to be included to account for their unique characteristics.
- Energy assessments must be coordinated between areas to harmonize interchange assumptions.
- Extreme event analysis needs to be defined and included in the assessments.
- Requirements for energy assessment should include a clearly defined periodic basis and performed in each of the NERC defined planning time horizons, as well as the operations time horizon. Periodicity should include clauses for their re-performance and/or update of existing assessment when changes to assumptions and input data invalidates an existing assessment.

[2] https://www.nerc.com/comm/Pages/Reliability-and-Security-Guidelines.aspx
[3] Extreme environmental events includes long-duration environments such as cloud cover, smoke, no wind, etc.

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# Standard Authorization Request (SAR)

Complete and submit this form, with attachment(s) to the NERC Help Desk. Upon entering the Captcha, please type in your contact information, and attach the SAR to your ticket. Once submitted, you will receive a confirmation number which you can use to track your request.

The North American Electric Reliability Corporation (NERC) welcomes suggestions to improve the reliability of the bulk power system through improved Reliability Standards.

| Requested information | | | |
|---|---|---|---|
| SAR Title: | Fuel Assurance with Energy-Constrained Resources | | |
| Date Submitted: | 4/1/2022 | | |
| SAR Requester | | | |
| Name: | Chair Peter Brandien on behalf of the | | |
| Organization: | Energy Reliability Assessment Task Force (ERATF) of the Reliability and Security Technical Committee (RSTC) | | |
| Telephone: | (413) 535-4022 | Email: | pbrandien@iso-ne.com |
| SAR Type (Check as many as apply) | | | |
| ☒ New Standard<br>☒ Revision to Existing Standard<br>☒ Add, Modify or Retire a Glossary Term<br>☐ Withdraw/retire an Existing Standard | | ☐ Imminent Action/Confidential Issue (SPM Section 10)<br>☐ Variance development or revision<br>☐ Other (Please specify) | |
| Justification for this proposed standard development project (Check all that apply to help NERC prioritize development) | | | |
| ☒ Regulatory Initiation<br>☐ Emerging Risk (Reliability Issues Steering Committee) Identified<br>☐ Reliability Standard Development Plan | | ☒ NERC Standing Committee Identified<br>☐ Enhanced Periodic Review Initiated<br>☒ Industry Stakeholder Identified | |
| Industry Need (What Bulk Electric System (BES) reliability benefit does the proposed project provide?): | | | |
| Unassured deliverability of fuel supplies, coincident with the timing and inconsistent output from variable renewable energy resources and volatility in forecasted load, can result in insufficient amounts of capacity and energy on the bulk electric system (BES) needed to serve electrical demand and ensure the reliable operation of the BES throughout each hour of the time period being evaluated[1].<br><br>Historically, analysis of the energy assessments of the bulk power system focused on capacity over peak time periods. Assessments focused on capacity reserve levels compared to peak demand because resources were generally dispatchable and, except for unit outages and de-rates, were available when needed. Reserve margins were planned so that deficiency in capacity to meet daily peak demand (Loss of Load Expectation (LOLE) or Loss-of-Load Probability (LOLP)) occurred no more than one day-in-ten- | | | |

[1] The industry need is described in the *Ensuring Energy Adequacy with Energy-Constrained Resources* white paper, presented to the RSTC, December 2020.

## Requested information

years. Reserve margins are calculated from probabilistic analysis using generating unit forced outage rates based on random equipment failures derived from their historic performance. The targeted level has typically been one event every ten years, based on daily peaks (rather than hourly energy obligations). Additional insights were traditionally gained by also calculating Loss-of-Load-Hours (LOLH) and expected unserved energy (EUE) based on the mean-time-to-repair (MTTR) unit averages.

A key assumption in this analysis has been that fuel is available when capacity is required to provide the requisite energy. This is not surprising since fuel availability was assured with either long-term fuel contracts (commodity plus transportation capacity), on-site storage (e.g. oil, coal and reservoir-based hydro), or with required periodic and predictable fuel replacement (e.g. nuclear). With diverse, dispatchable resource technologies, capacity from other technologies could mitigate impacts if fuel for one resource type became unavailable.

Today, this framework is changing. Transitioning from coal and nuclear resources to wind, solar, gas that is dual fueled, and hybrid resources creates a more complex scenario, hence better understanding fuel assurance and forward energy supply planning becomes increasingly important. Understanding generating capacity alone is insufficient to ensure the reliable operation of the bulk power system. Policy efforts to increase the contribution of renewable energy has resulted in a higher emphasis on the 'on call' availability of capacity to supply energy to serve net demand. Production flexibility from these balancing resources has already become important and will become critical in the future. Operational uncertainty is increasing due to the types of, and conditions under which, energy, and by implication, fuel, is available or acquired. Examples of these uncertainties are resources solely dependent on the availability of wind and solar, which are similar to run-of-river hydro plants in that they have no energy storage capabilities and are completely dependent on real time weather conditions. These also include distribution level resources and flexible load programs which may introduce additional volatility into energy forecasts.

Layered into this uncertainty, natural gas fueled resources may, depending on the contract for fuel acquisition, be subject to fuel curtailment or interruption during peak fuel demands. Additionally, gas pipeline design and how gas generators interconnect with the pipeline can vary, which can result in significantly different impacts to the generator and the BES under gas pipeline disruption scenarios. Further, in some areas, variable energy resources require that there are sufficient flexible energy resources available to quickly respond to off-set ramping requirements. In addition, these impacts can be mitigated with the supply and geographical diversity from renewable and smaller distributed resources. These uncertainties are already causing many system operators to consider scheduling, optimization and commitment of resources over a multi-day timeframe. The changing resource mix requires industry to consider both capacity requirements and energy, and by extension fuel, availability. Even if sufficient capacity is available, a level of certainty in the delivery of fuel is required to ensure that energy is available to support demand.

## Requested information

Standard Requirement:

One common underlying risk is the increased use of just-in-time delivery of fuel. More specifically, challenges are mounting from the single points of failure caused by the penetration of wind, solar, and natural gas with increased uncertainties due to unexpected interruptions of fuel delivery. This could be a result of the sun not shining or the sun being blocked by snow and ice, the wind not blowing, or blowing too much, extreme cold or heat, and natural gas becoming unavailable (due to the contract type, or equipment failure, or pipeline maintenance, or pipeline failure).

Energy security, and by extension fuel security, risks are increasingly becoming more apparent as extreme weather has resulted in deficits in energy (rather than capacity). During the past 10 years, there were four events that jeopardized the BES. In February 2011[2], there was an arctic cold front in the southwest and resulted in generation outages and natural gas facility outages. In January 2014[3], there was a Polar Vortex that affected central and eastern U.S. and Texas. Again, the 2014 event triggered generation outages and natural gas availability issues. In January 2018[4], the south-central U.S. experienced many generation outages resulting in emergency measures. The February 2021[5] event is the fourth event, and an arctic cold air mass impacted Mississippi, Louisiana, Arkansas, Oklahoma and Texas.

High impact points of failure require study by the industry towards understanding impacts and putting in place plans to address them. Either enhancements to existing NERC Reliability Standards or creating new Standards is needed to mitigate issues that were documented during the January 2019 and February 2021 events. For example, study of the loss of a large natural gas pipeline is already called for as an extreme event(s) in the transmission planning Reliability Standard TPL-001-4, but more scenarios for planning and extreme events are needed to represent common modes of failure, such as the loss of solar, wind, water, and natural gas. This could be demonstrated by entities performing energy assessments ensuring that they understand the risks. Furthermore, corrective action plans should be in place to mitigate impacts from agreed upon planned event design basis and an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts from agreed upon extreme event(s).

The scenarios belonging in planned events versus extreme events require the development of an agreed upon design basis identifying what risks/impacts are acceptable and which are not and require mitigation. The resulting Reliability Standard should provide certainty of risk mitigation and expected reliability performance across the industry when the system is planned. Rather than a burden, these enhancements should provide certainty of risk mitigation between organizations and throughout the interconnections, thereby, ensuring that an Adequate Level of Reliability for the BES is maintained.

[2] Outages and Curtailments During the Southwest Cold Weather Event of February 1-5, 2011 - FERC and NERC
[3] Polar Vortex Review
[4] 2019 FERC and NERC Staff Report: The South Central United States Cold Weather Bulk Electric System Event of January 17, 2018
[5] February 2021 Cold Weather Grid Operations: Preliminary Findings and Recommendations - FERC, NERC and Regional Entity Joint Staff Inquiry

| Requested information |
| --- |
| Purpose or Goal (How does this proposed project provide the reliability-related benefit described above?): |
| This project will enhance reliability by requiring industry to analyze their energy-related issues and the impact of currently unstudied constraints on the reliability of the BES. The focus of an energy assessment is to analyze two parameters: fuel assurance and flexibility based on the evolving resource mix, and gas delivery security. These two parameters need to be analyzed in three time horizons: Operations, Near-Term Transmission Planning and Long-Term Transmission Planning.<br><br>Regarding fuel assurance and flexibility, as the mix of resources trends toward more renewable energy, primarily with variable and intermittent supplies of fuel (e.g. sunshine, wind, and water), maintaining a balanced power system will require a more flexible approach to energy and capacity adequacy in order to maintain operational awareness. Traditionally, peak-hour capacity can be solved in an isolated case that ignores all other hours, but in a limited energy situation, the utilization of system resources affects the availability during peak hours. In addition, generator flexibility is gaining importance as load ramps begin to stress existing infrastructure.<br><br>Regarding gas delivery security, maintaining system balance in cooperation with a limited energy set of resources will require some level of controllability with the remaining fleet, which will most likely be gas fired generation. In addition, the variability of the renewable resources will likely change how gas is utilized, requiring a higher precision of understanding to determine if the existing system is capable of serving the changing needs (e.g. larger swings of gas demand due to higher overall gas generation ramp rates and shorter periods of online time). This issue is further complicated since stakeholders external to power system operators may influence gas delivery security, such as policies and procedure developments from FERC, NAESB, natural gas pipeline companies, or other entities. |
| Project Scope (Define the parameters of the proposed project): |
| The project scope is to create or modify the NERC Reliability Standards to address the following:<br><br>▪ Define terms e.g. energy assessment, fuel, fuel assurance, etc.<br>▪ For energy assessments, metrics and observations should be compared to targets or predefined criteria. Results should be in terms of the impact to the Bulk Power System.<br>▪ Energy assessments should be required to include the appropriate assumptions and scenarios that account for but not limited to: time-coupled restrictions on the availability of fuel, the impact of energy storage and other flexible resources, the logistical constraints of the associated fuel delivery supply chains, common mode outages not connected to fuel supply, coincident outages of multiple independent resources, outage duration based on failure modes, and intermittent resources need to account to be included to account for their unique characteristics.<br>▪ Energy assessments must be coordinated between areas to harmonize interchange assumptions.<br>▪ Extreme event analysis needs to be defined and included in the assessments.<br>▪ Requirements for energy assessment should include a clearly defined periodic basis and performed in each of the NERC defined planning time horizons, as well as the operations time horizon. |

| Requested information |
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| Periodicity should include clauses for their re-performance and/or update of existing assessment when changes to assumptions and input data invalidates an existing assessment. |
| 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[6] 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): |
| The Energy Reliability Assessment Task Force (ERATF) was formed to assess risks associated with unassured energy supplies. The task force was created to provide a formal process to analyze and collaborate with stakeholders addressing the issues identified in the Ensuring Energy Adequacy with Energy-Constrained Resources whitepaper. This whitepaper identified energy sufficiency concerns related to operations, operations planning, and mid to long-term planning time frames.<br>Based on the eleven questions formulated in the whitepaper, the task force created a survey questionnaire. The survey was distributed it to sub-groups of the Reliability and Security Technical Committee (RSTC) and ISO/RTOs to gather feedback on energy assurance for three focus areas: Energy Adequacy and Flexibility for Evolving Resource Mix, Natural Gas Delivery Assurance, and Metrics, Procedures & Analysis. The goal of the survey was to better understanding how stakeholders are evaluating their energy constraint issues and, by extension, fuel availability issues. The original 11 questions from the whitepaper were modified slightly for the purpose of survey in order to seek out answers to more specific, tactical questions which would inform the ERATF's recommendations. For example, sub-questions were added to understand how specific assessment input assumptions were developed and how the impact of varying those assumptions was assessed.<br><br>The survey questionnaire had 18 core questions and 12 responses were received from NERC stakeholder groups, Independent System Operators, and individual utilities. These responses provided a tremendous volume of information (over 500 answers) to help evaluate the energy constraint issues.<br><br><u>NERC ERATF Energy Assessment Survey</u><br>The NERC ERATF formed a sub-group of volunteers to review all the survey responses and identify recommendations. The rigor and thoroughness of the responses was excellent and it is clear entities "put a lot of work" into their responses. On October 18, this sub-group presented high-level summaries of the responses to the eighteen questions and higher-level, generalized responses as described below:<br><br>▪ Across many of the responses, it was not always clear if entities were addressing current practices for "capacity" assessments or "energy" assessments. Many entities responded that they modify capacity assessments with higher forced outage rates and extreme scenarios to develop to assess evaluate a range of operating conditions. But based on the |

[6] 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 |
| --- |
| responses energy assessments are not well defined and not being perform consistently across industry.<br>▪ The survey demonstrated differences in how energy assessments are performed in the three time frames (operations, operational planning, mid/long term planning).<br>▪ Unclear what operating entities do with low likelihood, high impact energy assessment results. Some provide the results publically to stakeholders for awareness, yet most do not. For predicted energy deficiencies in the operational planning timeframe of 1-3 days, almost all entities do schedule additional capacity. Most do not provide energy assessments reflective of low likelihood, high impact events in seasonal assessments. Some respondents mentioned review of extreme contingencies in the longer-term planning timeframe yet it is unclear if any planning actions are taken:<br>  ▪ Most of the responses were focused on extreme weather scenarios. Very few comments on the evaluation criteria included other potential failure modes, including cyber-attacks or other disruptions that could impact energy assurance, specifically cyber-attacks impacting the fuel supply chain.<br>  ▪ Many entities use history looking back 30 years to develop planning forecasts. Yet others responded that "…the world climate and social policies (heating & transportation electrification) are changing fast…" and entities should focus and forecast the future based predicted future events more so than history, including worse case extreme weather.<br>▪ Many responded that developing forecasts and assumptions for the mid- and long-term assessments is very difficult and it is challenging to assign levels of confidence in those forecasted assumptions. As an example, it is hard to forecast fuel replenishment or renewable production in the 6-12 month timeframe and more challenging in the long-term planning timeframe.<br>▪ Some entities responded that, in the future, the worst conditions could be in the fall or spring seasons with low renewable generation rather than heat wave peak conditions, if those peak conditions also included high renewable generation.<br>▪ Some entities responded that there are regional differences that may result or define different energy assessment reliability issues. More specifically, some operating entities have wider ranges in peak loads for extreme temperatures, some have significant fuel risks, some have extreme storm risks, some have significant forest fire risks, and some have drought risks. The reliability implications can vary regionally and therefore risks can vary regionally. Yet most responded it is commonly important across all of NERC industry to "…develop common and consistent energy assessment methods…"<br>▪ A few responded on the need to assess sufficient energy flexibility including dispatch energy, reserves, and regulation.<br>▪ Some offered transitioning from capacity adequacy to energy assurance can initially be performed by considering more conservative assumptions with fuel, wind, and solar, modeling higher probabilities of derates and extreme weather but more sophisticated techniques need to be developed. |

## Requested information

- Some entities offered that based on the February 2021 extreme cold weather events it is clear that extreme peaks can be coincident with loss of fuel.
- Many respondents indicated that energy assessments should be performed throughout the year, not just during peak conditions, to capture the risk for fuel unavailability.
- Classic forced outage rate measurements such as Effective Force Outage Rates – Demand (EFORD) metrics and Unforced Capacity (UCAP) constructs are not great for assessing renewable energy assurance, as they assume a randomness to failures, rather than a coincidence. Many existing capacity valuation constructs, especially for longer term resource adequacy does not value capacity that might support energy deficits resulting from multi-day loss of resources such as loss of fuel for over a week; especially for common mode loss of regional fuel.
- Some entities offered a significant issue in the planning horizon is assumptions regarding retirements of legacy fossil flexible resources with flexibility.
- Developing mid- to long-term assumptions is very important. For example, "what to assume for non-ICAP imports" or "what to assume for fuel replenishment" in seasonal timeframes.
- Some use 90-10 for extreme scenario assessments, others do something different.

<u>NERC Reliability Standards Review</u>

A set of sub teams of the ERATF were formed to review of the existing NERC Reliability Standards from the viewpoint of energy (required to make electricity) assurance and identify any gaps. The perspective of this review was addressing the assumption Reliability Standards may have that energy is always available. This assumption is now under review with the new resource mix, and may not be always true without having performed an energy assessment and without monitoring the resources ability to deliver. One team reviewed the operations planning time frame, and a second team assessed at the mid- and long-term planning time frame.

The comments from the operations planning sub team were the following observations:

1. The existing Reliability Standards do not explicitly define or require energy assessments.
2. A number of the Standards depend on resources to deliver energy to adhere to the requirements, such as operating within system operating limits (SOL) and interconnection reliability operating limits (IROLs), contingency reserves to regulate the system, and energy characteristics such as large ramps that may constrict or be limited by available energy. The timing of deploying energy resources to meet the demand is crucial.
3. There is little understanding of critical infrastructure interdependencies and the potential impacts on power generation.
4. Currently, there are insufficient tools to model and forecast wind, solar, etc. for energy assessments. Also mentioned was to consider power system modeling to create more accurate predictive tools, and include dynamic modeling of the gas system.
5. As the majority of fuel infrastructure exists beyond a single area, there is a need to understand and model the fuel infrastructure on a larger basis (e.g. affects from events outside of a specific area that can have impact on that area), so the impacts can be understood.

| Requested information |
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| 6. Considering that NERC Standards that require the use of generation assume that fuel is available, situational awareness was mentioned. The Emergency Operations (EOP) and Transmission Operations (TOP) Reliability Standards, and transmission operational requirements should require energy assessments. With the current Reliability Standards, it can an adequate analysis of the transmission system has been conducted and while still not meeting the energy requirements needed for the Reliable Operations of the bulk power system. Are the standards assuming that there is adequate situational awareness, and can maintain the energy supply? There is an 'energy' aspect of situational awareness that is missing from the current set of Reliability Standards.<br>7. Consider moving some elements of the NERC Reliability and Security guidelines into NERC's Reliability Standards.<br><br>The comments and recommendations from the mid/long term planning sub team include the following observations:<br><br>1. The existing Reliability Standards do not explicitly require energy assessments. In a new or revised standard consider the following attributes:<br>a. Add requirement(s) for extreme weather or environmental events.<br>b. Determine how much time is required to recover and prepare for the next stress event.<br>c. Create an approach to support assessments of the impact of decarbonization goals.<br>d. Consider the risk to gas supply disruption, such as natural gas being unavailable due to high demand.<br>e. Ensure that there is adequate coordination between the operations and planning teams.<br>f. When writing transmission planning studies, consider including other transmission equipment along with transformers.<br>g. Studies need to account for additional characteristics, e.g. ramp rate, start/stop of units.<br>h. Consideration is needed for 'dynamic load model' studies.<br>2. It was noted that the TPL standards are potentially the most appropriate location to add an energy assurance requirement, or a new class of Standards would need to be created. |
| Cost Impact Assessment, if known (Provide a paragraph describing the potential cost impacts associated with the proposed project): |
| It is not the intention of the ERATF to require solutions to the energy related issues being addressed. This SAR is intended to require study of energy related issues to clearly convey the risks related to operating the BES under conditions of the concurrent limited fuel supply and variable output resources. |
| Please describe any unique characteristics of the BES facilities that may be impacted by this proposed standard development project (*e.g.*, Dispersed Generation Resources): |
| The BES facilities impacted by this proposed project will all have unique characteristics including fuel type, delivery, location (ability to access additional fuel, i.e. are road networks sufficient, rail line contingencies, barges for waterway-based plants, etc.), design, construction, time of year (season) and operational characteristics, etc. These unique characteristics need to be addressed during drafting to achieve the intended enhancements to reliability. |

| Requested information |
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| 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): |
| Reliability Coordinator, Balancing Authority, Transmission Operator, and Generation Operator. |
| Do you know of any consensus building activities[7] in connection with this SAR? If so, please provide any recommendations or findings resulting from the consensus building activity. |
| On February X, 2022, the ERATF is sponsoring a workshop that outlines the challenges and works towards solutions in the Operational Planning and Operational time horizons. |
| 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)? |
| SAR 2021 10 06 Extreme Cold Weather Grid Operations, Preparedness, and Coordination; consider the impact to the TPL, EOP and TOP standards. |
| 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. |
| There have been three Reliability Guidelines, however, in the past 10 years, there have been four cold weather events during the months of February 2011, January 2014, January 2018, and February 2021. The numerous events illustrate that the guidelines are not as widely adopted as necessary to prevent reoccurrence.<br><br>Reliability and Security Guidelines (nerc.com)<br>▪ Reliability Guideline: Fuel Assurance and Fuel-Related Reliability Risk Analysis<br>▪ Reliability Guideline: Generating Unit Winter Weather Readiness<br>▪ Reliability Guideline: Gas and Electrical Operational Coordination Considerations |

| 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. |

[7] Consensus building activities are occasionally conducted by NERC and/or project review teams. They typically are conducted to obtain industry inputs prior to proposing any standard development project to revise, or develop a standard or definition.

| Reliability Principles | |
|---|---|
| ☐ | 5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems. |
| ☒ | 6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions. |
| ☐ | 7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis. |
| ☐ | 8. Bulk power systems shall be protected from malicious physical or cyber attacks. |

| Market Interface Principles | |
|---|---|
| Does the proposed standard development project comply with all of the following Market Interface Principles? | Enter (yes/no) |
| 1. A reliability standard shall not give any market participant an unfair competitive advantage. | yes |
| 2. A reliability standard shall neither mandate nor prohibit any specific market structure. | yes |
| 3. A reliability standard shall not preclude market solutions to achieving compliance with that standard. | yes |
| 4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards. | yes |

| Identified Existing or Potential Regional or Interconnection Variances | |
|---|---|
| Region(s)/ Interconnection | Explanation |
| *e.g.*, NPCC | |

# For Use by NERC Only

| SAR Status Tracking (Check off as appropriate). | |
|---|---|
| ☐ Draft SAR reviewed by NERC Staff<br>☐ Draft SAR presented to SC for acceptance<br>☐ DRAFT SAR approved for posting by the SC | ☐ Final SAR endorsed by the SC<br>☐ SAR assigned a Standards Project by NERC<br>☐ 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 |

# Reliability Guideline: Cyber Intrusion Guide for the System Operator

## Action

Accept to post for 45-day comment period.

## Summary

As part of the three-year review cycle for Reliability Guidelines, the *Reliability Guideline: Cyber Intrusion Guide for the System Operator* was reviewed and updated. The update includes the additions of specific metrics to facilitate determining the effectiveness of the guideline per the FERC Order. The RTOS is seeking RSTC acceptance to post the guideline for a 45-day comment period.

# Reliability Guideline

## Cyber Intrusion Guide for System Operators: Version 2

## Applicability

Reliability Coordinators (RC), Balancing Authorities (BA), Transmission Operators (TOP), Generator Operators (GOP), and Distribution Providers (DP).

## Preamble

It is in the public interest for NERC to develop guidelines that are useful for maintaining and enhancing the reliability of the Bulk Electric System (BES). The subgroups of the Reliability and Security Technical Committee (RSTC)—in accordance with the RSTC charter[1] are authorized by the NERC Board of Trustees to develop reliability and security guidelines. These guidelines establish a voluntary code of practice on a particular topic for consideration and use by BES users, owners, and operators. These guidelines are coordinated by the technical committees and include the collective experience, expertise, and judgment of the industry. The objective of this reliability guideline is to distribute key practices and information on specific issues critical to appropriately maintaining BES reliability. Reliability guidelines are not to be used to provide binding norms or create parameters by which compliance to NERC Reliability Standards are monitored or enforced. While the incorporation of guideline practices is strictly voluntary, reviewing, revising, or developing a program using these practices is highly encouraged to promote and achieve appropriate BES reliability.

## 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[2].

### Baseline Metrics

- Performance of the BPS prior to and after a reliability guideline, as reflected in NERC's State of Reliability Report and reliability assessments (e.g., the Long Term Reliability Assessment and seasonal assessments);
- The 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.

[1] https://www.nerc.com/comm/RSTC/RelatedFiles/RSTC_Charter_approved20191105.pdf
[2] https://auth.internal.nerc.com/comm/RSTC/Pages/default.aspx

## Background and Purpose

System Operators are uniquely positioned to recognize cyber threats to the BES. Through direct access to Cyber Assets, and direct contact with field personnel, operators may be the first to recognize real-time threats to system security. They may also be targets of social engineering attempts.[3] Operators are potentially the first and last line of defence against cyber threats. This fact notwithstanding, it is the System Operator *organization* that establishes and sustains the conditions necessary for *individual* System Operators to successfully meet their responsibilities in real time.

The Real Time Operating Subcommittee (RTOS) recognizes not all organizations are the same, so this guidance is general and is based on the assumption that each entity has an approved Cyber Security Incident recognition, response and reporting process in place to follow any time a Cyber Security Incident has been identified, assessed, and confirmed.

The following guideline will assist System Operators in recognizing events that may be an indicator of a cyber-attack, and how and when to share information with others. While this *Cyber Intrusion Guide* was created for electric System Operators, the principles within are applicable to any operators or support staff engaged in maintaining Reliable Operation of the BES. The intent is to increase cross-discipline familiarity and recognition of when to ask a question or raise an issue, not to make cybersecurity professionals out of System Operators or vice versa, consistent with ongoing findings from the U.S Department of Energy's CyOTE program.[4]

This document is intended to be used as a guide only. It is not intended to detract or conflict with an entity's Cyber Security Incident response plan. Rather, the guide should highlight the plans to operators so that they can understand their role and what their company expects them to do. Developers of Cyber Security Incident response plans are encouraged to consider operators' perspective when creating their organization's plans.

As noted above, Reliability Guidelines are not to be used to provide binding norms or create parameters by which compliance to standards is monitored or enforced.

## Contents



## A. Could this be a sign of an attack? Recognizing indicators of potentially malicious activity

[3] For an overview of Social Engineering and Phishing attacks, please refer to US-CERT Security Tip ST04-14 at https://us-cert.cisa.gov/ncas/tips/ST04-014.

[4] See https://inl.gov/cyote/ for more information, particularly the Methodology paper linked from there.

As threats to Cyber Assets are continually evolving, it is difficult to provide a comprehensive list of anomalies that may require investigation or a response. Rather, an operator's familiarity with their systems, awareness and a questioning attitude likely provide the greatest value. Real-time operating staff should be vigilant in asking themselves why their Cyber Assets are responding unusually. The System Operator should be asking their Information Technology (IT) support to investigate any strange, unusual behavior, whenever it is detected. Similar to physical security concerns, operators should be encouraged to "say something when they see something." It is understood that increased vigilance may result in false positive reports. However, it is better to "play it safe" when Cyber Assets are behaving unusually.

Examples of anomalies that may require attention:

- Workstation unexpectedly locked out and/or receive a message indicates password has been changed
- Pointer or mouse cursor moving by itself
- Files / messages flashing / suspicious pop-ups appear on the screen
- New icons appear on desktop or in start menu
- System is unusually slow or unresponsive
  - Simultaneous loss of operational support systems (e.g., Heating, Ventilation, and Air Conditioning (HVAC), Fire Suppression, phone/communications)
- Observing unusual system activity or alarms from Cyber Assets. For example:
  - Simultaneous loss of multiple components of the Energy Management Systems (EMS), Supervisory Control and Data Acquisition (SCADA) system
  - Multiple breaker operations during a non-storm event
  - Any unexplainable manual operations
  - Multiple perceived suspicious readings
  - Requests for information about the system (social engineering attempts)
  - Unexpected system shutdown or reboot
  - Complete loss of SCADA capabilities that support Real-time operations.
  - Erratic EMS/SCADA system equipment behaviour, messages/alarms, or degradation of performance, especially when more than one device exhibits the same behaviour
  - Anti-malware application alerts on operator Human Machine Interface(s)
  - Unexpected user account authentication lockouts or change in user privileges
  - Calls from data partners (other entities who see your data) to verify suspicious data being received via communication associations/exchange

## B. Initial Actions and Internal Notifications

When unusual system behavior is observed, take any immediate steps outlined in your Cyber Security Incident response plan. As soon as possible, contact your cyber security team and follow their instructions. When describing the issue, include details on the observed and potential impacts of the situation. This will help responders as they work through the identification, containment, eradication, and recovery phases of incident response. Depending on an entity's Cyber Security Incident response plan, this may require an operator to:

- Contact EMS, Operational Technology (OT), IT, and cyber security personnel.
- Notify the other operators on duty.
- Notify field personnel working in or around potentially involved facilities.

## C. Response Actions and External Notifications

Once your organization's Cyber Security Incident response plan has been initiated, follow the reporting instructions of the plan. This may involve:

- Notifying other control centers – adjacent, distribution via Reliability Coordinator Information System (RCIS), etc.
- Receiving legal guidance on allowable release of information, or cyber security staff assuming responsibility for confidential communications related to the incident.
- Cyber security staff isolating certain equipment for containment, forensic analysis, evidence retention, and recovery.
- Law enforcement personnel requesting particular actions to preserve evidence. Reliable operations should be maintained through a coordinated response between law enforcement, operations, and an entity's physical/cyber security teams.

As the incident response progresses, be prepared to take actions as documented in your organization's Operating Plan. These could include implementing specific Operating Procedures as a result of incident response activities (e.g., changing the status of equipment or monitoring and control systems to support investigation), or general Operating Processes as proactive steps (e.g., declaring a conservative operations status).

## D. Summary

Due to their unique role in operating the BES, System Operators may be the first to observe unusual behavior. To ensure that entities are able to respond effectively, it is important that operators maintain a questioning attitude to assist in identifying something that requires further investigation. Further, electric operators should understand their important role in recognizing strange and unusual cyber security behavior and notifying the right people consistent with their incident response plan.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

# Reliability Guideline

Cyber Intrusion Guide for System Operators: Version 2

## Applicability

Reliability Coordinators (RC), Balancing Authorities (BA), Transmission Operators (TOP), Generator Operators (GOP), and Distribution Providers (DP).

## Preamble

It is in the public interest for NERC to develop guidelines that are useful for maintaining and enhancing the reliability of the Bulk Electric System (BES). The subgroups of the Reliability and Security Technical Committee (RSTC)—in accordance with the RSTC charter[1] are authorized by the NERC Board of Trustees to develop reliability and security guidelines. These guidelines establish a voluntary code of practice on a particular topic for consideration and use by BES users, owners, and operators. These guidelines are coordinated by the technical committees and include the collective experience, expertise, and judgment of the industry. The objective of this reliability guideline is to distribute key practices and information on specific issues critical to appropriately maintaining BES reliability. Reliability guidelines are not to be used to provide binding norms or create parameters by which compliance to NERC Reliability Standards are monitored or enforced. While the incorporation, of guideline practices, is strictly voluntary, reviewing, revising, or developing a program using these practices is highly encouraged to promote and achieve appropriate BES reliability. ~~It is in the public interest for the North American Electric Reliability Corporation (NERC) to develop guidelines that are useful for maintaining or enhancing the reliability of the Bulk Electric System (BES). Per their charters, the Technical Committees of NERC; the Operating Committee (OC), the Planning Committee (PC) and the Critical Infrastructure Protection Committee (CIPC) are authorized by the NERC Board of Trustees (Board) to develop Reliability (OC and PC) and Security (CIPC) Guidelines. Guidelines establish voluntary codes of practice for consideration and use by BES users, owners, and operators. These guidelines are developed by technical committees and include the collective experience, expertise and judgment of the industry. Reliability guidelines are not to be used to provide binding norms or create parameters by which compliance to standards is monitored or enforced. While the incorporation and use of guideline practices is strictly voluntary, the review, revision, and development of a program using these practices is highly encouraged to promote and achieve the highest levels of reliability for the BES.~~

## 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[2].

[1] https://www.nerc.com/comm/RSTC/RelatedFiles/RSTC_Charter_approved20191105.pdf
[2] https://auth.internal.nerc.com/comm/RSTC/Pages/default.aspx



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## Baseline Metrics

- Performance of the BPS prior to and after a reliability guideline, as reflected in NERC's State of Reliability Report and reliability assessments (e.g., the Long Term Reliability Assessment and seasonal assessments);
- The 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.

~~This Cyber Intrusion Guide was created for electric System Operators, but the priciples within are applicable to any operators or support staff engaged in maintaining Reliable Operation of the BES.~~

- No additional metrics

# Background and ~~Section 1: Background~~Purpose

System Operators are uniquely positioned to recognize cyber threats to the BES. Through direct access to Cyber Assets, and direct contact with field personnel, ~~O~~operators may be the first to recognize real-time threats to system security. They may also be targets of social engineering~~–~~ attempts.[3]~~,~~ Operators are potentially the first and last line of defence against cyber~~to potential~~ threats. This fact notwithstanding, it is the System Operator *organization* that establishes and sustains~~maintains~~ the conditions necessary for *individual* System Operators to successfully meet their responsibilities in real time.

~~The OC has tasked its Operating Reliability Subcommittee (ORS) to create a high-level guideline to assist System Operators in detecting and responding to potential Cyber Security Incidents.~~ The Real -Time Operating Subcommittee (RTOS~~ORS~~) recognizes not all organizations are the same, so this guidance is general and is based on the assumption that each entity has an approved Cyber Security Incident recognition, response and reporting process in place to follow any time a Cyber Security Incident has been identified, assessed, and confirmed.

The following guideline will assist System Operators in recognizing events that may be an indicator of a cyber-attack, and how and when to share information with others. While ~~T~~this *Cyber Intrusion Guide* was created for electric System Operators, ~~but~~ the principles within are applicable to any operators or support staff engaged in maintaining Reliable Operation of the BES. The intent is to increase cross-discipline familiarity and recognition of when to ask a question or raise an issue, not to make cybersecurity

[3] For an overview of Social Engineering and Phishing attacks, please refer to US-CERT ~~Security Tip ST04-14 at https://us-cert.cisa.gov/ncas/tips/ST04-014.~~Security Tip ST04-14 at https://us-cert.cisa.gov/ncas/tips/ST04-014.

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professionals out of System Operators or vice versa, consistent with ongoing findings from the U.S Department of Energy's CyOTE program.[4]

This document is intended to be used as a guide only. It is not intended to detract or conflict with an entity's Cyber Security Incident response plan. Rather, the guide should highlight the ~~Plans~~ plans to operators so that they can understand their role and what their company expects them to do. Developers of Cyber Security Incident response plans are encouraged to consider operators' perspective when creating their organization's plans.

As noted above, Reliability Guidelines are not to be used to provide binding norms or create parameters by which compliance to standards is monitored or enforced.

## Contents



## A. ~~Section 2:~~ Could this be a sign of an ~~Are we under~~ attack? Recognizing indicators of potentially malicious activity~~an attack or an attempt to attack~~

~~System Operators are uniquely positioned to recognize cyber threats to the BES. Through direct access to Cyber Assets, and direct contact with field personnel, Operators may be the first to recognize real-time threats to system security. They may also be targets of social engineering attempts[5]. Operators are potentially the first and last line of defence to potential threats.~~

As threats to Cyber Assets are continually evolving, it is difficult to provide a comprehensive list of anomalies that may require investigation or a response. Rather, an operator's familiarity with their systems, awareness and a questioning attitude likely provide the greatest value. Real-time operating staff should be vigilant in asking themselves why their Cyber Assets are responding unusually. The System Operator should be asking their Information Technology (IT)~~IT~~ support to investigate any strange, unusual behavior, whenever it is detected. Similar to physical security concerns, operators should be encouraged to "say something when they see something." It is understood that increased vigilance may result in false positive reports. However, it is better to "play it safe" when Cyber Assets are behaving unusually.

Examples of anomalies that may require attention:

[4] See https://inl.gov/cyote/ for more information, particularly the Methodology paper linked from there.
~~[5] For an overview of Social Engineering and Phishing attacks, please refer to US-CERT Security Tip.~~

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- Workstation unexpectedly locked out and/or receive a message indicates password has been changed
- Pointer or mouse cursor moving by itself
- Files / messages flashing / suspicious pop-ups appear on the screen
- New icons appear on desktop or in start menu
- System is unusually slow or unresponsive
  - Simultaneous loss of operational support systems (e.g., Heating, Ventilation, and Air Conditioning (HVAC)~~HVAC~~, Fire Suppression, phone/communications)
- Observing unusual system activity or alarms from Cyber Assets. For example:
  - Simultaneous loss of multiple components of the Energy Management Systems (EMS), Supervisory Control and Data Acquisition (SCADA)~~EMS/SCADA~~ system
  - Multiple breaker operations during a non-storm event
  - Any unexplainable manual operations
  - Multiple perceived suspicious readings
  - Requests for information about the system (social engineering attempts)
  - Unexpected system shutdown or reboot
  - Complete loss of SCADA capabilities that support Real-time operations.
  - Erratic EMS/SCADA system equipment behaviour, messages/alarms, or degradation of performance, especially when more than one device exhibits the same behaviour
  - Anti-malware application alerts on operator Human Machine Interface(s)
  - Unexpected user account authentication lockouts or change in user privileges
  - Calls from data partners (other ~~Entities~~ entities who see your data) to verify suspicious data being received via communication associations/exchange

## B. ~~Section 3:~~ Initial Actions and Internal Notifications ~~Response~~

When unusual system behavior is observed, take any immediate steps outlined in your Cyber Security Incident response plan. As soon as possible, contact your cyber security team and follow their instructions. When describing the issue, include details on the observed and potential impact~~(~~s~~)~~ of the situation~~problem~~. This will help responders as they work through the ~~to follow best protocol to safe~~ identification~~resolution~~, containment, eradication, and recovery phases of incident response~~preservation of evidence~~. Depending on an entity's Cyber Security Incident response plan, this may require an operator to:

- Contact ~~Energy Management System (~~EMS~~)~~, Operational Technology (OT), ~~Information Technology (~~IT~~)~~, and cyber security personnel.
- Notify the other operators on duty.
- Notify field personnel working in or around potentially involved facilities.

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## C. ~~Section 4:~~ Response Actions and External Notifications~~Response~~

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Once your organization's Cyber Security Incident response plan has been initiated, ~~an attack attempt has been confirmed,~~ follow the reporting instructions of the plan~~your organization's Cyber Security Incident reponse plan (if available)~~. ~~-~~This may involve:

- Notifying other control centers – adjacent, distribution via Reliability Coordinator Information System (RCIS), etc.
- Receiving ~~L~~legal guidance on allowable release of information, or cyber security ~~S~~staff assuming responsibility for confidential communications related to the incident~~Cyber event~~.
- Cyber ~~Security~~ security ~~Staff~~staff isolating certain equipment for containment, forensic analysis, evidence retention, and~~/or~~ recovery.
- Law ~~Enforcement~~ enforcement ~~P~~personnel requesting particular actions to preserve evidence~~taking control of an area or confiscating equipment~~. ~~-~~Reliable ~~Operations~~ operations should be maintained through a coordinated response between ~~Law~~ law ~~Enforcement~~enforcement, operations, and an entity's physical/cyber security teams.

As the incident response progresses, be prepared to take actions as documented in your organization's Operating Plan. These could include implementing specific Operating Procedures as a result of incident response activities (e.g., changing the status of equipment or monitoring and control systems to support investigation), or general Operating Processes as proactive steps (e.g., declaring a conservative operations status).

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## D. Summary

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Due to their unique role in operating the BES, System Operators may be the first to observe unusual behavior. To ensure that entities are able to respond effectively, it is important that ~~Operators~~ operators maintain a questioning attitude to assist in identifying something that requires further investigation. Further, electric operators should understand their important role in recognizing strange and unusual cyber security behavior and notifying the right people consistent with their incident response plan.



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# GMD Monitoring Reference Document

## Action

Accept to post for 45-day comment period.

## Summary

As part of the three-year review cycle for Reference Documents, the GMD Monitoring Reference Document was reviewed and updated. The RTOS is seeking RSTC acceptance to post the guideline for a 45-day comment period.

# Geomagnetic Disturbance Monitoring Reference Document v6 DRAFT

## Introduction

This procedure outlines responsibilities of Reliability Coordinators (RCs) serving as Geomagnetic Disturbance (GMD) monitors in the North American Interconnections. Changes to this reference document will be at the direction of the Reliability and Security Technical Committee (RSTC) with the participation of the Real Time Operating Subcommittee (RTOS).

This document applies to current and future GMD related procedural responsibilities assigned to the GMD monitor as outlined in NERC Reliability Standards (EOP-010).

## Designation of GMD Monitor

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

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

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

## Responsibilities of the GMD Monitor

The GMD monitors will receive GMD watches, alerts, and warnings through subscription to Space Weather Prediction Center (SWPC) emails. All K-7 or higher GMD warnings and alerts shall be routed by established procedures to operating entities within the applicable Interconnection. The SWPC is expected to initiate a NERC Hotline call for all K-7 or higher GMD warnings and/or alerts. **Appendix B** documents the expected call script during the SWPC initiated NERC Hotline call. Periodic testing of the GMD NERC Hotline process will be conducted at least once per calendar quarter as detailed in **Appendix C**.

### Eastern Interconnection GMD Monitors

The Eastern Interconnection GMD monitor will participate in the SWPC initiated phone communication with other RCs via the NERC Hotline. The GMD monitor will perform a roll call of RCs (all Interconnections)

expected to participate. The GMD monitor will repeat back the GMD information provided by the SWPC during the call for clarity and correct any errors. The Eastern Interconnection GMD monitor will call the RC's in the Eastern Interconnection, ERCOT, Hydro Quebec and/or Western Interconnection GMD Monitor who did not participate in the SWPC call (unacknowledged during the roll call).

The GMD monitor will post a message to the RC Information System (RCIS) outlining the GMD event information (level, time, including time zone, etc.).

**Western Interconnection (WECC) GMD Monitors**

The Western Interconnection GMD monitor will participate in the SWPC initiated phone communication with other RCs via the NERC Hotline. If the Eastern Interconnection GMD Monitor is not present, the Western Interconnection GMD monitor will perform a roll call of RCs (all Interconnections) expected to participate. The Western Interconnection GMD monitor will call those RC's in the WECC, ERCOT, Hydro Quebec and/or Eastern Interconnection GMD Monitor who did not participate in the SWPC call (unacknowledged during the roll call). The GMD monitor will post a message to the Grid Messaging System (GMS) outlining the GMD event information (level, time, including time zone, etc.).

## GMD Monitor Transition

The current GMD monitor will contact the next scheduled GMD monitor no later than October 1 to begin coordinating the transition that will occur on February 1 of the following year. This coordination should include local procedure(s) currently in use, data requirements, and communications. **Appendix A** includes a transition checklist. In the event the designated Eastern Interconnection GMD monitor is unable to fulfill its responsibilities, the previous GMD monitor should maintain the capability to perform the GMD monitor duties.

## Interconnection GMD Monitors

Each Interconnection has identified the following RC as its GMD monitor:

1. ERCOT Interconnection – ERCOT RC
2. Québec Interconnection – Hydro-Québec TransÉnergie RC
3. Eastern Interconnection – The RCs in the Eastern Interconnection will rotate the GMD monitor responsibilities on an annual basis as follows:
    a. TVA – February 1, 2021 through January 31, 2022
    b. MISO – February 1, 2022 through January 31, 2023
    c. IESO (Ontario) – February 1, 2023 through January 31, 2024
    d. NBP (New Brunswick Power) – February 1, 2024 through January 31, 2025
    e. VACAR-South – February 1, 2025 through January 31, 2026
    f. SPP – February 1, 2026 through January 31, 2027
    g. NYISO – February 1, 2027 through January 31, 2028

h. PJM – February 1, 2028 through January 31, 2029

i. ISO-NE – February 1, 2029 through January 31, 2030

j. FRCC – February 1, 2030 through January 31, 2031

4. Western Interconnection (WECC) – The RCs in the Western Interconnection will rotate the GMD monitor responsibilities on an annual basis as follows:

   a. BCRC – February 1, 2021 through January 31, 2022

   b. SPP – February 1, 2022 through January 31, 2023

   c. CAISO RC West – February 1, 2023 through January 31, 2024

   d. BCRC – February 1, 2024 through January 31, 2025

   e. AESO – February 1, 2025 through January 31, 2026 (requires NERC Hotline Access)

# Appendix A: GMD Monitor Transition Checklist

The following items are to be used as a guide for transitioning to the new GMD Monitor prior to the new effective date.

1. SWPC subscriptions – the outgoing GMD Monitor will provide a list of the SWPC subscriptions currently received to the incoming GMD Monitor
2. Process documents – the outgoing GMD Monitor will provide process steps, as requested, to the incoming GMD Monitor. The incoming GMD Monitors for the Eastern/Western Interconnections will distribute their process documents to other RCs within their interconnection.
3. Roll call process – the outgoing GMD Monitor will provide instruction to the incoming GMD Monitor on performing the roll call. The Eastern Interconnection GMD Monitor is responsible for performing the roll call. If not present, the Western Interconnection GMD Monitor will be prepared to initiate the roll call.
4. Orientation call with SWPC – the incoming GMD Monitor(s) will arrange to attend an orientation call with the SWPC to discuss engagement with SWPC during NERC Hotline calls.

# Appendix B: NERC Hotline Call Script

1. SWPC initiates NERC Hotline call, waits for RC to initiate a roll call.
2. One of the GMD Monitors will initiate a roll call (primary – Eastern GMD Monitor, backup – Western GMD Monitor) and will facilitate the call.
3. Once roll call completed, the SWPC will provide the GMD warning/alert information.
4. The GMD Monitor facilitating the call will summarize the information provided by the SWPC to allow for confirmation and/or clarification of any details.
5. The GMD Monitor will request any questions from the RCs participating in the call.
6. Once questions have been addressed the GMD Monitor will end the call.

# Appendix C: GMD Hotline Call Test Schedule

The GMD Hotline call will be tested quarterly, in February, May, August and November each year. The test will take place on the fourth Monday of each month at 11:00 a.m. Eastern time using the following schedule. SWPC will initiate the call and the call will be moderated by the Eastern Interconnection Time Monitor or the Western Interconnection Time Monitor as indicated below.

| GMD Hotline Test Schedule | | | |
|---|---|---|---|
| **Date of Test** | **Responsible GMD Monitor** | **Date of Test** | **Responsible GMD Monitor** |
| February 28, 2022 | MISO | February 26, 2024 | NBPC |
| May 23, 2022 | SPP (West) | May 27, 2024 | BCRC |
| August 22, 2022 | MISO | August 26, 2024 | NBPC |
| November 28, 2022 | SPP (West) | November 25, 2024 | BCRC |
| February 27, 2023 | IESO | February 24, 2025 | VACAR-S |
| May 22, 2023 | RC West | May 26, 2025 | AESO |
| August 21, 2023 | IESO | August 25, 2025 | VACAR-S |
| November 27, 2023 | RC West | November 24, 2025 | AESO |

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# Geomagnetic Disturbance Monitoring Reference Document v6 DRAFT

## Introduction

This procedure outlines responsibilities of Reliability Coordinators (RCs) serving as Geomagnetic Disturbance (GMD) monitors in the North American Interconnections. Changes to this reference document will be at the direction of the Reliability and Security Technical Committee (RSTC) ~~NERC Operating Committee (OC)~~ with the participation of the Real Time Operating Subcommittee (RTOS)~~Operating Reliability Subcommittee (ORS)~~.

This document applies to current and future GMD related procedural responsibilities assigned to the GMD monitor as outlined in NERC Reliability Standards (EOP-010).

## Designation of GMD Monitor

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

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

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

## Responsibilities of the GMD Monitor

The GMD monitors will receive GMD watches, alerts, and warnings through subscription to Space Weather Prediction Center (SWPC) emails. All K-7 or higher GMD warnings and alerts shall be routed by established procedures to operating entities within the applicable Interconnection. The ~~Space Weather Prediction Center (~~SWPC~~)~~ is expected to initiate a NERC Hotline call for all K-7 or higher GMD warnings and/or alerts. **Appendix B**~~Appendix B~~ documents the expected call script during the SWPC initiated NERC Hotline call. Periodic testing of the GMD NERC Hotline process will be conducted at least once per calendar quarter as detailed in **Appendix C**~~Appendix C~~.

**Eastern Interconnection GMD Monitors**

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**Commented [A1]:** Purpose to clarify when NERC Hotline call is initiated. Appendix B allows for inclusion of call script. Periodic testing recommended, details could be included in Appendix B or in this section.

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The Eastern Interconnection GMD monitor will participate in the ~~Space Weather Prediction Center (~~SWPC~~)~~ initiated phone communication with other ~~Reliability Coordinator~~RCs via the NERC Hotline. The GMD monitor will perform a roll call of RCs (all Interconnections) expected to participate. The GMD monitor will repeat back the GMD information provided by the SWPC during the call for clarity and correct any errors. The Eastern Interconnection GMD monitor will call the RC's in the Eastern Interconnection, ERCOT, ~~and/or~~ Hydro Quebec (and/or Western Interconnection GMD Monitor) who did not participate in the SWPC call (unacknowledged during the roll call).

**Commented [A2]:** Allows for follow-up if Western Monitor not on call.

The GMD monitor will post a message to the ~~Reliability Coordinator~~RC Information System (RCIS) outlining the GMD event information (level, time, including time zone, etc.).

**Western Interconnection (WECC) GMD Monitors**

The Western Interconnection GMD monitor will participate in the ~~Space Weather Prediction Center (~~SWPC~~)~~ initiated phone communication with other ~~Reliability Coordinator~~RCs via the NERC Hotline. If the Eastern Interconnection GMD Monitor is not present, the Western Interconnection GMD monitor will perform a roll call of RCs (all Interconnections) expected to participate. The Western Interconnection GMD monitor will call those RC's in the WECC, ERCOT, Hydro Quebec and/or Eastern Interconnection GMD Monitor who did not participate in the SWPC call (unacknowledged during the roll call). The GMD monitor will post a message to the Grid Messaging System (GMS) outlining the GMD event information (level, time, including time zone, etc.).

**Commented [A3]:** Allows for documented backup of the Eastern Monitor if they are not on call.

## GMD Monitor Transition

The current GMD monitor will contact the next scheduled GMD monitor no later than October 1 to begin coordinating the transition that will occur on February 1 of the following year. This coordination should include local procedure(s) currently in use, data requirements, and communications. **Appendix A** includes a transition checklist. In the event the designated Eastern Interconnection GMD monitor is unable to fulfill its responsibilities, the previous GMD monitor should maintain the capability to perform the GMD monitor duties.

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## Interconnection GMD Monitors

Each Interconnection has identified the following ~~Reliability Coordinator~~RC as its GMD monitor:

1. ERCOT Interconnection – ERCOT ~~Reliability Coordinator~~RC
2. Québec Interconnection – Hydro-Québec TransÉnergie ~~Reliability Coordinator~~RC
3. Eastern Interconnection – The ~~Reliability Coordinator~~RCs in the Eastern Interconnection will rotate the GMD monitor responsibilities on an annual basis as follows:

   ~~a. SaskPower – February 1, 2019 through January 31, 2020~~

   ~~b. Southeastern – February 1, 2020 through January 31, 2021~~

   ~~c.~~a. TVA – February 1, 2021 through January 31, 2022

   ~~d.~~b. MISO – February 1, 2022 through January 31, 2023

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~~e.~~c. IESO (Ontario) – February 1, 2023 through January 31, 2024

~~f.~~d. NBP (New Brunswick Power) – February 1, 2024 through January 31, 2025

~~g.~~e. VACAR-South – February 1, 2025 through January 31, 2026

~~h.~~f. SPP – February 1, 2026 through January 31, 2027

~~i.~~g. NYISO – February 1, 2027 through January 31, 2028

~~j.~~h. PJM – February 1, 2028 through January 31, 2029

~~k.~~i. ISO-NE – February 1, 2029 through January 31, 2030

~~l.~~j. FRCC – February 1, 2030 through January 31, 2031

4. Western Interconnection (WECC) – The ~~Reliability Coordinator~~RCs in the Western Interconnection will rotate the GMD monitor responsibilities on an annual basis as follows:

~~a. CAISO RC West – December 3, 2019 through January 31, 2021~~

~~b.~~ BCRC – February 1, 2021 through January 31, 2022 ~~(requires NERC Hotline Access)~~

a.

b. SPP – February 1, 2023~~3~~2 through January 31, 2023~~3~~4

c. CAISO RC West – February 1, 2023 through January 31, 2024

~~c.~~ BCRC – February 1, 2024 through January 31, 2025 ~~BCRC~~

d.

~~d.~~e. AESO – February 1, 2025~~2~~ through January 31, 2026~~3~~ (requires NERC Hotline Access)

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**Commented [A4]:** Updated to reflect proposed rotation since AESO no longer taking their rotation in Feb 2022.

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# Appendix A: ~~Appendix A —~~GMD Monitor Transition Checklist~~SPP – February 1, 2023 through January 31, 2024~~

The following items are to be used as a guide for transitioning to the new GMD Monitor prior to the new effective date.

1. SWPC subscriptions – the outgoing GMD Monitor will provide a list of the SWPC subscriptions currently received to the incoming GMD Monitor
2. Process documents – the outgoing GMD Monitor will provide process steps, as requested, to the incoming GMD Monitor.– The incoming GMD Monitors for the Eastern/Western Interconnections will distribute their process documents to other RCs within their interconnection.
3. Roll call process – the outgoing GMD Monitor will provide instruction to the incoming GMD Monitor on performing the roll call.- The Eastern Interconnection GMD Monitor is responsible for performing the roll call.- If not present, the Western Interconnection GMD Monitor will be prepared to initiate the roll call.
4. Orientation call with SWPC – the incoming GMD Monitor(s) will arrange to attend an orientation call with the SWPC to discuss engagement with SWPC during NERC Hotline calls.

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# Appendix B: ~~Appendix B —~~NERC Hotline Call Script

1. SWPC initiates NERC Hotline call, waits for RC to initiate a roll call.
2. One of the GMD Monitors will initiate a roll call (primary – Eastern GMD Monitor, backup – Western GMD Monitor) and will facilitate the call.
3. Once roll call completed, the SWPC will provide the GMD warning/alert information.
4. The GMD Monitor facilitating the call will summarize the information provided by the SWPC to allow for confirmation and/or clarification of any details.
5. The GMD Monitor will request any questions from the RCs participating in the call.
6. Once questions have been addressed the GMD Monitor will end the call.

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# Appendix CA: ~~ppendix C —~~GMD Hotline Call Test Schedule

The GMD Hotline call will be tested quarterly, in February, May, August and November each year. The test will take place on the fourth Monday of each month at 11:00 a.m. Eastern time ~~prevailing time~~ using the following schedule.~~-~~SWPC will initiate the call and the call will be moderated by the Eastern Interconnection Time Monitor or the Western Interconnection Time Monitor as indicated below.

| GMD Hotline Test Schedule~~Date of Test~~ ~~Responsible GMD Monitor~~ ~~Date of Test~~ ~~Responsible GMD Monitor~~ | | | |
|---|---|---|---|
| Date of Test | Responsible GMD Monitor | Date of Test | Responsible GMD Monitor |
| February 28, 2022 | MISO | February 26, 2024 | NBPC |
| May 23, 2022 | SPP (West) | May 27, 2024 | BCRC |
| August 22, 2022 | MISO | August 26, 2024 | NBPC |
| November 28, 2022 | SPP (West) | November 25, 2024 | BCRC |
| February 27, 2023 | IESO | February 24, 2025 | VACAR-S |
| May 22, 2023 | RC West | May 26, 2025 | AESO |
| August 21, 2023 | IESO | August 25, 2025 | VACAR-S |
| November 27, 2023 | RC West | November 24, 2025 | AESO |

~~a.~~



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# Resources Subcommittee (RS) Reporting ACE Definition SAR

## Action
Endorse

## Summary
The current definition of Reporting ACE has a conflict with the Western Interconnection's Automatic Time Error Correction (ATEC) process and does not allow other Interconnections to pursue ATEC. Additionally, there could be some confusion in that the terms ACE and Reporting ACE are both used throughout the standards. The RS has a revised draft of the Reporting ACE definition that accommodates any Interconnection that has an approved ATEC process. The revised definition is also shortened to remove verbiage that duplicates obligations in the BAL standards. Having duplicative language adds complexity to future changes to the applicable BAL standards. The RS is seeking RSTC endorsement of the SAR and subsequent submittal to the Standards Committee for action.

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# Standard Authorization Request (SAR)

Complete and submit this form, with attachment(s) to the NERC Help Desk. Upon entering the Captcha, please type in your contact information, and attach the SAR to your ticket. Once submitted, you will receive a confirmation number which you can use to track your request.

The North American Electric Reliability Corporation (NERC) welcomes suggestions to improve the reliability of the bulk power system through improved Reliability Standards.

| Requested information | | | |
|---|---|---|---|
| SAR Title: | Reporting ACE Definition and Associated Terms | | |
| Date Submitted: | TBD | | |
| SAR Requester | | | |
| Name: | Greg Park on behalf of the NERC Resources Subcommittee (RS) | | |
| Organization: | Northwest Power Pool | | |
| Telephone: | (503)445-1089 | Email: | greg.park@nwpp.org |
| SAR Type (Check as many as apply) | | | |
| ☐ New Standard<br>☐ Revision to Existing Standard<br>☒ Add, Modify or Retire a Glossary Term<br>☐ Withdraw/retire an Existing Standard | | ☐ Imminent Action/ Confidential Issue (SPM Section 10)<br>☐ Variance development or revision<br>☐ Other (Please specify) | |
| Justification for this proposed standard development project (Check all that apply to help NERC prioritize development) | | | |
| ☐ Regulatory Initiation<br>☐ Emerging Risk (Reliability Issues Steering Committee) Identified<br>☐ Reliability Standard Development Plan | | ☒ NERC Standing Committee Identified<br>☐ Enhanced Periodic Review Initiated<br>☐ Industry Stakeholder Identified | |
| Industry Need (What Bulk Electric System (BES) reliability benefit does the proposed project provide?): | | | |
| The current definition of Reporting ACE has a conflict with the Western Interconnection's Automatic Time Error Correction (ATEC) process and does not allow other Interconnections to pursue ATEC. Additionally, there could be some confusion in that the terms ACE and Reporting ACE are both used throughout the standards. | | | |
| Purpose or Goal (How does this proposed project provide the reliability-related benefit described above?): | | | |
| A revised definition should provide improve long-term average frequency performance as well as give other Interconnections the ability to pursue automatic correction approaches. | | | |
| Project Scope (Define the parameters of the proposed project): | | | |
| The RS has a revised draft of the Reporting ACE definition that accommodates any Interconnection that has an approved Automatic Time Error Correction process. The revised definition is also shortened to remove verbiage that duplicates obligations in the BAL standards. Having duplicative language adds complexity to future changes to the applicable BAL standards. | | | |

| Requested information |
| --- |
| Detailed Description (Describe the proposed deliverable(s) with sufficient detail for a drafting team to execute the project. If you propose a new or substantially revised Reliability Standard or definition, provide: (1) a technical justification[1] 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): |
| With the Eastern Interconnection experiencing a large amount of accumulated time error, the Resources Subcommittee has been investigating acceptable methods for correction in alignment with current standards, guidelines, and reference documents. These changes will not only allow all interconnections to implement an automated time error correction process but will also reduce confusion on what components make up the ACE used for reporting. Making the Automatic Time Error Correction (ATEC) term generic (as opposed to Western Interconnection-specific) will accommodate other acceptable approaches.<br><br>Additionally, the drafting team should consider the usage of "Reporting ACE", "ACE", "Reserve Sharing Group Reporting ACE", "ACE Diversity Interchange" or other related terms associated with an ACE equation in the standards. Reporting ACE and Area Control Error (ACE (standalone term)) are both used over 100 times in the set of standards, guidelines, and reference documents. For example, The Resources Subcommittee and the Real-Time Operating Subcommittee has input to the NERC Reliability & Security Technical Committee approved Time Monitoring Reference Document which the Reporting ACE definition supports. An evaluation of all components of ACE and their associated definitions to ensure a consistent application between Responsible Entities would be beneficial to the industry.<br><br>Finally, there is a glossary term Automatic Time Error Correction ($I_{ATEC}$) to support BAL-004-WECC-03. If kept in the NERC Glossary, the term should be reviewed and modified as necessary (e.g. change the glossary to "ATEC (WECC)"). |
| Cost Impact Assessment, if known (Provide a paragraph describing the potential cost impacts associated with the proposed project): |
| There are no added requirements, and no additional costs are expected. |
| Please describe any unique characteristics of the BES facilities that may be impacted by this proposed standard development project (*e.g.*, Dispersed Generation Resources): |
| No negative impacts expected. If average Frequency and Time Error are better controlled, there should be fewer manual Time Error Corrections, which would be a Reliability improvement. |
| 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): |
| Resource Subcommittee members, particularly those affiliated with Balancing Authorities or Reserve Sharing Groups. |

[1] 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 |
|---|
| Do you know of any consensus building activities[2] in connection with this SAR? If so, please provide any recommendations or findings resulting from the consensus building activity. |
| A webinar would be appropriate. |
| 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)? |
| None |
| Are there alternatives (e.g., guidelines, white paper, alerts, etc.) that have been considered or could meet the objectives? If so, please list the alternatives. |

This is not a standard. The definition change supports NERC OC Reference Documents and Guidelines.

| 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 |

[2] 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.

| Market Interface Principles | |
|---|---|
| 3. A reliability standard shall not preclude market solutions to achieving compliance with that standard. | Yes |
| 4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards. | Yes |

| Identified Existing or Potential Regional or Interconnection Variances | |
|---|---|
| Region(s)/ Interconnection | Explanation |
| *None* | |

# For Use by NERC Only

| SAR Status Tracking (Check off as appropriate). | |
|---|---|
| ☐ Draft SAR reviewed by NERC Staff<br>☐ Draft SAR presented to SC for acceptance<br>☐ DRAFT SAR approved for posting by the SC | ☐ Final SAR endorsed by the SC<br>☐ SAR assigned a Standards Project by NERC<br>☐ 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 |

# White Paper: Grid Forming Technology, Bulk Power System Reliability Considerations

## Action
Approve

## Summary
As inverter-based resources (IBRs) penetrations continue to grow across North America, grid dynamics and controls strategies have also adapted and advanced over the recent years. One such technology that is now gaining momentum is grid forming (GFM) inverter technology. GFM inverters have been widely researched in battery energy storage systems (BESS), wind power plants, solar photovoltaic (PV) plants, and hybrid plants. Further, there are several installed projects where GFM functions have been successfully tested, including extremely fast power injection in the inertial timeframe in response to frequency events, islanded operation capability without synchronous generation, blackstart capability, and operation in parallel with grid following (GFL) resources and synchronous machines. Widespread understanding of GFM controls and their impacts to bulk power system performance is still in the early stages; however, the technology shows significant promise. The IRPWG has developed a White Paper with recommendations on this subject and is seeking RSTC approval.

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# Grid Forming Technology

## Bulk Power System Reliability Considerations

November 2021

**RELIABILITY | RESILIENCE | SECURITY**




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

# Table of Contents

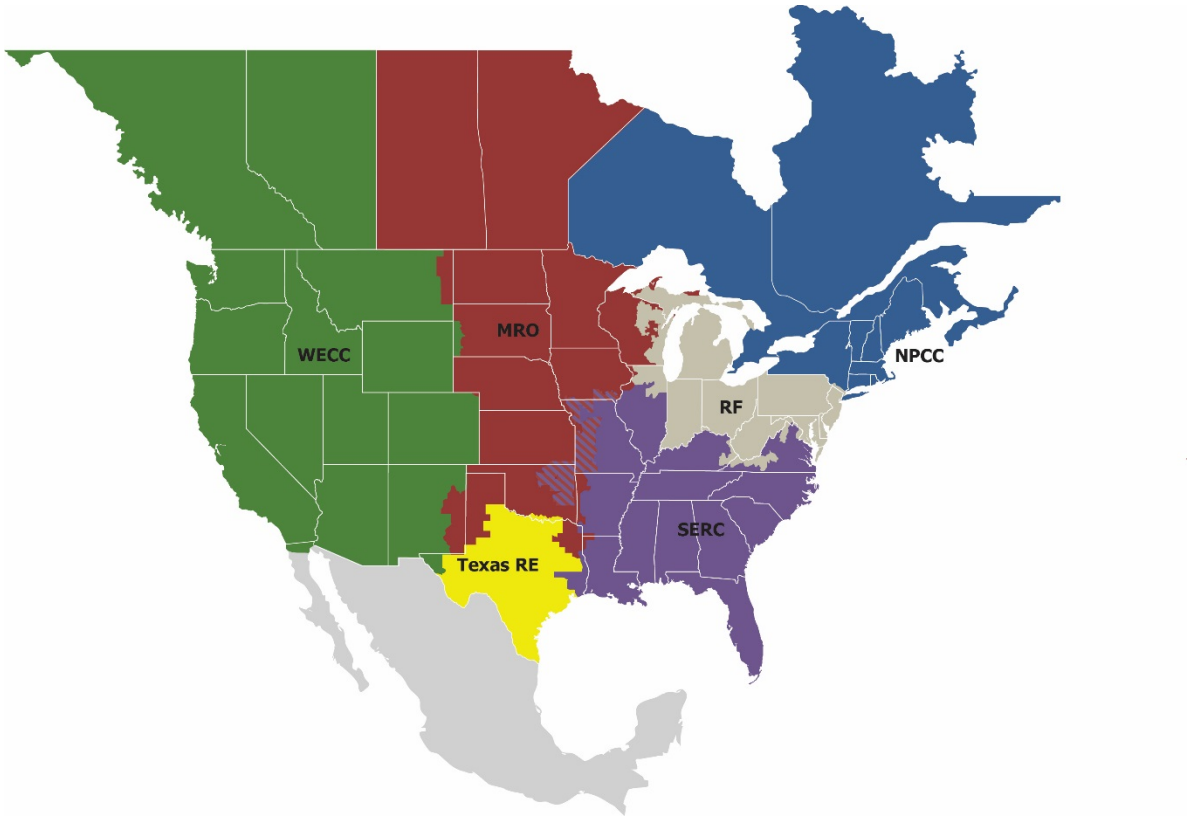
# Preface

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

Reliability | Resilience | Security

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

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




| | |
|---|---|
| **MRO** | Midwest Reliability Organization |
| **NPCC** | Northeast Power Coordinating Council |
| **RF** | ReliabilityFirst |
| **SERC** | SERC Reliability Corporation |
| **Texas RE** | Texas Reliability Entity |
| **WECC** | Western Electricity Coordinating Council |

# Executive Summary

As inverter-based resources (IBRs) penetrations continue to grow across North America, grid dynamics and controls strategies have also adapted and advanced over the recent years. One such technology that is now gaining momentum is grid forming (GFM) inverter technology. GFM inverters have been widely researched in battery energy storage systems (BESS), wind power plants, solar photovoltaic (PV) plants, and hybrid[1] plants. Further, there are several installed projects where GFM functions have been successfully tested, including extremely fast power injection in the inertial timeframe in response to frequency events, islanded operation capability without synchronous generation, blackstart capability, and operation in parallel with grid following (GFL) resources and synchronous machines. Widespread understanding of GFM controls and their impacts to BPS performance is still in the early stages; however, the technology shows significant promise. Study findings from system conditions with high penetration IBRs show the benefits for GFM controls and equipment vendors have commercially available products that can provide GFM capability. While GFM inverters still need to be studied and tuned to specific system conditions (similarly to GFL controls), they do have advantages compared to the GFL control schemes applied in nearly all existing IBRs today. GFM IBRs are expected to be very beneficial for increasing IBR penetration levels, and GFM IBRs will likely play an important role in contributing to the stability and reliability of the BPS under future high IBR penetration conditions.

There are presently no universally agreed upon definitions of GFL and GFM inverter controls in the industry. This white paper recommends the following definition:

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

*GFM control are recommended to provide robust dynamic support[2] to the grid including (but not limited to):*

- *Operation in low system strength condition*
- *Grid frequency and voltage stabilization*
- *Small signal stability damping to maintain power system stability*
- *Re-synchronization capability to restore and reconnect to the grid*
- *Fault ride through for large grid disturbance events with adequate fault current contribution as required by protection systems (if hardware limits allow)*
- *System restoration and blackstart capability (for some GFM inverters)*

GFM and GFL IBR capability and their major performance characteristics and advantages are compared in this white paper. Currently, the most commonly used GFM control strategies of droop-based GFM control, virtual synchronous machine control, and virtual oscillator control are briefly summarized.[3] This white paper also provides

[1] Hybrid plants are defined here as "A generating resource that is comprised of multiple generation or energy storage technologies controlled as a single entity and operated as a single resource behind a single POI": https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Reliability_Guideline_BESS_Hybrid_Performance_Modeling_Studies_.pdf

[2] Some but not all of these capabilities can also be made available from GFL controls

[3] For further details regarding actual installed GFM or GFL controls, readers should consult with original equipment manufacturers (OEMs).

recommendations for entities across North America to consider studying and deploying GFM technology to support BPS reliability and resilience with increasing IBR penetration levels.

## Key Takeaways and Recommendations

Table 1.1 lists a number of recommendations for industry action and the associated entities to which the recommendations are directed. These recommendations apply generally to entities involved with BPS-connected IBRs.

**Table E.1: Recommendations and Applicability**

| Recommendation | Applicability |
|---|---|
| **Installation of GFM Controls Functionality:** Equipment manufacturers, particularly for BESS, should ensure that products being installed today are suited to support the rapidly evolving BPS in the future. Developers should consider installing GFM-capable equipment with the capability to enable this functionality in resources in the future, if needed. Resources installed with GFL functionality enabled may need to be converted to GFM functionality in the future, particularly under high penetration of IBR conditions. Having this functionality available when needed will result in significantly lower operating costs for these types of operating conditions. | Equipment manufacturers, project developers, Generator Owners (GOs), Generator Operators (GOPs) |
| **Use of GFM Technology in Low System Strength Conditions:** Many areas of the grid are undergoing significant drops system strength (sometimes roughly quantified by short-circuit ratio [SCR])[4] with the retirement of synchronous generation. Deploying GFM controls on IBRs connecting in areas with low system strength is an effective solution to ensure voltage stability. Although GFL controls can be tuned to reliably operate in areas with a low short-circuit ratio to meet interconnection requirements, GFL controls fundamentally require some minimum system strength to maintain stable operation. GFM inverters also require tuning but may unlock higher levels of IBR penetration in the future at lower overall cost. | Equipment manufacturers, project developers, GOs, Transmission Owners (TOs), Transmission Planners (TPs), Planning Committees (PCs), Transmission Operators (TOPs), Reliability Coordinators (RCs) |
| **Accurate Modeling of GFM Controls:** Reliable interconnection of GFM-capable IBRs is incumbent on the ability to study their interaction with and support to the BPS prior to the resources being interconnected. It is critical that accurate models are developed and provided to the TPs and PCs for studying these resources during the interconnection process. Accurate Positive sequence dynamic models and electromagnetic transient (EMT) models should be developed, validated, and benchmarked against each other by the GOs, TPs, and PCs. This includes sufficient documentation regarding the control strategy and the performance of the resource during large signal disturbances. TPs and PCs should improve their modeling requirements and model quality checks to ensure these are also applicable to GFM technology. All IBRs, particularly, with the capability to operate with GFM controls, should provide accurate, validated, and high-quality positive sequence and EMT models for future reliability study needs. | Equipment manufacturers, developers, GOs, TPs, PCs |

[4] https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/Short_Circuit_whitepaper_Final_1_26_18.pdf

| Table E.1: Recommendations and Applicability | |
|---|---|
| **Recommendation** | **Applicability** |
| **Improved Interconnection Process and Study Practices for GFM IBRs:**<br>All TOs, in coordination with their TPs and PCs, should develop a process for determining situations and locations, where GFM technology is needed (or beneficial) and appropriate study approaches for qualifying and quantifying the potential benefits of GFM technology. This process should be implemented as part of the interconnection requirements and study process per NERC FAC-001 and FAC-002 standards. Use of GFM controls should be considered as one of many solution options to mitigate potential reliability issues. In some areas, particularly under high penetration of IBR conditions, use of GFM may be a cost-effective and necessary solution for controls stability issues as well as other grid reliability and resilience issues.<br><br>TPs and PCs will need to perform detailed studies of future operating conditions to determine the need and benefits for GFM IBRs among other solution options. This will require both detailed positive sequence and detailed EMT studies with sufficient model validation and model quality checks. These activities will require additional time, new tools and expertise, and likely will need improvements to the interconnection process to enable these activities. | TOs, TPs, PCs |
| **IRPWG Focus on GFM Interconnection Requirements and Standardized Processes:**<br>The IRPWG should develop a set of standardized processes, recommended practices related to establishing requirements and performing studies with GFM IBRs during the interconnection process. This guidance material should support equipment manufacturers, GOs, developers, TPs, and PCs in their activities to interconnect resources leveraging GFM technology. | NERC Inverter-Based Resource Performance Working Group (IRPWG) |
| **Unlocking GFM Capability by Improved Incentive Structures:**<br>A significant challenge with leveraging GFM capability is the ability to implement the technology at additional cost, while appropriately allocating the cost in situations where benefits are socialized to many different entities. For example, the installation of GFM controls at one facility (or multiple facilities) could help mitigate the need for curtailment or transmission system upgrades across a larger geographical region, which could be studied and quantified. We recommend that FERC and wholesale electricity markets (i.e., ISO/RTOs) should evaluate opportunities for including GFM controls as a "grid enhancing technology" to support BPS reliability where the benefits of implementing the GFM technology impact many other entities. This will help break down barriers that currently may be hindering the implementation of this technology on a larger scale. | FERC, ISO/RTOs |
| **Future Research, Work Needed:**<br>GFM control is an evolving technology and will continue to require additional research moving forward. This includes, but is not limited to, the following:<br>• Appropriate GFM IBR designs<br>• GFM control tuning<br>• Control interactions of multiple GFM IBRs and overall system stability | Research institutions, national laboratories, U.S. Department of Energy, academic institutes, etc. |

| Table E.1: Recommendations and Applicability | |
|---|---|
| **Recommendation** | **Applicability** |
| • Coordination of GFM and GFL IBRs along with synchronous generators still in operation<br>• Levels of current, power, and energy headroom needed to extract the maximum benefit of GFM controls<br>• Levels of GFM IBR capacity needed to obtain the desired benefits for a given grid condition<br>• The role of GFM IBR versus synchronous condensers to strengthen the grid<br>• Review and revision of interconnection standards to accommodate GFM IBRs<br>• Metrics for quantifying system strength that account for GFM benefits; metric for quantifying the stabilizing benefit of GFM IBRs, GFL IBRs, and synchronous machines<br>• Methods for planning and maintaining the stability of high IBR penetration systems<br>• Impact of GFM controls on protection system operations in high-IBR grids; recommended magnitudes, durations, and electrical characteristics of GFM IBR fault responses<br>• Control strategies for blackstart using GFM IBRs (where needed) | |

# Background

Today's bulk electric grid is quickly changing with the retirement of synchronous generators (SG) and rapidly increasing deployment of IBRs such as wind plants (WP), PV, BESS and hybrid plants. In today's power system, SGs, along with its auxiliary control loops/elements, provide many grid services such as inertial response (i.e. use of rotational kinetic energy) to slow down initial rate of change of frequency after large generation trip events, primary frequency response (PFR) to stabilize grid frequency, grid voltage support, power oscillation damping and sourcing of negative sequence current. Further, traditional protection relay algorithms have been designed and tuned based on the high and predictably consistent short circuit contribution of synchronous generators and other rotating machines to grid short circuit disturbances. With increasing GFL IBR deployment, the reduced number of strong voltage sources, reduced inertial energy storage, and decreased short circuit current will impact grid stability for large and small system disturbances and system protection.

GFL inverter controls are used in most grid-connected IBRs today. GFL typically includes a fast current control loop and a phase-locked loop (PLL). The control objective of the current loop is to achieve fast regulation of the IBR output current, and the control objective of the PLL is to synchronize the IBR output current with the grid voltage and to provide the phase information for the internal current control loops. GFL IBR converters are typically represented as controlled current sources. Due to this control structure, there is a delay of the PLL phase information and voltage information calculation. Therefore, GFL controls cannot instantaneously change IBR's active and reactive current output. Due to this fundamental limitation, GFL IBR performance is related to and dependent on the grid strength, control topology and tuning of control parameters.

It has been shown that GFL controls become unstable under certain low system strength[5, 6] conditions. The PLL based converters' (HVDC) performance has also been studied in low strength scenarios based on the simplified Great Britain (GB) transmission network and the CIGRE-developed voltage source converter model by National Grid Electricity System Operator[7] (NG ESO). This study shows that there is an increasing stability risk for GFL IBRs as the system strength is decreasing.

To address GFL IBR stability issues, the robustness of IBR controls have been continuously improved by Original Equipment Manufacturers (OEMs) by tuning the IBR controller parameters and switching to more robust controllers and PLL architectures. These changes can help improve project stability in low system strength conditions for normal or after credible contingencies at moderate IBR penetration levels. However, at higher penetration levels, GFL-controlled IBRs could become inadequate for maintaining grid stability.

The dynamic behavior of IBRs in the transient time frame is governed by the speed and accuracy of its signal measurements and communication quantities, robustness of internal signal processing algorithms, control topology, and the parameters of the controllers. Every IBR control system topology and parameter value set have a finite region of stability in terms of system strength and system inertial strength. As penetrations of GFL IBRs continues to grow, GFL IBRs will be challenged to maintain system stability without other supporting equipment. However, particularly in areas of decreasing short-circuit strength, GFM IBRs may be able to expand the region of stability or help support the grid in these areas.

Compared to GFL, GFM most commonly uses an instantaneously measured voltage signal rather than a processed signal from a PLL in a GFL inverter. GFM response and support to the grid are instantaneous in the transient time

[5] System strength typically refers either to a high source impedance between the GFL IBR and the main grid voltage source).

[6] "Appendix D – Hornsea Technical Report Submitted by Orsted (into the performance of windfarm)", https://www.nationalgrideso.com/document/152351/download

[7] https://www.nationalgrideso.com/document/102876/download

frame. Grid forming (GFM) technology[8,9,10] has been recently proposed in the IBR industry for use in parallel with the BPS,[11] which, when mature, is expected to address the majority of the risks and concerns of high (up to 100%) IBR penetration grid operation and stability, with coordinated control and appropriate studies. As many as seven different GFM architectures have been described[12], and field experience with GFM IBRs is being accumulated[13,14]. Because of the expected benefits of GFM IBR controls, interest in them is high and increasing.

For example, the U.S. Department of Energy announced funding for a consortium to advance the research, development, and commercialization of IBR grid-forming technologies to enhance power systems operation on Aug. 2021[15]. NREL's "Research Roadmap on Grid-Forming Inverters" report[16] provides a roadmap on GFM controls, IBR impact on grid stability, and evaluating crucial system interactions for the future grid comprised of the combination of synchronous generators and GFM & GFL inverter-based resources. Great Britain (GB) developed the grid code modification GC0137 to add requirements for GFM IBRs and HVDC systems[17] to ensure stabile and reliable operation of the grid with high penetration of IBRs (combination of GFL, GFM and SGs).[18,19] The GFM specifications are being developed as non-mandatory, and GFM capability is expected to be procured as a market product or in some cases as requests for proposals (RFPs)[20]. The GFM basic concept, functions, project experiences, differences from GFL, and specification requirements for grid code considerations were presented in the ESIG Spring Workshop 2021[21]. Australia has also been actively developing strategies to use GFM IBRs to support high IBR penetration into the power system. Recent research has shown that GFM IBRs provide a successful alternative to synchronous condensers that have traditionally been used to provided system strength and voltage support.[22] Australia has, and continues to explore, numerous options for increasing system strength.[23] IBR OEMs and North American research organizations are also developing GFM positive sequence models for GFM IBRs interconnection studies and large grid stability studies,[24,25] and NG ESO applied the simplified GFM positive sequence model in the GB grid for the high penetration of IBR scenarios in their planning studies.[26] While positive sequence models can capture many aspects of GFM behavior, positive sequence models are fundamentally limited in their ability and accuracy compared to EMT model. In many situations, GFM EMT models are needed.

[8] J. Matevosyan, et al., "Grid-Forming Inverters: Are They the Key for High Renewable Penetration?," in IEEE Power and Energy Magazine, vol. 17, no. 6, pp. 89-98, Nov.-Dec. 2019. https://ieeexplore.ieee.org/document/8879610

[9] https://www.nrel.gov/docs/fy21osti/73476.pdf.

[10] David Roop, "Weak Grids and Grid Forming Converters", Feb, 2021. https://cdn.misoenergy.org/20210216%20New%20Approaches%20Workshop%20Item%2005c%20VSCs%20and%20Weak%20Grid%20and%20Grid%20Forming%20Solutions523105.pdf

[11] GFM inverter operation in off-grid and islanded applications has been widespread for decades.

[12] Peter Unruh etc., "Overview on Grid Forming Inverter Control Methods", May 2020. https://doi.org/10.3390/en13102589

[13] A. Roscoe, et al., "Practical Experience of Operating a Grid Forming Wind Park and its Response to System Events" in Proc. 18th Wind Intgr. Workshop, Dublin, Ireland, Oct. 2019.

[14] A. Roscoe, et al., "Practical Experience of Operating a Grid Forming Wind Park and its Response to System Events" in Proc. 18th Wind Intgr. Workshop, Dublin, Ireland, Oct. 2019.

[15] https://www.energy.gov/eere/solar/funding-opportunity-announcement-solar-energy-technologies-office-fiscal-year-2021

[16] https://www.nrel.gov/docs/fy21osti/73476.pdf

[17] GB GC0137: Draft Final Modification Report and Annexes, Oct. 2021. GC0137: Minimum Specification Required for Provision of GB Grid Forming (GBGF) Capability (formerly Virtual Synchronous Machine/VSM Capability) | National Grid ESO

[18] R. Ierna, et al., "Effects of VSM Convertor Control on Penetration Limits of Non-Synchronous Generation in the GB Power System", 15th Wind Integration Workshop, 2016.

[19] https://www.h2020-migrate.eu/downloads.html (D3.2, D3.3, D3.6)

[20] https://www.hawaiianelectric.com/clean-energy-hawaii/selling-power-to-the-utility/competitive-bidding-for-system-resources/competitive-bidding-archived-rfp-information/stage-2-rfps

[21] https://www.esig.energy/event/2021-spring-technical-workshop/

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

[23] https://arena.gov.au/renewable-energy/system-security-reliability/

[24] https://www.wecc.org/Administrative/Du-%20Droop%20Controlled%20Grid%20Forming%20Inverters.pdf

[25] D. Ramasubramanian, P. Pourbeik, E. Farantatos and A. Gaikwad, "Simulation of 100% Inverter-Based Resource Grids With Positive Sequence Modeling," in IEEE Electrification Magazine, vol. 9, no. 2, pp. 62-71, June 2021.doi: 10.1109/MELE.2021.3070938

[26] https://www.nationalgrid.com/sites/default/files/documents/GC0100%20Annex%209%20%20VSM_0.pdf

There are many different ways to develop and bring grid friendly IBR controls to real projects and academic research. This white paper defines "grid forming controls" and provides an overview of GFM IBR performance features expected from the bulk power system point of view. The GFM IBR functions, capabilities, impacts, and application benefits to the future high IBR penetration grid are summarized.

# Chapter 1: Definition and Characteristics of GFM

## GFM Definition

GFM control for BPS-connected IBRs is defined in this document as follows:

- The primary objective of grid-forming (GFM) controls for BPS-connected IBRs is to maintain an internal voltage phasor that is constant or nearly constant in the sub-transient to transient time frame. This allows the IBR to immediately respond to changes in the external system and maintain IBR control stability during challenging network conditions. The voltage phasor must be controlled to maintain synchronism with other devices on the grid and must also regulate active and reactive power appropriately to support the grid.

GFM-IBRs could be expected to have many of the following functions and characteristics:[27,28,29, 30]

- Creation of an open circuit voltage source at the GFM IBR terminals. A GFM IBR facility can be capable of operating in islanded mode so that the IBR can serve its own auxiliary load and the connected loads in the absence of a synchronous resource or other GFM IBR support for the isolated grid conditions. With this characteristic, IBR can operate in a stable manner without the need for synchronous machines[31].
- A GFM IBR can be controlled to synchronize and stably operate with other resources in the grid and different types of loads. These other resources include conventional synchronous machines and other GFM or GFL IBRs.
- Upon the occurrence of a large load step or generation trip event, a GFM IBR could contribute towards arresting the decline or increase of frequency and also contribute towards the subsequent recovery of frequency to the nominal value, assuming energy and power margins are available.
- A GFM IBR would contribute towards provision of reactive power support and voltage regulation within the continuous operation region and to some degree outside the continuous operating region, thus aiding fast and stable voltage recovery after a fault.
- Reduce adverse converter control interactions among GFM IBRs, GFL IBRs, other power electronic devices and rotating machines on the grid.
- Contribute towards providing the prescribed level of oscillation damping within the interconnection. As the IBR characteristics and penetration level change the grid, interactions or oscillation modes could change. Frequent studies and analysis may be required to verify the damping levels and adjust controls accordingly.
- Provide active low-order harmonics cancellation.
- Provide blackstart capability, if needed and designed for this purpose[32,33]

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[27] Some but not all of these capabilities can also be made available from GFL IBRs

[28] Synchronous Energy Storage System with Inertia Capabilities for Angle, Voltage and Frequency Stabilization in Power Grids", 11th Solar & Storage Integration Workshop, 28. September 2021, Berlin, Germany

[29] PVPS PV as an ancillary service provider. https://iea-pvps.org/key-topics/pv-as-an-ancillary-service-provider/

[30] Grid Forming Inverters: EPRI Tutorial, EPRI, Palo Alto, CA: 2020, 3002018676. https://www.epri.com/research/products/000000003002018676.

[31] A. Hoke et al., "Inverter-Based Operation of Maui: Electromagnetic Transient Simulations," https://www.nrel.gov/docs/fy21osti/79852.pdf

[32] Additional considerations such as energy assurance, dedicated blackstart control functionality and inverter overcurrent capability would need to be taken into account for blackstart resources; however, the ability for GFM to operate in a standalone manner and reliably transition to grid-connected operation is a critical factor in its use during system restoration.

[33] "Blackstart and System Restoration using Inverter Based Resources: Supply of critical load", NERC IRPWG, July 2021 https://www.nerc.com/comm/RSTC/IRPWG/IRPWG_Meeting_Presentations_-_2021_07_21.docx.pdf

# High-Level Explanation of GFM and Comparison with GFL Controls

There are multiple types of GFM control strategies[34], as illustrated in **Figure 1.1**. These include, but are not limited to, the following:

1. **Droop-Based GFM Control:**[35,36,37] GFM droop control is realized by active & reactive power droop control, which controls the IBR voltage phasor frequency in proportion to the active power extracted from it. GFM reactive power droop control has similar logic for the Q-V relationship.
2. **Virtual Synchronous Machine (VSM):** [38 39] VSM programs the IBR's control to emulate a synchronous generator's (SG) response so that the IBR can act similarly to a SG to provide an active power response that mimics a SG's expected contribution to a sudden generation loss, load change or system fault.
3. **Virtual Oscillator Control (VOC):**[40,41] VOC controls are inspired by the phenomenon of self-synchronization in networks of non-linear oscillators. VOC controls cause the IBR to act as a non-linear oscillator with a dead zone.

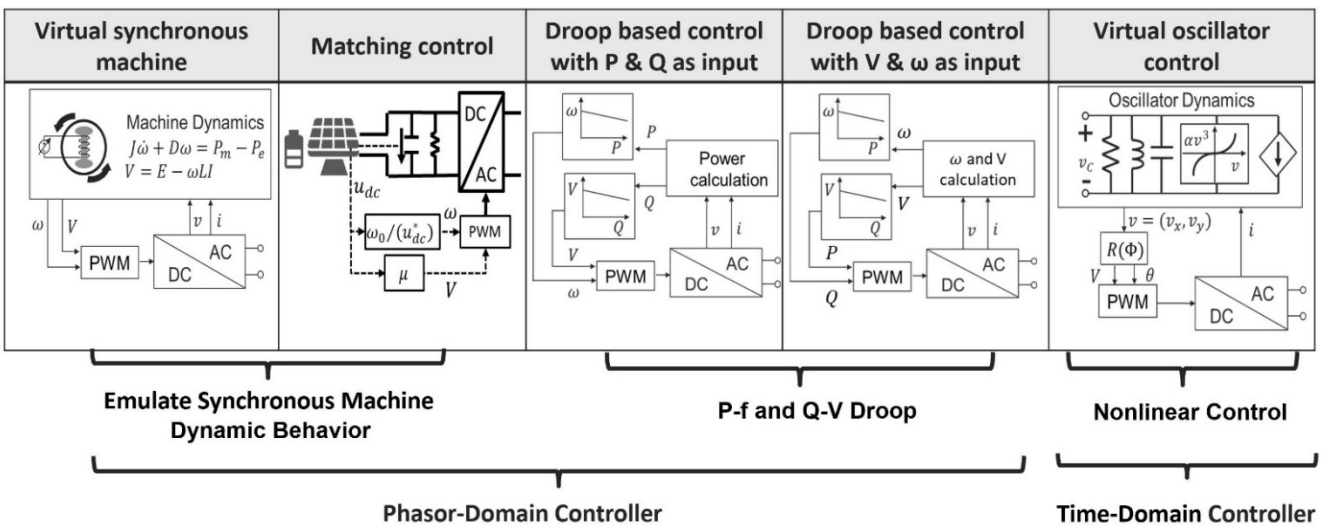


**Figure 1.1: Different Types of GFM Control [Source: EPRI]**

**Figure 1.2** and **Figure 1.3** are high-level examples of block diagrams for GFM and GFL control, respectively, and illustrate some of the similarities and differences between the different types of controls. Some of the main differentiations between GFM and GFL control are summarized in **Table 1.1**.

[34] C. Cardozo, "From Grid-Forming Definition to Experimental Validation with a VSC", in Proc. 18th Wind Intgr. Workshop, Dublin, Ireland, Oct. 2019.

[35] Experiences with large grid forming inverters on various island and micro grid projects. https://hybridpowersystems.org/wp-content/uploads/sites/13/2019/06/3A_3_HYB19_017_presentation_Schoemann_Oliver_web.pdf

[36] D. Ramasubramanian, "Would Traditional Primary Frequency Response and Automatic Voltage Control Naturally help Usher in Grid Forming Control?," CIGRÉ Science & Engineering, vol. 20, pp. 52-60, February 2021

[37] Grid-Forming Inverters: A Critical Asset for the Power Grid, IEEE Journal of Emerging and Selected Topics in Power Electronics, June 2020.

[38] Zhong, Qing-Chang. "Virtual Synchronous Machines: A unified interface for grid integration." *IEEE Power Electronics Magazine* 3.4 (2016): 18-27. https://ieeexplore.ieee.org/abstract/document/7790991/

[39] https://standards.ieee.org/project/2988.html

[40] MIGRATE D3.3 - New options for existing system services and needs for new system services. https://www.h2020-migrate.eu/downloads.html

[41] Johnson, B. et al., "Comparison of virtual oscillator and droop control", In Proc. IEEE 18th Workshop on Control and Modeling for Power Electronics. NJ, USA, 2017.

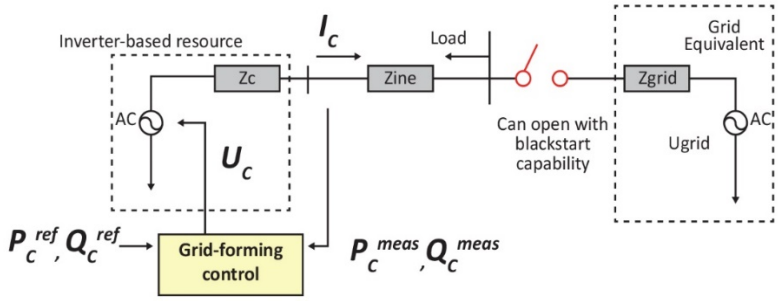


**Figure 1.2: One method of GFM control**

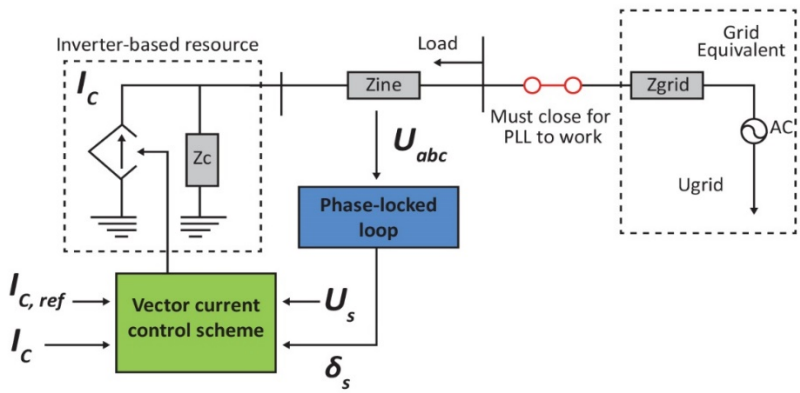


**Figure 1.3: One method of GFL control**

| Table 1.1: GFM & GFL major difference comparison | |
|---|---|
| **GFM** | **GFL** |
| Control IBR terminal voltage magnitude and angle or frequency | Control IBR current magnitude and phase angle |
| May not use a PLL for synchronization | Needs PLL or equivalent |
| May be designed to operate standalone | Dependent on grid other resources to operate stably and provide grid support |
| Can operate grid at 100% IBR, provided some IBRs are GFM | Cannot operate grid at 100% GFL IBR penetration |
| Inherently provides fast energy injection in the inertial timeframe | Can provide fast frequency response (FFR) with a short time delay needed for frequency measurement and control response |
| Stable operation under very low grid strength conditions e.g., SCR<1 (still subject to power transmission constraints) | Stable operation region terminates at some minimum system strength e.g., SCR>1 |
| Can serve as an initial blackstart resource if designed for that purpose | Cannot serve as an initial blackstart resource |

## Grid Forming Projects around the World

GFM control strategies and products are still being actively developed and commercialized by research organizations and OEMs. Although GFM IBRs have no unified control methods in the industry at present, there have been several GFM IBR projects installed in the field (or tested in simulations), and more IBR projects are being developed with GFM technology. Examples of existing projects deployed using GFM technology are briefly mentioned below:

- The VSM controlled Dalrymple Substation Battery[42] GFM project in South Australia started commercial operation in Dec. 2018 and demonstrated that GFM IBR is not only capable to operate in low system strength conditions (SCR<1) but also can improve grid reliability and provide security service with short-circuit current contribution, virtual inertia response, blackstart and islanding operation capability.[43]
  - The newly expanded Hornsdale Power Reserve, has reported a successful BESS ROCOF function test (new "virtual machine mode") when it reacted to the grid disturbances created by the Callide coal plant explosion in Queensland on May, 2021.[44]
  - The California Imperial Irrigation District (IID) BESS (30 MW-20 MWh lithium-ion battery) project demonstrated blackstart capability in 2016. It is the first demonstration of a BESS blackstarting a synchronous generator (44 MW combined-cycle natural gas turbine) to achieve synchronization in a U.S. utility.[45]
  - GFM BESS frequency droop control and blackstart function have also been applied on a Caribbean Island with other renewable energy resources (PV and wind) as a hybrid IBR resource to reduce the use of diesel generation.[46]
  - In Great Britain, controls of an existing 69 MW wind farm consisting of Type 4 full converter wind turbines were modified to GFM VSM[47]. The wind farm then was successfully tested for virtual inertia capability providing rate of change of frequency (ROCOF) support, blackstart, and islanded operation capability.
  - Droop-based GFM solar PV models have been applied to investigate GFM frequency support for the Hawaiian islands of Oahu[48] and Maui.[49]
  - Hawaiian Electric Company (HECO) plans to implement wide-spread GFM BESS technology throughout their island power systems by the year 2023. Significant work in specification, procurement, and detailed EMT studies have been completed. These detailed studies indicate that the GFM technology will be critical to allow the envisioned high renewable penetration scenarios to operate reliably[50]. Further work remains to examine additional operating scenarios and control tuning advances prior to commissioning in 2023.
  - A 100% inverter-based microgrid[51] was constructed by American Electric Power (AEP) in 2006. The GFM IBR separation from the grid and load step changes during islanded operation have been field tested and have shown good dynamic performance[52]. The derived GFM positive sequence models are used to assess

[42] A 30MW Grid Forming BESS Boosting Reliability in South Australia and Providing Market Services on the National Electricity Market", 18th Int'l Wind Integration Workshop, Oct. 2019.

[43] https://www.escri-sa.com.au/globalassets/reports/grid-forming-energy-storage-webinar-escri-sa---july-2020.pdf

[44] https://reneweconomy-com-au.cdn.ampproject.org/c/s/reneweconomy.com.au/virtual-machine-hornsdale-battery-steps-in-to-protect-grid-after-callide-explosion/amp/

[45] https://energycentral.com/c/tr/battery-driven-utility-grid-%E2%80%9Cblack-start%E2%80%9D-southern-california-marks-major

[46] https://hybridpowersystems.org/wp-content/uploads/sites/13/2019/06/3A_3_HYB19_017_presentation_Schoemann_Oliver_web.pdf

[47] A. Roscoe, et. al., "Practical experience of providing enhanced grid forming services from an onshore wind park," in Proc. 19th Wind Integr. Workshop, Nov. 2020.

[48] ME Elkhatib, "Evaluation of Inverter-based Grid Frequency Support using Frequency-Watt and Grid-Forming PV Inverters", 2018 PESGM.

[49] A. Hoke et al., "Inverter-Based Operation of Maui: Electromagnetic Transient Simulations," https://www.nrel.gov/docs/fy21osti/79852.pdf

[50] https://dms.puc.hawaii.gov/dms/DocumentViewer?pid=A1001001A21F14B62327F00172

[51] https://www.energy.gov/sites/prod/files/EAC%20Presentation%20-%20Microgrids%202011%20-%20Lasseter.pdf

[52] https://www.wecc.org/Administrative/Du-%20Droop%20Controlled%20Grid%20Forming%20Inverters.pdf

the high penetration GFM IBR (65% of peak load) impact to microgrid transient, frequency, and voltage stability with a synchronous generator loss disturbance.

# Chapter 2: GFM IBR Challenges and Recommendations

GFM technology is rapidly evolving as new commercial products are being introduced, new research is furthering the understanding of different control topologies, and field tests are proving operational benefits. The industry is faced with opportunities to leverage GFM technology to ensure grid reliability and resilience with increasing penetration of inverter-based resources. However, there are also challenges associated with effectively adopting any new technology. The following recommendations are provided for all entities across North America considering deploying GFM technology on their systems.

## Capabilities and Performance

The following recommendations relate to the capabilities and performance associated with GFM technology:

- **GFM Technology Availability:** Although GFM technology has been used in remote and island electric grids for decades, this technology is still in the early stages of technology maturity and adoption in the BPS. OEMs are exploring different GFM controls, testing GFM controls in field trials and studies, and some OEMs have implemented them in commercial products. However, not all OEMs have GFM technology commercially available, and GFM technology is currently most commonly available in BESS.
- **GFM Resource Capability:** GFM technology does not solve issues associated with fault current levels from IBRs, which is needed for grid protection, as the inverter DC and AC current and voltage limits still dictate their ability to contribute currents and withstand voltages outside nominal ranges[53]. Also, the ability of a GFM IBR to supply significant energy during large disturbance events may be limited by the prime mover and/or by the size of the energy buffer (i.e. dc capacitor). This is inherent in inverter-based technology and not a function of GFM versus GFL controls. Similarly, an IBR's ability to provide FFR or other high-speed energy injection will be dependent on the availability of the power and energy source behind the inverter (e.g., battery, wind speed, solar irradiance). The fault current contribution and protection issue associate with both the GFM and GFL technology needs to be further investigated.
- **GFM as a Solution Option for Low System Strength Conditions:** GFM controls can operate at very low system strength levels and do not have the same stability concerns as GFL inverters. Therefore, GFM inverter technology is one viable solution among a number of different options to support reliable operation of the BPS at very high IBR penetration levels. Even in cases where synchronous condensers are used to provide fault current, system strength, or system inertia,[54] GFM IBRs may still provide benefits in terms of system stabilization.
    - In most cases, existing GFL inverters may not need to be modified to GFM; however, existing GFL inverter firmware could be upgraded to support operation in areas with high penetrations of IBRs. It is also possible to supplement GFM IBRs with existing parallel GFL IBRs (e.g. adding new GFM BESS project to existing GFL PV). In some cases, it may be cost-effective and beneficial for an existing GFL facility to upgrade to GFM IBRs. It would be beneficial to understand what fraction of the GFL IBR fleet is capable of being updated to GFM controls without a complete repowering of the project. OEMs will need to be heavily involved in this process.
    - TOs, TPs, and PCs should study the reliability of the BPS moving forward under high penetration grid conditions, which will require both detailed positive sequences and EMT studies to be conducted to identify situations where existing controls may fail to operate reliably, potentially pointing to the need for GFM controls.

[53] An IBR can be designed to provide higher levels of fault current, but most are not currently designed for it.

[54] Conventional synchronous condensers have relatively small inertia since they do not include a turbine. If synchronous condensers are specifically added for inertia contribution, then a flywheel is most likely needed to increase its overall inertia.

- In areas, where conventional GFL controls fail to operate reliably under potential operating conditions, operating limits (such as IBR curtailment) will be established to either limit the instantaneous output of online GFL IBRs or other corrective action plans (e.g., installing synchronous condensers, strengthening the transmission system, retuning GFL controls, or introducing incentives for GFM IBRs) will need to be developed to support increasing levels of IBRs. Societal costs of each solution option should be thoroughly explored to ensure the most cost-effective option to the end-use consumer is selected.
- TOs, TPs, and PCs should clearly identify (where applicable) minimum system strength requirements and provide that information to developers, GOs, GOPs, and OEMs so they understand any requirements regarding low system strength operations ahead of real-time operation. OEMs may be able to design GFL inverter controls early in the interconnection process to reliably operate under those conditions, or the developer may opt for GFM IBR.
- TOs, TPs, and PCs may also consider other alternative options such as installing synchronous condensers or strengthening the local transmission, since those solutions provide multiple benefits for grid operations such as additional reactive power support, short-circuit current contribution for correct protective relay operation, and supporting system strength.

- **Blackstart and Grid Resilience Considerations:** GFM technology provides a significant advantage over conventional GFL technology because GFM inverters can be designed as an initial black-start resource (i.e., that is not reliant on a strong synchronous grid to reestablish the grid from an outage). Depending on the location of the GFM in the network it can serve as a traditional, centralized black start resource or it can serve as a distributed black start resource if located at the edge of the grid[55]. Each TOP and RC developing a restoration plan and studying cranking paths should fully understand how any potential GFM IBRs being used in the path would operate. EMT studies are needed to fully understand how the GFM resource will operate under such low system strength conditions and to validate that the GFM IBR can energize transformers, charge lines, and start motor loads. GFM technology may be able to help shorten outage durations and provide grid resilience; however, energy assurance from variable weather and inverter overcurrent capability will also need to be considered.
- **GFM Limitations:** Although GFM technology shows significant promise in addressing system issues and will play a significant part in future high penetration of IBR scenarios, it is important to recognize that the technology is not without limitations, particularly in the near term while OEMs continue to refine and develop control strategies and hardware configurations. These include:
  - The response of the GFM device to system events needs particular considerations on IBR headroom in current, power, and energy. The extent to which these may be limited in a device due to hardware, prime mover, or energy storage constraints may affect the stability and service benefit provided by the device. When a device reaches a physical limit (for example, a current limit during a fault), the GFM controls must accommodate these limits gracefully, while continuing to support the network to the extent possible. Failure of the controls to accommodate physical limits in a suitable manner may actually result in degraded system performance. System planners should study the levels of headroom needed for GFM IBRs to provide grid stabilization services and communicate the studied levels to system operators. The desired behavior of GFM controls when approaching physical limits is a topic of research.
  - Use of GFM controls can address instabilities introduced by other IBRs, but it may also introduce new, unexpected modes of instability into the system. This occurs in the same way that a new synchronous machine may introduce new oscillatory modes into a system, or alter existing modes. These will require careful study and potentially new automation strategies or oscillation damping control technology.

[55] https://www.esig.energy/download/session-9-black-start-from-der-vahan-gevorgian/#

  - GFM technology is proven to address control stability in areas with low system strength. It does not, however, address long distance high power transfer stability limits based on physical network constraints.
  - As mentioned above, GFM technology is new to the grid, and it should be expected that new issues and limitations will be uncovered as the industry continues to gain experience.

- **Considerations for Utilizing GFM Technology for GOs and GOPs:** TOs, TPs, and PCs will establish performance requirements per the latest effective version of NERC FAC-001, and newly interconnecting resources need to meet those performance requirements. As the grid continues to rapidly evolve, those requirements are also expected to change. As described above, GFM technology introduces flexibility for IBRs to provide grid essential reliability services. Developers and GOs seeking interconnection to low system strength networks should understand the grid reliability issues associated with operation of GFL technology in those conditions and should explore the use of GFM as one of the viable solution options, working closely with the OEMs and the TP to ensure the GFM is modeled and tuned correctly. System strength will likely continue to decrease over time with the retirement of synchronous generators and increasing levels of GFL IBRs. Therefore, GOs may want to consider moving to GFM technology to enable operation under a wider range of grid conditions and to provide additional grid support capabilities. This is particularly true for BESS and hybrid plant installations.

  GOs should work closely with OEMs regarding coordination of system strength limits established by the TOs, TPs, and PCs. Further, GOs should also work closely with OEMs, any consultants providing modeling support, and the TPs and PCs to ensure EMT models are provided for all applicable GFL and GFM inverter-based resources.

## Interconnection Requirements

The following recommendations relate to the establishment of interconnection requirements for GFM technology:

- **Establishing Interconnection Requirements and Conducting Interconnection Studies for GFM Resources:** Each TO, per the latest effective version of NERC FAC-001, is responsible for establishing interconnection requirements for interconnecting new resources to their network or materially modifying existing resources. TOs are strongly encouraged to fully understand ways GFM technology will operate within their system and should establish clear and consistent requirements for GFM technology to ensure reliable operation of their grid with this new technology. TOs should work closely with their TPs and PCs, per the latest effective version of NERC FAC-002, to ensure adequate models are provided during the interconnection process to reflect the as-built equipment installed in the field. Thorough studies with the sufficiently detailed models should be conducted prior to interconnecting any new resource, and assurance that the GFM controls are appropriately modeled is critical with this new technology. Further, any significant changes in the deployed technology from the models submitted during the interconnection process (GFM controls, settings, topology, ratings, or any other change affecting the electrical behavior of the resources) should initiate a re-study by the TP and PC. The interconnection process should not proceed until those studies have been thoroughly and adequately conducted.

- **Focus on Performance, Not Control Strategy:** GFM control strategies will differ between OEMs. The interconnection requirements should not preclude the use of any one control strategy; rather, the requirements should establish clear performance requirements that the resource must meet and allow any control strategy which can meet or exceed those performance requirements. Interconnection studies will need to be conducted using validated models to represent the full GFM capabilities and characteristics of the resource being supplied.

## Modeling and Studies

The following recommendations relate to modeling and studies associated with GFM technology:

- **GFM IBR positive sequence model and transient EMT model:** GFM positive sequence standard library models for grid stability studies are not available to the public at the writing of this document in 2021. OEMs are developing and testing IBR positive sequence models and EMT models with their different GFM IBR controls, which contain confidential information and are not open to the public. This will challenge TPs and PCs during their FAC-002 interconnections studies, hinder TP and PC abilities to create interconnection-wide base cases that (in some areas) require the use of standard library models. These issues will need to be addressed to ensure that GFM technology that is already commercially available (and future products) can be effectively studied and integrated into large-scale planning cases.

  While GFL standard library models have the major functions developed, validated, and published in the power system simulation software, it is important for IBR standard library models to include GFM functions as the industry reaches agreement on standardized GFM control types and topologies. Considering the confidential nature of GFM controls and the need for GFM models for planning studies with high penetration of IBRs, it is recommended that the WECC Modeling and Validation Subcommittee (MVS) or other industry modeling groups start GFM model development with support from OEMs and research organizations in the near future.

- **Study of System Benefits of GFM IBRs:** GFM IBRs will be a critical resource for maintaining stability of the BPS under increasing IBR penetration. These major benefits of the technology can and should be weighed against the incremental costs of leveraging this technology to newly interconnecting resources. It is important to study and coordinate different GFM IBR functions and their specific contributions to overall BPS stability, and incorporate those findings into how individual GFM IBR projects are assessed during routine interconnection studies. System-wide reliability studies may also inform the development of both GFM and GFL IBR interconnection requirements.

# White Paper: BPS-Connected IBR and Hybrid Plant Capabilities for Frequency Response

## Action
Approve

## Summary
The Federal Energy Regulatory Commission (FERC) issued Order No. 842 in 2018, amending the pro forma Large Generator Interconnection Agreement (LGIA) and Small Generator Interconnection Agreement (SGIA) to require all "newly interconnecting large and small generating facilities, both synchronous and non-synchronous, to install, maintain, and operate equipment capable of providing primary frequency response (PFR) as a condition of interconnection." On the same subject, NERC recently published a white paper, *Fast Frequency Response Concepts and Bulk Power System Reliability Needs*, in March 2020 describing the interrelationships between primary frequency response (PFR) and fast frequency response (FFR). This work extends on the FERC Order NO. 842 and the NERC white paper and recommends leveraging PFR and FFR capabilities from inverter-based resources to the extent possible to support BPS frequency as an essential reliability service. The IRPWG has developed a White Paper with recommendations on this subject and is seeking RSTC approval.

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# Utilizing the Excess Capability of BPS-Connected Inverter-Based Resources for Frequency Support

NERC Inverter-Based Resource Performance Working Group (IRPWG)
White Paper
September 2021

The Federal Energy Regulatory Commission (FERC) issued Order No. 842 in 2018, amending the pro forma Large Generator Interconnection Agreement (LGIA) and Small Generator Interconnection Agreement (SGIA) to require all "newly interconnecting large and small generating facilities, both synchronous and non-synchronous, to install, maintain, and operate equipment capable of providing primary frequency response (PFR) as a condition of interconnection."[1] On the same subject, NERC recently published a white paper, *Fast Frequency Response Concepts and Bulk Power System Reliability Needs*,[2] in March 2020 describing the interrelationships between primary frequency response (PFR) and fast frequency response (FFR). This work extends on the FERC Order NO. 842 and the NERC white paper and recommends leveraging PFR and FFR capabilities from inverter-based resources to the extent possible to support BPS frequency as an essential reliability service.

Specifically, inverter-based resources operating at their maximum contractual agreement, also referred to as the steady-state interconnection limit (SSIL), may be able to support the grid during underfrequency events beyond their SSIL. This situation is most likely to occur in ac-coupled[3] hybrid plants (i.e., the combination of battery energy storage and wind or solar PV) or in standalone wind, solar PV, and battery energy storage plants where additional capacity is available but not presently utilized due to the SSIL constraints imposed by interconnection agreements. It should be noted that this paper only focuses on the excess capability of inverter-based resources that is limited by the SSIL; it does not consider the short-term overload capability of individual inverters.

By establishing a short-term interconnection limit (STIL)[4] in interconnection agreements, inverter-based resources with excess active power capability beyond SSIL can use this capability to better support the grid frequency. However, once the system frequency recovers to nominal, the MW output of the plant should

[1] https://www.nerc.com/FilingsOrders/us/FERCOrdersRules/E-2_Order%20on%20Primary%20Frequency%20Response.pdf
[2] "White Paper: 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
[3] Dc-coupled hybrid plants can be deemed similar to the standalone IBR facilities for the topic of this paper.
[4] A similar concept is also introduced in IEEE P2800 standard. However, there are some differences. A prudent reader is encouraged to refer to the IEEE P2800 standard to fully understand the similarities and differences: https://standards.ieee.org/project/2800.html#:~:text=IEEE%20P2800%20%2D%20IEEE%20Draft%20Standard,Associated%20Transmission%20Electric%20Power%20Systems

return to a value equal to or below SSIL. Moreover, if the equipment can only withstand operation between SSIL and STIL temporarily due to thermal or any other constraints, then it can return to SSIL prior to the recovery of the system frequency.

Currently, exceedance of SSIL to provide PFR or FFR is either not permitted in interconnection agreements or not well-defined. Provided all equipment ratings and stability limits are properly studied and respected, the excess capability of an inverter-based resource can be leveraged to enhance BPS reliability. This can be accomplished by establishing an STIL in the interconnection agreement of the inverter-based resource with excess capability. This will afford additional PFR and FFR during underfrequency events to the Balancing Authority and thus enhance BPS reliability.

In an effort to advance this concept, the NERC IRPWG has developed a set of recommendations and identified the applicable entities within the industry that would need to act upon these recommendations to enable this capability.

| **Recommendations for Utilizing the Excess Capability of BPS-Connected Inverter-Based Resources for PFR and FFR Support** | |
|---|---|
| **Recommendation** | **Applicability** |
| The *pro forma* LGIA and SGIA should be amended to specify conditions under which the SSIL and STIL of the facility established in the interconnection agreement would complement each other to enable the facility to respond to underfrequency events and provide PFR or FFR to the BPS for the duration until the frequency is restored. | Federal Energy Regulatory Commission (FERC) |
| Transmission Owners (TOs), in coordination with their Transmission Planner (TP) and Planning Coordinator (PC), should update local interconnection requirements per NERC FAC-001 to permit operation of all newly interconnecting inverter-based resources to provide PFR and FFR while operating at their SSIL up to their STIL. PFR and FFR requirements should focus on the required performance—droops, dead-bands, response times, and reaction times.[5] | TOs, TPs, PCs |
| TPs and PCs should evaluate and enhance their interconnection study processes per NERC FAC-002 to ensure the added provision of FFR and PFR from inverter-based resources does not adversely affect BPS reliability or stability. Adequate simulations are needed to ensure all system operating limits are met with these capabilities enabled.<br><br>TPs and PCs should review, amend, and file their *pro forma* interconnection agreements and procedures to clarify SSIL and STIL to support PFR or FFR whenever excess capability is available.<br><br>TPs and PCs should also ensure any transmission planning studies including PFR or FFR from these types of resources are appropriately modeled in underfrequency load shedding (UFLS) studies per the latest effective version of NERC PRC-006. | TPs, PCs |

[5] Refer to 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

| Recommendations for Utilizing the Excess Capability of BPS-Connected Inverter-Based Resources for PFR and FFR Support | |
|---|---|
| **Recommendation** | **Applicability** |
| Equipment manufacturers, developers, Generator Owners (GOs), and Generator Operators (GOPs) of BPS-connected inverter-based resources that have excess capabilities and able to provide additional active power (above SSIL) to support frequency response should utilize the STIL established by interconnection agreements or requirements. If the agreements and requirements are amenable to this functionality being enabled, it should be functionally available per FERC Order No. 842. Any provision of additional active power should not hinder or limit the capability to provide reactive power to the BPS and take into account the facilities' required power factor limits relative to the SSIL established in the interconnection agreement as well as active or reactive current priority control settings. | Inverter and plant-level controller manufacturers, inverter-based resource developers, GOs, GOPs |
| Reliability Coordinators (RCs) and Transmission Operators (TOPs) should ensure the additional active power generated by resources exceeding their SSIL up to their STIL to provide PFR or FFR would not cause any adverse impacts to reliability and stability of the BPS during real-time operations. This includes ensuring that no system operating limits are exceeded and operational planning assessments and real-time assessments are reflective of these additional capacities from inverter-based resources.<br><br>Balancing Authorities (BAs) should ensure awareness of the on-line FFR and PFR capabilities to ensure sufficient reserves to support BPS frequency immediately following sudden loss of generation or sudden increase in load events. | RCs, TOPs, BAs |

Upon approval of this white paper, the NERC IRPWG will hold an informational webinar to comprehensively discuss various plant design scenarios under which STIL (above SSIL) is possible.

# TPL-001-5 SAR for BPS-Connected IBRs

## Action
Endorse

## Summary
The NERC IRPWG (formerly IRPTF) undertook a complete review of the NERC Reliability Standards in the context of increasing levels of BPS-connected inverter-based resources and published a white paper on the outcomes and recommendations of this review in March 2020. The review was approved by the NERC Planning Committee and served as the technical justification for future standards revision efforts. Based on the outcome of the review, it was determined that the TPL-001-4/5 needed clarifications "to address terminology throughout the standard that is unclear with regards to inverter-based resources" the next time the standard is revised. The IRPWG brought a SAR to the RSTC in March 2021 which was not endorsed. The IRPWG sought and received feedback from RSTC members and addressed the comments and made conforming revisions to the SAR. The IRPWG is seeking endorsement of the proposed SAR and subsequent submittal to the Standards Committee for action.

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# Standard Authorization Request (SAR)

Complete and submit this form, with attachment(s) to the NERC Help Desk. Upon entering the Captcha, please type in your contact information, and attach the SAR to your ticket. Once submitted, you will receive a confirmation number which you can use to track your request.

The North American Electric Reliability Corporation (NERC) welcomes suggestions to improve the reliability of the bulk power system through improved Reliability Standards.

| Requested information | | | |
|---|---|---|---|
| SAR Title: | TPL-001-5.1 Transmission System Planning Performance Requirements | | |
| Date Submitted: | _/_/2021 | | |
| SAR Requester | | | |
| Name: | Allen Schriver, NextEra Energy (NERC IRPWG Chair)<br>Julia Matevosyan, ERCOT (NERC IRPWG Vice Chair) | | |
| Organization: | NERC Inverter-Based Resource Performance Working Group (IRPWG) | | |
| Telephone: | Al – 561-904-3234<br>Julia – 512-994-7914 | Email: | Allen.Schriver@fpl.com<br>Julia.Matevosyan@ercot.com |
| SAR Type (Check as many as apply) | | | |
| ☐ New Standard<br>☒ Revision to Existing Standard<br>☐ Add, Modify or Retire a Glossary Term<br>☐ Withdraw/retire an Existing Standard | | ☐ Imminent Action/ Confidential Issue (SPM Section 10)<br>☐ Variance development or revision<br>☐ Other (Please specify) | |
| Justification for this proposed standard development project (Check all that apply to help NERC prioritize development) | | | |
| ☐ Regulatory Initiation<br>☒ Emerging Risk (Reliability Issues Steering Committee) Identified<br>☐ Reliability Standard Development Plan | | ☒ NERC Standing Committee Identified<br>☐ Enhanced Periodic Review Initiated<br>☒ Industry Stakeholder Identified | |
| Industry Need (What Bulk Electric System (BES) reliability benefit does the proposed project provide?): | | | |
| Many areas of the North American bulk power system (BPS) continue to experience an increase in BPS-connected inverter-based resources (e.g., wind, solar photovoltaic (PV), battery energy storage systems (BESS), and hybrid power plants). NERC Reliability Standard TPL-001-5.1 is a foundational standard used for "establishing transmission system performance requirements within the planning horizon to develop a bulk electric system (BES) that will operate reliably over a broad spectrum of system conditions and following a wide range of probable contingencies." Transmission Planners (TPs) and Planning Coordinators (PCs) develop and use models of the electrical grid to perform planning assessments (e.g., steady-state, dynamic, and short-circuit) to develop corrective action plans for future reliability issues identified. Ensuring that the TPL-001 standard is reflective of the evolving nature of the BPS and its resource mix is paramount to ensuring reliable operation and resilience of the BPS moving forward. | | | |

| Requested information |
| --- |
| The NERC Inverter-Based Resource Performance Task Force (IRPTF)[1] undertook a complete review of the NERC Reliability Standards in the context of increasing levels of BPS-connected inverter-based resources and published a white paper on the outcomes and recommendations of this review in March 2020.[2] The review was approved by the NERC Planning Committee and served as the technical justification for future standards revision efforts. The white paper recommended modifications to seven standards, and IRPWG presented four SARs to the NERC Reliability and Security Technical Committee (RSTC) in June 2020 that addressed the deficiencies identified in six of the seven standards.<br><br>Based on the outcome of the review, it was determined that the TPL-001-4/5[3] needed clarifications "to address terminology throughout the standard that is unclear with regards to inverter-based resources" the next time the standard is revised. The language used in the white paper regarding "the next time the standard is revised" was based on the understanding that the NERC System Planning Impacts from Distributed Energy Resources Working Group (SPIDERWG) was developing a SAR and that the recommended modifications to TPL-001-5 from IRPWG could be included in the SPIDERWG SAR. The combined SAR was presented to the NERC RSTC at their March 2021 meeting and was rejected. The overarching comments received were with regards to the DER-related issues and a comment was made that the recommendations pertaining to BPS-connected inverter-based resources were not the primary focus of concern.<br><br>Therefore, IRPWG presents this SAR to move the effort forward regarding specifically BPS-connected inverter-based resources. This SAR does not include any modification to TPL-001-5 regarding the inclusion of distributed energy resources (DERs). IRPWG believes that industry needs to be proactive in addressing standards gaps, particularly, where lack of clarity and confusion may lead to studies not adequately capturing possible BPS reliability issues. As the North American BPS continues to experience rising penetration levels of BPS-connected inverter-based resources and is likely to do so into the foreseeable future, these changes are critical for overall BPS reliability and industry efforts to reliably integrate these resources. |
| Purpose or Goal (How does this proposed project provide the reliability-related benefit described above?): |
| This SAR revises requirements within the TPL-001-5 standard to provide clarity and consistency for how BPS-connected inverter-based resources are considered, modeled, and studied in planning assessments. The proposed revisions to TPL-001-5 will ensure industry is effectively and efficiently conducting planning assessments and that the requirements are equally suitable for inverter-based resources as they are for synchronous generation. |

[1] The IRPTF has subsequently become the IRPWG under the NERC Reliability and Security Technical Committee (RSTC).
[2] NERC IRPTF, "IRPTF Review of NERC Reliability Standards," March 2020: https://www.nerc.com/comm/PC/InverterBased%20Resource%20Performance%20Task%20Force%20IRPT/Review_of_NERC_Reliability_Standards_White_Paper.pdf
[3] At the time of review, the TPL-001-5 standard had just recently been approved by FERC and was yet to be subject to enforcement.

| Requested information |
| --- |
| Project Scope (Define the parameters of the proposed project): |
| As described in further detail below, the scope of this project includes the following revisions to TPL-001-5.1:<br><br>• Modify Requirements 3.3 and 4.3 and their applicable sub-requirements to make the term "GSU transformer" suitable for all generation types since it introduces confusion for BPS-connected inverter-based resources<br>• Modify Requirements 4.1.1 and 4.1.2 regarding the use of the term "pulls out of synchronism," which is only applicable for synchronous generator technologies and is not suitable for BPS-connected inverter-based resources<br>• Modify Requirement 4.3.2 so that the list of devices that impact the study area are inclusive of BPS-connected inverter-based resource technologies<br>• |
| 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[4] 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): |
| The following detailed description is copied verbatim from the IRPTF white paper that was approved by the NERC PC:<br><br>TPL-001-4 requires Planning Coordinators (PCs) and TPs to assess the reliability of their portion of the BES for various conditions across several specified future years and to plan Corrective Action Plans to address identified performance deficiencies. The requirements and sub-requirements include, among other things, certain simulation assumptions to be used by the planner and performance requirements.<br><br>Sub-requirements 3.3 and 4.3 describe simulation assumptions that the planner should use when performing contingency analysis for the steady-state and stability portion of the assessment, respectively. Sub-requirements 3.3.1.1 and 4.3.1.2 each require the planner to include the impact of the "tripping of generators where simulations show generator bus voltages or high side of the [GSU] voltages are less than known or assumed generator" low voltage ride-through capability.<br><br>The term GSU transformer can 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 (MPT)) to step the voltage up from the collector system voltage to transmission system voltage. It was likely the intent of the TPL-001-2 SDT to be referring to transmission system voltages when drafting the language that refers to known or assumed |

[4] 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 |
| --- |
| generator low voltage ride-through capability at the high-side of the GSU. Therefore, the language in these sub-requirements should be modified to provide clarity for inverter-based resources.<br><br>Sub-requirements 4.1.1 and 4.1.2 provide stability performance criteria when a generator "pulls out of synchronism" in system simulations. Although an inverter-based resource does synchronize with the grid, the phrase "pulls out of synchronism" is typically applicable only to synchronous generators, referring to when a synchronous machine has an angular separation from the rest of the grid. Therefore, these sub-requirements could be clarified by clearly stating that this performance criteria is for synchronous generators.<br><br>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.<br><br>The suggested clarifications for sub-requirements 3.3, 4.3, 4.1.1, 4.1.2, and 4.3.2 should be considered by a future SDT when editing the standard. However, the IRPTF does not believe the clarifications by themselves warrant changing the standard at this time. It should be noted that the identified issues with TPL-001-4 also apply to the draft TPL-001-5 standard that is awaiting FERC approval as of the publication of this whitepaper. |
| Cost Impact Assessment, if known (Provide a paragraph describing the potential cost impacts associated with the proposed project): |
| The cost impacts for the proposed changes to TPL-001-5 are expected to be minimal. The changes being proposed are clarifications that will bring consistency and effectiveness industry related to how planning assessments are conducted and how planning engineers set up and conduct those assessments. |
| 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, Transmission Planners, and Generator Owners of inverter-based resources |

| Requested information |
|---|
| |
| Do you know of any consensus building activities[5] in connection with this SAR? If so, please provide any recommendations or findings resulting from the consensus building activity. |
| This SAR is an outcome of the white paper produced by the NERC IRPTF and approved by the NERC PC, which can be found here: https://www.nerc.com/comm/PC/InverterBased%20Resource%20Performance%20Task%20Force%20IRPT/Review_of_NERC_Reliability_Standards_White_Paper.pdf<br><br>The SAR is a follow-on to the recommendation contained within the white paper, developed by the NERC IRPWG under the NERC RSTC. |
| 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. |
| The NERC IRPWG (previously IRPTF) has published multiple technical reference documents, white papers, and reliability guidelines related to the performance, modeling, and studies of BPS-connected inverter-based resources. These technical materials are used widely by industry and have provided significant value for improving planning practices. However, those efforts do not address the larger issue related to the TPL-001 standards language being written predominantly for synchronous generation technology and not adequately considering or clarifying how the requirements relate to BPS-connected inverter-based resource technologies. |

| 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. |

[5] Consensus building activities are occasionally conducted by NERC and/or project review teams. They typically are conducted to obtain industry inputs prior to proposing any standard development project to revise, or develop a standard or definition.

| Requested information | |
|---|---|
| ☐ | 6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions. |
| ☐ | 7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis. |
| ☐ | 8. Bulk power systems shall be protected from malicious physical or cyber attacks. |

| Market Interface Principles | |
|---|---|
| Does the proposed standard development project comply with all of the following Market Interface Principles? | Enter (yes/no) |
| 1. A reliability standard shall not give any market participant an unfair competitive advantage. | Yes |
| 2. A reliability standard shall neither mandate nor prohibit any specific market structure. | Yes |
| 3. A reliability standard shall not preclude market solutions to achieving compliance with that standard. | Yes |
| 4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards. | Yes |

| Identified Existing or Potential Regional or Interconnection Variances | |
|---|---|
| Region(s)/ Interconnection | Explanation |
| None | None |

# For Use by NERC Only

| SAR Status Tracking (Check off as appropriate). | |
|---|---|
| ☐ Draft SAR reviewed by NERC Staff<br>☐ Draft SAR presented to SC for acceptance<br>☐ DRAFT SAR approved for posting by the SC | ☐ Final SAR endorsed by the SC<br>☐ SAR assigned a Standards Project by NERC<br>☐ SAR denied or proposed as Guidance document |

**Version History**

| Version | Date | Owner | Change Tracking |
|---|---|---|---|
| 1 | June 3, 2013 | | Revised |

| | | | |
|---|---|---|---|
| 1 | August 29, 2014 | Standards Information Staff | Updated template |
| 2 | January 18, 2017 | Standards Information Staff | Revised |
| 2 | June 28, 2017 | Standards Information Staff | Updated template |
| 3 | February 22, 2019 | Standards Information Staff | Added instructions to submit via Help Desk |
| 4 | February 25, 2020 | Standards Information Staff | Updated template footer |

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# Standard Authorization Request (SAR)

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The North American Electric Reliability Corporation (NERC) welcomes suggestions to improve the reliability of the bulk power system through improved Reliability Standards.

| Requested information | | | |
|---|---|---|---|
| SAR Title: | TPL-001-5.1 Transmission System Planning Performance Requirements | | |
| Date Submitted: | _/_/2021 | | |
| SAR Requester | | | |
| Name: | Allen Schriver, NextEra Energy (NERC IRPWG Chair)<br>Julia Matevosyan, ERCOT (NERC IRPWG Vice Chair) | | |
| Organization: | NERC Inverter-Based Resource Performance Working Group (IRPWG) | | |
| Telephone: | Al – 561-904-3234<br>Julia – 512-994-7914 | Email: | Allen.Schriver@fpl.com<br>Julia.Matevosyan@ercot.com |
| SAR Type (Check as many as apply) | | | |
| ☐ New Standard<br>☒ Revision to Existing Standard<br>☐ Add, Modify or Retire a Glossary Term<br>☐ Withdraw/retire an Existing Standard | | ☐ Imminent Action/ Confidential Issue (SPM Section 10)<br>☐ Variance development or revision<br>☐ Other (Please specify) | |
| Justification for this proposed standard development project (Check all that apply to help NERC prioritize development) | | | |
| ☐ Regulatory Initiation<br>☒ Emerging Risk (Reliability Issues Steering Committee) Identified<br>☐ Reliability Standard Development Plan | | ☒ NERC Standing Committee Identified<br>☐ Enhanced Periodic Review Initiated<br>☒ Industry Stakeholder Identified | |
| Industry Need (What Bulk Electric System (BES) reliability benefit does the proposed project provide?): | | | |
| Many areas of the North American bulk power system (BPS) continue to experience an increase in BPS-connected inverter-based resources (e.g., wind, solar photovoltaic (PV), battery energy storage systems (BESS), and hybrid power plants). NERC Reliability Standard TPL-001-5.1 is a foundational standard used for "establishing transmission system performance requirements within the planning horizon to develop a bulk electric system (BES) that will operate reliably over a broad spectrum of system conditions and following a wide range of probable contingencies." Transmission Planners (TPs) and Planning Coordinators (PCs) develop and use models of the electrical grid to perform planning assessments (e.g., steady-state, dynamic, and short-circuit) to develop corrective action plans for future reliability issues identified. Ensuring that the TPL-001 standard is reflective of the evolving nature of the BPS and its resource mix is paramount to ensuring reliable operation and resilience of the BPS moving forward. | | | |

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| The NERC Inverter-Based Resource Performance Task Force (IRPTF)[1] undertook a complete review of the NERC Reliability Standards in the context of increasing levels of BPS-connected inverter-based resources and published a white paper on the outcomes and recommendations of this review in March 2020.[2] The review was approved by the NERC Planning Committee and served as the technical justification for future standards revision efforts. The white paper recommended modifications to seven standards, and IRPWG presented four SARs to the NERC Reliability and Security Technical Committee (RSTC) in June 2020 that addressed the deficiencies identified in six of the seven standards.<br><br>Based on the outcome of the review, it was determined that the TPL-001-4/5[3] needed clarifications "to address terminology throughout the standard that is unclear with regards to inverter-based resources" the next time the standard is revised. The language used in the white paper regarding "the next time the standard is revised" was based on the understanding that the NERC System Planning Impacts from Distributed Energy Resources Working Group (SPIDERWG) was developing a SAR and that the recommended modifications to TPL-001-5 from IRPWG could be included in the SPIDERWG SAR. The combined SAR was presented to the NERC RSTC at their March 2021 meeting and was rejected. The overarching comments received were with regards to the DER-related issues and a comment was made that the recommendations pertaining to BPS-connected inverter-based resources were not the primary focus of concern.<br><br>Therefore, IRPWG presents this SAR to move the effort forward regarding specifically BPS-connected inverter-based resources. This SAR does not include any modification to TPL-001-5 regarding the inclusion of distributed energy resources (DERs). IRPWG believes that industry needs to be proactive in addressing standards gaps, particularly, where lack of clarity and confusion may lead to studies not adequately capturing possible BPS reliability issues. As the North American BPS continues to experience rising penetration levels of BPS-connected inverter-based resources and is likely to do so into the foreseeable future, these changes are critical for overall BPS reliability and industry efforts to reliably integrate these resources. |
| Purpose or Goal (How does this proposed project provide the reliability-related benefit described above?): |
| This SAR revises requirements within the TPL-001-5 standard to provide clarity and consistency for how BPS-connected inverter-based resources are considered, modeled, and studied in planning assessments. The proposed revisions to TPL-001-5 will ensure industry is effectively and efficiently conducting planning assessments and that the requirements are equally suitable for inverter-based resources as they are for synchronous generation. |

[1] The IRPTF has subsequently become the IRPWG under the NERC Reliability and Security Technical Committee (RSTC).
[2] NERC IRPTF, "IRPTF Review of NERC Reliability Standards," March 2020: https://www.nerc.com/comm/PC/InverterBased%20Resource%20Performance%20Task%20Force%20IRPT/Review_of_NERC_Reliability_Standards_White_Paper.pdf
[3] At the time of review, the TPL-001-5 standard had just recently been approved by FERC and was yet to be subject to enforcement.

| Requested information |
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| Project Scope (Define the parameters of the proposed project): |
| As described in further detail below, the scope of this project includes the following revisions to TPL-001-5.1:<br><br>• Modify Requirements 3.3 and 4.3 and their applicable sub-requirements to make the term "GSU transformer" suitable for all generation types since it introduces confusion for BPS-connected inverter-based resources<br>• Modify Requirements 4.1.1 and 4.1.2 regarding the use of the term "pulls out of synchronism," which is only applicable for synchronous generator technologies and is not suitable for BPS-connected inverter-based resources<br>• Modify Requirement 4.3.2 so that the list of devices that impact the study area are inclusive of BPS-connected inverter-based resource technologies<br>• ~~Modify other Requirements, if necessary as deemed appropriate by the Standard Drafting Team, regarding the aforementioned issues if the IRPTF review missed any other related issues~~<br>• |
| 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[4] 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): |
| The following detailed description is copied verbatim from the IRPTF white paper that was approved by the NERC PC:<br><br>TPL-001-4 requires Planning Coordinators (PCs) and TPs to assess the reliability of their portion of the BES for various conditions across several specified future years and to plan Corrective Action Plans to address identified performance deficiencies. The requirements and sub-requirements include, among other things, certain simulation assumptions to be used by the planner and performance requirements.<br><br>Sub-requirements 3.3 and 4.3 describe simulation assumptions that the planner should use when performing contingency analysis for the steady-state and stability portion of the assessment, respectively. Sub-requirements 3.3.1.1 and 4.3.1.2 each require the planner to include the impact of the "tripping of generators where simulations show generator bus voltages or high side of the [GSU] voltages are less than known or assumed generator" low voltage ride-through capability.<br><br>The term GSU transformer can 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 (MPT)) to step the voltage up from the collector system voltage to |

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[4] 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 |
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| transmission system voltage. It was likely the intent of the TPL-001-2 SDT to be referring to transmission system voltages when drafting the language that refers to known or assumed generator low voltage ride-through capability at the high-side of the GSU. Therefore, the language in these sub-requirements should be modified to provide clarity for inverter-based resources.<br><br>Sub-requirements 4.1.1 and 4.1.2 provide stability performance criteria when a generator "pulls out of synchronism" in system simulations. Although an inverter-based resource does synchronize with the grid, the phrase "pulls out of synchronism" is typically applicable only to synchronous generators, referring to when a synchronous machine has an angular separation from the rest of the grid. Therefore, these sub-requirements could be clarified by clearly stating that this performance criteria is for synchronous generators.<br><br>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.<br><br>The suggested clarifications for sub-requirements 3.3, 4.3, 4.1.1, 4.1.2, and 4.3.2 should be considered by a future SDT when editing the standard. However, the IRPTF does not believe the clarifications by themselves warrant changing the standard at this time. It should be noted that the identified issues with TPL-001-4 also apply to the draft TPL-001-5 standard that is awaiting FERC approval as of the publication of this whitepaper. |
| Cost Impact Assessment, if known (Provide a paragraph describing the potential cost impacts associated with the proposed project): |
| The cost impacts for the proposed changes to TPL-001-5 are expected to be minimal. The changes being proposed are clarifications that will bring consistency and effectiveness industry related to how planning assessments are conducted and how planning engineers set up and conduct those assessments. |
| 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 |

| Requested information |
|---|
| Operator, Reliability Coordinator, etc. See the most recent version of the NERC Functional Model for definitions): |
| Planning Coordinators, Transmission Planners, and Generator Owners of inverter-based resources |
| Do you know of any consensus building activities[5] in connection with this SAR? If so, please provide any recommendations or findings resulting from the consensus building activity. |
| This SAR is an outcome of the white paper produced by the NERC IRPTF and approved by the NERC PC, which can be found here: https://www.nerc.com/comm/PC/InverterBased%20Resource%20Performance%20Task%20Force%20IRPT/Review_of_NERC_Reliability_Standards_White_Paper.pdf<br><br>The SAR is a follow-on to the recommendation contained within the white paper, developed by the NERC IRPWG under the NERC RSTC. |
| 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. |
| The NERC IRPWG (previously IRPTF) has published multiple technical reference documents, white papers, and reliability guidelines related to the performance, modeling, and studies of BPS-connected inverter-based resources. These technical materials are used widely by industry and have provided significant value for improving planning practices. However, those efforts do not address the larger issue related to the TPL-001 standards language being written predominantly for synchronous generation technology and not adequately considering or clarifying how the requirements relate to BPS-connected inverter-based resource technologies. |

| 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. |

[5] Consensus building activities are occasionally conducted by NERC and/or project review teams. They typically are conducted to obtain industry inputs prior to proposing any standard development project to revise, or develop a standard or definition.

| Requested information | |
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| ☐ | 4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented. |
| ☐ | 5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems. |
| ☐ | 6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions. |
| ☐ | 7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis. |
| ☐ | 8. Bulk power systems shall be protected from malicious physical or cyber attacks. |

| Market Interface Principles | |
|---|---|
| Does the proposed standard development project comply with all of the following Market Interface Principles? | Enter (yes/no) |
| 1. A reliability standard shall not give any market participant an unfair competitive advantage. | Yes |
| 2. A reliability standard shall neither mandate nor prohibit any specific market structure. | Yes |
| 3. A reliability standard shall not preclude market solutions to achieving compliance with that standard. | Yes |
| 4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards. | Yes |

| Identified Existing or Potential Regional or Interconnection Variances | |
|---|---|
| Region(s)/ Interconnection | Explanation |
| None | None |

## For Use by NERC Only

| SAR Status Tracking (Check off as appropriate). | |
|---|---|
| ☐ Draft SAR reviewed by NERC Staff<br>☐ Draft SAR presented to SC for acceptance<br>☐ DRAFT SAR approved for posting by the SC | ☐ Final SAR endorsed by the SC<br>☐ SAR assigned a Standards Project by NERC<br>☐ 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 |

| Feedback |
| --- |
| The proposed SAR should include the addition of an “Applicable Facilities” section delineating what BES or non-BES elements should be subject to the requirements of this standard. |
| The proposed SAR should include provisions for amending MOD-032 to provide for the identification of Distribution Provider in the listing of Applicable Entities, along with associated requirements. |
| The SAR states that the Project Scope includes modifying 3.3 and 4.3 and their subparts to make the term “GSU Transformer” suitable for all generation types. I assume this means creating a definition that would be included in the NERC GOT. If that’s the case, the SAR type should also include “Add, Modify or Retire a Glossary Term”. |
| From the discussion at the June RSTC, I believe much of the concern came from the repeated references to “BPS” or BPS-Connected”. It was indicated in the discussion that there was no intent to go beyond the “BES”. I believe making that simple change would alleviate much of the concern with the SAR. |
| Lastly, the last bullet in the Project Scope of the SAR seems overly broad. Deletion of that bullet would alleviate some ambiguity around this SAR.<br><br>For reference, “Modify other Requirements, if necessary as deemed appropriate by the Standard Drafting Team, regarding the aforementioned issues if the IRPTF review missed any other related issues" |
| I don’t believe the applicability section of the TPL standard needs to be modified as noted by Brian. There was a white paper that reviewed proposed revisions to NERC standards related to “Dispersed Generation Resources”. In this review, they noted no change to TPL applicability was needed as the TPL standard was not affecting the GO or GOPs directly. Input from these entities is provided through the MOD standards (i.e. MOD-032). I believe this is still true for the case of inverter-based resources. |

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|---|
| I’m supportive of a TPL SAR to clarify IBR/DER modelling and analysis. My concern is that we have two groups proposing changes within the RSTC: The IRPWG and SPIDER. These two groups should coordinate on developing a single SAR for TPL. If other standards are proposed to be modified, it would be nice if the SARs could be packaged into a group to see how the changes work together. |
| There is a recognized need for additional changes but that should not prevent this from moving forward. Many times, a drafting team needs the general information to begin the process of working with industry to get to the right answer. It seems it would be time to let that process work. |

| IRPWG Leadership Response |
| --- |
| The TPL standard is a transmission planning standard focused on performing system studies to ensure planning performance requirements are met in the planning horizon. The standard leverages the MOD-032 standard, and is not directly a modelling standard. Its applicability is solely on the PCs and TPs that perform these studies, and does not focus on the asset owners that would be providing models (under MOD-032). These two topics are clearly differentiated in the existing standards, and this does not need to change. There is no identified reliability risk that the current business of performing BPS planning assessments needs to change for BPS-connected resources (the focus of the IRPWG efforts).<br><br>There was a white paper that reviewed proposed revisions to NERC standards related to “Dispersed Generation Resources”. In this review, they noted no change to TPL applicability was needed as the TPL standard was not affecting the GO or GOPs directly. Input from these entities is provided through the MOD standards (i.e. MOD-032).<br><br>Therefore the IRPWG Leadership does not believe this change is needed for the SAR. |
| The IRPWG Leadership believes that this is irrelevant to IRPWG-related issues and is a SPIDERWG issue. It is cautioned not to get the two mixed up. They were seperated to ensure there was a distinction between the two.<br><br>Therefore the IRPWG Leadership does not believe this change is needed for the SAR. |
| The IRPWG discussed this issue in its developments and believes that a standard revision is not necessarily needed to address this point. A term such as "main power transformer(s)" could be used and would be suitable to get the main points across.<br><br>Therefore the IRPWG Leadership does not believe this change is needed for the SAR. |
| Transmission planning studies include both BES and non-BES elements connected to the BPS to ensure the system is suitable and accurately represented. This is the present industry standard, and IRPWG does not intend to change that in any way. When BES performance issues are not met, corrective actions are implemented. However, the correct representation and consideration of both BES and non-BES resources connected to the BPS are considered today. This comments seems more relevant for a SDT comment period as well.<br><br>Therefore the IRPWG Leadership does not believe this change is needed for the SAR. |
| IRPWG Leadership agrees with this comment and has removed this bullet from the Project Scope of the SAR. |
| The IRPWG Leardership agrees with this position and adds to the response above. |

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| The RSTC perviously rejected a combined SAR.  Therefore IRPWG Leadership does not believe it to be appropriate to re-combine. |
| The IRPWG Leadership agrees with the comment and plans to bring up for endorcement at the December RSTC Meeting. |

# TPL-001-5 SAR for BPS-Connected IBRs

## Action
Endorse

## Summary
The NERC SPIDERWG undertook a review of the TPL-001 standard considering the potential impact of DERs. This review is captured in the following RSTC-approved white paper and serves as the technical justification for the revisions suggested in this SAR:

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

This SAR proposes to update TPL-001-5.1 to address some of the issues identified in the white paper. The SPIDERWG brought a SAR to the RSTC in March 2021 which was not endorsed. The SPIDERWG sought and received feedback from RSTC members and addressed the comments and made conforming revisions to the SAR. The SPIDERWG is seeking endorsement of the proposed SAR and subsequent submittal to the Standards Committee for action.

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.

| Requested information | | | |
|---|---|---|---|
| SAR Title: | TPL-001-5.1 Transmission System Planning Performance Requirements | | |
| Date Submitted: | 12/15/2021 | | |
| SAR Requester | | | |
| Name: | Kun Zhu, MISO (NERC SPIDERWG Chair)<br>Bill Quaintance, Duke Energy Progress (NERC SPIDERWG Vice-Chair) | | |
| Organization: | NERC System Planning Impacts from DERs Working Group (SPIDERWG) | | |
| Telephone: | Kun – 317-249-5789<br>Bill – 919-546-4810 | Email: | kzhu@misoenergy.org<br>william.quaintance@duke-energy.com |
| SAR Type (Check as many as apply) | | | |
| ☐ New Standard<br>☒ Revision to Existing Standard<br>☒ Add, Modify or Retire a Glossary Term<br>☐ Withdraw/retire an Existing Standard | | ☐ Imminent Action/ Confidential Issue (SPM Section 10)<br>☐ Variance development or revision<br>☐ Other (Please specify) | |
| Justification for this proposed standard development project (Check all that apply to help NERC prioritize development) | | | |
| ☐ Regulatory Initiation<br>☒ Emerging Risk (Reliability Issues Steering Committee) Identified<br>☐ Reliability Standard Development Plan | | ☒ NERC Standing Committee Identified<br>☐ Enhanced Periodic Review Initiated<br>☒ Industry Stakeholder Identified | |
| Industry Need (What Bulk Electric System (BES) reliability benefit does the proposed project provide?): | | | |
| Many areas of the North American BES are experiencing increasing penetrations of distributed energy resources (DERs). 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 were significantly lower than current and future projections.<br><br>Considering current trends, the NERC SPIDERWG undertook a review of the TPL-001 standard considering the potential impact of DERs. This review is captured in the following RSTC-approved white paper and serves as the technical justification for the revisions suggested in this SAR:<br>• SPIDERWG: Assessment of DER impacts on NERC Reliability Standard TPL-001 (here) | | | |

[1] The scope of recent modifications to TPL-001-5 did not include considering the impacts of DER on BPS planning.

## Requested information

This SAR proposes to update TPL-001-5.1 to address some of the issues identified in the white paper.

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. As the penetration of DERs increases, and based on the DER data and models available, Planning Assessments should include DERs that can potentially impact Transmission System performance assessment. NERC's "Lesson Learned: Single Phase Fault Precipitates Loss of Generation and Load", evaluating a 2019 frequency event in Southern England 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.[2] In July 2020, a significant quantity of solar PV facilities across a large geographic area in Southern CA reduced about 1000 MW output due to a disturbance on the bulk power system[3]. 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 the BES should be included in planning assessments if DER data and models are available. Any choice to exclude the consideration of the impact of DER on the BES should be supported by a technical rationale and/or 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 to ensure the accuracy of Transmission System Planning Assessments.

**Project Scope (Define the parameters of the proposed project):**

As identified by SPIDERWG, the following sections of TPL-001-5.1 should be revised to ensure the accuracy of Transmission System Planning Assessments:

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 if data and models are available. The SDT can consider whether a threshold needs to be established.
c. R4.1.1 and 4.1.2, the stability performance criteria should be applicable to both synchronous and asynchronous generation, inclusive of DER.

[2] https://www.nerc.com/pa/rrm/ea/Lessons%20Learned%20Document%20Library/LL20201001_Single_Phase_Fault_Precipitates_Loss_of_Generation_and_Load.pdf
[3] https://www.nerc.com/pa/rrm/ea/Pages/July_2020_San_Fernando_Disturbance_Report.aspx

| Requested information |
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| d. R4.3.2, the list of dynamic control devices should include DER 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[4] 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:<br><br>a. R2.1 and R2.2, the use of phrase "System peak Load"<br><br>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. As such, there is a need for individual TPs to be required to document and define their peak load conditions (e.g., gross or net) in their assessments. 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.<br><br>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 if data is available. The SDT can consider whether a threshold needs to be established.<br><br>The terms "generators" in Sub-requirements 3.3.1.1 and 4.3.1.2 should be clarified. DERs that are explicitly modeled as generators 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 consider inclusion in the assessment any assumptions made in estimating DER bus voltage.<br><br>c. R4.1.1 and 4.1.2, the stability performance criteria should be applicable to both synchronous and asynchronous generation, inclusive of DER.<br><br>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). However, large amounts of asynchronous DER tripping on low/high voltage/frequency conditions |

[4] 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 |
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| can also adversely affect BES 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. It is recommended to expand the stability performance criteria to include both synchronous and asynchronous generation.<br><br>d. R4.3.2, the standard should recognize that the list of dynamic control devices should consider the expected automatic operation of DER (e.g., DER tripping, dynamic voltage and frequency controls, momentary cessation, etc.) in stability analyses. The SDT can consider adding asynchronous generator related devices like inverter, plant controller, 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 will increase as Transmission System Planning Assessments reflect additional dynamic components and controls. It is anticipated that this cost will vary depending on training, tools, scenario development, and other factors in each Planning Coordinators and Transmission Planners' area. |
| 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 primarily impact Transmission System Planning Assessments, not any specific BES facilities, although as individual IBRs continue to increase in size (e.g. 14MW wind turbines), there may be some impact in the near future. |
| 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. Additionally, Distribution Providers, Generator Owners, and DER aggregators participating in markets- i.e. not an applicable entity to this standard, would be useful to include. |
| Do you know of any consensus building activities[5] in connection with this SAR? If so, please provide any recommendations or findings resulting from the consensus building activity. |
| This SAR is the outcome of the following white paper that was developed by the NERC technical sub-group under the RSTC. |

[5] Consensus building activities are occasionally conducted by NERC and/or project review teams. They typically are conducted to obtain industry inputs prior to proposing any standard development project to revise, or develop a standard or definition.

| Requested information |
|---|
| • SPIDERWG: Assessment of DER impacts on NERC Reliability Standard TPL-001 (here)<br><br>Deliverables, and the key findings and recommendations contained within, were thoroughly reviewed and approved by the RSTC. |
| 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 white paper, 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 |

| Market Interface Principles | |
|---|---|
| 2. A reliability standard shall neither mandate nor prohibit any specific market structure. | Yes |
| 3. A reliability standard shall not preclude market solutions to achieving compliance with that standard. | Yes |
| 4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards. | Yes |

| Identified Existing or Potential Regional or Interconnection Variances | |
|---|---|
| Region(s)/ Interconnection | Explanation |
| None | None |

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| SAR Status Tracking (Check off as appropriate). | |
|---|---|
| ☐ Draft SAR reviewed by NERC Staff<br>☐ Draft SAR presented to SC for acceptance<br>☐ DRAFT SAR approved for posting by the SC | ☐ Final SAR endorsed by the SC<br>☐ SAR assigned a Standards Project by NERC<br>☐ SAR denied or proposed as Guidance document |

**Version History**

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| 3 | February 22, 2019 | Standards Information Staff | Added instructions to submit via Help Desk |
| 4 | February 25, 2020 | Standards Information Staff | Updated template footer |

**Brian Evans-Mongeon:**

20210312 TPL SAR with comments.docx

**David Jacobsen:**

There was an action item to document what changes might be suggested to allow the TPL-001-5 to pass a vote. Here are some quick thoughts. I'm willing to work with the group to explore further.

R2.1 and R2.2 – System peak load; The TPL assessment is made on models developed through the MOD-032 process. If changes to the peak load case definition is required, it should start there. In general, the peak is based on a 50:50 forecast and considers expected demand side management and available DER levels for a net load representation. Attachment 1 of MOD-032 notes that the Load Serving Entity should provide aggregate demand for steady state models. The MOD-032 load is quite often derived from MOD-031-2.

R3.3.1.1 and R4.3.1.2 – Modelling tripping of DER assumes that DER is specifically modelled in all TPL assessment models. Currently these models are not being created through the MOD-032 process. Steady state models likely assume net load representations.

R3.3.1.1 and R4.3.1.2 – From a BES point of view, GSU still works for large installations. Currently only 20 MVA generators meet the BES definition for being modelled. The proposed aggregate DER model (U-DER, R-DER) perhaps should be considered.

R4.1.1 and R4.1.2 useful to clarify in regards to large IBR with specific models at minimum. The BES definition is currently limited to gross plant rating greater than 20 MVA or aggregate rating greater than 75 MVA. An IBR that meets this BES criteria should have a specific model provided for MOD-032 and be assessed in TPL.

R4.3.2 not sure that DER power plant controller controls need this granularity. Should consider aggregate DER models and ability to model based on particular vintage of controls.

Overall, the SAR implies that all models being assessed in the TPL standard will fully include DER models for steady state and dynamic models. As an initial phase, perhaps a sensitivity analysis could be added to 2.4.3. Currently dynamic load model assumptions are listed as a sensitivity case. The NERC load modelling task force has been working with industry to help develop models for testing in these studies.

**Commented [ZC(1]:** SPIDERWG Review Finding on the TPL-001-5 R1 "…The models shall use data consistent with that provided in accordance with the MOD-032 standard, supplemented by other sources as needed…" concluded that
*The existing language does not preclude consideration of DER.*
*The existing language is clear for consideration of DER.*
In other words, the MOD-032 process is sufficient in providing the system net peak load required from this SAR.

**Commented [ZC(2]:** The solution is, only model tripping of DERs with models available for now. With the time being, gradually include others with model information improving. Some entities set a threshold of MW value above which the detailed DER model is required. We can model tripping of DERs with MW capacity above that threshold and have models available.

**Commented [ZC(3]:** This is an item that IRPWG identified and will be removed from this SAR.

**Commented [ZC(4]:** We are trying to include DERs which are non-BES resources in TPL-001 planning assessment. This paragraph is talking about BES resources.

**Commented [ZC(5]:** This is an item that IRPWG identified and will be removed from this SAR.

**Commented [ZC(6]:** The SAR intends to apply the changes to DER with model information available.

The MMWG will be releasing one out year case with dynamic load models included for TPL assessments. This type of gradual approach for DER dynamic aggregate models should also be taken.

**Marc Child:**

I do not have any issue with the 'why' for the SAR but struggle with the how it can be effectively implemented. Currently we do not have any requirements to account for non-BES connected energy resources let alone DER resources. This could be a loophole in the SAR that should also be closed. I also think a more rigorous analysis on the cost impacts are warranted. The cost impact section of the SAR could be expanded and more defined. It states that these costs are unknown and costs may increase for PCs and TPs. They will definitely increase with the additional modelling requirements and analysis that will need to be performed based on the suggested changes to the Standard. At the very least, the "may" should be changed to "will".

**Commented [ZC(7]:** The cost will be case by case and hard to generalize.

**Commented [ZC(8]:** Changed.

I think the most glaring issue is the section on identifying which functional entities the Standard would apply to. Some of these requirements for the data collection necessary for these advanced modelling efforts will need to come from the DER asset owners. I am not sure which functional group they currently fall under. Are they GOs or DPs? Probably neither by current NERC definition. This may be a big problem with the enforcement of this Standard since the modelling effort will only be as good as the data provided by the owners of this data.

**Commented [ZC(9]:** This is not a standard for modeling although model plays an important role in the outcomes of the planning studies. Added some language about threshold MW that entities used for collecting models. The planning assessment changes will only apply to DERs with models available.

**Todd Lucas:**

TPL-001 SAR COMMENTS.docx

I would suggest that Carl's comments (below) be addressed even though they are after the requested submission date. To move the SAR forward SPIDERWG will need as much support as we can get from the various RSTC members who did not support it originally.

Thanks,

W

**From:** Carl Turner <Carl.Turner@fmpa.com>
**Sent:** Wednesday, June 09, 2021 10:57 AM
**To:** Wayne Guttormson <wguttormson@saskpower.com>
**Subject:** EXTERNAL EMAIL: RE: SPIDERWG TPL SAR

**EXTERNAL EMAIL:** Take extra caution when clicking links or opening files. Report any suspected phishing.

Wayne,

As mentioned yesterday, here are my comments on the SPIDERWG portions of the TPL-001 SAR that was proposed at our March Meeting. I'll go through in order from Project Scope section of the SAR:

a. **R2.1 and R2.2, the use of phrase "System peak Load"**
   I. Agree this is an issue. Worried about whether industry has worked out "best practices" yet. The SAR says "the most stressed load driven condition of the overall transmission system should be defined by the net load rather than the gross load." I worry that will lead to them simply changing the base case load required in the standard to "net" without adding any nuance to it. I think we needed a few years of having planners study both scenarios as sensitivities – for small systems with little DER (there are still some out there), showing evidence they used net load would not be worth the effort. I think is somewhat non-conservative to say that net load is the "most stressed" – I think we mean it is the "most likely" stressed condition. At least for certain load pockets, we can expect that brief cloud cover on an otherwise hot day would potentially be worse than net load, but not as high as gross load.
   II. In short – I think I can support this item but I really would have rather seen us have several years of solid industry experience studying sensitivities with both gross and net, and at different times of day (in model space) for the peak, before we as industry attempted to change TPL-001-5 because this standard is the basis for a large amount of annual study work. To get rid of the lack of clarity in the standard, we could have just requested the PC explicitly determine through study

**Commented [ZC(10]:** How about we change the SAR to "include net load as sensitivity study"?

**Commented [SB11R10]:** I don't think that we should include net load as sensitivity study. For the baseline peak load (stressed load driven) condition, net peak should be used. If the system has little DER, then the net peak and gross peak would be very similar. If the system has high DER, I agree that cloud cover during gross load period could be of a concern. This can be studied as a sensitivity.

whether gross or net or more appropriate for their footprint (having studied both). We do this today with the stability studies where we say that we are studying those contingencies that produce the most severe results, which implies that PC's and TP's need to be running a larger number of simulations on their own to be sure they are picking the worst-case events.

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*)**
   I. This makes sense, technically, but we may be out over our skis. My concern is almost no-one besides perhaps the major pockets have fully switched to the integrated DER / CMLD modeling that NERC has been working on. Our recommendation here seems to be requiring activities that would be best performed once this model is implemented and that would be difficult to do efficiently without it.

c. **R3.3.1.1 and R4.3.1.2, the use of the term "GSU transformer" (NERC IRPTF white paper recommendation)** – No concerns on this one moving forward since it is now separated out.

d. **R4.1.1and 4.1.2, the stability performance criteria only applicable to synchronous generators (recommendation from both white papers)** – I am supportive of including improvements on this and agree the terms such as "pulls out of synchronism" need to be updated or supplemented.

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)**
   I. I have the same concern here as I did on item b above – We don't yet have wide adoption and use of the tools that are required to demonstrate compliance with this, unless I've missed something. Maybe if we put the target adoption as a long-term implementation plan, but even then I'd prefer that industry had started using these tools and had practices established.

**Commented [ZC(12]:** The revised SAR only includes those DER or aggregated DER that are already modeled in the case.

**Commented [ZC(13]:** The revised SAR removed the "**include power plant controller and inverter controls**" part since that belongs to the IRPWG SAR, and only requires to consider the DERs with dynamic models already included in the case.

Happy to discuss – I'll try and be more responsive in the future.

Regards

Carl

Carl J. Turner, PE

Engineering Services Director

_____

Direct: 321-239-1054

Florida Municipal Power Agency

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# MOD-032 SAR

## Action
Endorse

## Summary
The original MOD-032 SAR was endorsed by the NERC Planning Committee (PC) in 2020 after reviewing its technical content. The NERC Standards Committee (SC) formed a SAR drafting team (SDT) which deemed the SAR flexible enough for future SDT work. The SAR was posted for industry comments. The SC subsequently rejected the SAR due to "insufficient support" and the SDT dismissed. The SPIDERWG believes a reliability gap still exists. The RSTC Executive Committee approved the SPIDERWG to revise the SAR. The SPIDERWG updated the SAR and developed a clarifying document for industry. The ISO/RTO Council has also written a letter of support (included in the agenda package) of the SPIDERWG efforts to develop mandatory provisions to compel Distribution Providers to provide Distributed Energy Resource (DER) data to reliability entities in support of accurate and comprehensive reliability studies, specifically SPIDERWG's request to revive the SAR for Project 2020-01: Modifications to MOD-032: Data for Power System Modeling and Analysis. The SPIDERWG is resubmitting the SAR for RSTC endorsement and subsequent SC action.

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# Standard Authorization Request (SAR)

Complete and submit this form, with attachment(s) to the NERC Help Desk. Upon entering the Captcha, please type in your contact information, and attach the SAR to your ticket. Once submitted, you will receive a confirmation number which you can use to track your request.

The North American Electric Reliability Corporation (NERC) welcomes suggestions to improve the reliability of the bulk power system through improved Reliability Standards.

| Requested information | | | |
|---|---|---|---|
| SAR Title: | MOD-032-1 Data for Power System Modeling and Analysis | | |
| Date Submitted: | 12/15/2021 | | |
| SAR Requester | | | |
| Name: | Kun Zhu (NERC SPIDERWG Chair)<br>Bill Quaintance (NERC SPIDERWG Vice Chair) | | |
| Organization: | Kun Zhu – MISO<br>Bill Quaintance – Duke Energy Progress | | |
| Telephone: | Kun – 317-249-5789<br>Bill – 919-546-4810 | Email: | kzhu@misoenergy.org<br>william.quaintance@duke-energy.com |
| SAR Type (Check as many as apply) | | | |
| ☐ New Standard<br>☒ Revision to Existing Standard<br>☐ Add, Modify or Retire a Glossary Term<br>☐ Withdraw/retire an Existing Standard | | ☐ Imminent Action/ Confidential Issue (SPM Section 10)<br>☐ Variance development or revision<br>☐ Other (Please specify) | |
| Justification for this proposed standard development project (Check all that apply to help NERC prioritize development) | | | |
| ☐ Regulatory Initiation<br>☒ Emerging Risk (Reliability Issues Steering Committee) Identified<br>☐ Reliability Standard Development Plan | | ☒ NERC Standing Committee Identified<br>☐ Enhanced Periodic Review Initiated<br>☒ Industry Stakeholder Identified | |
| Industry Need (What Bulk Electric System (BES) reliability benefit does the proposed project provide?): | | | |
| As the penetration of distributed energy resources (DERs) continues to increase across the North American bulk power system (BPS), it is necessary to account for the potential impacts of DERs on reliability in the planning, operation, and design of the BES. The NERC System Planning Impacts of Distributed Energy Resources Working Group (SPIDERWG) has identified the need for improved modeling of aggregate DER for planning studies (including both utility-scale and retail-scale DER) conducted by Transmission Planners (TPs) and Planning Coordinators (PCs). MOD-032-1 addresses the gathering of modeling data to perform planning assessments but the standard currently has no specific reference to DER data. This SAR proposes to update MOD-032-1 to: (1) include "data requirements and reporting | | | |

| Requested information |
| --- |
| procedures"[1] for DER that are necessary to support the development of accurate interconnection-wide models, (2) replace Load-Serving Entity (LSE) with Distribution Provider (DP) because of the removal of LSEs from the NERC registry criteria, (3) enable the SDT to review any additional gaps in DER data collection with the de-registration of LSE. |
| Purpose or Goal (How does this proposed project provide the reliability-related benefit described above?): |
| This SAR proposes to revise MOD-032-1 to address gaps in data collection for the purposes of modeling aggregate levels of DERs in planning assessments. The goal is to provide clarity and consistency for data collection across PCs and TPs when coordinating with the DP to gather aggregate load and aggregate DER data. |
| Project Scope (Define the parameters of the proposed project): |
| The proposed scope of this project is as follows:<br>a. The table in Attachment 1 should be updated to include DER in the steady-state and dynamics columns. Details of the changes to be considered by the Standard Drafting Team are included in the "Detailed Description" below.<br>b. Based on item a.) and the detailed description below, the SDT should consider whether including a definition for "Distributed Energy Resource (DER)" in the NERC Glossary of Terms is necessary.<br>c. In alignment with the SAR submitted by the previous NERC Essential Reliability Services Working Group (ERSWG), LSE should be removed and replaced by DP as the applicable entity in Section 4.1.3 and all instances in the standard requirements and attachments.<br>d. The SDT should review any potential gaps regarding data collection for aggregate DER data with the de-registration of LSE or based on applicability transfer from LSE to DP (item c in this list). |
| 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[2] 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): |
| This SAR proposes to address the issues identified in the project scope above. Specifically, the following details should be considered and addressed by the drafting team:<br>• In the Applicability section of MOD-032-1, LSE should be replaced with DP, in alignment with the SAR previously submitted by ERSWG. Similarly, all relevant uses of LSE should be replaced with DP. |

[1] See Requirement R1 of MOD-032-1, which requires each TP and PC to develop data requirements and reporting procedures for the collection of modeling data used for the development of models for each PC footprint.
[2] 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 |
| --- |
| ▪ The table in Attachment 1 should include references to aggregate DER in the steady-state and dynamics columns. The drafting team should consider the data needed for modeling aggregate DER for the purposes of reliability studies. In particular, the drafting team should consider the recommendations set forth in *NERC Reliability Guideline: DER Data Collection for Modeling in Transmission Planning Studies*.<br>• Note that the SPIDERWG does not see a need to modify the short circuit column of Attachment 1 because #1 already states "all applicable elements" in the steady-state column should have necessary information related to positive, negative, and zero sequence data provided accordingly. If the TP/PC determines that aggregate DER is needed for these studies, then they have the capability to request such data. However, this is not a prevalent issue currently.<br>• In alignment with adding "DER" to the Attachment 1 table regarding necessary data for modeling purposes, it may be needed (based on the discretion of the SDT) to add a definition for "Distributed Energy Resource (DER)" to the NERC Glossary of Terms.<br>As stated, SPIDERWG has published *NERC Reliability Guideline: DER Data Collection for Modeling in Transmission Planning Studies* that includes recommended practices and for the collection of aggregate DER data for transmission planning studies. **These materials are not intended to dilute the criticality of this SAR to address the issues identified above within MOD-032-1 itself. Rather, the SDT can use these materials when determining the specific language for inclusion in the standard requirements revisions.** |
| Cost Impact Assessment, if known (Provide a paragraph describing the potential cost impacts associated with the proposed project): |
| Cost impacts are not fully known. However, due to the limited scope of the requested data, cost impact is expected to be minimal to all entities. DPs typically collect the information need to model aggregate levels of DERs in planning assessments. Therefore, data collection effort by the DP would be minimal additional effort. DPs already have processes to provide load data to the TP and PC, so DER data can be managed in a similar manner to reduce cost and effort. If the scope of the required data is expanded, cost impact would likely increase. |
| Please describe any unique characteristics of the BES facilities that may be impacted by this proposed standard development project (*e.g*. Dispersed Generation Resources): |
| DER owners are not subject to NERC Reliability Standards. However, SPIDERWG believes the DP (a NERC Registered Entity) has the information regarding DER connected to its distribution system that is needed for modeling the aggregate behavior of DER for the purposes of BES reliability planning studies. The DP should provide that information to the TP and PC accordingly. |
| 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): |
| Transmission Planner, Planning Coordinator, Distribution Provider |

| Requested information |
|---|
| While not a Functional Entity per the NERC Functional Model, the "MOD-032 Designees" that are designated by the ERO to develop interconnection-wide base cases (i.e., the Regional Entities), will also be affected by these changes and should be considered for appointment to the Standard Drafting Team. |
| Do you know of any consensus building activities[3] in connection with this SAR? If so, please provide any recommendations or findings resulting from the consensus building activity. |
| The proposals in this SAR were developed by the NERC SPIDERWG, a stakeholder group under the NERC Planning Committee. |
| 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)? |
| The ERSWG submitted a SAR related to MOD-032-1, as described above. This SAR supports those changes, and further expands on a few necessary additional changes related to DER modeling. |
| Are there alternatives (e.g. guidelines, white paper, alerts, etc.) that have been considered or could meet the objectives? If so, please list the alternatives. |
| The NERC SPIDERWG is preparing a Reliability Guideline on data collection for DER modeling. That guideline will provide recommendations for improvements to the data requirements and reporting procedures developed jointly by PCs and their TPs. However, updates to MOD-032-1 are also needed to ensure minimum planning consideration and reporting requirement on DER, particularly in Attachment 1. Therefore, this SAR aligns with the necessary changes to meet the objective. |

| 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. |

[3] 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.

| Reliability Principles | |
|---|---|
| ☐ | 6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions. |
| ☐ | 7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis. |
| ☐ | 8. Bulk power systems shall be protected from malicious physical or cyber attacks. |

| Market Interface Principles | |
|---|---|
| Does the proposed standard development project comply with all of the following Market Interface Principles? | Enter (yes/no) |
| 1. A reliability standard shall not give any market participant an unfair competitive advantage. | Yes |
| 2. A reliability standard shall neither mandate nor prohibit any specific market structure. | Yes |
| 3. A reliability standard shall not preclude market solutions to achieving compliance with that standard. | Yes |
| 4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards. | Yes |

| Identified Existing or Potential Regional or Interconnection Variances | |
|---|---|
| Region(s)/ Interconnection | Explanation |
| None | None |

# For Use by NERC Only

| SAR Status Tracking (Check off as appropriate) | |
|---|---|
| ☐ Draft SAR reviewed by NERC Staff<br>☐ Draft SAR presented to SC for acceptance<br>☐ DRAFT SAR approved for posting by the SC | ☐ Final SAR endorsed by the SC<br>☐ SAR assigned a Standards Project by NERC<br>☐ 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 |

**Date:** November 18, 2021

Stephen Crutchfield, NERC staff for Reliability and Security Technical Committee (RSTC)
Stephen.Crutchfield@nerc.net
Greg Ford, RSTC Chair greg.ford@gasoc.com
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**NERC**
3353 Peachtree Road NE
Suite 600 North tower
Atlanta, GA 30326

**Subject:** Request to Revive the Standards Authorization Request (SAR) for Modifications to MOD-032 as requested by the System Planning Impacts from DER Working Group (SPIDERWG)

Dear Sirs:

The ISO/RTO Council (IRC) Standards Review Committee (SRC)[1] is writing this letter in support of the System Planning Impacts from DER Working Group's (SPIDERWG) efforts to develop mandatory provisions to compel Distribution Providers to provide Distributed Energy Resource (DER) data to reliability entities in support of accurate and comprehensive reliability studies, specifically SPIDERWG's request to revive the Standard Authorization Request (SAR) for Project 2020-01: Modifications to MOD-032: Data for Power System Modeling and Analysis.

As background, SPIDERWG justified the original SAR to provide aggregated DER data due to the increasing penetration of DERs across the continent and the associated risk aggregated DERs pose to reliability if planners are unable to accurately model DERs and their response to system dynamics. The need to address this risk persists as identified in the recently released **2021 ERO Reliability Risk Priorities Report** under Risk 1 – Grid Transformation, there is a related bullet:

"*Coordination of DERs with the BPS: Distributed generation and storage (including behind the meter DERs and other DER technologies) currently follow local interconnection requirements and operational protocols that pose potential challenges to the BPS from a planning and forecasting perspective as penetration levels increase.*"[2]

[1] For purposes of this letter, the IRC SRC comprises the following independent system operators ("ISOs") and regional transmission organization ("RTOs"): California Independent System Operator ("CAISO"), the Independent Electricity System Operator of Ontario, Inc. ("IESO"), ISO New England Inc. ("ISO-NE"), Midcontinent Independent System Operator, Inc. ("MISO"), New York Independent System Operator, Inc. ("NYISO"), PJM Interconnection, L.L.C. ("PJM") and Southwest Power Pool, Inc. ("SPP").
[2] **2021 ERO Reliability Risk Priorities Report**, page 24.

The report goes on to acknowledge that mitigating this risk is key to ensuring reliable performance and that a needed step in accomplishing this goal is to "*Update data, modeling and assessment requirements to ensure valid and accurate results given resource and grid transformation*." [3]

Unfortunately, the initial SAR was rejected by the NERC Standards Committee in December 2020 citing that, based on industry comments received during posting, there is *insufficient stakeholder support* for this project and continued revisions of the SAR would not be productive. That said, industry comment did not negate the reliability need for the data to perform accurate and comprehensive modeling. Rather, the lack of industry support arose from the fact that many utilities are able to acquire aggregated DER data from other division within their own organization that perform the Distribution Provider function. In contrast, independent companies, such as ISO/RTOs and independent transmission companies, do not have this capability.

The MOD-032 project is one example of how RCs and ISO/RTOs are tasked with performing planning and operational studies to ensure overall grid reliability, including stable frequency and energy balance, yet are not afforded the means to compel Distribution Providers to provide the aggregated DER data in a consistent and standardized format necessary to achieve these goals. The IRC SRC strongly supports projects such as MOD-032, if the scope and standard revisions are sufficient to allow aggregated DER data to be made available directly to RTO/ISOs from Distribution Providers, or other appropriate entity(ies) as determined through the standards drafting process.

The IRC SRC supports the NERC ANSI accredited process for standards development as it ensures the ability for all impacted parties to have their concerns addressed; however, we would like to see the process be improved in its ability to develop reliability requirements which provide the best reliability outcomes and less about the best compliance outcomes. The ability for parties to challenge proposed requirements is important – but not to the extent that reliability objectives are not met or achieved.

For these reasons, the **IRC SRC requests that NERC revive the Standard Authorization Request (SAR) for Project 2020-01: Modifications to MOD-032: Data for Power System Modeling and Analysis as requested by the SPIDERWG** so Planning Coordinators can obtain and utilize the necessary aggregated DER data that Distribution Providers are best situated to provide.

Thank you for your consideration.

Sincerely,

Bobbi Welch

(Acting) Chair, ISO/RTO Council Standards Review Committee

**Cc:**
Amy Casuscelli, Standards Committee (SC) Chair Amy.R.Casuscelli@xcelenergy.com

---

[3] **2021 ERO Reliability Risk Priorities Report**, page 18 and page 25.

Todd Bennett, SC Vice Chair tbennett@aeci.org
Kun Zhu, SPIDERWG Chair kzhu@misoenergy.org
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# Clarifications for MOD-032 SAR Resubmittal

NERC SPIDERWG – December 2021

## Executive Summary

This document provides the reasoning behind the MOD-032 standard authorization request (SAR) resubmission by the NERC System Planning Impacts from Distributed Energy Resources Working Group (SPIDERWG) and is intended to accompany the SAR at all stages to clarify any areas of confusion regarding its resubmittal.

The original SAR submitted was rejected by NERC Standards Committee (SC) due to "insufficient stakeholder support". However, many entities that submitted 'No' vote did not realize the flexibility given in the SAR language. The SAR Drafting Team (SAR DT) intentionally kept the original SAR language, because these flexibilities would allow the DT to collaborate with the industry to determine the best requirement language. Many 'against' comments would not become the reason to forfeit the DT's opportunity to work on this SAR when such flexibilities are considered.

This document reviews some common concerns and provides clarifications to common misunderstandings and unnecessary fears. Examples are:

- Reliability Guideline vs. SAR;
- The use of the 'other' data category in the existing standard;
- Jurisdiction and confidentiality issues;
- Aggregate vs individual DER data;
- DER definition inclusion.

The SAR is also revised to further soften the tones to address a few concerns.

A power system served by a considerate amount of DER is imminent. A revised MOD-032 SAR to ensure DER data transfer is critical in achieving a reliable and resilient BES in the future, especially when a large area of the power grid is overseen by transmission-only entities such as ISO, RTO, and Independent Transmission Companies. Given the time a standard revision takes, the time to act is now.

## Background on SAR DT Efforts

In its original work plan, SPIDERWG identified updates to the NERC MOD-032-1 standard as a high priority task and developed the SAR that was subsequently endorsed by the NERC Planning Committee in September 2019. The NERC SC accepted the SPIDERWG MOD-032 SAR for posting at the March 2020 meeting.[1] Project 2020-01 posted the SAR for an informal comment period and the SAR Drafting Team (SAR DT) reviewed all comments received per the NERC Standards Process Manual Appendix 3A section 4.2. The drafting team compiled the comments and posted the results, broad themes of the comments, and individual responses on their project page.[2] The SAR DT stated that the SAR was appropriately worded to accommodate the broad sets of comments received, and therefore did not revise the SAR in response to such comments since they were appropriately scoped. This record was presented at the December 2020 NERC SC meeting. Based on this activity and some potential confusion[3] regarding comments on the SAR, it was rejected "on the grounds that based on the comments received during posting, there is insufficient

[1] https://www.nerc.com/comm/SC/Agenda%20Highlights%20and%20Minutes/SC_March_Meeting_Minutes_Approved_April_22_2020.pdf

[2] See here, here, and here, respectively.

[3] Additionally, it came to light that certain original negative votes on the comment spreadsheet submitted during SAR posting, appeared to voice support for concepts in the SAR generally at the meeting in which the SAR was rejected. This indicates that there may have been some confusion regarding the intended comments.

stakeholder support for this project."[4,5] Per the NERC Standards Process Manual (SPM), this informed the SAR submitter (i.e., SPIDERWG) of the rejection and directed the SAR DT to end work on Project 2020-01.

## SPIDERWG Review

SPIDERWG reviewed the common themes of industry comments developed by the SAR DT, reviewed the individual comments by industry members, and believes that the SAR should be revised and re-submitted in a manner that can allow a future Standards Drafting Team (SDT) to proceed with edits to address risks presented with increasing integration of DERs. SPIDERWG has attached this review in detail to the document in Attachment 1. In particular, the proposed revised SAR considers comments received and made necessary changes, still enabling effective transfer and communication of aggregate DER data between Distribution Provider, Transmission Planners, and Planning Coordinators for performing long-term planning assessments.

Since the SAR was submitted, FERC issued Order 2222[6] that further increased the need of obtaining DER data for transmission impact analysis. While individual regional transmission organizations (RTOs) are still working on Order 2222 compliance, the strong need for visibility and use of aggregate DER data is a common theme in transmission level studies. This also warrants review of the MOD-032 SAR.

In its review of the comments and general themes submitted to the SAR DT, SPIDERWG identified some confusion among industry members on how planning models are created, the increasing level of DERs across North America, and the support among SPIDERWG members to facilitate data transfer of DER information to Registered Entities for accurate planning assessments (particularly long-term planning studies). Multiple planning organizations have expressed the value and importance of aggregate DER information and that revisions to Reliability Standards to support analysis in this area would be critical.

Comments on the TPL-001 SAR provided by RSTC members highlighted a compliance risk regarding the lack of DER data with respect to performing adequate planning assessments using aggregate DER models. While SPIDERWG focuses on the technical aspects and not on compliance risk, SPIDERWG also agrees that modifying MOD-032 to ensure transfer of aggregate DER information would support (and can be done in tandem with) a SAR proposing revisions to TPL-001 regarding clarifications for accounting for DERs. Revising and reintroducing the MOD-032 SAR would address certain concerns raised at March 2021 RSTC comments on combining the inverter-based resource performance working group (IRPWG) and SPIDERWG SAR on TPL-001 which recognized the connection between these two Reliability Standards.

## List of Changes Made

The SPIDERWG has made the changes to the SAR language, summarized in this section.

- Removal of the detailed set of information reported in the Detailed Scope section
- Removal of "as they become available" for materials as they currently are published
- Alteration of language in the purpose/goal section from "interconnection wide case creation regarding DER" to generalized language such as "perform planning assessments" and "for the purposes of modeling aggregate levels of DER". Such language changes soften the tone in the SAR.

[4] https://www.nerc.com/pa/Stand/Project_202001_Modifications_to_MOD0321/SC%20Response%20to%20SPIDERWG%20SAR%20MOD-032-1.pdf

[5] Per the Standards Process Manual: "While there is no established limit on the number of times a SAR may be posted for comment, the Standards Committee retains the right to reverse its prior decision and reject a SAR if it believes continued revisions are not productive. The Standards Committee shall notify the sponsor in writing of the rejection within 10 days."

[6] https://www.ferc.gov/sites/default/files/2020-09/E-1_0.pdf

- Alteration of the language in the Cost impact section to not assume the types of data collected by Distribution Providers.

# Attachment 1 – SPIDERWG Technical Review of Industry Comments

## SPIDERWG Response to Major and Minor Themes from Project 2020-01 SAR DT Summary

Table 1 shows the major and minor themes from the SAR DT comment period, the response of the SAR DT to the theme, and SPIDERWG's follow-up review and response. These responses serve as the technical basis for SPIDERWG's conclusion to resubmit a revised version of the MOD-032 SAR.

**Table 1: Review and Response to Comment Summary Themes**

| SAR DT Response | SPIDERWG Follow-Up |
|---|---|
| ***Theme 1:*** *Table 1 of MOD-032 Attachment 1 does not need to be updated because "Item 9" already allows the PC or TP the flexibility to request any other information necessary for modeling purposes which includes DER data.* | |
| The SAR DT acknowledges the described concerns from industry in relation to whether adding additional references to aggregate DERs in the information listed in Table 1 of MOD-032 is necessary and those comments will be considered by the SDT in the development of any additions or modifications. The SAR DT feels that there is enough flexibility in the SAR language to empower the SDT to develop a risk-based, balanced outcome which takes in to consideration the issues and concerns that are representative of multiple entities and regions with an appropriate amount of industry outreach and feedback. | The "Item 9" already allowing for PC or TP flexibility to model risks specific to their system should not be conflated with it being a catch-all used for any changes hereafter associated with the BPS. Rather, SPIDERWG believes the standard should be revised to provide clarity and consistency for entities to ensure that data at the distribution level is made available, in aggregate, for BES reliability studies conducted by the TP and PC. This is similar to how load level and load forecast data are collected to populate study models. Aggregate information is collected, not individual data points. And appropriate data requirements are created by the TP and PC to effectively facilitate that type of data transfer. The same is needed for DER, as their penetration is rapidly growing. From a risk-based perspective, this is an important area to ensure TPs and PCs can effectively conduct studies in the future. |
| ***Theme 2:*** SAR is too prescriptive and proposed revisions are potentially over burdensome.<br>• Potential jurisdictional issues (not allowed to request, state requirements, etc.) with collecting is data since this is non-Bulk Electric System (BES) generation with references to retail scale DER.<br>• Entities that TP would rely on to provide data may not be NERC Functional Entities (e.g. small DP's that are not registered entities).<br>• PC/TP should be allowed to develop data specifications jointly with DP.<br>• DPs may not have the data, software, expertise, or forecasting ability.<br>• Should not require BES level modeling data for non-BES DER.<br>• Responsibility of BES modeling should not be placed on DPs who operate non-BES components.<br>• Unknown cost impact may not be minimal as stated.<br>• No technical justification to demonstrate a reliability gap exists with existing MOD-032. | |

| Table 1: Review and Response to Comment Summary Themes | |
|---|---|
| **SAR DT Response** | **SPIDERWG Follow-Up** |
| The SAR DT acknowledges the described concerns of the industry in relation to responsible entities, prescriptiveness, and potential technical justifications and will incorporate the comments as considerations for developing requirement language with an appropriate amount of flexibility. The SDT will strive to create language that is not too prescriptive for an entity, overly burdensome, or unreasonable to implement. In addition, the SAR DT feels there is technical justification supporting the SAR outlined in the *NERC Reliability Guideline: DER Data Collection for Modeling in Transmission Planning Studies*. The SAR DT feels that there is enough flexibility in the SAR language to empower the SDT to develop a risk-based, balanced outcome which takes in to consideration the issues and concerns that are representative of multiple entities and regions with an appropriate amount of industry outreach and feedback. This would include further investigation into the technical justifications. | SPIDERWG does not believe the SAR is too prescriptive and believes that the comments are more suitable for a SDT effort, not a SAR drafting team effort. As stated, aggregate load information is collected to populate TP and PC models; this information can be collected for aggregate DERs as well. There are no known "jurisdictional issues" with collecting aggregate load information for TP and PC BES study purposes. DPs should have aggregate DER information available as they interconnect DERs to their system. Resource planners and other external information can help populate future projections (again, as is done with demand levels and load data). The joint specifications are not how the standard is currently implemented – the current TP and PC specifications for modeling information is suitable and SPIDERWG is not seeking to change that. DPs not having necessary information to conduct critical studies for BES reliability should not be a suitable justification for this information to not be collected. In fact, currently DPs who operate non-BES components are expected to and responsible for providing information on those components that impact the reliable operation of the BES. Industry needs to address this issue immediately to ensure this data is available for studies. The points made regarding BES and non-BES are irrelevant to modeling and studies conducted by TPs and PCs. Aggregate data for non-BES (and even distribution-level) systems/load/resources are modeled today and have been for many years. |
| ***Theme 3:*** MOD-032 language is too broad to ensure the responsible entity provides all necessary data without long iterative negotiations with individual entities, resulting in inadequate data and modeling delays.<br>THEME 3 reads essentially as the inverse of THEME 1.<br>• This is particularly true for non-vertically integrated utilities.<br>• Needed to improve quality of system modeling and data exchange which is a major Theme contributing to major reliability events over time.<br>• Does not ensure that all entities will follow industry best practices and include adequate DER modeling data.<br>• Inconsistencies and gaps in aggregated DER modeling data requirements and reporting procedures will likely occur in absence of specifications and will negatively affect reliability tasks.<br>• "Item 9" interpretation by entities may or may not give the TP/PC the authority to request DER data. Discussions between entities can often transition into a question/debate about market rules, rather than relying on MOD-032. | |
| The SAR DT acknowledges the comments made by industry that additional references to aggregate DERs in the information listed in Table 1 of MOD-032 is necessary in order to aid in the timely collection of data and those comments will be considered by the SDT in the development of any additions or modifications. The SAR DT feels that there is enough flexibility in the SAR language to empower the SDT to develop a risk-based, balanced outcome which takes in to consideration the issues and concerns that are representative of multiple entities and regions with an appropriate amount of industry outreach and feedback. | SPIDERWG agrees with the SAR DT that there is sufficient flexibility in the SAR language to empower the SDT to develop a suitable standard with appropriate requirements language. SPIDERWG identified these issues as the driving force for this SAR and developed the SAR to address these issues. The lack of clarity and consistency across TP and PC footprints has led to some entities struggling to gather DER-related information for studies effectively. The concepts articulated in the theme are sufficient technical justification for a SAR to address these gaps in modeling data needed to execute TP and PC studies for long-term planning of the BPS. This is particularly critical as the penetration of DERs continues to grow rapidly. |
| ***Theme 4:*** Most comments mention no adequate justification to consider DER definition at this time. In addition, the DER term is not well understood and appropriate detail should be defined somewhere in NERC documents. | |

| Table 1: Review and Response to Comment Summary Themes | |
|---|---|
| **SAR DT Response** | **SPIDERWG Follow-Up** |
| Depending on the requirement language drafted, the SDT will consider whether to include DER as a defined term or if a generally accepted/working definition for DER will be used. As stated in the SAR, "in alignment with adding 'DER' to the Attachment 1 table regarding necessary data for modeling purposes, it may be needed (based on the discretion of the SDT) to add a definition for 'Distributed Energy Resource (DER)' to the NERC Glossary of Terms." Existing available DER definitions and related terms (e.g. DER or aggregate DER) from the SPIDERWG, FERC Order 2222, and other pertinent resources will be considered by the SDT. | The SPIDERWG strongly supports the SAR DT response here. The SAR was crafted to provide flexibility for the SDT to address a term addition, if needed. SPIDERWG has a working definitions document used to guide its DER-related efforts and strongly recommends the working definition for DER that has been developed, if and when a DER definition is needed. However, again, the SAR provides sufficient flexibility and clarity for the SDT to address this if needed. |
| ***Theme 5a:*** A Reliability Guideline allows flexibility for the DP to work with the TP/PC and is a more efficient and effective method to address DER data requests. This and other SPIDERWG work products should be utilized to guide better approaches and methods to data collection and analysis. | |
| The SAR DT acknowledges the comments made in reference to utilization of NERC Reliability Guidelines in lieu of standard modifications at this time. The SAR DT feels that it is appropriate to consider modifications to the standard at this time. There is enough flexibility in the SAR language to empower the SDT to develop a risk-based, balanced outcome which takes into consideration the issues and concerns that are representative of multiple entities and regions with an appropriate amount of industry outreach and feedback. The SAR DT is aware of and has given consideration to the *NERC Reliability Guideline: DER Data Collection for Modeling in Transmission Planning Studies*. | SPIDERWG agrees with the SAR DT in that it is appropriate to address the modeling data gaps and challenges for DER data collection by TPs and PCs by updates to MOD-032. Sole reliance on a reliability guideline will not address the gaps in consistency and clarity that exist in the standard today. Standard revisions are needed. Further, guidelines cannot be used to support meeting NERC's mandatory Reliability Standards. |
| ***Theme 5b:*** Wait for Reliability Guideline to be developed and practiced for a period before evaluating the proposed MOD-032 revisions in the SAR. | |
| The SAR DT acknowledges the comments made by industry in reference to utilization of NERC Reliability Guidelines in lieu of standard modifications at this time. The SAR DT feels that it is appropriate to consider modifications to the standard at this time and that there is enough flexibility in the SAR language to empower the SDT to develop a risk-based, balanced outcome which takes in to consideration the issues and concerns that are representative of multiple entities and regions with an appropriate amount of industry outreach and feedback. The SAR DT is aware of and has given consideration to the *NERC Reliability Guideline: DER Data Collection for Modeling in Transmission Planning Studies*. | SPIDERWG agrees with the SAR DT in that it is appropriate to address the modeling data gaps and challenges for DER data collection by TPs and PCs by updates to MOD-032. Sole reliance on a reliability guideline will not address the gaps in consistency and clarity that exist in the standard today. Standard revisions are needed. Further, guidelines cannot be used to support meeting NERC's mandatory Reliability Standards. |
| ***Theme 6:*** *SAR should give latitude to PC/TP to devise mechanism for collecting DER information needed for its area. Information needed and process required may vary by area/region and penetration levels.* | |

| Table 1: Review and Response to Comment Summary Themes | |
|---|---|
| **SAR DT Response** | **SPIDERWG Follow-Up** |
| The SAR DT acknowledges and will incorporate the comments as considerations for developing requirement language with an appropriate amount of flexibility for PCs/TPs. The SAR DT feels that there is enough flexibility in the SAR language to empower the SDT to develop a risk-based, balanced outcome which takes in to consideration the issues and concerns that are representative of multiple entities and regions with an appropriate amount of industry outreach and feedback. | The current MOD-032 standard "gives latitude to the PC/TP to devise" modeling and data transfer requirements for its area already. However, the lack of consideration of DER-related information is what is being addressed by this SAR. The SAR does not seek to modify the ability of the PC and TP to develop detailed modeling requirements for their footprint. |
| ***Theme 7:*** Most comments were supportive of change from LSE to DP.<br>• This change could be done as a part of five-year review process Project 2017-07 Standards Alignment with Registration.<br>• Need to conduct thorough analysis to ensure DP is the correct replacement for LSE.<br>• Quick resolution needed on replacement of LSE with DP. Potential gap with current data collection of DER. (Already approved under Project 2017-07 Standards Alignment with Registration)<br>• Removal of LSE is appropriate, but replacement with DP is inconsistent with FERC Order approving removal of LSE because it is low risk to the BES.<br>• Concern with DP being the responsible entity, when several entities are not registered as a DP. | |
| The SAR DT acknowledges the comments in relation to changes to the responsible entities and will incorporate the comments as considerations for developing requirement language. As outlined in SAR Project Scope Parts C and D, the SAR DT feels it is appropriate for the SDT to consider the change from LSE to DP, to include adding responsible entities, and further investigate any potential gaps or additional considerations that may be necessary. The SAR DT feels that there is enough flexibility in the SAR language to empower the SDT to develop a risk-based, balanced outcome which takes in to consideration the issues and concerns that are representative of multiple entities and regions with an appropriate amount of industry outreach and feedback. | The change from LSE to DP was identified by the NERC DER Task Force and then subsequently identified by the NERC SPIDERWG. Upon disbanding of the SAR DT, this issue still stands and is yet to be addressed with a standard revision. Therefore, it is kept in the SAR. |
| ***Theme 8:*** *Recommend scope of SAR be expanded to include potential changes to TPL-001. Data collection requirement in MOD-032 could become just an administrative item if there is not corresponding requirement in TPL-001 to use the data.* | |
| While the SAR DT understands the working relationship between these two standards, SPIDERWG is currently evaluating the TPL Standard to see if any technical gaps exist. In order to ensure a timely resolution of items addressed in the current SAR version, the SAR DT will not seek to expand the SAR to include any revisions to TPL-001. | SPIDERWG is presenting a SAR for MOD-032 and a SAR for TPL-001 to the RSTC for approval in December 2021. This will address issues with both modeling data and study approaches for assessing the BPS impacts of aggregate DERs. |
| ***Theme 9:*** *Single SAR and SDT should be formed to handle all DER related revisions at one time.* | |
| The SPIDERWG prioritized this effort for DER revisions above other items. MOD-032 revisions will be pursued first in order to ensure a timely resolution of items addressed in the current SAR version. | SPIDERWG does not believe this to be an effective path forward nor is this theme relevant to the submitted SAR at hand. SPIDERWG has prioritized MOD-032 as a foundational standard needing revisions immediately. SPIDERWG is also working on a comprehensive review of NERC standards; however, that effort should not limit this revision from occurring. |

# White Paper: Survey of DER Modeling Practices

## Action
Approve

## Summary
The SPIDERWG sought RSTC reviewers for the draft white paper at the September RSTC meeting. Based on reviewer comments, the white paper was updated to revise recommendations and to further clarify the scope of the survey data (within SPIDERWG members) throughout the document. The SPIDERWG is seeking RSTC approval of the revised white paper.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

# Survey of DER Modeling Practices

## NERC System Planning Impacts from Distributed Energy Resources Working Group (SPIDERWG) - White Paper

December 2021

RELIABILITY | RESILIENCE | SECURITY




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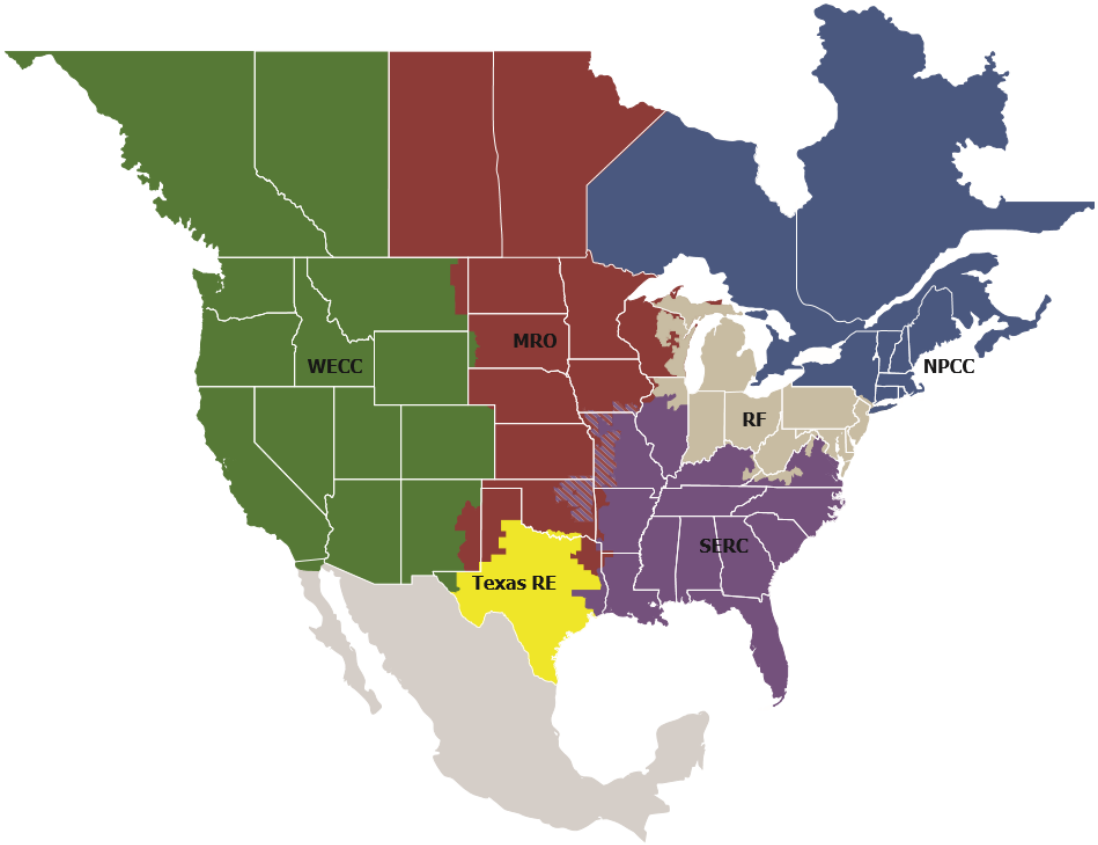
# Preface

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 made up of 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 |

# Executive Summary

The NERC SPIDERWG performed an informal survey of its membership regarding distributed energy resource (DER) modeling practices.[1] The SPIDERWG consists of a wide range of industry experts and a cross-section of industry representation, and 45 entities participated. The survey was primarily geared towards understanding DER modeling practices of Transmission Planners (TPs) and Planning Coordinators (PCs), which are well-represented on SPIDERWG. Results from the survey were analyzed to identify any major trends in DER modeling practices, to characterize the level of detail that TPs and PCs are using for DER modeling, and to identify any potential gaps in these practices that should lead future efforts for SPIDERWG and industry.

## Key Findings

The following key findings were identified from this survey:

- **Questions 2 and 3:** Responding entities ranged in their peak gross load, from over 20,000 MW to less than 500 MW. However, only 18% of respondents have a minimum load over 10,000 MW and slightly over 50% of respondents have a minimum load less than 1,000 MW.
- **Question 5:** Over 30% of respondents reported having over 1,000 MW of installed DER in their footprint, 60% reported having more than 100 MW, and about 40% reported having less than 100 MW.
- **Question 6:** Forecasted DER penetration levels are likely to increase in the coming years, particularly in the planning horizon. Responses shifted towards increased penetration levels by 2024. 16% of respondents, however, did not have a DER forecast out to 2024.
- **Question 7:** 40% of respondents reported observing DER tripping during fault events on the electrical grid. Few entities were able to report a quantitative amount of DER tripping due to limited data available.
- **Question 8:** 40% of respondents reported a shift in peak or light net load hours due to the increased penetration of DERs in the planning timeframe or real-time horizon. Shifts in peak or light net load hours has an impact on the planning assumptions used for BPS reliability assessments, which impacts how NERC TPL-001 reliability studies are executed.
- **Question 9:** About 50% of respondents reported that they receive operational DER information (i.e., DER output) for individual DERs above a size threshold. The majority of remaining respondents do not receive any operational data regarding DERs in their system, even in an aggregated manner.
- **Question 10:** 45% of respondents model DERs explicitly with some representation of the aggregate level of DERs in their system. Most of those respondents model the aggregate DER using a generator record in the simulation tools. 40% of respondents use a negative load or embed DERs into load forecasts (i.e., no explicit dynamic behavior representation of DER in study). 15% use a mix of explicit representation and net load reduction. Entities responding that they use negative load or embedded in the load forecasts stated they do not have tools to represent DERs, do not have enough data to represent DERs in study, or have DER capacity too small to make an impact on the BPS.
- **Question 11:** About 50% of respondents do not have a threshold for modeling utility-scale DERs (U-DERs), i.e., larger DERs that are three-phase installations, and do not model U-DERs in their studies. The remaining respondents use some threshold ranging from less than 1 MW to above 10 MW.

[1] For this survey and its results, distributed energy resources are defined as "any source of electric power located on the distribution system," as defined in the NERC SPIDERWG Terms and Definitions Working Document: https://www.nerc.com/comm/PC/System%20Planning%20Impacts%20from%20Distributed%20Energy%20Re/SPIDERWG%20Terms%20and%20Definitions%20Working%20Document%20rev%201.docx.pdf

- **Question 12:** 62% of respondents stated that they do not model retail-scale DER (R-DER) to represent aggregate levels of DER. 20% use a threshold less than 1 MW and 16% use a threshold between 1 MW and 5 MW.
- **Question 13:** Over 50% of respondents stated that they are not modeling DERs in any aggregated manner in their studies. 22% aggregate based on connection point (i.e., T-D substation). 16% aggregate based on size, fuel type, and connection point.
- **Question 14:** 73% of respondents stated that they do not model DERs in dynamic studies in any fashion; 27% reported that they do model DERs in dynamic studies. Reasons for not modeling DERs in dynamic studies were low amount of DERs in their footprint, unavailability of DER models or tools, and lack of DER information to populate the dynamic models in a meaningful way.
- **Question 15:** Those that are modeling DERs in dynamic studies are using primarily either the DER_A dynamic model or the more detailed second-generation renewable energy system models. No entities reported using the obsolete PV1 or PVD1 models. One entity reported using their own in-house dynamic model.
- **Questions 16 and 17:** About 70% of respondents stated they do not model distributed energy storage in their models; about 30% reported that they do model distributed energy storage. For those that do model distributed energy storage, about 70% stated that they model both full injection and full absorption scenarios; 23% reported modeling the distributed battery at maximum injection level only; one entity reported modeling their distributed storage off-line in studies presently.

# Recommendations and Next Steps

The survey among SPIDERWG members highlights that DER penetrations are rising yet DER data collection, modeling, and modeling practices need to improve across the industry. SPIDERWG will continue to support industry education of DER modeling and studying their impacts to BPS reliability through workshops, webinars, guidelines, and technical reports. Based on the results of the survey of its membership, of which a large plurality of the respondents were registered TPs or PCs[2], SPIDERWG recommends the following to all TPs and PCs to improve DER modeling practices:

1. **TPs and PCs with minimal DER penetration:** TPs and PCs with minimal levels of DERs should continue monitoring DER forecasts and be prepared to incorporate DER models explicitly into planning assessments to understand their potential impacts to BPS reliability for steady-state and dynamic studies. Regardless of DER penetration level, all entities should track its DER growth such that the penetration of DERs can be accounted for in studies and forecasts appropriately.
2. **TPs and PCs with DER penetrations but lack of available DER modeling information:** TPs and PCs in this situation should incorporate the recommendation in NERC *Reliability Guideline: DER Data Collection for Modeling in Transmission Planning Studies,*[3] and work with their respective Distribution Providers to collect appropriate aggregate DER data for the purposes of BPS reliability studies. Without sufficient information regarding DER penetration levels, TPs and PCs cannot execute accurate reliability assessments in the planning horizon. Distribution Providers are strongly recommended to review NERC *Reliability Guideline: Bulk Power System Reliability Perspectives on the Adoption of IEEE 1547-2018*[4] and ensure DER data is being collected and provided to the TP and PC for the purposes of BPS planning assessments.
3. **TPs and PCs seeking guidance for recommended DER modeling practices:** All TPs and PCs should review the recommendations provided in NERC reliability guidelines[5] pertaining to recommended DER modeling practices, and improve their modeling capabilities for representing aggregate levels of DERs. Modeling of DERs is required prior to being able to identifying any potential reliability issues that may be presented with increasing levels of DERs; hence, entities cannot assess impact with DER information and models to study those impacts.

SPIDERWG will continue to monitor the current state[6] of DER modeling practices and ensure that any limitations to the collection of DER information are addressed, such as through a subsequent survey.

[2] However, each entity can be registered in a number of roles. This means that a plurality could in fact be a majority of the total entities, but not of the functional registration.
[3] This document is available here
[4] This document is available here
[5] This document is available here
[6] This white paper illustrates that DERs are having an impact on the BPS, particularly tripping during fault events, and that entities are using limited or no DER modeling practices in some cases. Further, the extent of DER modeling in dynamic studies is fairly minimal considering the current and projected forecasts of DERs in many footprints. Limitations to DER modeling include lack of information regarding DER installations and limited DER modeling capability.

# Introduction

Many areas of the North American bulk power system (BPS) are experiencing an increasing penetration of DERs, and this is already affecting TP and PC modeling practices and planning assessments. Representing DERs in planning assessments becomes increasingly important as the penetration of DERs rises across many TP and PC footprints. NERC SPIDERWG has developed reliability guidelines and recommendations for modeling DERs in planning assessments, and continues to support industry awareness and voluntary adoption of these recommendations. Unlike BPS elements that are often modeled explicitly, DERs are usually represented in aggregate due to the small size of individual units. While these resources are located on the distribution system, their growing impact to the BPS cannot be neglected and this is especially true in BPS planning assessments. DER models are needed to perform steady-state power flow, dynamics, short-circuit, electromagnetic transient (EMT), and other types of planning studies. TPs and PCs may need information and data that enable them to develop models of aggregate DERs for planning purposes.

In addition to issuing recommendations and guidelines, SPIDERWG conducted an informal survey of its members to analyze the DER modeling practices of different entities[7]. Understanding the different modeling practices across entities helps identify any gaps and develop a strategy for DER modeling as part of the overall reliable integration of these resources. This white paper discusses the survey questions and the results of the survey.

## DER Survey Setup

The Modeling Subgroup of the NERC SPIDERWG developed and executed an informal survey of its membership. The survey questions were developed by the subgroup and reviewed by the overall SPIDERWG. The survey was specifically geared towards TPs and PCs regarding their modeling practices, and 63 entities within SPIDERWG were asked to participate. A total of 45 of those entities provided a response to the survey. At the time of the survey, the NERC Compliance Registry consists of 75 entities registered as PCs and 206 entities as TPs.[8] Some respondents did not provide completed surveys or answers to specific questions, which is believed to be due to the lack of information. Detailed descriptions of the survey setup and questions are in Appendix A.

[7] Note that the definition of "DER" has been agreed upon by SPIDERWG members to mean the definition as posted on the SPIDERWG's definitions document here.

[8] Note that the registration criteria for these types of entities is not mutually exclusive.

# Chapter 1: Review and Analysis of DER Survey Responses

The section briefly describes the key findings and takeaways from the analysis of the survey results. Appendix B provides a summary of the responses to the survey questions. Information regarding specific entities' responses are withheld for confidentiality reasons. Relevant Key Findings are summarized in **Table 1.1**

**Table 1.1: Key Findings from Survey Questions**

| # | Related Questions | Key Finding |
|---|---|---|
| 1 | Question 6 | From responses to this question and from comparison of the existing and future amounts of DER, it is seen that in the future with the DER growth, some entities will have an increase in amount of DER that will move them to a higher category. For example, currently, there are eleven entities with the DER capacity between 1000 and 5000 MW, and in the future there will be nine entities in this category. This is because for two entities, the increase in the DER will move them to the category of entities with the DER capacity larger than 5000 MW. The same is true for entities with other DER amounts. |
| 2 | Question 7 | Five respondents observed widespread tripping of the DER with faults[9], none of them has provided the amounts of the DER that were tripped.<br><br>Although not many of the respondents observed widespread DER tripping with faults, this may be due to lack of visibility on the distribution systems and thus, insufficient data on the DER output and tripping. Other prevailing inferences could be that faults didn't occur in their regions or that the DER penetration is so low that any trip of DER is lost in the "noise" of the response. Any of these would result in no observed widespread DER tripping. |
| 3 | Questions 16 and 17 | The reasons for not modeling energy storage explicitly[10] were absence of such storage, absence or lack of data on distribution-connected energy storage, or absence of appropriate tools. The largest category of "No" responses was due to the absence of distribution-connected energy storage, followed by the category of lack of data on distribution-connected energy storage. |

Based on the results of the survey, there are still not many entities that model DER, especially in dynamic stability studies. Significant number of entities model DER netted with load even if the amount of DER in the system is substantial and represents noticeable percentage of the system load. Such amount of DER would have impact on the system performance, but this impact is not considered if the DER are not modeled explicitly in the studies undertaken by TPs, PCs, and other transmission entities. With the growing penetrations of renewable resources, which is currently focused on distribution-connected growth in many electric utilities, modeling DER is becoming more important. Based on the attention to growing penetrations of DER, the SPIDERWG modeling subgroup identified categories of percentage penetration of DER to system peak load (non-coincident) based on the responses to Questions 2, 5, and 6. These can be found in **Table 1.2**[11]. The prominent modeling practices along with the number of entities that fall into this category are also provided in **Table 1.2**.

[9] As this question was put generally, the five responses could indicate either five different faults seen by the different survey responders or it could be a single fault seen by the five different entities.

[10] Responses to the survey varied between assuming an implicit or explicit representation based on inference between the questions. Most assumed explicit representation from the survey question.

[11] One survey result did not have both Questions 5 and 6 completed, which may skew this data slightly.

**Table 1.2: DER Penetration based on Questions 2, 5, and 6**

| Penetration Percentage | # of Entities | Prominent Modeling Practices |
|---|---|---|
| Over 100 Percent | 1 | In this entity DERs were modeled as generators, both in power flow and in dynamic simulations |
| Between 50 percent and 100 percent | 1 | DERs were modeled as negative load due to lack of appropriate modeling tools |
| Between 20 percent and 50 percent | 2 | One entity modeled DERs as negative load, again due to lack of modeling tools. The other modeled DERs as a generator as part of the composite load. DERs were modeled with second generation renewable dynamic models. |
| Between 10 percent and 20 percent | 11 | Out of these 11 entities, three modeled all DER in power flow regardless of size, three others modeled only DER that are larger than 1 MW, two entities modeled in power flow only DER that are larger than 5 MW, one entity modeled DER larger than 10 MW, and two modeled all DER as negative load. As for dynamic simulations, five entities out of these eleven didn't model DER due of absence of data or lack of tools, and six entities modeled DER. Out of these six, five modeled DER as generators with renewable models and one modeled DER some as generators and some as a part of composite load model. |
| Between 5 percent and 10 percent | 20 | In power flow, two entities modeled all DER regardless of size, one modeled only DER that are larger than 1 MW and five modeled them as negative load.<br><br>In dynamic stability, eight entities modeled DER. The explanations of that were absence of tools and absence of DER data and for some entities, that they haven't observed visible impact of the DER on transmission system that would justify modeling DER in dynamic stability. Out of these entities, two modeled DER in power flow as generators or as a part of composite load model, and the ten modeled DER as negative load. In dynamic stability, ten entities did not model DER and the other two modeled DER with the DER_A model. Not modeling DER was explained by the absence of tools, absence of DER data and negligible impact of the DER on transmission system. |
| Less than 1 percent | 9 | Out of these nine entities, seven did not model DER, and two modeled DER in power flow and stability as generators with DER_A model. The survey respondents provided the following reasons for not modeling DER:<br>▪ Low amount of DER in the system<br>▪ Lack of data on the DER locations, and their output<br>▪ Lack of tools to model DER<br>▪ Lack of knowledge of the models |

Significant amount of entities reported that they observed shifting of the system peak because of the DER output. Peak shifting causes TPs and PCs to study more system conditions than the ones that were studied before, and as the current dominant DER technology is solar photovoltaic (PV), creates a need for DER models of high quality and

fidelity[12]. In addition to the system peak and off-peak conditions, such conditions as net system peak when DER output is low and the system load is still high will also need to be studied[13]. These cases may represent hours 18 or 19 on summer weekdays when sun goes down, but the load is high due to air-conditioners. Off-peak system conditions with high DER output and low load, which represent spring weekend afternoons, may also appear to be critical. System conditions with high gross load and high DER output (when these conditions are coincident) may be a challenge for dynamic stability system performance because of stalling of single-phase induction motor load with faults and possible tripping of DER because of low voltages. In all these cases, adequate modeling of the DER is becoming more and more important.

This shifting of system peak because of DER output should be taken into account when attempting to correlate the responses related to Question 3 (minimum gross load) and Question 5 (DER capacity) as shown below in **Figure 1.1** Nevertheless, it is significant and important to recognize that there are many jurisdictions where the ratio of maximum DER capacity to minimum gross load is above 20 percent.

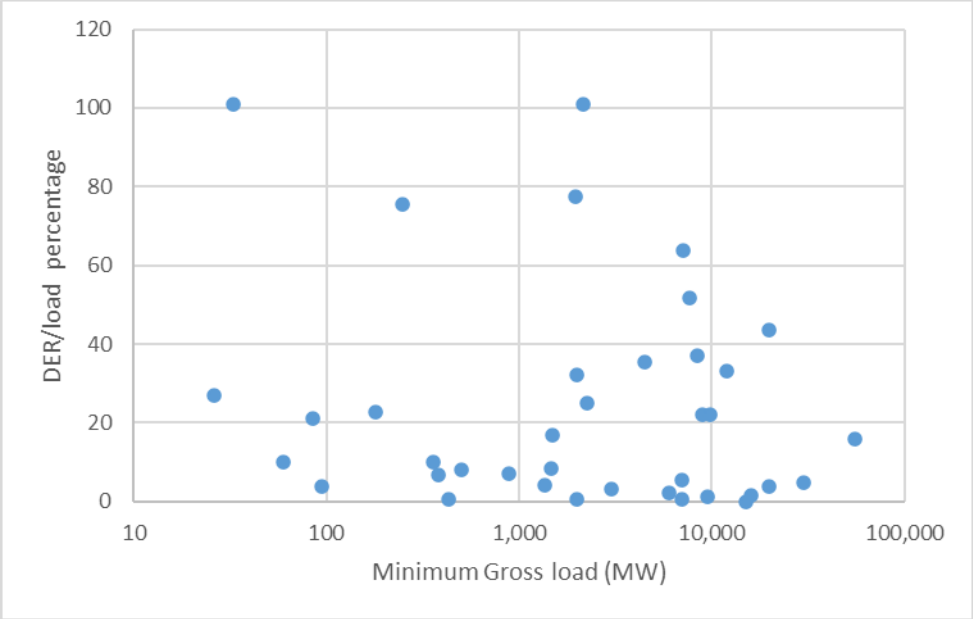
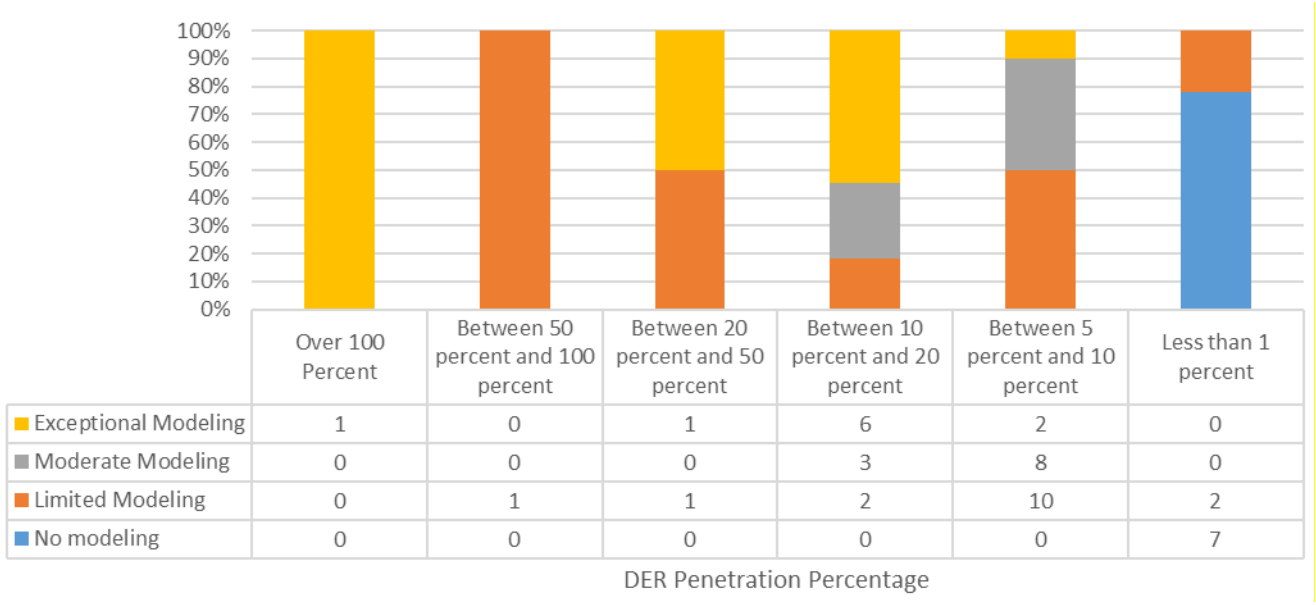



**Figure 1.1: Ratio of Maximum DER capacity to Gross Minimum Load**

From the results in the survey, the SPIDERWG categorized the number of entities by their modeling practices based on their penetration level in **Figure 1.2**. Entities that did not model in powerflow or dynamics were recorded as "no modeling", entities that had powerflow models, but no dynamic models or were modeled as negative load were recorded as "limited modeling", entities that had a dynamic record associated with the DER were recorded with "moderate modeling", and entities that used a dynamic record modeled according to latest guidance available were recorded as "exceptional modeling".

[12] This also applies to BPS-connected solar PV models. To reiterate, all solar PV models will need to modify their available power output based on the time of day selected for the study.

[13] This point is emphasized in "Verification Process for DER Modeling in Interconnection-wide Base Case Creation," published in the June 2020 CIGRE journal: https://e-cigre.org/publication/CSE018-cse-018.




| | Over 100 Percent | Between 50 percent and 100 percent | Between 20 percent and 50 percent | Between 10 percent and 20 percent | Between 5 percent and 10 percent | Less than 1 percent |
|---|---|---|---|---|---|---|
| Exceptional Modeling | 1 | 0 | 1 | 6 | 2 | 0 |
| Moderate Modeling | 0 | 0 | 0 | 3 | 8 | 0 |
| Limited Modeling | 0 | 1 | 1 | 2 | 10 | 2 |
| No modeling | 0 | 0 | 0 | 0 | 0 | 7 |

**Figure 1.2: Modeling Practice Percentage by DER Penetration**

Although the respondents used their best knowledge in responses to the survey questions, the responses to the question regarding total amount of the DER in the system may make conclusions of the survey to be less accurate. Since different entities included different types of technologies in the DER definition, the amount of the DER reported answering this question may not reflect actual amount of the DER in the system. These DER were counted differently in different entities. Some included only solar PV, some included also energy storage, and some entities included all kind of generation, and also demand response.

# Appendix A: Detailed Survey Process with Questions

SPIDERWG determined that the best approach would be to conduct the DER survey in several phases, with the first phase containing general questions regarding DER penetrations and basic modeling practices for each entity. The first phase did not include questions about the DER model parameterization or forecasting, and only included data sources in a cursory manner. SPIDERWG recommends conducting a more detailed follow-up survey of modeling practice upon completion and findings from this phase one survey.[14] The following questions were asked in this phase one survey:

1. What is your company's function(s)?[15]
2. What is the peak gross load of your area [MW]?
3. What is the minimum gross load of your area [MW]?
4. What technologies are included in the DER definition used when answering this survey?
5. What is the total capacity of DER connected to your system [MW]?
6. What is the 5-year forecast for DER capacity to be connected to your system in 2024 [MW]?
7. Have you observed widespread tripping of DER due to faults in operations? If yes, how much DER tripped? (can be estimated from change in net load if detailed data is not available)
8. Have you observed shifting peak or light hours of net load due to increasing DER penetration level in planning timeframes or real-time/historical, for any sub-set of the system you are responsible for?
9. Do you receive any DER operational data (e.g., output of DERs)? On what level?
10. How do you model DERs in load flow studies?
11. What is the MW threshold to explicitly model individual (or multiple) U-DERs in the base case?
12. What is the MW threshold to explicitly model aggregate R-DERs in load flow studies?
13. How are DERs being aggregated in your system?
14. Do you model DERs in dynamic studies?
15. Which DER model do you use in your dynamic studies?
16. Do you model distribution-connected energy storage in your system?
17. How do you model energy storage in your system?

[14] Such questions include DER forecasting methods, sources of DER data, impacts of DERs on base case creation, considerations of DERs in special studies, and study impacts of DERs.

[15] Based on the entity's NERC Registration: https://www.nerc.com/pa/comp/Pages/Registration.aspx.

# Appendix B: DER Survey Responses

This appendix provides the aggregated responses from the survey as well as the key takeaways for each question asked. The values in the charts that follow show the number of respondents and the percentage of total respondents, respectively, for each question.

## Question 1

*"What is your company function?"*[16]

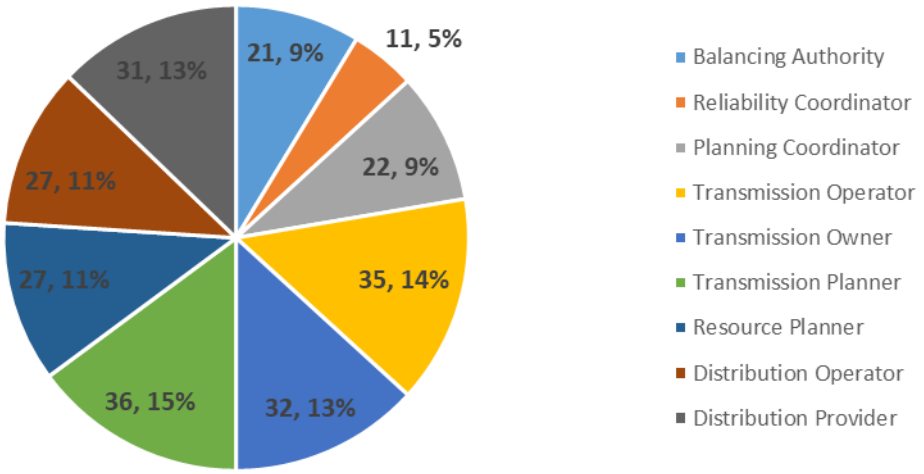



**Figure B.1: Responses to Question 1**

**Key Takeaway – Question 1:**
A wide array of SPIDERWG members responded to this survey, 36 and 22 entities identifying as TPs and PCs, respectively (not mutually exclusive).

[16] Respondents were requested to mark all that apply; hence the higher response count. 45 entities responded to the survey.

## Question 2

*"What is the peak gross load of your area [MW]?"*

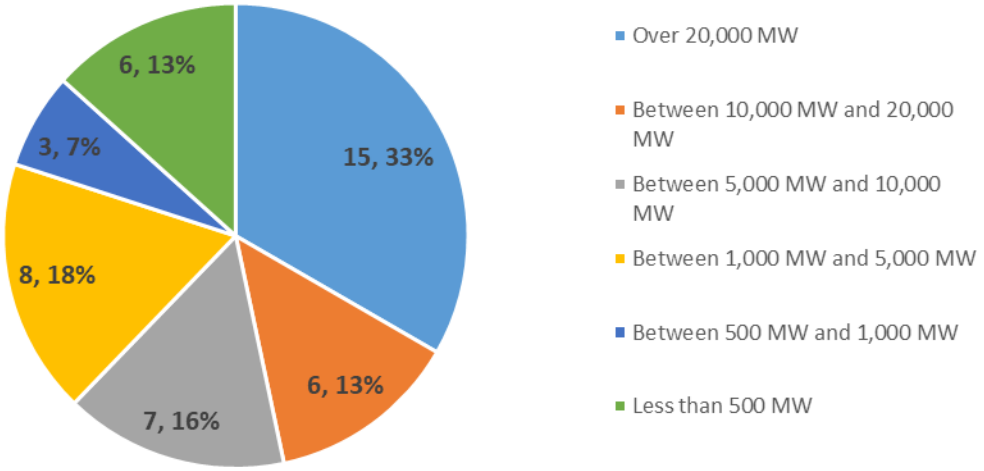



**Figure B.2: Responses to Question 2.**

**Key Takeaway – Question 2:**
Entities ranged in their peak gross load, from over 20,000 MW to less than 500 MW.

## Question 3

*"What is the minimum gross load of your area [MW]?"*

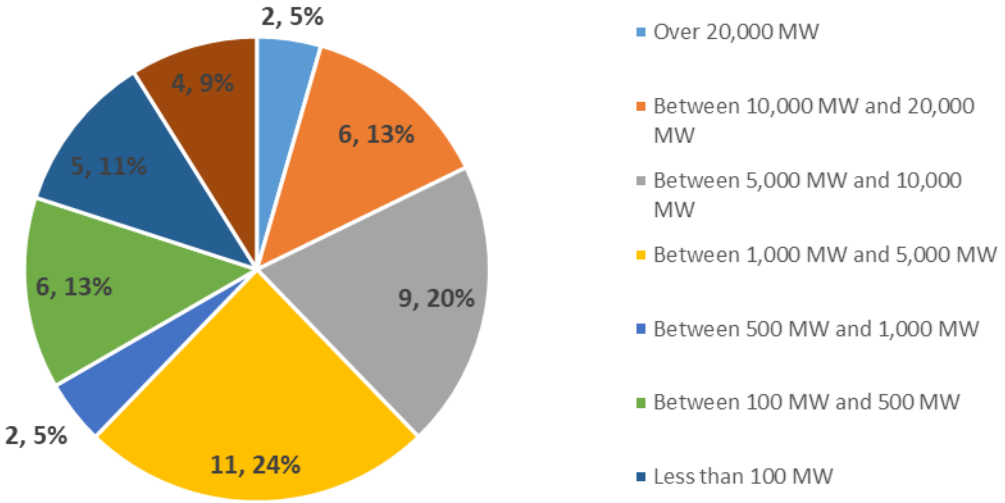



**Figure B.3: Responses to Question 3**

**Key Takeaway – Question 3:**
Entities also ranged in their minimum gross load. However, only 18% of respondents have a minimum load over 10,000 MW and slightly over 50% of respondents have a minimum load less than 1,000 MW.

## Question 4

*"What technologies are included in the DER definition used when answering this survey?"*

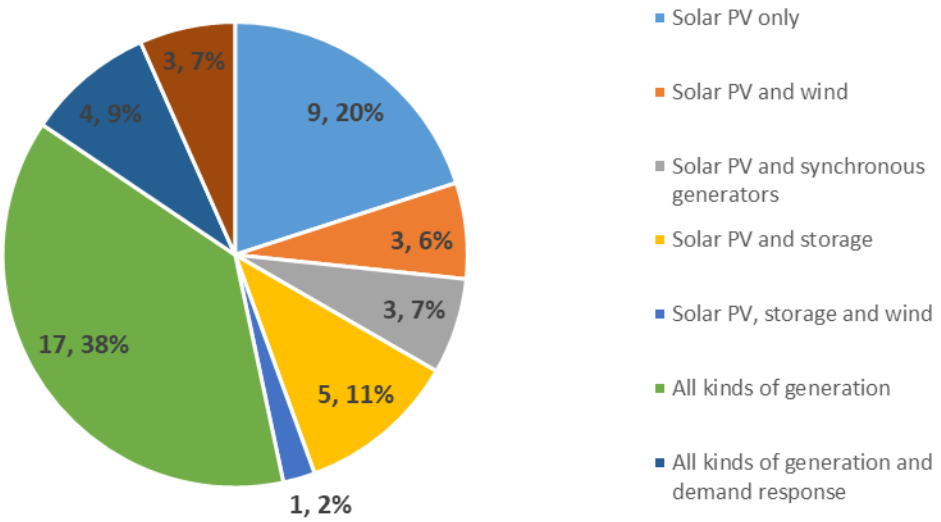



**Figure B.4: Responses to Question 4**

**Key Takeaway – Question 4:**
Some entities included demand response in their definition of DER; however, the majority of respondents focused on "sources of electric power" with most focusing specifically on inverter-based DERs such as solar PV, wind, and battery energy storage.

## Question 5

*"What is the total capacity of DER connected to your system [MW]?"* [17]

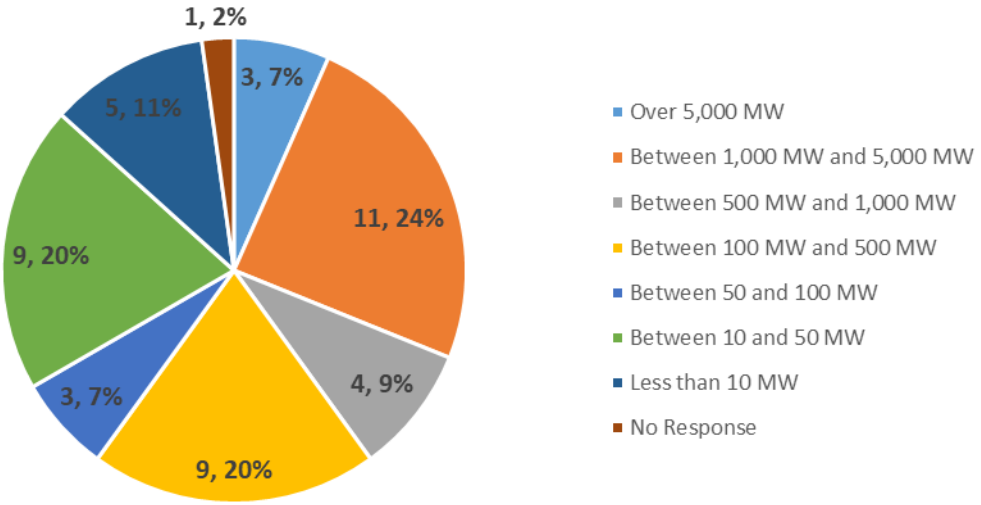



**Figure B.5: Responses to Question 5**

**Key Takeaway – Question 5:**
Over 30% of respondents reported having over 1,000 MW of installed DER in their footprint, 60% reported having more than 100 MW, and about 40% reported having less than 100 MW.

[17] Regarding this question, since different entities include different types of technologies in the DER definition, as seen from the responses to the previous question, the amount of the DER reported answering this question may not reflect actual amount of the DER in the system based on the SPIDERWG definition.

## Question 6

*"What is the 5-year forecast for DER capacity to be connected to your system in 2024 [MW]?"*[18]

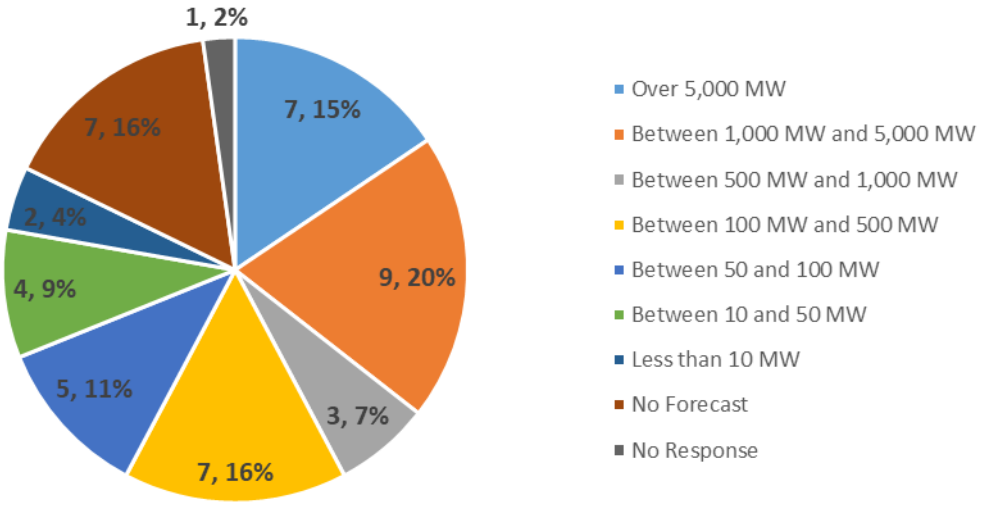



**Figure B.6: Responses to Question 6**

**Key Takeaway – Question 6:**
In 2024, over 35% of respondents reported having over 1,000 MW of installed DER in their footprint, about 60% reported having more than 100 MW, and about 24% reported having less than 100 MW. About 15% of respondents reported having no DER forecast out to 2024.

[18] In summarizing the responses to this question, the DER forecast was compared with the existing amount of DER.

## Question 7

*"Have you observed widespread tripping of DER due to faults in operations? If yes, how much DER tripped?"*[19]

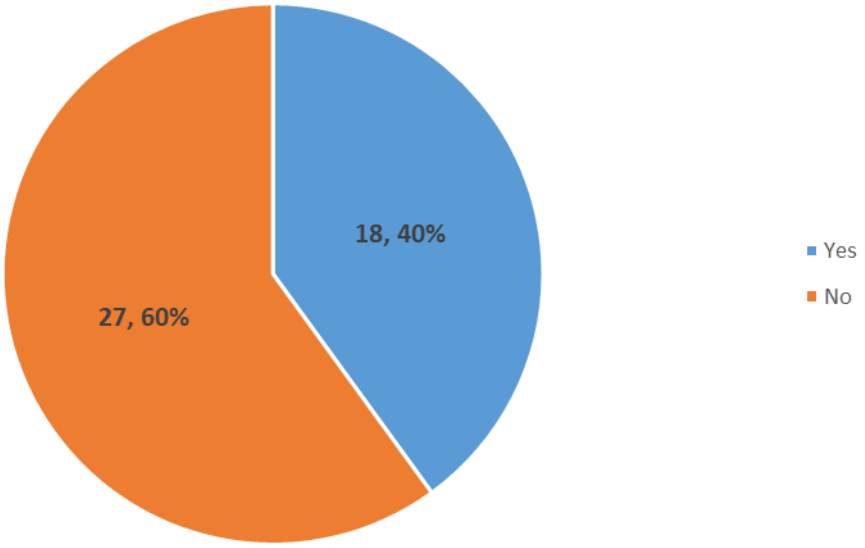



**Figure B.7: Responses to Question 7**

**Key Takeaway – Question 7:**
40% of respondents reported observing widespread tripping of DERs during fault events in their footprint; the remaining 60% had not observed any DER-related tripping events so far.

[19] Note that the response to this question can be estimated from the change in net load if detailed data is not available.

## Question 8

*"Have you observed shifting peak or light hours of net load due to increasing DER penetration level in planning timeframes or real-time/historical, for any sub-set of the system you are responsible for?"*

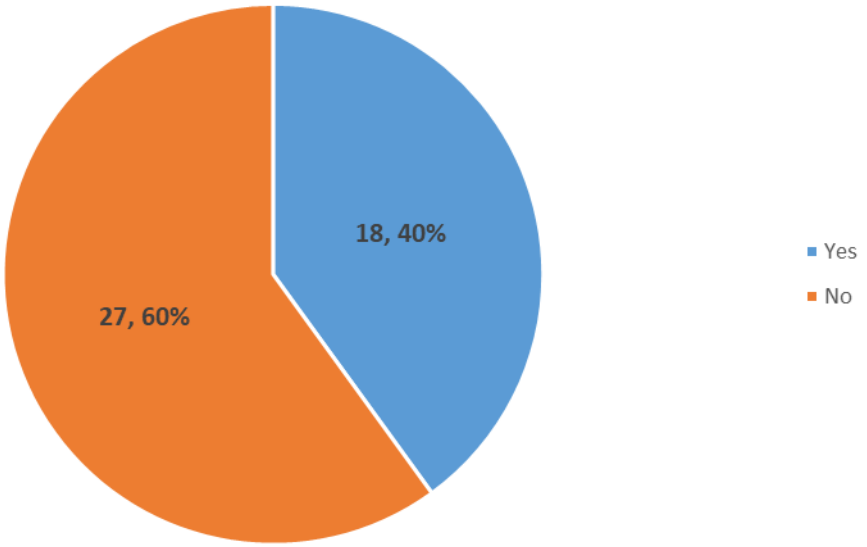



**Figure B.8: Responses to Question 8**

**Key Takeaway – Question 8:**
40% of respondents reported a shift in peak or light net load hours due to the increased penetration of DERs in the planning timeframe or real-time horizon; the remaining 60% had not observed any shift in net loading on their system.

## Question 9

*"Do you receive any DER operational data (e.g., output of DERs)?"*

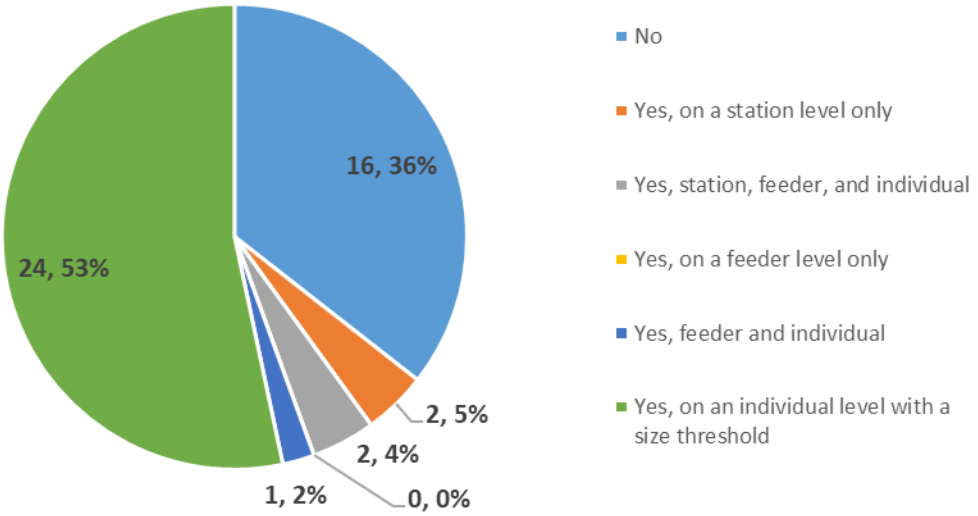



**Figure B.9: Responses to Question 9**

**Key Takeaway – Question 9:**
About 50% of respondents reported that they receive operational DER information (i.e., DER output) for individual DERs above a size threshold. The majority of remaining respondents do not receive any operational data regarding DERs in their system, even in an aggregated manner. Some respondents receive limited DER information on a station- or feeder-level.

## Question 10

*"How do you model DERs in load flow studies?"*[20]

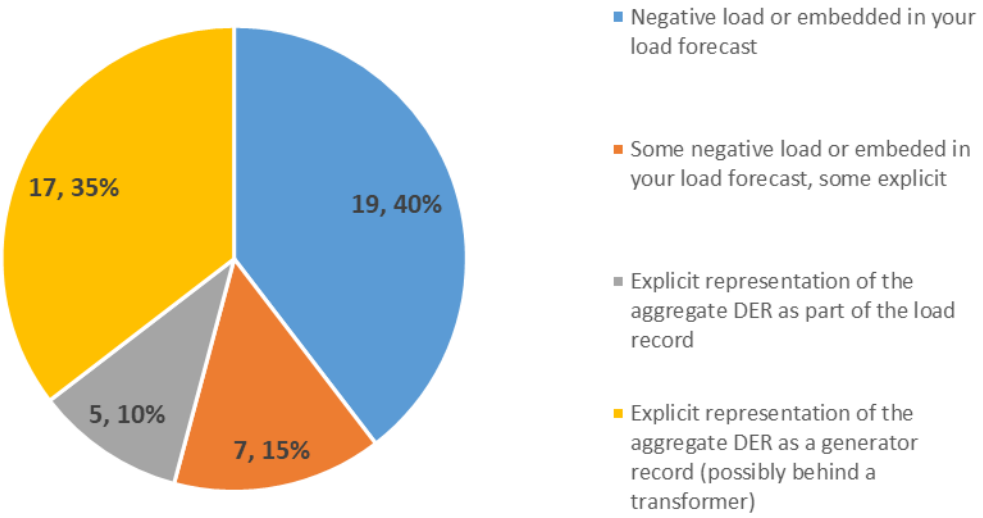



**Figure B.10: Responses to Question 10**

**Key Takeaway – Question 9:**
45% of respondents model DERs explicitly with some representation of the aggregate level of DERs in their system. Most of those respondents model the aggregate DER using a generator record in the simulation tools. 40% of respondents use a negative load or embed DERs into load forecasts (i.e., no DER representation in study). 15% use a mix of explicit representation and net load reduction. Entities responding that they use negative load or embedded in the load forecasts stated they do not have tools to represent DERs, do not have enough data to represent DERs in study, or have DER capacity too small to make an impact on the BPS.

[20] Note that the response to this question include some overlap as respondents reported more than one option.

## Question 11

*"What is the MW threshold to explicitly model individual (or multiple) utility-scale (U-DERs) in the base case?"* [21]

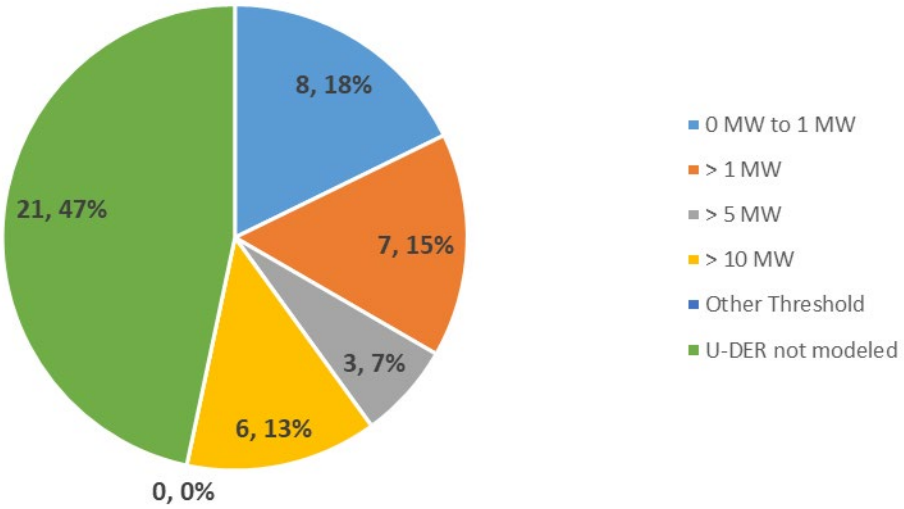



**Figure B.11: Responses to Question 11**

**Key Takeaway – Question 11:**
About 50% of respondents do not have a threshold for modeling utility-scale DERs (i.e., larger DERs that are often three-phase installations), and do not model U-DERs in their studies. 13% use a threshold over 10 MW, 7% use a threshold between 5 MW and 10 MW, 15% use a threshold between 1 MW and 5 MW, and 18% use a threshold less than 1 MW.

## Question 12

*"What is the MW threshold to explicitly model aggregate retail-scale (R-DERs) in load flow studies?"*

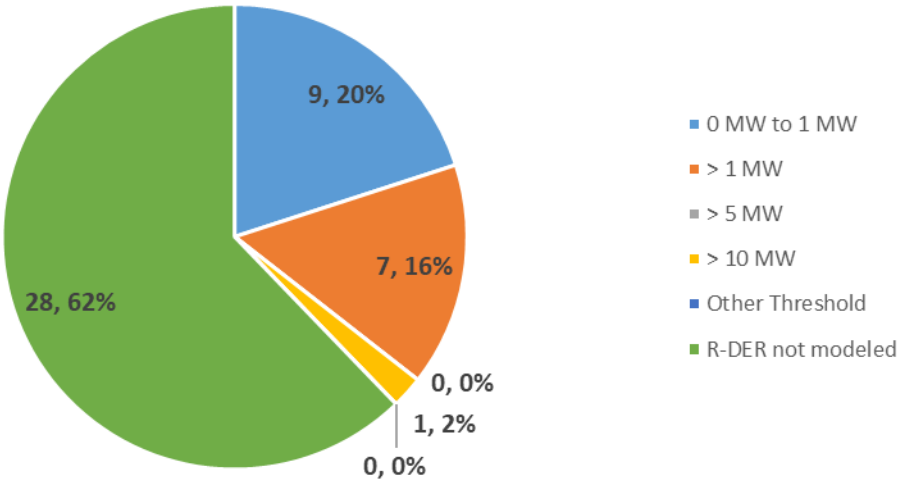



**Figure B.12: Responses to Question 12**

**Key Takeaway – Question 12:**
62% of respondents stated that they do not model R-DER to represent aggregate levels of DER. 20% use a threshold less than 1 MW and 16% use a threshold between 1 MW and 5 MW.

## Question 13

*"How are DERs being aggregated in your system?"*

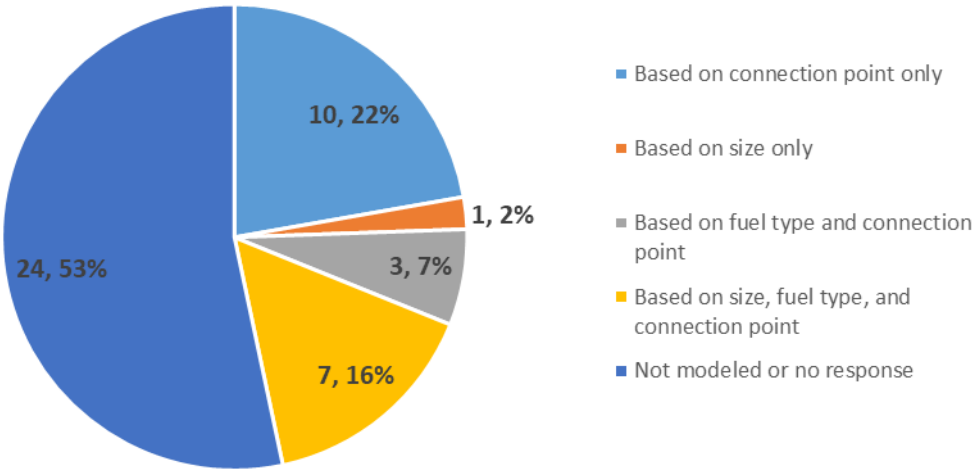



**Figure B.13: Responses to Question 13**

**Key Takeaway – Question 13:**
Over 50% of respondents stated that they are not modeling DERs in any aggregated manner in their studies. 22% aggregate based on connection point (i.e., T-D substation). 16% aggregate based on size, fuel type, and connection point.

## Question 14

*"Do you model DERs in dynamic studies?"*

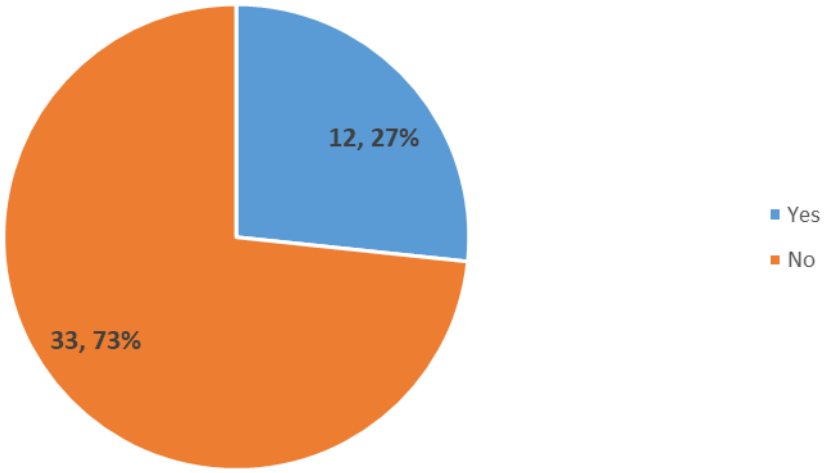



**Figure B.14: Responses to Question 14**

**Key Takeaway – Question 14:**
73% of respondents stated that they do not model DERs in dynamic studies in any fashion; 27% reported that they do model DERs in dynamic studies. Reasons for not modeling DERs in dynamic studies were low amount of DERs in their footprint, unavailability of DER models or tools, and lack of DER information to populate the dynamic models in a meaningful way.

## Question 15

*"Which DER model do you use in your dynamic studies?"*

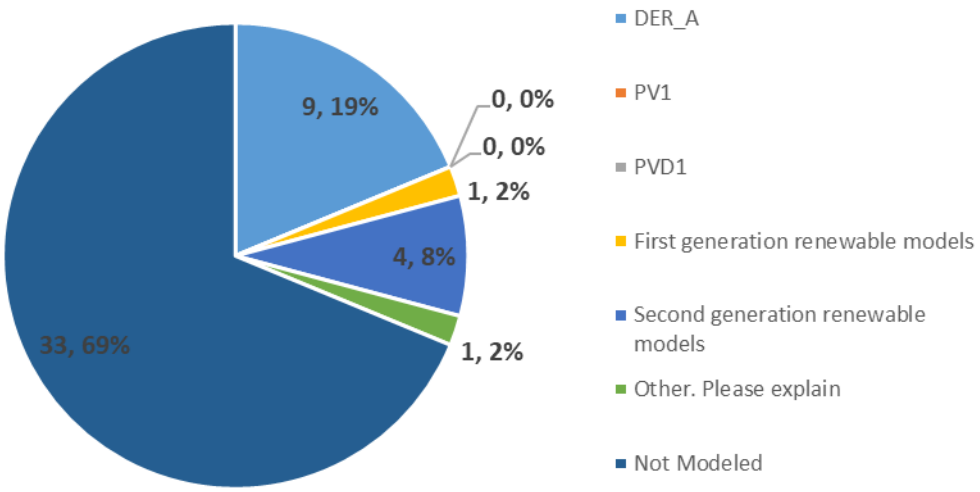



**Figure B.15: Responses to Question 15**

**Key Takeaway – Question 15:**
Most respondents reported not modeling DERs in dynamic studies. Those that are modeling DERs in dynamic studies are using primarily either the DER_A dynamic model or the more detailed second-generation renewable energy system models. No entities reported using the obsolete PV1 or PVD1 models. One entity reported using their own in-house dynamic model.

## Question 16

*"Do you model distribution-connected energy storage in your system?"*

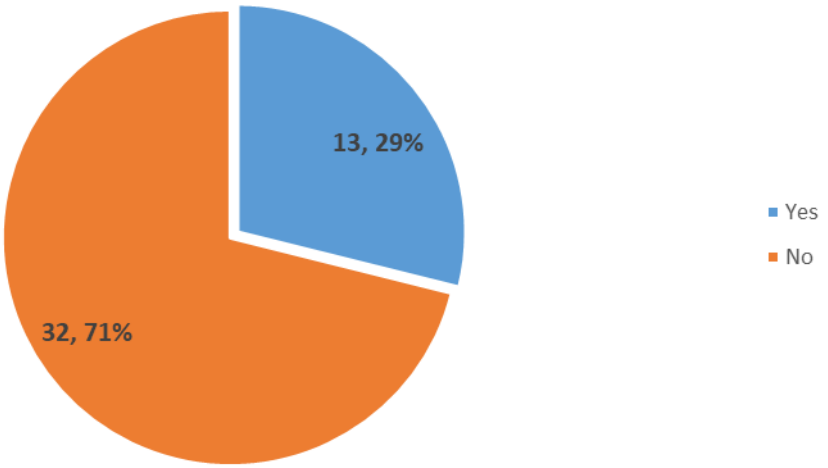



**Figure B.16: Responses to Question 16**

**Key Takeaway – Question 16:**
About 70% of respondents stated they do not model distributed energy storage in their models; about 30% reported that they do model distributed energy storage.

## Question 17

*"How do you model energy storage in your system?"*

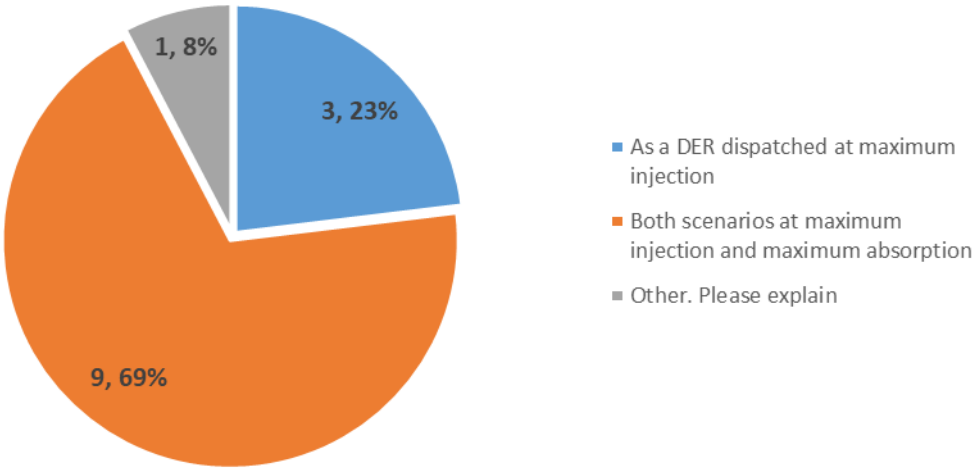



**Figure B.17: Responses to Question 17**

**Key Takeaway – Question 17:**
About 70% of respondents stated that they model both scenarios for full injection and full absorption for the distributed battery output; 23% reported modeling the distributed battery at maximum injection level only; one entity reported modeling their distributed storage off-line in studies presently.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

# Survey of DER Modeling Practices

NERC System Planning Impacts from Distributed Energy Resources Working Group (SPIDERWG) - White Paper

~~April~~ December 2021

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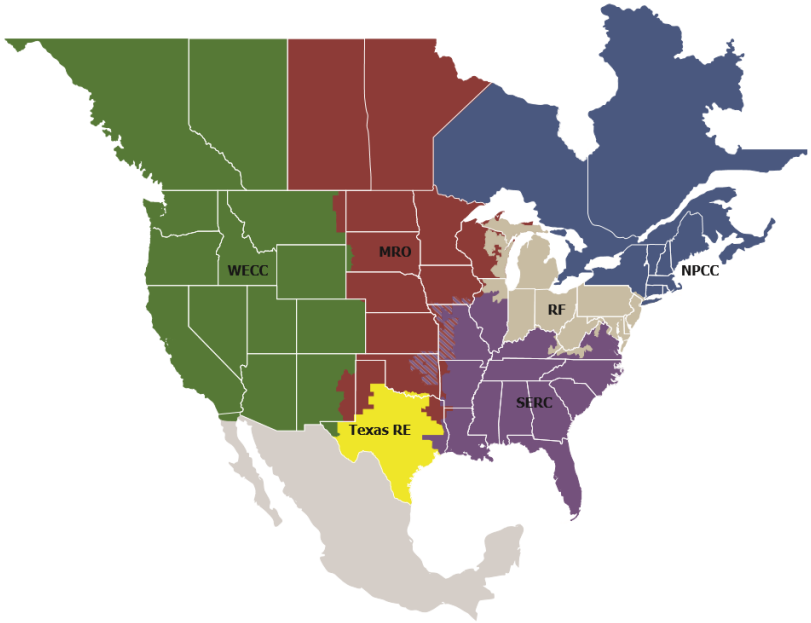
# Preface

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 made up of 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 |

# Executive Summary

The NERC SPIDERWG performed an informal survey of its membership regarding distributed energy resource (DER) modeling practices.[1] The SPIDERWG consists of a wide range of industry experts and a cross-section of industry representation, and 45 entities participated. The survey was primarily geared towards understanding DER modeling practices of Transmission Planners (TPs) and Planning Coordinators (PCs), which are well-represented on SPIDERWG. Results from the survey were analyzed to identify any major trends in DER modeling practices, to characterize the level of detail that TPs and PCs are using for DER modeling, and to identify any potential gaps in these practices that should lead future efforts for SPIDERWG and industry.

## Key Findings

The following key findings were identified from this survey:

- **Questions 2 and 3:** Responding ~~E~~entities ranged in their peak gross load, from over 20,000 MW to less than 500 MW. However, only 18% of respondents have a minimum load over 10,000 MW and slightly over 50% of respondents have a minimum load less than 1,000 MW.
- **Question 5:** Over 30% of respondents reported having over 1,000 MW of installed DER in their footprint, 60% reported having more than 100 MW, and about 40% reported having less than 100 MW.
- **Question 6:** Forecasted DER penetration levels are likely to increase in the coming years, particularly in the planning horizon. Responses shifted towards increased penetration levels by 2024. 16% of respondents, however, did not have a DER forecast out to 2024.
- **Question 7:** 40% of respondents reported observing DER tripping during fault events on the electrical grid. Few entities were able to report a quantitative amount of DER tripping due to limited data available.
- **Question 8:** 40% of respondents reported a shift in peak or light net load hours due to the increased penetration of DERs in the planning timeframe or real-time horizon. Shifts in peak or light net load hours has an impact on the planning assumptions used for BPS reliability assessments, which impacts how NERC TPL-001 reliability studies are executed.
- **Question 9:** About 50% of respondents reported that they receive operational DER information (i.e., DER output) for individual DERs above a size threshold. The majority of remaining respondents do not receive any operational data regarding DERs in their system, even in an aggregated manner.
- **Question 10:** 45% of respondents model DERs explicitly with some representation of the aggregate level of DERs in their system. Most of those respondents model the aggregate DER using a generator record in the simulation tools. 40% of respondents use a negative load or embed DERs into load forecasts (i.e., no explicit dynamic behavior representation of DER in study). 15% use a mix of explicit representation and net load reduction. Entities responding that they use negative load or embedded in the load forecasts stated they do not have tools to represent DERs, do not have enough data to represent DERs in study, or have DER capacity too small to make an impact on the BPS.
- **Question 11:** About 50% of respondents do not have a threshold for modeling utility-scale DERs (U-DERs), i.e., larger DERs that are three-phase installations, and do not model U-DERs in their studies. The remaining respondents use some threshold ranging from less than 1 MW to above 10 MW.

[1] For this survey and its results, distributed energy resources are defined as "any source of electric power located on the distribution system," as defined in the NERC SPIDERWG Terms and Definitions Working Document: https://www.nerc.com/comm/PC/System%20Planning%20Impacts%20from%20Distributed%20Energy%20Re/SPIDERWG%20Terms%20and%20Definitions%20Working%20Document%20rev%201.docx.pdf

- **Question 12:** 62% of respondents stated that they do not model retail-scale DER (R-DER) to represent aggregate levels of DER. 20% use a threshold less than 1 MW and 16% use a threshold between 1 MW and 5 MW.
- **Question 13:** Over 50% of respondents stated that they are not modeling DERs in any aggregated manner in their studies. 22% aggregate based on connection point (i.e., T-D substation). 16% aggregate based on size, fuel type, and connection point.
- **Question 14:** 73% of respondents stated that they do not model DERs in dynamic studies in any fashion; 27% reported that they do model DERs in dynamic studies. Reasons for not modeling DERs in dynamic studies were low amount of DERs in their footprint, unavailability of DER models or tools, and lack of DER information to populate the dynamic models in a meaningful way.
- **Question 15:** Those that are modeling DERs in dynamic studies are using primarily either the DER_A dynamic model or the more detailed second-generation renewable energy system models. No entities reported using the obsolete PV1 or PVD1 models. One entity reported using their own in-house dynamic model.
- **Questions 16 and 17:** About 70% of respondents stated they do not model distributed energy storage in their models; about 30% reported that they do model distributed energy storage. For those that do model distributed energy storage, about 70% stated that they model both full injection and full absorption scenarios; 23% reported modeling the distributed battery at maximum injection level only; one entity reported modeling their distributed storage off-line in studies presently.

## Recommendations and Next Steps

The survey among SPIDERWG members highlights that DER penetrations are rising yet DER data collection, modeling, and modeling practices need to improve across the industry. SPIDERWG will continue to support industry education of DER modeling and studying their impacts to BPS reliability through workshops, webinars, guidelines, and technical reports. Based on the results of the survey of its membership, of which a large plurality of the respondents were registered TPs or PCs[2], SPIDERWG recommends the following to all TPs and PCs to improve DER modeling practices:

1. **TPs and PCs with minimal DER penetration:** TPs and PCs with minimal levels of DERs should continue monitoring DER forecasts and be prepared to incorporate DER models explicitly into planning assessments to understand their potential impacts to BPS reliability for steady-state and dynamic studies. Regardless of DER penetration level, all entities should ~~ensure that DER tracking and data collection is in place~~track its DER growth such that the penetration of DERs can be accounted for in studies and forecasts appropriately.
2. **TPs and PCs with DER penetrations but lack of available DER modeling information:** TPs and PCs in this situation should incorporate the recommendation in NERC *Reliability Guideline: DER Data Collection for Modeling in Transmission Planning Studies*,[3] and work with their respective Distribution Providers to ~~ensure that DER information is collected and made available~~collect appropriate aggregate DER data for the purposes of BPS reliability studies. Without sufficient information regarding DER penetration levels, TPs and PCs cannot execute accurate reliability assessments in the planning horizon. Distribution Providers are strongly recommended to review NERC *Reliability Guideline: Bulk Power System Reliability Perspectives on the Adoption of IEEE 1547-2018*[4] and ensure DER data is being collected and provided to the TP and PC for the purposes of BPS planning assessments.
3. **TPs and PCs seeking guidance for recommended DER modeling practices:** All TPs and PCs should review the recommendations provided in NERC reliability guidelines[5] pertaining to recommended DER modeling practices, and improve their modeling capabilities for representing aggregate levels of DERs. Modeling of DERs is ~~paramount~~ required prior to being able to identifying any potential reliability issues that may be presented with increasing levels of DERs; hence, entities cannot assess impact with DER information and models to study those impacts.

SPIDERWG will ~~recommends that the NERC Reliability and Security Technical Committee (RSTC) should consider~~continue to monitor the current state[6] of DER modeling practices and ensure that any limitations to ~~barriers to~~ the collection of DER information are addressed, such as through a subsequent survey. ~~for the purposes of executing planning assessments are addressed and broken down appropriately.~~

[2] However, each entity can be registered in a number of roles. This means that a plurality could in fact be a majority of the total entities, but not of the functional registration.

[3] This document is available here

[4] This document is available here

[5] This document is available here

[6] This white paper illustrates that DERs are having an impact on the BPS, particularly tripping during fault events, and that entities are using limited or no DER modeling practices in some cases. Further, the extent of DER modeling in dynamic studies is fairly minimal considering the current and projected forecasts of DERs in many footprints. Limitations to DER modeling include lack of information regarding DER installations and limited DER modeling capability.

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# Introduction

Many areas of the North American bulk power system (BPS) are experiencing an increasing penetration of DERs, and this is already affecting TP and PC modeling practices and planning assessments. Representing DERs in planning assessments becomes increasingly important as the penetration of DERs rises across many TP and PC footprints. NERC SPIDERWG has developed reliability guidelines and recommendations for modeling DERs in planning assessments, and continues to support industry awareness and voluntary adoption of these recommendations. Unlike BPS elements that are often modeled explicitly, DERs are usually represented in aggregate due to the small size of individual units. While these resources are located on the distribution system, their growing impact to the BPS cannot be neglected and this is especially true in BPS planning assessments. DER models are needed to perform steady-state power flow, dynamics, short-circuit, electromagnetic transient (EMT), and other types of planning studies. TPs and PCs may need information and data that enable them to develop models of aggregate DERs for planning purposes.

In addition to issuing recommendations and guidelines, SPIDERWG conducted an informal survey of its members to analyze the DER modeling practices of different entities[7]. Understanding the different modeling practices across entities helps identify any gaps and develop a strategy for DER modeling as part of the overall reliable integration of these resources. This white paper discusses the survey questions and the results of the survey.

## DER Survey Setup

The Modeling Subgroup of the NERC SPIDERWG developed and executed an informal survey of its membership. The survey questions were developed by the subgroup and reviewed by the overall SPIDERWG. The survey was specifically geared towards TPs and PCs regarding their modeling practices, and 63 entities within SPIDERWG were asked to participate. A total of 45 of those entities provided a response to the survey. At the time of the survey, the NERC Compliance Registry consists of 75 entities registered as PCs and 206 entities as TPs.[8] Some respondents did not provide completed surveys or answers to specific questions, which is believed to be due to the lack of information. Detailed descriptions of the survey setup and questions are in Appendix A.

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[7] Note that the definition of "DER" has been agreed upon by SPIDERWG members to mean the definition as posted on the SPIDERWG's definitions document here.

[8] Note that the registration criteria for these types of entities is not mutually exclusive.

# Chapter 1: Review and Analysis of DER Survey Responses

The section briefly describes the key findings and takeaways from the analysis of the survey results. Appendix B provides a summary of the responses to the survey questions. Information regarding specific entities' responses are withheld for confidentiality reasons. Relevant Key Findings are summarized in **Table 1.1**

**Table 1.1: Key Findings from Survey Questions**

| # | Related Questions | Key Finding |
|---|---|---|
| 1 | Question 6 | From responses to this question and from comparison of the existing and future amounts of DER, it is seen that in the future with the DER growth, some entities will have an increase in amount of DER that will move them to a higher category. For example, currently, there are eleven entities with the DER capacity between 1000 and 5000 MW, and in the future there will be nine entities in this category. This is because for two entities, the increase in the DER will move them to the category of entities with the DER capacity larger than 5000 MW. The same is true for entities with other DER amounts. |
| 2 | Question 7 | Five respondents observed widespread tripping of the DER with faults[9], none of them has provided the amounts of the DER that were tripped.<br><br>Although not many of the respondents observed widespread DER tripping with faults, this may be due to lack of visibility on the distribution systems and thus, insufficient data on the DER output and tripping. Other prevailing inferences could be that faults didn't occur in their regions or that the DER penetration is so low that any trip of DER is lost in the "noise" of the response. Any of these would result in no observed widespread DER tripping. |
| 3 | Questions 16 and 17 | The reasons for not modeling energy storage explicitly[10] were absence of such storage, absence or lack of data on distribution-connected energy storage, or absence of appropriate tools. The largest category of "No" responses was due to the absence of distribution-connected energy storage, followed by the category of lack of data on distribution-connected energy storage. |

Based on the results of the survey, there are still not many entities that model DER, especially in dynamic stability studies. Significant number of entities model DER netted with load even if the amount of DER in the system is substantial and represents noticeable percentage of the system load. Such amount of DER would have impact on the system performance, but this impact is not considered if the DER are not modeled explicitly in the studies undertaken by TPs, PCs, and other transmission entities. With the growing penetrations of renewable resources, which is currently focused on distribution-connected growth in many electric utilities, modeling DER is becoming more important. Based on the attention to growing penetrations of DER, the SPIDERWG modeling subgroup identified categories of percentage penetration of DER to system peak load (non-coincident) based on the responses to Questions 2, 5, and 6. These can be found in **Table 1.2**[11]. The prominent modeling practices along with the number of entities that fall into this category are also provided in **Table 1.2**.

[9] As this question was put generally, the five responses could indicate either five different faults seen by the different survey responders or it could be a single fault seen by the five different entities.

[10] Responses to the survey varied between assuming an implicit or explicit representation based on inference between the questions. Most assumed explicit representation from the survey question.

[11] One survey result did not have both Questions 5 and 6 completed, which may skew this data slightly.

**Table 1.2: DER Penetration based on Questions 2, 5, and 6**

| Penetration Percentage | # of Entities | Prominent Modeling Practices |
|---|---|---|
| Over 100 Percent | 1 | In this entity DERs were modeled as generators, both in power flow and in dynamic simulations |
| Between 50 percent and 100 percent | 1 | DERs were modeled as negative load due to lack of appropriate modeling tools |
| Between 20 percent and 50 percent | 2 | One entity modeled DERs as negative load, again due to lack of modeling tools. The other modeled DERs as a generator as part of the composite load. DERs were modeled with second generation renewable dynamic models. |
| Between 10 percent and 20 percent | 11 | Out of these 11 entities, three modeled all DER in power flow regardless of size, three others modeled only DER that are larger than 1 MW, two entities modeled in power flow only DER that are larger than 5 MW, one entity modeled DER larger than 10 MW, and two modeled all DER as negative load. As for dynamic simulations, five entities out of these eleven didn't model DER due of absence of data or lack of tools, and six entities modeled DER. Out of these six, five modeled DER as generators with renewable models and one modeled DER some as generators and some as a part of composite load model. |
| Between 5 percent and 10 percent | 20 | In power flow, two entities modeled all DER regardless of size, one modeled only DER that are larger than 1 MW and five modeled them as negative load.<br><br>In dynamic stability, eight entities modeled DER. The explanations of that were absence of tools and absence of DER data and for some entities, that they haven't observed visible impact of the DER on transmission system that would justify modeling DER in dynamic stability. Out of these entities, two modeled DER in power flow as generators or as a part of composite load model, and the ten modeled DER as negative load. In dynamic stability, ten entities did not model DER and the other two modeled DER with the DER_A model. Not modeling DER was explained by the absence of tools, absence of DER data and negligible impact of the DER on transmission system. |
| Less than 1 percent | 9 | Out of these nine entities, seven did not model DER, and two modeled DER in power flow and stability as generators with DER_A model. The survey respondents provided the following reasons for not modeling DER:<br>▪ Low amount of DER in the system<br>▪ Lack of data on the DER locations, and their output<br>▪ Lack of tools to model DER<br>▪ Lack of knowledge of the models |

Significant amount of entities reported that they observed shifting of the system peak because of the DER output. Peak shifting causes TPs and PCs to study more system conditions than the ones that were studied before, and as the current dominant DER technology is solar photovoltaic (PV), creates a need for DER models of high quality and

fidelity[12]. In addition to the system peak and off-peak conditions, such conditions as net system peak when DER output is low and the system load is still high will also need to be studied[13]. These cases may represent hours 18 or 19 on summer weekdays when sun goes down, but the load is high due to air-conditioners. Off-peak system conditions with high DER output and low load, which represent spring weekend afternoons, may also appear to be critical. System conditions with high gross load and high DER output (when these conditions are coincident) may be a challenge for dynamic stability system performance because of stalling of single-phase induction motor load with faults and possible tripping of DER because of low voltages. In all these cases, adequate modeling of the DER is becoming more and more important.

This shifting of system peak because of DER output should be taken into account when attempting to correlate the responses related to Question 3 (minimum gross load) and Question 5 (DER capacity) as shown below in **Figure 1.1** Nevertheless, it is significant and important to recognize that there are many jurisdictions where the ratio of maximum DER capacity to minimum gross load is above 20 percent.

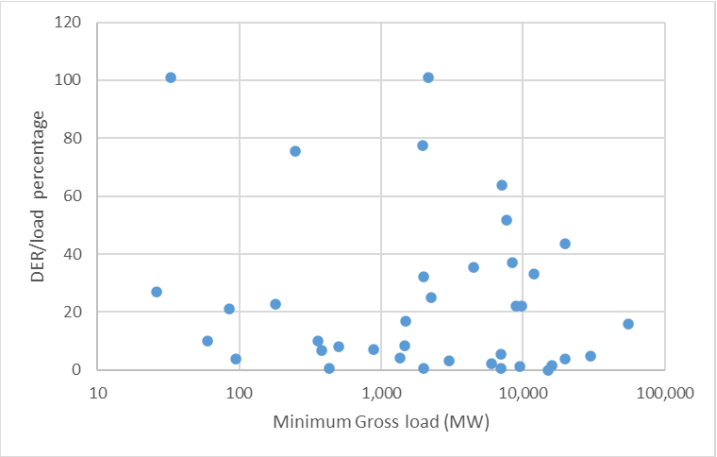
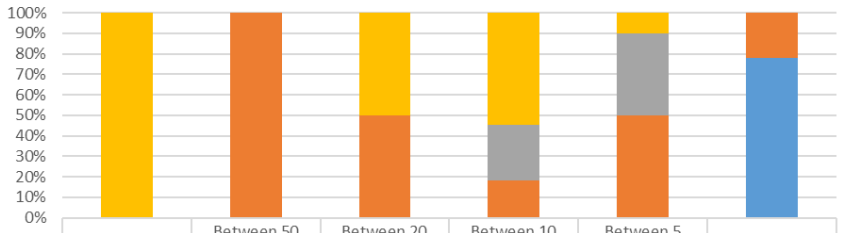



**Figure 1.1: Ratio of Maximum DER capacity to Gross Minimum Load**

From the results in the survey, the SPIDERWG categorized the number of entities by their modeling practices based on their penetration level in **Figure 1.2**. Entities that did not model in powerflow or dynamics were recorded as "no modeling", entities that had powerflow models, but no dynamic models or were modeled as negative load were recorded as "limited modeling", entities that had a dynamic record associated with the DER were recorded with "moderate modeling", and entities that used a dynamic record modeled according to latest guidance available were recorded as "exceptional modeling".

[12] This also applies to BPS-connected solar PV models. To reiterate, all solar PV models will need to modify their available power output based on the time of day selected for the study.

[13] This point is emphasized in "Verification Process for DER Modeling in Interconnection-wide Base Case Creation," published in the June 2020 CIGRE journal: https://e-cigre.org/publication/CSE018-cse-018.




| | Over 100 Percent | Between 50 percent and 100 percent | Between 20 percent and 50 percent | Between 10 percent and 20 percent | Between 5 percent and 10 percent | Less than 1 percent |
|---|---|---|---|---|---|---|
| Exceptional Modeling | 1 | 0 | 1 | 6 | 2 | 0 |
| Moderate Modeling | 0 | 0 | 0 | 3 | 8 | 0 |
| Limited Modeling | 0 | 1 | 1 | 2 | 10 | 2 |
| No modeling | 0 | 0 | 0 | 0 | 0 | 7 |

DER Penetration Percentage

**Figure 1.2: Modeling Practice Percentage by DER Penetration**

Although the respondents used their best knowledge in responses to the survey questions, the responses to the question regarding total amount of the DER in the system may make conclusions of the survey to be less accurate. Since different entities included different types of technologies in the DER definition, the amount of the DER reported answering this question may not reflect actual amount of the DER in the system. These DER were counted differently in different entities. Some included only solar PV, some included also energy storage, and some entities included all kind of generation, and also demand response.

# Appendix A: Detailed Survey Process with Questions

SPIDERWG determined that the best approach would be to conduct the DER survey in several phases, with the first phase containing general questions regarding DER penetrations and basic modeling practices for each entity. The first phase did not include questions about the DER model parameterization or forecasting, and only included data sources in a cursory manner. SPIDERWG recommends conducting a more detailed follow-up survey of modeling practice upon completion and findings from this phase one survey.[14] The following questions were asked in this phase one survey:

1. What is your company's function(s)?[15]
2. What is the peak gross load of your area [MW]?
3. What is the minimum gross load of your area [MW]?
4. What technologies are included in the DER definition used when answering this survey?
5. What is the total capacity of DER connected to your system [MW]?
6. What is the 5-year forecast for DER capacity to be connected to your system in 2024 [MW]?
7. Have you observed widespread tripping of DER due to faults in operations? If yes, how much DER tripped? (can be estimated from change in net load if detailed data is not available)
8. Have you observed shifting peak or light hours of net load due to increasing DER penetration level in planning timeframes or real-time/historical, for any sub-set of the system you are responsible for?
9. Do you receive any DER operational data (e.g., output of DERs)? On what level?
10. How do you model DERs in load flow studies?
11. What is the MW threshold to explicitly model individual (or multiple) U-DERs in the base case?
12. What is the MW threshold to explicitly model aggregate R-DERs in load flow studies?
13. How are DERs being aggregated in your system?
14. Do you model DERs in dynamic studies?
15. Which DER model do you use in your dynamic studies?
16. Do you model distribution-connected energy storage in your system?
17. How do you model energy storage in your system?

[14] Such questions include DER forecasting methods, sources of DER data, impacts of DERs on base case creation, considerations of DERs in special studies, and study impacts of DERs.
[15] Based on the entity's NERC Registration: https://www.nerc.com/pa/comp/Pages/Registration.aspx.

# Appendix B: DER Survey Responses

This appendix provides the aggregated responses from the survey as well as the key takeaways for each question asked. The values in the charts that follow show the number of respondents and the percentage of total respondents, respectively, for each question.

### Question 1

*"What is your company function?"*[16]

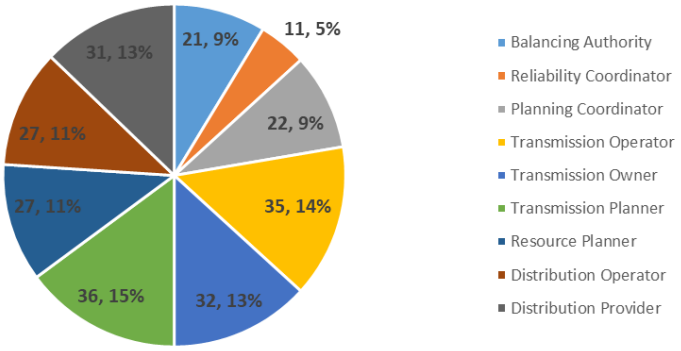



**Figure B.1: Responses to Question 1**

**Key Takeaway – Question 1:**
A wide array of SPIDERWG members responded to this survey, 36 and 22 entities identifying as TPs and PCs, respectively (not mutually exclusive).

[16] Respondents were requested to mark all that apply; hence the higher response count. 45 entities responded to the survey.

## Question 2

*"What is the peak gross load of your area [MW]?"*

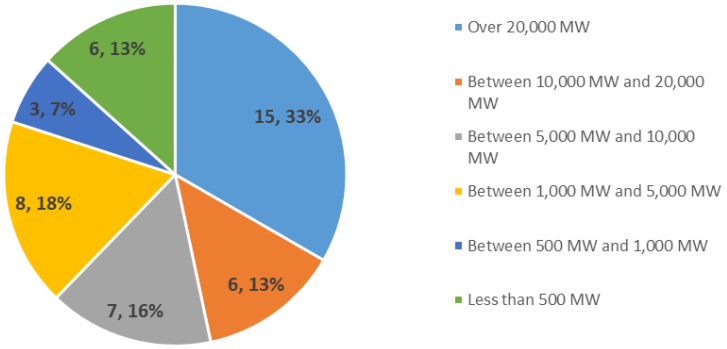



**Figure B.2: Responses to Question 2.**

**Key Takeaway – Question 2:**
Entities ranged in their peak gross load, from over 20,000 MW to less than 500 MW.

## Question 3

*"What is the minimum gross load of your area [MW]?"*

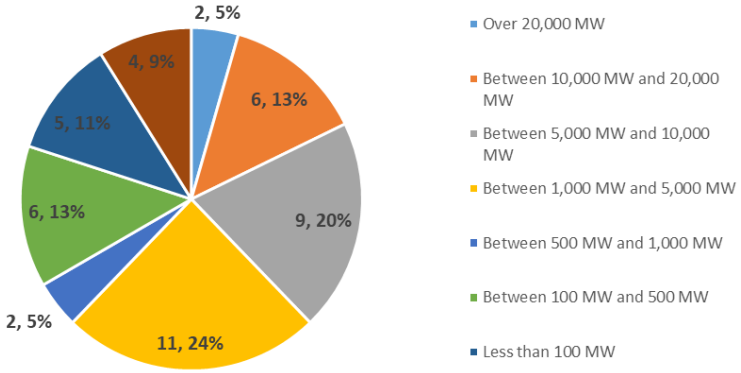



**Figure B.3: Responses to Question 3**

**Key Takeaway – Question 3:**
Entities also ranged in their minimum gross load. However, only 18% of respondents have a minimum load over 10,000 MW and slightly over 50% of respondents have a minimum load less than 1,000 MW.

## Question 4

*"What technologies are included in the DER definition used when answering this survey?"*

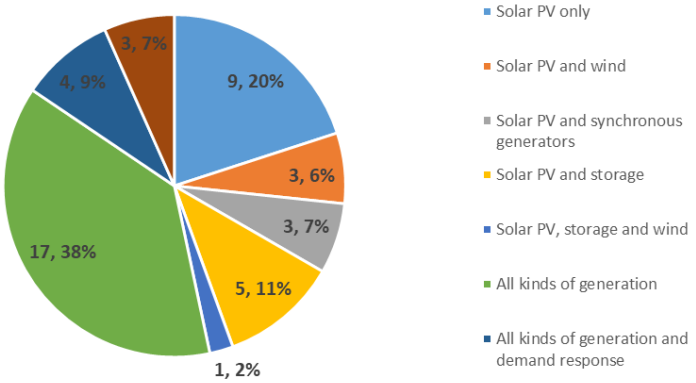



**Figure B.4: Responses to Question 4**

**Key Takeaway – Question 4:**
Some entities included demand response in their definition of DER; however, the majority of respondents focused on "sources of electric power" with most focusing specifically on inverter-based DERs such as solar PV, wind, and battery energy storage.

## Question 5

*"What is the total capacity of DER connected to your system [MW]?"* [17]

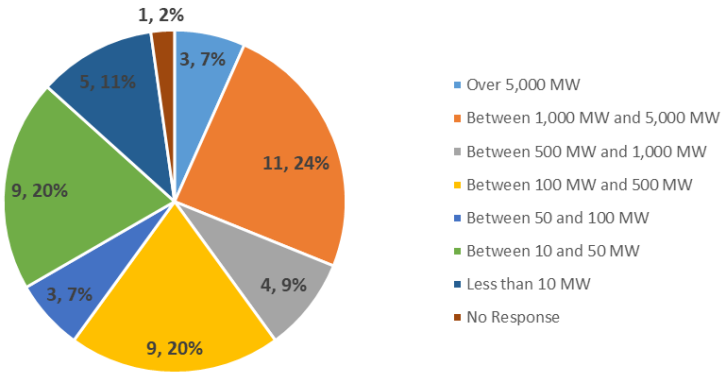



**Figure B.5: Responses to Question 5**

**Key Takeaway – Question 5:**
Over 30% of respondents reported having over 1,000 MW of installed DER in their footprint, 60% reported having more than 100 MW, and about 40% reported having less than 100 MW.

[17] Regarding this question, since different entities include different types of technologies in the DER definition, as seen from the responses to the previous question, the amount of the DER reported answering this question may not reflect actual amount of the DER in the system based on the SPIDERWG definition.

## Question 6

*"What is the 5-year forecast for DER capacity to be connected to your system in 2024 [MW]?"*[18]

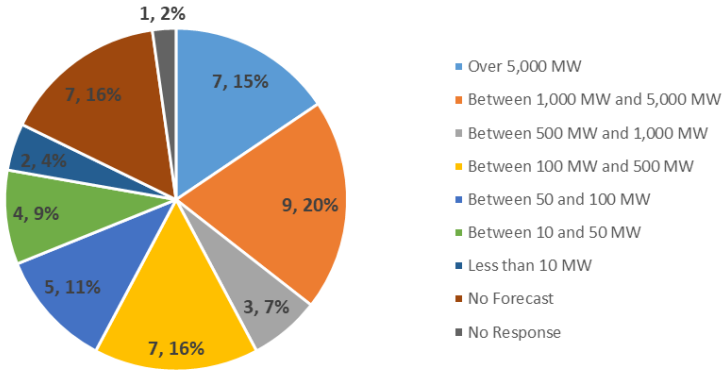



**Figure B.6: Responses to Question 6**

**Key Takeaway – Question 6:**
In 2024, over 35% of respondents reported having over 1,000 MW of installed DER in their footprint, about 60% reported having more than 100 MW, and about 24% reported having less than 100 MW. About 15% of respondents reported having no DER forecast out to 2024.

[18] In summarizing the responses to this question, the DER forecast was compared with the existing amount of DER.

## Question 7

*"Have you observed widespread tripping of DER due to faults in operations? If yes, how much DER tripped?"*[19]

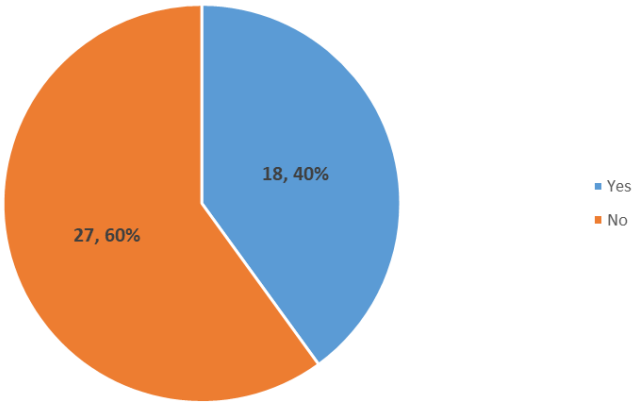



**Figure B.7: Responses to Question 7**

**Key Takeaway – Question 7:**
40% of respondents reported observing widespread tripping of DERs during fault events in their footprint; the remaining 60% had not observed any DER-related tripping events so far.

[19] Note that the response to this question can be estimated from the change in net load if detailed data is not available.

## Question 8

*"Have you observed shifting peak or light hours of net load due to increasing DER penetration level in planning timeframes or real-time/historical, for any sub-set of the system you are responsible for?"*

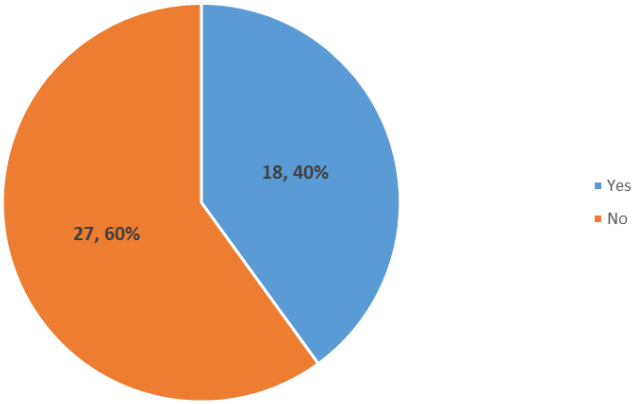



**Figure B.8: Responses to Question 8**

**Key Takeaway – Question 8:**
40% of respondents reported a shift in peak or light net load hours due to the increased penetration of DERs in the planning timeframe or real-time horizon; the remaining 60% had not observed any shift in net loading on their system.

## Question 9

*"Do you receive any DER operational data (e.g., output of DERs)?"*

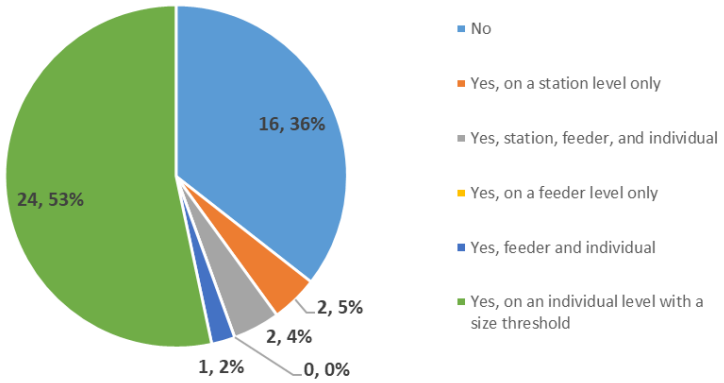



**Figure B.9: Responses to Question 9**

**Key Takeaway – Question 9:**
About 50% of respondents reported that they receive operational DER information (i.e., DER output) for individual DERs above a size threshold. The majority of remaining respondents do not receive any operational data regarding DERs in their system, even in an aggregated manner. Some respondents receive limited DER information on a station- or feeder-level.

## Question 10

*"How do you model DERs in load flow studies?"*[20]

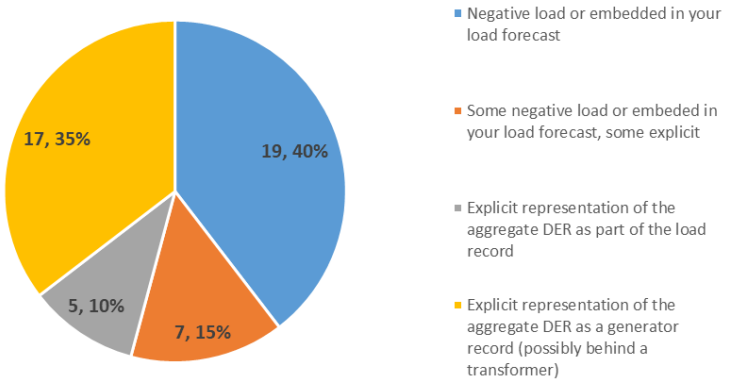



**Figure B.10: Responses to Question 10**

**Key Takeaway – Question 9:**
45% of respondents model DERs explicitly with some representation of the aggregate level of DERs in their system. Most of those respondents model the aggregate DER using a generator record in the simulation tools. 40% of respondents use a negative load or embed DERs into load forecasts (i.e., no DER representation in study). 15% use a mix of explicit representation and net load reduction. Entities responding that they use negative load or embedded in the load forecasts stated they do not have tools to represent DERs, do not have enough data to represent DERs in study, or have DER capacity too small to make an impact on the BPS.

[20] Note that the response to this question include some overlap as respondents reported more than one option.

## Question 11

*"What is the MW threshold to explicitly model individual (or multiple) utility-scale (U-DERs) in the base case?"* [21]

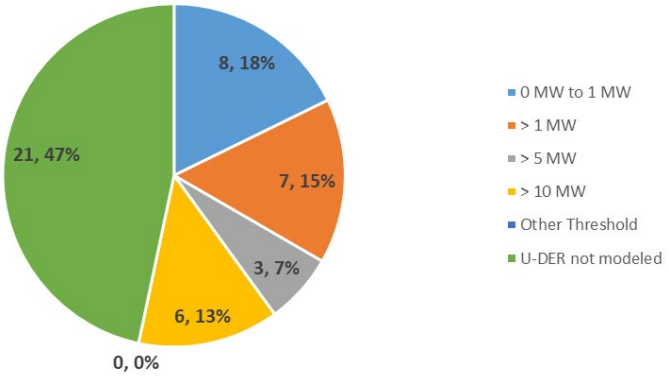



**Figure B.11: Responses to Question 11**

**Key Takeaway – Question 11:**
About 50% of respondents do not have a threshold for modeling utility-scale DERs (i.e., larger DERs that are often three-phase installations), and do not model U-DERs in their studies. 13% use a threshold over 10 MW, 7% use a threshold between 5 MW and 10 MW, 15% use a threshold between 1 MW and 5 MW, and 18% use a threshold less than 1 MW.

## Question 12

*"What is the MW threshold to explicitly model aggregate retail-scale (R-DERs) in load flow studies?"*

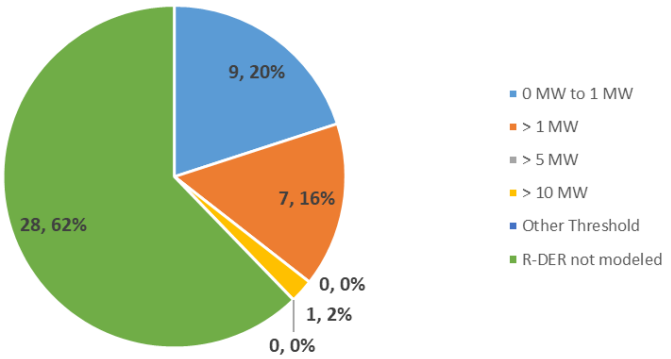



**Figure B.12: Responses to Question 12**

**Key Takeaway – Question 12:**
62% of respondents stated that they do not model R-DER to represent aggregate levels of DER. 20% use a threshold less than 1 MW and 16% use a threshold between 1 MW and 5 MW.

## Question 13

*"How are DERs being aggregated in your system?"*

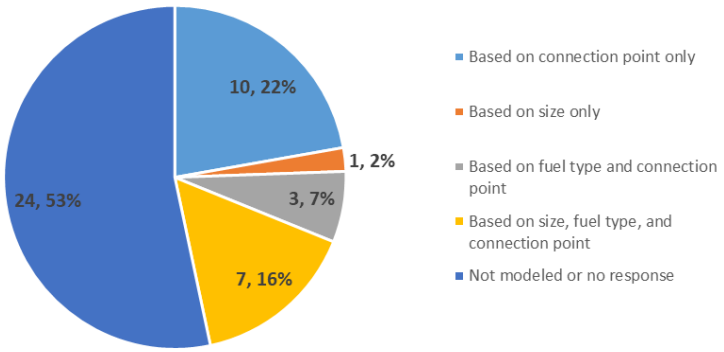



**Figure B.13: Responses to Question 13**

**Key Takeaway – Question 13:**
Over 50% of respondents stated that they are not modeling DERs in any aggregated manner in their studies. 22% aggregate based on connection point (i.e., T-D substation). 16% aggregate based on size, fuel type, and connection point.

## Question 14

*"Do you model DERs in dynamic studies?"*

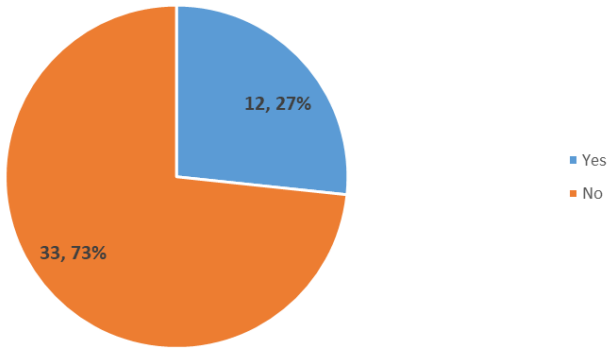



**Figure B.14: Responses to Question 14**

**Key Takeaway – Question 14:**
73% of respondents stated that they do not model DERs in dynamic studies in any fashion; 27% reported that they do model DERs in dynamic studies. Reasons for not modeling DERs in dynamic studies were low amount of DERs in their footprint, unavailability of DER models or tools, and lack of DER information to populate the dynamic models in a meaningful way.

## Question 15

*"Which DER model do you use in your dynamic studies?"*

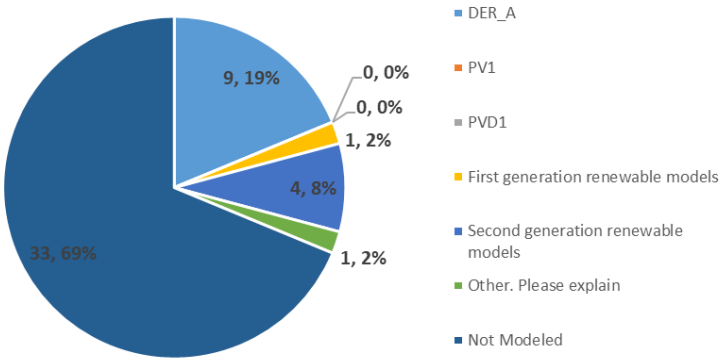



**Figure B.15: Responses to Question 15**

**Key Takeaway – Question 15:**
Most respondents reported not modeling DERs in dynamic studies. Those that are modeling DERs in dynamic studies are using primarily either the DER_A dynamic model or the more detailed second-generation renewable energy system models. No entities reported using the obsolete PV1 or PVD1 models. One entity reported using their own in-house dynamic model.

## Question 16

*"Do you model distribution-connected energy storage in your system?"*

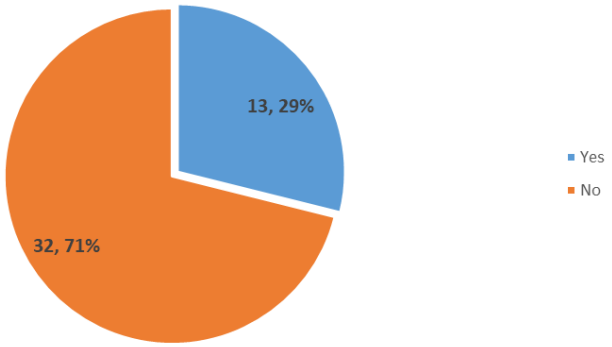



**Figure B.16: Responses to Question 16**

**Key Takeaway – Question 16:**
About 70% of respondents stated they do not model distributed energy storage in their models; about 30% reported that they do model distributed energy storage.

## Question 17

*"How do you model energy storage in your system?"*

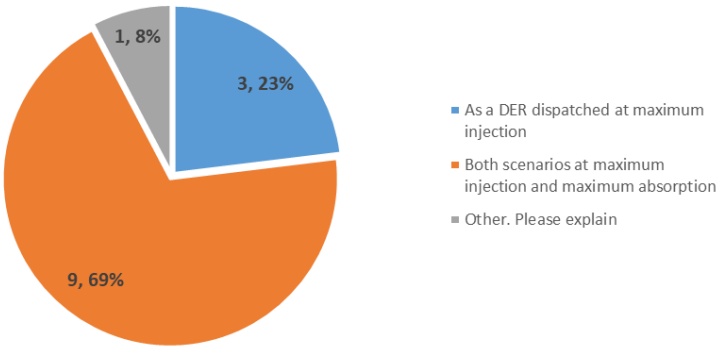



**Figure B.17: Responses to Question 17**

**Key Takeaway – Question 17:**
About 70% of respondents stated that they model both scenarios for full injection and full absorption for the distributed battery output; 23% reported modeling the distributed battery at maximum injection level only; one entity reported modeling their distributed storage off-line in studies presently.

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# SPIDERWG DER Modeling Practices Survey

NERC SPIDERWG – December 2021

This document serves as the SPIDERWG response to the RSTC members who volunteered to review the SPIDERWG white paper on its survey of SPIDERWG members on their DER modeling practices.

## Response to Comments

Table 1 provides a summary of the major themes from RSTC members and the SPIDERWG response. These themes were generalized based on the submitted comments.

**Table 1: Review and Response to Comments**

| Theme | SPIDERWG Response |
|---|---|
| The survey used the term "DER", but "DER" was not defined in the document. | Please see the terms and definitions document that the SPIDERWG has posted that defines DER and DER related concepts here: https://www.nerc.com/comm/RSTC/SPIDERWG/SPIDERWG%20Terms%20and%20Definitions%20Working%20Document.pdf |
| Define and provide a modeling threshold to determine what minimal DER is as well as when it is an impact to the Bulk Electric System | The SPIDERWG intentionally did not quantify a value to model DER as the purpose of the survey was not to define such a threshold but rather to gather information on current modeling practices of entities within SPIDERWG. Due to local transmission and distribution equipment, the impact to the BES is not quantified by a value of DER as it is not correct to draw a line in the sand and say anything below it will not impact the system stability. |
| The accuracy of the results can be skewed since the respondents were informal and were only SPIDERWG members. | SPIDERWG consists of a variety of TPs, PCs, BAs, and many other NERC functional entities. This is a survey of SPIDERWG members, and is accurate based on the polling of SPIDERWG. No alterations to the survey responses were performed. |
| Please perform another survey with extra questions and clarifications to existing questions | SPIDERWG will consider performing another survey of different scope if it is needed. The results from the questions as written in the survey is provided in the white paper. |
| Please clarify specific language used in the survey | SPIDERWG has altered the white paper to provide clarity |
| Recommendations are duplicative and lack alignment between the survey, its results, and the guidance provided in the Reliability Guideline. | SPIDERWG does not see the duplicative recommendation being an issue. The survey showed self-reported modeling practices and the Reliability Guideline demonstrates ways to enhance modeling practices. |
| Participants of the informal survey were subject matter experts that provide input based on their knowledge and their organization's view, but may not fully reflect the views of industry or of various sectors | SPIDERWG believes the results of this survey are informative and provide support to its work. As stated in the white paper, "SPIDERWG will continue to support industry education of DER modeling and studying their impacts to BPS reliability through workshops, webinars, guidelines, and technical reports." |

## Comments Received

The SPIDERWG received the following set of comments from RSTC members and have made changes in the document to reflect the general comments in the section above and some of the specific requests in the sets below.

John Stephens.msg

*John Stephens*

Thank you for the opportunity to review the Survey of DER Modeling Practices.

I would like to offer the following comments:

- Clarify certain definitions related to the survey questions
  - DER – please define DER and specify which technologies (solar, batteries, demand response, fossil generation) are typically employed. Question 4 could be modified to ask "What DER technologies are connected to your system?"
  - GROSS LOAD – Please define this term
  - U-DER and R-DER – Please define these terms
- Question 9: Suggest adding "At what size threshold (MW) do you receive operational data for individual DERs?"
- Question 13:
  - Clarify if the question refers to operational aggregation, or aggregate modelling of DERs?
  - Add response option for "No current aggregation of DERs."
- Question 14: Suggest asking respondents for the same detail expressed in Questions 11 and 12 for load flow studies.
- Question 15: Please define or provide examples of First Generation and Second Generation renewable models
- Suggest asking, "Is DER output metered separately (Gross), or combined with load (Net) at the point of interconnection?"
  - If the answer is Net, "Does your company have a process to model the Gross impact of DERs? Please explain."

David Jacobson.msg

*David Jacobson*

All,

Here are my comments.

In general, the survey is an interesting snapshot in time of where the industry currently is in terms of DER modeling practices. For me, the important information is in the Recommendations and next steps (page vi). I feel the frustration from the SPIDERWG that they have produced a lot of excellent documents but TP's and PC's are so far

inconsistent in their adoption of the recommended practices. I'm not sure if the three recommendations made to TP's and PC's will be sufficient to change industry behavior.

The last sentence on page vi deserves some discussion:
"SPIDERWG recommends that the NERC Reliability and Security Technical Committee (RSTC) should consider the current state of DER modeling practices and ensure that barriers to the collection of DER information for the purposes of executing planning assessments are addressed and broken down appropriately."

Question 14 tried to dive into this question I believe. 73% of respondents said they don't model DERs in dynamic studies in any fashion. The reasons included: were low amount of DERs in their footprint, unavailability of DER models or tools, and lack of DER information to populate the dynamic models in a meaningful way. It's unclear what the real underlying reason is and what the RSTC can do about it. I can see an entity with minimal amount of DER penetration not having any experience with DER modelling. Those with a modest amount should be collecting DER information and there are NERC guides as to what data should be collected. Because DER is on the distribution system, FAC-001 can't be modified to address DER data collection. It's up to organizations to modify their own grid codes and interconnection practices to address. NERC also provides reasonable assumptions in cases where you don't have data collection practices. Perhaps the NERC LTRA could request additional information from PCs related to DER such as do you have DER forecasting, do you have DER tracking and data collection procedures, etc. Peer pressure might be sufficient to change behavior. This might also be something for the North American transmission forum to survey on and document best practices.

Many entities like to use the NERC models developed by the regions in their planning assessments. If these models don't have DER then they won't get studied necessarily. Could NERC request the regions to develop a "special" model that has DER included? Maybe the SPIDERWG could assist PCs in developing those models similar to what the NERC load modeling task force did with dynamic load models. This would give entities a chance to test the robustness of their systems to different assumptions and test the simulation software to see if it can handle an Interconnection wide DER model. I know Interconnection wide dynamic load models didn't work well.

Tools to aggregate DER are not widely known or available. Maybe a collection of real life case studies could be compiled (if they haven't already). How do you translate a 10-year DER forecast for a PC area into reasonable aggregate models for planning assessments? This can be considered a daunting task.

Modification of NERC standards, such as TPL-001, has been proposed to mandate DER modelling. This approach will change industry behavior but the process takes a long time. There needs to be some initial steps to engage industry through voluntary assessments perhaps.

Should the RSTC help flush out some ideas, like the above, and include in this White paper now?

***Todd Lucas***

Todd Lucs.msg

See attached comments from EEI. [SPIDERWG notes that this is the same set of comments as submitted by Rich Hydzik, who submitted comments from EEI]

*Rich Hydzik*

White Paper Titled: Survey of DER Modeling Practices NERC System Planning Impacts from Distributed Energy Resources Working Group (SPIDERWG) White Paper, dated April 2021 (White Paper)

We appreciate the good efforts of the SPIDERWG in developing this White Paper and offer the following feedback.

Since the survey was informal, only included SPIDERWG members, and the accuracy of the results may be skewed because DERs was not defined in the survey, we recommend the data be used as an input for further analysis (and potentially a formal survey) to confirm conclusions of this informal survey and what/if any gaps exist to determine next steps (e.g., a white paper or technical document). Additionally, individuals participating in informal surveys are subject matter experts that are providing input based on their knowledge and potentially their organization's view but may not fully reflect the views of industry or of various sector.

- The recommendations state that there are barriers to the collection of DER information, and we suggest the survey clearly address those barriers and support this position. (Barrier is only mentioned once in the paper but is not clear what the barrier is for DER Modeling.)
- Questions 2, & 3 focus on the Peak and minimum gross load of the respondent's area but never tied that response to Question 5 which asked about the total capacity of DERs connected to the respondent's system. It would seem that aligning this data would be important to understanding how widespread and how much of an impact DERs are having in specific areas. It would also inform the surveyors of whether there is a widespread problem that needs to be addressed.
- The survey conclusions may also be incomplete or potentially flawed because DERs, in the context of this survey, were not defined resulting in a wide range of responses that may have skewed the results. As a next step, we suggest a more defined and directed analysis that might better pinpoint whether problems actually exist.
- Recommendation 1 – it is unclear what constitutes minimal DER penetration. It also states that all entities should ensure that DER tracking and data collection is in place such that the penetration of DERs can be accounted for in studies and forecasts appropriately developed without providing a basis for why this is necessary for entities that are experiencing "minimal DER penetration."
- Recommendation 2- It is unclear the basis for this recommendation, given the survey questions and answers. The survey did not contain a question that asked if TPs and PCs were having difficulty gathering DER data sufficient to conduct their planning models. Moreover, this recommendation may be unnecessary since it is focused on following the recommendations of other guidelines. It seems duplicative and difficult to align the ties between this survey and the recommendation.
- Recommendation 3 –This recommendation also points to another Reliability Guideline as the core of the recommendation without clear alignment between the survey and the recommendation. Additionally, the last sentence in this recommendation needs clarification (Modeling DERs is paramount to identifying any potential reliability issues that may be presented with increasing levels of DERs; hence, entities cannot assess impact with DER information and models to study those impacts).

# Reliability Guideline: Recommended Approaches for UFLS Program Design with Increasing Penetrations of DERs

## Action
Approve

## Summary
The *Reliability Guideline: Recommended Approaches for UFLS Program Design with Increasing Penetrations of DERs* was posted for a 45-day comment period. The SPIDERWG reviewed the comments received and made conforming revisions to the guideline. The SPIDERWG also included metrics to help assess the effectiveness of the guideline and is seeking RSTC approval of the revised guideline.

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# Reliability Guideline

## Recommended Approaches for UFLS Program Design with Increasing Penetrations of DERs

December 2021

RELIABILITY | RESILIENCE | SECURITY




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Atlanta, GA 30326
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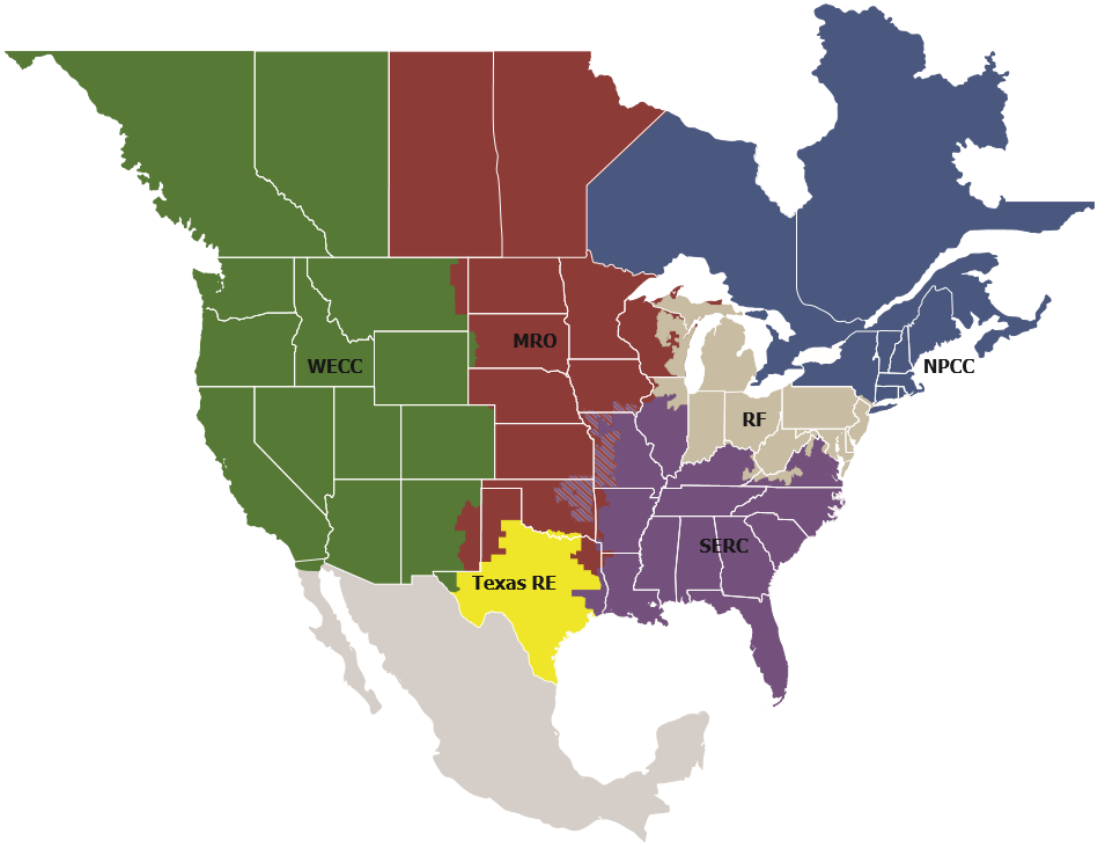
# Preface

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

Reliability | Resilience | Security

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

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




| | |
|---|---|
| **MRO** | Midwest Reliability Organization |
| **NPCC** | Northeast Power Coordinating Council |
| **RF** | ReliabilityFirst |
| **SERC** | SERC Reliability Corporation |
| **Texas RE** | Texas Reliability Entity |
| **WECC** | Western Electricity Coordinating Council |

# 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 nor are they Reliability Standards; however, NERC encourages entities to review, validate, adjust, and/or develop a program with the practices set forth in this guideline. Entities should review this guideline in detail and in conjunction with evaluations of their internal processes and procedures; these reviews could highlight that appropriate changes are needed, and these changes should be done with consideration of system design, configuration, and business practices.

# Metrics

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

**Baseline Metrics**

1. 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);
2. Use and effectiveness of a Reliability Guideline as reported by industry via survey; and
3. 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.

4. No additional metrics

# Executive Summary

The System Planning Impacts from Distributed Energy Resources Working Group (SPIDERWG) Scope Document, as approved by NERC's Planning Committee and replaced by the the Reliability and Security Technical Committee (RSTC), identifies one of SPIDER's key activities to be "provide guidance on impacts that higher penetration of SER may have on system restoration, UVLS, and UFLS, and potential solutions or recommended practices to overcome any identified issues."[1] This document provides guidance on impacts that a higher penetration of DER may have on underfrequency load shedding (UFLS) programs, as well as recommended practices to overcome identified issues. The first section discusses the background and importance of UFLS to BPS reliability, as determined by FERC in Order No. 763.[2] The second section discusses impacts of DER to electrical island-level frequency, which UFLS programs are designed to support.[3] The third section discusses impacts of DER to UFLS program design. The fourth section concludes with recommendations.

In this document, a distributed energy resource (DER) is defined as "any resource on the distribution system that produces electricity and is not otherwise included in the formal NERC definition of the Bulk Electric System (BES).[4] The fundamental premise of this document is as follows:

> *If a significant percentage of load is served by DER, electrical island-level frequency will be impacted. UFLS program design will follow from those impacts.*

From this premise, the importance of studying precisely how electrical island-level frequency will be impacted if a higher percentage of load is served by DER is clear. While NERC has called attention to the potential impact of DER to UFLS programs as early as 2011,[5] recent policy proposals and studies[6] have emphasized the increased need for examinations into the impact of DER to UFLS programs. These programs are developed by Planning Coordinators and implemented by UFLS entities, which may include Transmission Owners and Distribution Providers.[7] This document aims to provide industry notice of and guidance on the impacts of DER to UFLS programs.

In general, entities performing UFLS studies should:

- Include dynamic models of both U-DER and R-DER[8] for DER modeled in their simulation. At a minimum, U-DER voltage and frequency trip models should be included[9].
- Ensure accurate modeling of BPS-connected generators, including:
  - On-line operating reserves
  - Governor response
  - Voltage and frequency trip protection settings
  - Over excitation limitations and under excitation limitations, if present
  - Power system stabilizers, if present

[1] System Planning Impacts from Distributed Energy Resources Working Group (SPIDERWG) Scope Document (December 2018). Available here
[2] *Automatic Underfrequency Load Shedding and Load Shedding Plans Reliability Standards*, Order No. 763, 139 FERC ¶ 61,098 (2012).
[3] The NERC Reliability Standard covering UFLS programs is PRC-006 available here
[4] The SPIDERWG Terms and Definitions Working Document is available here:
[5] See the Special Report: Potential Bulk System Reliability Impacts of Distributed Resources (August 2011) that is available here:
[6] Some of which are included in the appendices of this document. FERC Order 2222 is one example of an enacted proposal, available here
[7] See the IEEE Power & Energy Society Technical Report PES-TR68: *Impact of Inverter Based Generation on Bulk Power System Dynamics and Short-Circuit Performance* (July 2018) that is available here
[8] The terms U-DER and R-DER are modeling terms related to SPIDERWG's recommended modeling framework for DER (as in Chapter 2). The set of terms for SPIDERWG documents is available here
[9] Note that DER modeled as R-DER are usually operated at unity power factor without voltage control, and may trip at or above UFLS load shedding trip settings. Further, smart inverters with voltage and frequency control capabilities that can challenge that assumption.

- Include additional cases reflecting other load conditions than Peak Load when developing the UFLS program.

# Introduction

Synchronous generators in North America operate around a nominal 60 Hz frequency, and frequency reflects the balance of generation and load. Situations where too much generation is produced cause frequency to increase and situations where insufficient generation is available cause frequency to decrease.[10] The change in frequency allows a continuous balance of generation and load at all times.

Underfrequency Load Shedding (UFLS) is a critical safety net designed to stabilize the balance between generation and load when an imbalance between generation and load causes frequency to fall rapidly (e.g., during an islanded operation). Automatic disconnection of end-use loads, typically through tripping of pre-designated distribution circuits or other pre-determined end-use customers, is intended to help recover frequency back to acceptable levels such that generation can rebalance and frequency can stabilize to within reasonable levels. UFLS operations serve to prevent large-scale outages from occurring; however, the BPS is planned, designed, and operated such that these types of safety nets only occur as a last resort for extreme or unexpected disturbances. The concept of UFLS and other safety nets is that controlled tripping of portions of the BPS, including end-use loads, may mitigate the potential for a larger and more widespread blackout.[11]

UFLS programs are designed to disconnect pre-determined end-use loads automatically if frequency falls below pre-specified thresholds. Some UFLS schemes include multiple levels of load disconnection to combat falling frequency to different depths. All UFLS frequency thresholds are set below the expected largest contingency event in each interconnection[12] to avoid spurious load disconnection, and are set to coordinate with generator underfrequency protection to avoid frequency damage.[13] Most commonly, the first stage of UFLS operation typically occurs around 59.5 Hz to 59.3 Hz; however, various regions of the BPS may have different thresholds for UFLS operation based on regional reliability needs.

A logic diagram that describes the high level procedures of a UFLS program is provided in **Figure I.1**. The actions the Planning Coordinators conduct are highlighted in blue and the UFLS Entity[14] actions are in grey. Where Planning Coordinators have overlapping areas, coordination among them and the respective UFLS Entities is required to ensure smooth operation of the designed scheme. As demonstrated in the diagram, there is a tight interchange of data between the Planning Coordinator (PC) and the UFLS Entities. Each PC is expected to provide studies based on knowledge of load and generation data, and the UFLS Entities are expected to be able to provide a firm amount of load disconnection. These two main expectations can be tested with the increase of DER, especially those DERs that are unknown to the PC or UFLS Entities.

[10] These increases and decreases cause electrical machines to speed up or slow down, respectively.

[11] *U.S.-Canada Power System Outage Task Force, Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations* (2004) (Blackout Report).

[12] Refer to the latest version of NERC Reliability Standard BAL-003: https://www.nerc.com/pa/stand/Pages/ReliabilityStandardsUnitedStates.aspx?jurisdiction=United%20States

[13] Refer to the latest version of NERC Reliability Standard PRC-024: https://www.nerc.com/pa/stand/Pages/ReliabilityStandardsUnitedStates.aspx?jurisdiction=United%20States

[14] Per PRC-006, a UFLS entity can be a Transmission Owner (TO) or Distribution Provide (DP)

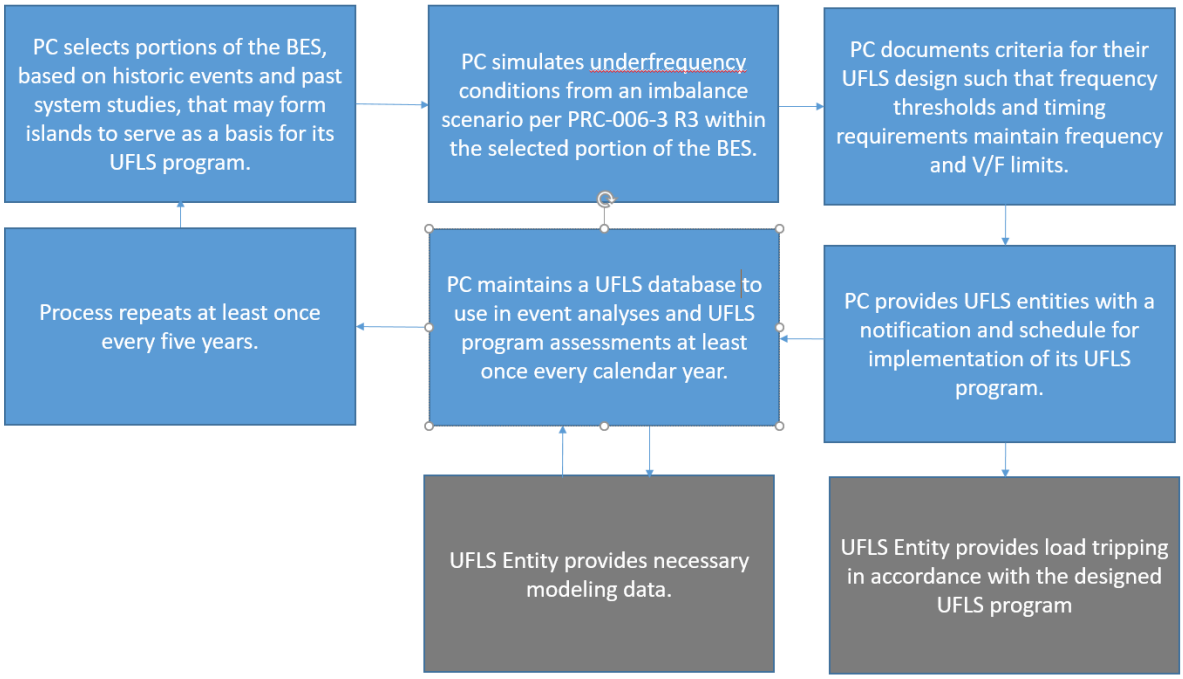



**Figure I.1: Logic Diagram of Generic UFLS Schemes**

# UFLS Program Design and NERC Reliability Standard PRC-006

The Federal Energy Regulatory Commission (FERC) Order No. 763[15] adopted NERC Reliability Standard PRC-006-1 in May 2012, and subsequent non-substantive revisions[16] were made (up to the currently implemented PRC-006-5[17]). In the Order, FERC considered the impact of resources not connected to BES facilities on the development of UFLS programs. The primary focus was on ensuring an understanding and appropriate model to account for non-BES resources in UFLS design simulations. Specifically, in response to NERC's comments to the Notice of Proposed Rulemaking (NOPR), FERC was "persuaded…that Reliability Standard PRC-006-1 does not limit the resources that can be modeled in the UFLS assessments and that power system models used in UFLS assessments generally model all qualifying generation, including resources not directly connected to the bulk electric system."[18] Therefore, while PRC-006 does not require all generating resources to be explicitly modeled in studies for UFLS program design, it is well understood by industry that power flow and dynamic base cases typically represent the vast majority of BPS generating resources, as well as aggregate representation of end-use loads. In addition, more recently, aggregate representation of DERs have been modeled in certain regions. FERC also highlighted in their response to comments from the above NOPR that accurately predicting system performance is critical for UFLS program design simulations, and that "inaccurate models can lead to invalid conclusions which can be detrimental to the analysis and operation of the bulk electric system." As this guideline will describe, a reasonable representation of BPS generation, aggregate load, as well as aggregate DER are critical for appropriate determination of UFLS programs moving forward.

[15] https://www.ferc.gov/CalendarFiles/20120507124509-RM11-20-000a.pdf

[16] Please note that PRC-006-1, PRC-006-2, and PRC-006-3 (effective October 1, 2017) are substantively similar. As stated in FERC's Letter Order on the *Petition of the North American Electric Reliability Corporation for Approval of Proposed Reliability Standard PRC-006-2* (March 4, 2015), PRC-006-2 revised R9 and R10 (adding a language requiring the implementation of corrective action plans) and R15 (adding a requirement for Planning Coordinators to develop Corrective Action Plans). And as indicated in NERC's *Informational Filing regarding Reliability Standard PRC-006-3* (September 5, 2017), PRC-006-3 revised the regional Variance for the Québec Interconnection but made no other changes to PRC-006-2.
https://www.nerc.com/FilingsOrders/us/FERCOrdersRules/PRC-006-2%20Letter%20Order.pdf
https://www.nerc.com/FilingsOrders/us/NERC%20Filings%20to%20FERC%20DL/Ltr%20to%20Sec%20Bose%20re%20PRC-006-3.pdf

[17] Available here: https://www.nerc.com/pa/stand/reliability%20standards/prc-006-5.pdf

[18] NOPR available here and response available here

PRC-006 establishes design and documentation requirements for automatic UFLS programs to arrest declining frequency, assist recovery of frequency following underfrequency events, and provide last resort system preservation measures. UFLS assessments include identification of expected island conditions for each PC area, and simulations of a frequency imbalance between generation and load of up to 25 percent that could occur from such island. The simulations should identify worst-case islanding conditions such that frequency thresholds of UFLS and the corresponding automatic load shedding will stabilize frequency acceptably.

NPCC, SERC, WECC, and the Québec Interconnection[19] have regional differences, particularly related to the UFLS program design considerations and the under- and overfrequency modeling curves. Refer to PRC-006 and the applicable Regional variances of the standard for more details. **Figure I.2** shows an illustration of the design performance and modeling curves for various Interconnections, and how UFLS frequency set points and generator underfrequency trip thresholds can differ across North America.

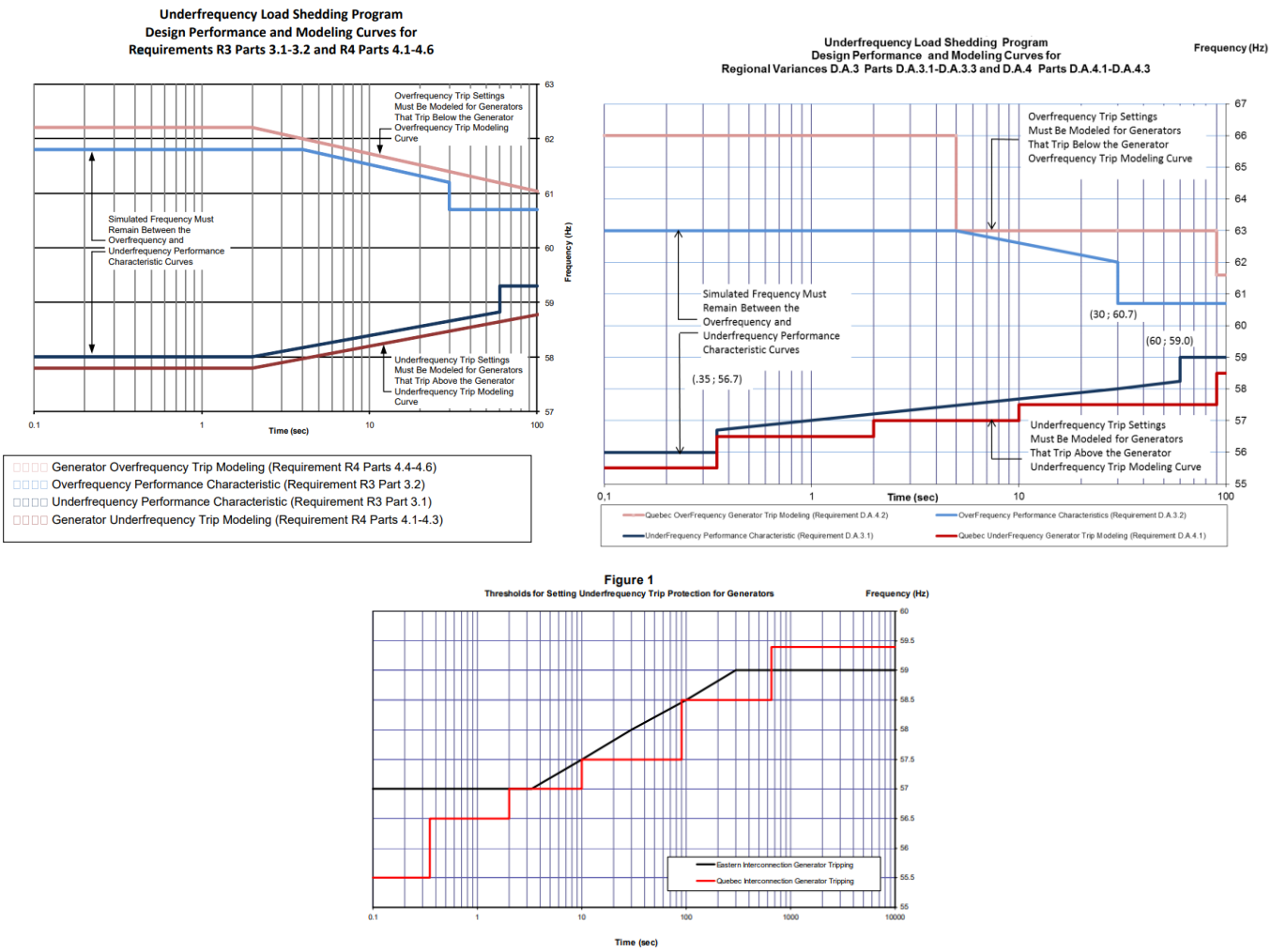



**Figure I.2: UFLS Design and Modeling Curves for Different Interconnections [Taken from PRC-006 and PRC-006-NPCC]**

PRC-006 defines "UFLS entities" as those entities that are "responsible for the ownership, operation, or control of UFLS equipment as required by the UFLS program" established by the PC. UFLS entities may include Transmission

[19] The Quebec Interconnection is part of NPCC but has specific requirements associated with its UFLS program.

Owners (TOs) or Distribution Providers (DPs). UFLS entities are responsible for implementing the UFLS programs developed by the PCs, by determining the appropriate end-use loads or distribution circuits to use in the UFLS program and arming these feeders and circuits with UFLS relays. These activities are intended to meet the load shedding requirements developed by the PCs in order to stabilize any severe imbalance between generation and load after an electrical island has been formed.

To illustrate load shedding requirements in different PC areas, consider **Table I.1** showing the UFLS program frequency set points and amount of load shed at each UFLS stage for ERCOT, ISO New England, and PJM. In ERCOT, all distribution service providers (DSPs) are subject to the same load shed requirements. ISO-NE requires different stages of load shed depending on MW peak net load. PJM, in contrast, requires different levels of shedding for its Mid-Atlantic Control Zone (MACZ), West Control Zone (WCZ), ComEd Control Zone (CECZ), and South Control Zone (SCZ). Appendix A provides a more comprehensive set of UFLS program settings across North America.

**Table I.1: Load Shedding Requirements in ERCOT, ISO New England, and PJM**

| Frequency Set Point (Hz) | ERCOT[1] | ISO New England[2] | | | PJM[3] | | | |
|---|---|---|---|---|---|---|---|---|
| | All DSPs | Peak ≥ 100 | 50 ≤ Peak < 100 | 25 ≤ Peak < 50 | MACZ | WCZ | CECZ | SCZ |
| 59.5 | | 6.5-7.5% | 14-25% | 28-50% | | 5% | | |
| 59.3 | 5% | 6.5-7.5% | | | 10% | 5% | 10% | 10% |
| 59.1 | | 6.5-7.5% | 14-25% | | | 5% | | |
| 59.0 | | | | | | | 10% | 10% |
| 58.9 | 10% | 6.5-7.5% | | | 10% | 5% | | |
| 58.7 | | | | | | 5% | 10% | |
| 58.5 | 10% | | | | 10% | | | 10% |
| 59.5 (10s) | | 2-3% | | | | | | |
| **Total % Shed** | **25%** | **29.5-31.5%** | **28-50%** | **28-50%** | **30%** | **25%** | **30%** | **30%** |

1. See ERCOT Nodal Operating Guides Section 2.6.1(1) for further information.
2. See PRC-006-NPCC-2 for further information. Please note that Peak values are in MW of the TOs', DPs', and DPUFs' load.
3. See PJM Manual 36: System Restoration Section 2.3.2 further information.

## Prior NERC Activities Related to Increasing DER and UFLS

NERC has been focusing on DER impacts to UFLS programs for the past decade. In 2011, the NERC Integration of Variable Generation Task Force (IVGTF) published a *Special Report: Potential Bulk System Reliability Impacts of Distributed Resources*,[20] highlighted that at "high levels of DER, the effectiveness of existing underfrequency load shed schemes may need to be reviewed." The report described that "the profile of circuit loads can change and may no longer conform to the assumed circuit demand curve" with increasing penetrations of DERs, and used solar PV DERs as an example of offsetting gross demand during daytime periods. The example described that "if the circuits are part of an underfrequency load-shed scheme during periods of high DER production, the reduction in system demand may be less than assumed in the design of the scheme and will not result in the loss of load being proportional to the overall demand curve. If the quantity of DER is large enough to actually result in export to the bulk power system, isolation of the circuit as part of a load shed scheme could result in increasing, rather than reducing, system demand." Similarly, the NERC Distributed Energy Resource Task Force (DERTF) published a report in 2017, *Distributed Energy Resources Connection Modeling and Reliability Considerations*[21] highlighting that high

[20] https://www.nerc.com/docs/pc/ivgtf/IVGTF_TF-1-8_Reliability-Impact-Distributed-Resources_Final-Draft_2011.pdf
[21] https://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/Distributed_Energy_Resources_Report.pdf

levels of DER can have an impact on system protection (including safety nets) and will require closer coordination among DPs and transmission entities.

These prior activities serve as a foundation for further exploration into the impacts that DERs can have on UFLS program design, simulations to study UFLS settings, and appropriate operation of UFLS for large system imbalances in generation and load. The planning assessments to develop a UFLS program rely on power system models that should suitably represent the expected system conditions facing the BPS in the future. This may require representing non-BES generating resources as well as end-use loads and DERs. Without appropriate accounting of the performance of these resources, PCs will be challenged in developing UFLS programs that are assured to operate appropriately for the expected frequency excursion event. The critical aspects of designing these UFLS programs pertaining to considering DERs in these studies is described in the following chapters.

# Chapter 1: Impacts of DERs on Electrical Island Frequency

With the increasing penetration of DERs in North America, it is important to understand how DERs may impact or contribute to BPS frequency control and electrical island frequency response with respect to a large imbalance of generation and load. Understanding these impacts or contributions is paramount to developing effective UFLS programs in the face of higher penetrations of DERs in the future. Currently, the dominant technology used in DERs is Solar PV, but can include other technology types. The guidance here reflects the continuation of IBRs sourcing the majority of DERs. High levels of DERs can impact BPS frequency response in at least the following ways:

- Lower system inertia and higher rate-of-change-of-frequency (ROCOF)[22]
- Higher percentage of generating resources unable to provide additional power injection during underfrequency conditions[23]
- Risk of DER tripping on off-nominal frequencies and high ROCOF prior to UFLS operation[24]
- Lack of visibility of DER output by BAs
- Variability and uncertainty in DER output

Consistent with FERC Order No. 763, each of these impacts further emphasizes the importance of modeling aggregate DERs in UFLS studies to ensure appropriate operation of UFLS actions, if needed. Even assuming that ROCOF is slow enough for UFLS to operate effectively and that sufficient frequency responsive resources are available to arrest frequency decline, PCs will need to ensure appropriate modeling of aggregate DER UFLS trip settings as inadvertent tripping of DER post-UFLS action could exacerbate any underfrequency condition[25]. Further, the variability of aggregate DER output and its impact on variations in net load during different operating conditions poses challenges for PCs when performing UFLS studies and determining appropriate UFLS arming levels.

As the percentage of end-use load that is served by DERs increases, the performance characteristics of DERs will have an increasing impact on the imbalances between generation and load in an electrical island. Modeling aggregate amounts of DERs in BPS planning studies, particularly related to PC studies of UFLS program design per PRC-006, is of critical importance to "accurately predict system performance."[26]

## Impact of Modeled DER on UFLS Studies

While each of the identified major impacts of DER can be explored in further detail, a high-level overview of a recent exploratory study by ISO-NE effectively summarizes the impacts DER may have on the study outcomes for UFLS. A more detailed report can be found in Appendix D. Of most important note is the difference between use of net load versus gross load in the simulation, and the impacts DER has on the simulation meeting the regional requirement. The impacts for the ISO-NE are presented in **Figure 1.1.** In the figure, the blue line would not meet the criteria set for the ISO-NE operating as an electrical island as the deficiency caused by DER also tripping after UFLS action would not recover the frequency in time. So, ISO-NE tested a potential design change to their UFLS studies that compensated for the effect DER has on the island during these deficiencies, which resulted in the orange line that met the requirement. Again, more detail is found in Appendix D.

[22] This is of primary concern in areas with high Inverter-Based Resources (IBRs)

[23] Since, currently, the vast majority of DERs operate at maximum available power. This is particularly the case for renewable, inverter-based DERs (e.g., solar PV and small-scale wind DERs). Additionally, this can be due to DERs that do not have a governor to assist in frequency regulation.

[24] This is primarily of concern with regard to legacy DER. However, some distribution utilities are implementing their own DER interconnection protections, or are requiring DER to have trip settings that are not coordinated with UFLS.

[25] Appendix D contains a section on how this can occur in simulations for the design of UFLS programs.

[26] Order No. 763, 139 FERC ¶ 61,098 (2012) at Paragraph 29.

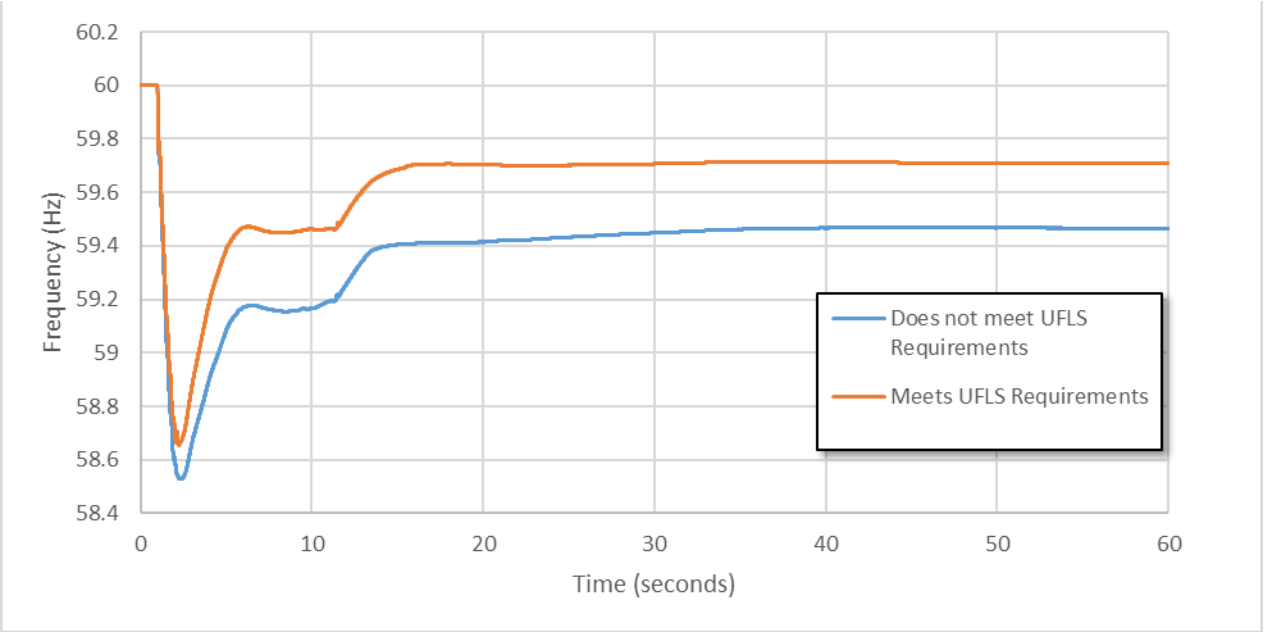



**Figure 1.1: UFLS Program Design Changes Based on DER**

## Lower System Inertia, Higher ROCOF, and Displaced BPS Generation

Decreasing amounts of on-line synchronous inertia and the effect that can have on higher ROCOF have been observed in some Interconnections across North America and also internationally.[27] As the penetrations of both BPS-connected inverter-based resources and DERs (predominantly inverter-based) continue to increase, these resources may offset on-line synchronous generating resources that contribute to system inertia.[28] In response to a sudden loss of generation, kinetic energy is automatically extracted from the on-line synchronous machines, deterring the speed at which frequency will decline. Total system inertia depends on the number and size of on-line synchronous generators and motors. Greater system inertia reduces ROCOF[29] following a disturbance, giving more time for primary frequency response to deploy and help arrest frequency decline prior to any UFLS operation. Therefore, smaller islanded systems (e.g., Texas Interconnection, Quebec Interconnection, Ireland, Hawai'i) are particularly prone to high ROCOF, low system inertia issues and will need to ensure appropriate mitigating steps to ensure reliable operation of the BPS.

Increasing penetrations of aggregate amounts of DERs across each Interconnection may displace BPS-connected generating resources. Further, BPS-connected inverter-based resources are already offsetting BPS synchronous generating resources. Therefore, it is expected that the displacement of synchronous inertia by both resources will cause system inertia to decline and ROCOF to increase. This becomes a problem only when ROCOF rises to a level that becomes unmanageable by the BA in terms of ensuring adequate primary and secondary frequency control.[30] High ROCOF in an electrical island may pose threats to UFLS programs since the available time to operate to adequately recover island frequency becomes shorter. Although UFLS programs could be redesigned to trip at lower frequencies, trip with less intentional time delay, and trip more selectively to accommodate higher ROCOF or changing frequency dynamics, that option may only provide PCs with a temporary solution as system inertia

[27] NERC, "Fast Frequency Response Concepts and Bulk Power System Reliability Needs," Atlanta, GA, 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

[28] https://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/ERSTF%20Framework%20Report%20-%20Final.pdf

[29] Classical factors that determine the ROCOF are system inertia, generation/load imbalance, and load damping response to declining frequencies

[30] See the IEEE Power & Energy Society Technical Report PES-TR68: *Impact of Inverter Based Generation on Bulk Power System Dynamics and Short-Circuit Performance* (July 2018) that is available here

continues to decrease[31]. Alternatively, more UFLS tripping is not a desirable option from a reliability perspective, as the system undergoes continual change in terms of its generation mix.

In the future, DERs may be able to provide fast frequency response (FFR) to support high ROCOF conditions during low synchronous inertia; however, at this time, this is not an expected operating mode for DERs based on current market rules and interconnection requirements. Very high penetrations of DERs and other inverter-based resources will require changes to these paradigms to ensure adequate frequency responsive reserves and performance of BPS frequency during normal and abnormal grid conditions such as large power imbalances. Future studies should take into consideration these changes.

Refer to Appendix B for a description of high ROCOF conditions analyzed by the Australian Energy Market Operator (AEMO) in the South Australia region of their system. Additionally, ISO-NE analyzed the same impact of reduction of inertia due to DER and found that as the DER offset the inertia providing resources in the simulation, not only did the ROCOF increase, but the settling frequencies also were altered. In **Figure 1.2**, the 60 second window of the simulation is shown, where the colors represent an amount of R-DER displacing BPS generation, tabulated in **Table 1.1**. The inertia was reduced in the simulation from the offset discussed above. Looking at the first few seconds of the same comparison in **Figure 1.3**, the recovery of the island frequency is also shown to be much slower with the increase of DER behind UFLS feeders. More details on this particular study can be found in Appendix D.

> **Key Takeaway**
>
> DER displaces BES and BPS connected generation. This impacts the island level frequency by increasing the ROCOF and reduces the island's ability to recover from the imbalance scenario

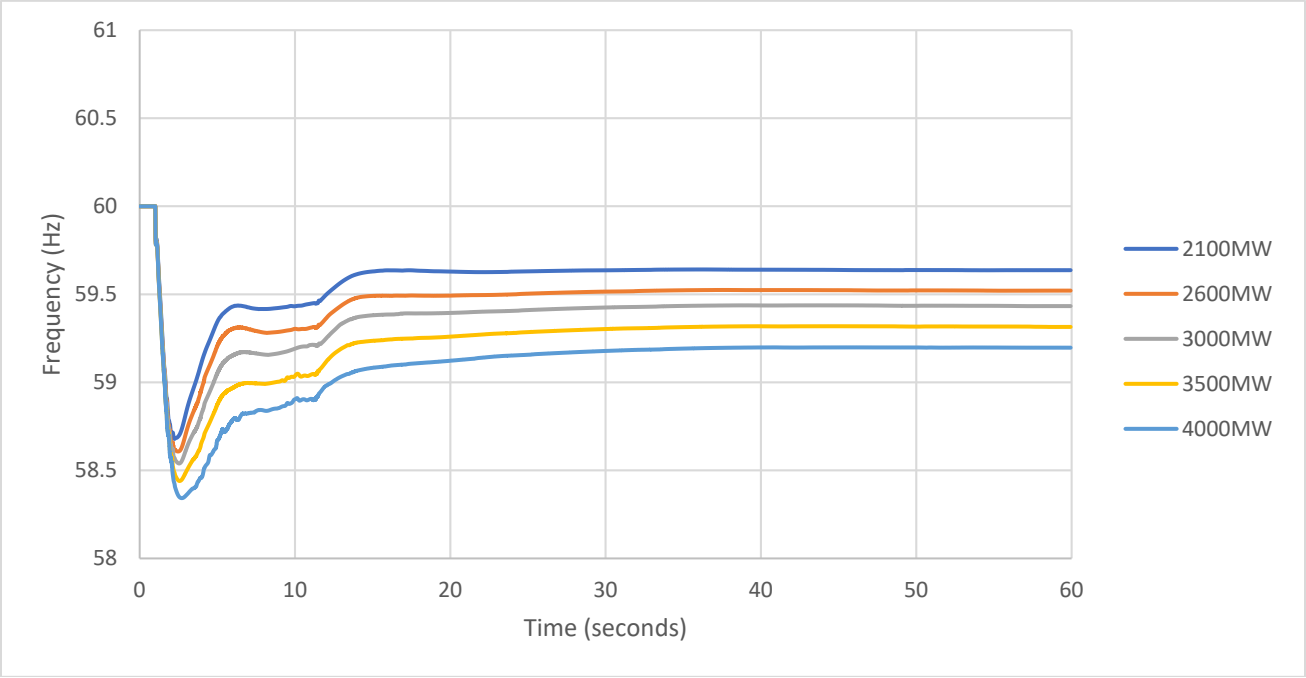



**Figure 1.2: Impact of Increasing DER tripping from UFLS Action on Island Frequency Performance**

[31] Furthermore, the underlying protection philosophy for UFLS should be reconsidered in high-IBR settings as the current UFLS program design protects against first swing stability of synchronous machines.

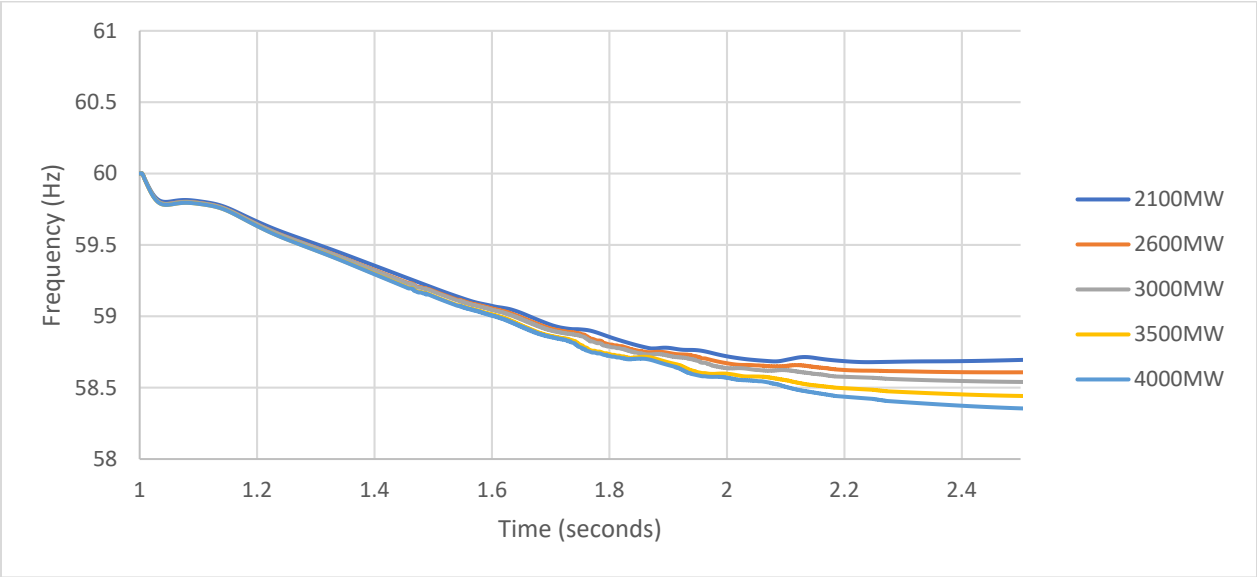



**Figure 1.3: Zoomed in Comparison of Increasing DER tripping from UFLS Action on Island Frequency Performance[32]**

**Table 1.1: Scenario List of DER and UFLS Studies for Island Frequency Performance**

| Scenario | U-DER (MW) | R-DER (MW) | Total (MW) | U-DER Tripped (MW) | R-DER Tripped (MW) |
|---|---|---|---|---|---|
| 1 | 3,097 | 2,100 | 5,270 | 652 | 2,100 |
| 2 | 3,097 | 2,600 | 5,670 | 685 | 2,600 |
| 3 | 3,097 | 3,000 | 6,070 | 689 | 3,000 |
| 4 | 3,097 | 3,500 | 6,570 | 721 | 3,500 |
| 5 | 3,097 | 4,000 | 7,097 | 755 | 4,000 |

## Higher Percentage of Generation Not Providing Frequency Response

Increasing penetration of DERs means that end-use load is increasingly served by DERs rather than BPS-connected generators. Many newly interconnecting resources, particularly renewable energy resources (i.e., inverter-based resources) with low energy costs are often run at maximum available power. Specifically, BPS-connected inverter-based resources are usually operated in this manner unless a curtailment signal[33] has been given by the Balancing Authority (BA) and inverter-based DERs are operated in a similar manner. DERs that are not under the control of the BA are not able to receive a curtailment signal and are typically programmed to provide maximum available power at all times. Therefore, the combination of BPS-connected inverter-based resources and inverter-based DERs operating at maximum available power and unresponsive to curtailment signals will continue to put pressure on the BAs to ensure that sufficient frequency-responsive reserves are available to arrest any large underfrequency events.[34] A lower number of units providing frequency response would result in a smaller subset of resources providing more incremental power to arrest frequency decline. This may put BAs in challenging situations unless long-term studies ensure that sufficient frequency responsive reserves are available.

[32] Note that the plot also demonstrates a change in ROCOF between the 2,100 MW modeled R-DER that trips on UFLS action scenario and the 4,000 MW scenario.

[33] Note that a curtailment signal issued by a BA or other grid operator may enable resources to have additional frequency responsive reserve to support BPS frequency; however, this should be coordinated by the BA and RC to ensure no other BPS performance metrics are adversely impacted.

[34] Synchronous DERs may or may not be frequency responsive; there are generally no requirements to provide that capability.

For UFLS studies, it is important for PCs to ensure their studies are representative of actual system conditions, particularly the dispatch of BPS-connected frequency-responsive resources, the coincident gross load, and gross load dynamics. As DERs continue to offset BPS generation, accurately representing generation dispatch will become more important.

## Risk of Legacy DER Tripping

One key risk that DER, particularly legacy DER, may pose to BPS reliability during severe off-nominal frequency events is the potential for tripping off-line during the event. As a resource providing generation to the BPS, the loss of DER generation will exacerbate any imbalance between generation and load in an underfrequency event and cause frequency to fall further. With high or increasing penetrations of inverters that do not ride through off-nominal frequency events, this could pose a risk to BPS reliability either now or in the future. Further, understanding this risk is critical to designing UFLS programs and performing UFLS studies because these effects will need to be modeled appropriately with reasonable modeling assumptions built into the studies. An example of legacy DER tripping was explored by ISO-NE (See Appendix D for specific details) and demonstrates that the tripping of legacy DER can impact the performance of the feeder in the simulation greatly, as seen in **Figure 1.4**. The blue color is electrical power from the U-DER model, showing a trip due to the overvoltage condition, represented by the orange line. With the legacy DER tripping on overvoltage conditions after the UFLS action, a noticeable decline in frequency can occur.

> **Key Takeaway**
> DER Tripping due to UFLS actions can pose a negative impact to the overall performance of the island in the UFLS Simulations

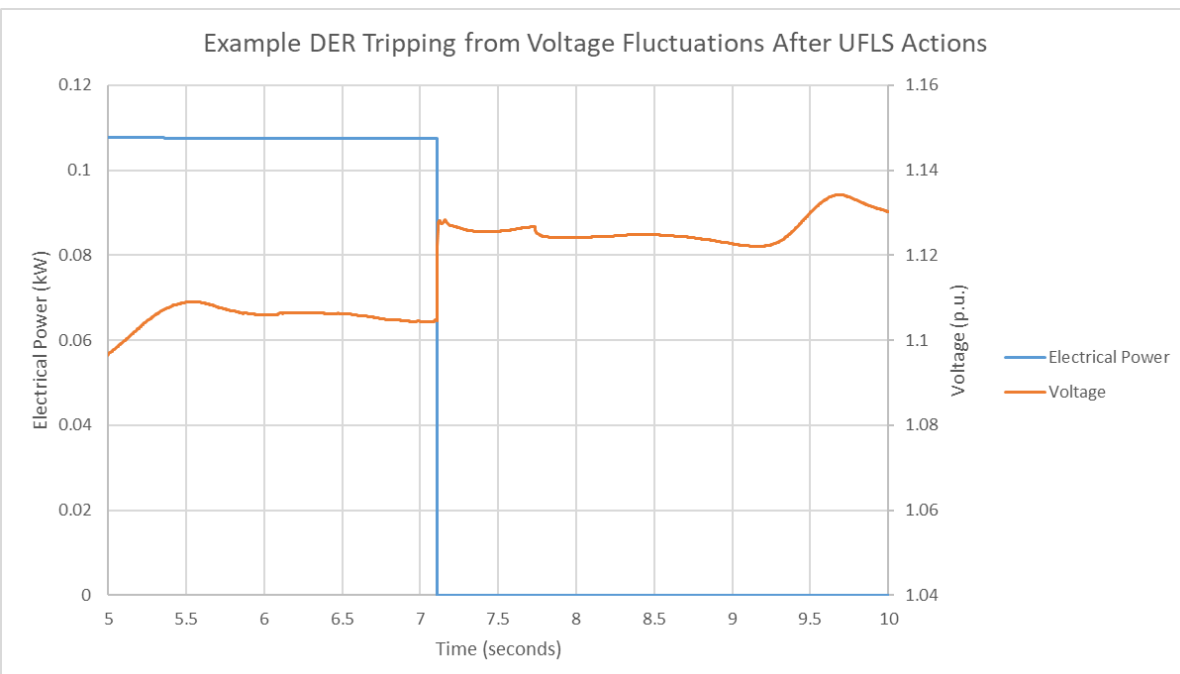



**Figure 1.4: DER Tripping from Voltage Fluctuations after UFLS Actions.**

The vintage of DER plays a key role in whether the resource is prone to tripping on underfrequency conditions. Older, legacy DERs that are subject to early versions of IEEE 1547 may have a propensity to trip at frequencies closer to nominal than newer DERs compliant IEEE 1547-2018, which will ride through a wider range of disturbances.[35] BPS-

[35] While the default frequency trip settings specified in IEEE 1547-2018 should ensure that DER remain connected during frequency events, some distribution utilities are requiring trip settings consistent with the previous IEEE 1547-2003 settings even on DER projects applying

perspectives on the implementation and adoption of IEEE 1547-2018 are found in the *Reliability Guideline: BPS-Perspectives on IEEE 1547-2018*[36]. Consider the following recommendations when developing modeling assumptions for DERs:

- **Availability of DERs Compliant with IEEE 1547 Standard Versions:**[37] DERs installed across North America will have varying vintages based on the availability of DERs compliant with the various revisions of IEEE 1547. **Table 1.2** provides a rough estimate of the availability of compliant DERs, which can be used to determine appropriate DER udnerfrequency trip settings and assumptions for use in UFLS studies.

**Table 1.2: DERs Compliant with IEEE 1547 Revisions [Source: EPRI]**

| Standard Revision | Test Procedures* | Availability of Compliant DERs† |
|---|---|---|
| IEEE 1547-2003 | IEEE 1547.1-2005/UL 1741 "utility interactive" | After January 1, 2007 |
| IEEE 1547a-2014 | IEEE 1547.1/UL 1741 SA "grid support utility interactive" | After September 1, 2017 |
| IEEE 1547-2018 | IEEE 1547.1/UL 1741 SB "grid support utility interactive" | After January 1, 2022 |

* UL 1741 for inverters only[38]

† These are estimated dates only, using conservative assumptions and known implementation plans.

- **DERs Compliant with IEEE 1547-2003:** DERs compliant to IEEE 1547-2003 have the trip characteristics, per the standard, described in **Table 1.3**. During the period of development of IEEE 1547-2003, the general approach was for DERs to disconnect from the grid in the event of any major grid disturbance. This was the predominant mentality at the time since the focus was primarily distribution impacts (i.e., anti-islanding and coordination with reclosers) with minimal BPS considerations due to the low DER penetrations at the time. The general belief is that nearly all DER installations greater than 30 kW compliant with IEEE 1547-2003 used the most conservative trip settings of tripping when frequency falls below 59.8 Hz for more than 0.16 seconds. Therefore, applying this assumption in studies is also reasonable. However, this may require further investigation by the PC and DP and possible verification with frequency disturbance data that could inform modifications to aggregate DER models once more information is available.

**Table 1.3: Underfrequency Trip Settings for IEEE 1547-2003 [Source: IEEE]**

| DER Size | Frequency Range | Clearing Time [s]† |
|---|---|---|
| ≤ 30 kW | < 59.3 | 0.16 |
| > 30 kW | < {59.8 – 57.0}* | 0.16 – 300* |

† For DER ≤ 30 kW, maximum clearing time; for DER > 30 kW, default clearing time.

* Adjustable values

- **DERs Compliant with IEEE 1547a-2014:** For the amendment to IEEE 1547-2003, frequency trip requirements moved to a set of default values with ranges of adjustability, as shown in **Table 1.4**. DERs compliant with IEEE 1547a-2014 are expected to trip, based on the UF2 default value, when frequency falls below 59.5 Hz for more than 2 seconds. While the range of adjustability for both UF1 and UF2 is wider, it is not expected that the default settings were widely changed at this time. Therefore, it is reasonable to assume that DER will trip

equipment certified to the new standard. Some distribution utilities are also applying their own protection equipment (e.g., reclosers) in series with DER interconnections set for very sensitive frequency tripping. These approaches, that is to add equipment or implement settings that are more restrictive than IEEE 1547-2018, are not supported by SPIDERWG.

[36] Available here: https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Guideline_IEEE_1547-2018_BPS_Perspectives.pdf

[37] Inverter manufacturers stated that inverters were still shipped with IEEE 1547-2003 default settings even after UL 1741 SA inverters became available on the market since only a few entities required or desired longer trip times. PCs should assume worst-case trip settings unless authorities governing interconnection requirements (e.g., State regulators) have mandated specific ride-through capabilities and trip settings.

[38] https://standardscatalog.ul.com/standards/en/standard_1741_2

at 59.5 Hz within 2 seconds and at 57.0 Hz within 0.16 seconds. Further investigation by the PC and DP may be needed.

| Table 1.4: Underfrequency Trip Settings for IEEE 1547a-2014 [Source: IEEE] | | | | |
|---|---|---|---|---|
| | Default Settings | | Ranges of Adjustability | |
| Function | Frequency [Hz] | Clearing Time [s] | Frequency [Hz] | Clearing Time [s]† |
| UF1 | < 57.0 | 0.16 | 56–60 | 10 |
| UF2 | < 59.5 | 2.0 | 56–60 | 300 |

† Adjustable time, up to and including

- **DERs Compliant with IEEE 1547-2018:** The new IEEE 1547-2018 version of the standard sets much wider frequency trip settings that ensure DERs can ride through large frequency excursion events to support BPS operation during these abnormal conditions. Table 1.5 shows the default settings and ranges of adjustability. Note that IEEE 1547-2018 requires that the mandatory trip settings for abnormal frequency conditions be coordinated with the Area Electric Power System (EPS) operators as well as the RC. It also mentions that the settings should be coordinated with regional UFLS program design, such that unexpected tripping of DERs compliant with IEEE 1547-2018 is unlikely for abnormal frequency conditions where UFLS operation would occur (i.e., DERs are able to ride through these events and continue providing power to the grid to support system frequency).

| Table 1.5: Mandatory Underfrequency Trip Settings for IEEE 1547-2018 [Source: IEEE] | | | | |
|---|---|---|---|---|
| | Default Settings* | | Ranges of Adjustability | |
| Function | Frequency [Hz] | Clearing Time [s] | Frequency [Hz] | Clearing Time [s] |
| UF1 | < 58.5 | 300 | 50–59 | 180–1,000 |
| UF2 | < 56.5 | 0.16 | 50–57 | 0.16–1,000 |

* Frequency and clearing time set points are field adjustable, and the actual applied trip settings must be specified by the Area EPS operator in coordination with the regional reliability coordinator (i.e., the RC) and typical regional UFLS programs. If the Area EPS operator does not specify any settings, the default settings shall be used.

## Potential DER Tripping on High ROCOF

High ROCOF during islanded conditions may potentially cause legacy DERs to trip based on the settings programmed into the inverter. For example, during the large-scale disturbance in the United Kingdom on August 9, 2019 that resulted in UFLS operation, approximately 350 MW of DERs tripped on ROCOF protection.[39] The disturbance report stated that "some parts of the system may have experienced a [ROCOF] of 0.125 Hz/s."[40] The potential for DERs to trip on high ROCOF, particularly for legacy DERs, should be a consideration when designing UFLS programs.

In North America, there were no direct requirements for ROCOF tripping or ride-through in IEEE 1547-2003 or IEEE 1547a-2014. Clause 4.4 of IEEE 1547-2003 included a requirement that DERs "shall detect the island and cease to energize the Area EPS within two seconds of the formation of an island," and included examples of ways to meet the requirement. Early methods employed by inverters may measure ROCOF to determine if an island exists, with relatively tight thresholds on this protection. Without any standardization, PCs will need to use engineering judgement to ensure that any potential DER tripping on high ROCOF does not pose an unnecessary risk to BPS reliability or UFLS operation. PCs should monitor the ROCOF in their simulations and compare it to experienced ROCOFs in their system to determine the thresholds in their engineering judgement. When the simulation experiences a higher ROCOF, PCs are recommended to perform sensitivity studies that trip various amounts of DER to determine the impact such ROCOF tripping will have on the UFLS program.

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

[40] Many islanded networks are expected to have a ROCOF greater than this level, and some interconnections already have ROCOF conditions that exceed this level for generation loss contingencies. In the UK, a minimum ROCOF setting of .5 Hz/s is required.

IEEE 1547-2018, on the other hand, does address ROCOF ride-through, stating that DERs "shall ride through and shall not trip for frequency excursions" with magnitudes defined in the standard. Table 1.6 shows the requirements for Category I, II, and III DERs[41] related to ROCOF ride-through. Lastly, the standard states that ROCOF should be an average value over a measurement window of at least 0.1 seconds.

**Table 1.6: ROCOF Ride-Through for DER Compliant with IEEE 1547-2018 [Source: IEEE]**

| Category I | Category II | Category III |
|---|---|---|
| 0.5 Hz/s | 2.0 Hz/s | 3.0 Hz/s |

### Potential DER Tripping on High or Low Voltage

During severe contingency events on the BPS, system voltages may experience large variations or swings that could potentially trip DERs. This is more likely a concern or consideration for legacy DERs. Reliability studies should have reasonable assumptions for any potential aggregate DER tripping for abnormal voltage conditions. Refer to the appropriate vintage of IEEE 1547 to determine if voltage-related tripping should be modeled. The DER vintage alone may not fully indicate voltage-responsive protection settings of the inverters. DPs may or may not allow the utilization of DER voltage ride-through capability. Further, feeder-level over-voltage and under-voltage settings may not be coordinated with DER protection[42]. In addition, the load response during events may lead to high or low voltages that may lead to DER tripping. Each of these instances illustrates the need for reliability studies to have aggregate DER tripping parameters.

## Lack of Visibility of DER Output by BAs

Many DERs, particularly behind-the-meter (BTM) DERs are not yet observable by, visible to, or controlled by the Balancing Authority in their efforts to control BPS frequency. While aggregate DERs have an impact on the generation-load balance since they provide power to the end-use loads like any other generating device, in many cases they are not under the control of the BA like BPS-connected or utility-scale DERs. For example, larger DERs may participate in ISO/RTO wholesale markets, and therefore may be observable and controllable by the BA; however, smaller BTM DERs likely are not participating in any markets (nor aggregation) at this time and therefore are not observable or controllable.

While this is more commonly associated with balancing and ramping concerns that the BA must manage (i.e., secondary frequency response), the lack of visibility and controllability poses challenges for establishing UFLS programs and overall frequency control. Without a complete understanding of how generation is serving load, TPs and PCs will have to use engineering judgment for long-term planning studies and BAs and RCs will also need to use engineering judgment for short-term reliability studies or real-time analyses.

## Variability and Uncertainty in DER Output

Most newly interconnecting DERs are renewable energy resources whose output is dictated by atmospheric and meteorological conditions. The industry is becoming increasingly aware of the challenges of variability and the potential risks this poses to BPS reliability for BPS-connected resources such as wind and solar PV. However, adding this degree of variability and uncertainty to the distribution system will pose additional challenges in the future. This,

[41] Category I, II, and III are defined in the IEEE 1547-2018 standard and are described more in detail in the Reliability Guideline on the subject referenced previously.

[42] To complicate the matter, FERC frequency and voltage ride-through requirements may impact local areas depending on the applicability based on the Small Generator Interconnection Procedure and Small Generator Interconnection Agreement for a particular DER installation. Still, SPIDERWG recommends using IEEE 1547 as the basis for DER voltage trip settings in simulation.

coupled with the lack of visibility of DER output, may pose a risk to UFLS programs in their design and implementation..

Variability of DERs affects the amount of net load being served by the BPS at any given time. Increased variability of net load will affect the necessary amount of feeders selected[43] for load shedding needed to arrest and stabilize frequency in the event of a major imbalance between generation and load. Using a single study performed in the long-term planning horizon once every five years, the minimum required per PRC-006, will become increasingly obsolete as the system rapidly changes operating conditions and expected net loading conditions. Further, it becomes increasingly important for PCs to study a wider range of expected operating conditions, particularly with respect to DER output levels, to understand the worst case scenarios regarding UFLS operation. The likelihood and severity of potential under-arming or over-arming of end-use loads as part of the UFLS program design increases drastically when studies performed years prior become obsolete by rapidly changing system conditions presented by DER variability and uncertainty.

## Illustration of DER Output Affecting UFLS Arming

To illustrate, consider a hypothetical PC developing a UFLS program when faced with a reasonably high solar PV DER penetration in their footprint. The PC footprint is summer peaking, and therefore, winter conditions are not typically studied for UFLS operation. The scenarios considered by the PC in this example include:

- **Summer Peak Load (Evening Hours):** During summer peak conditions[44] around 6 PM on a hot summer day, gross load is around 5,000 MW and DER output is near zero. Gross load is therefore the same as net load, and the 25% deficiency studied in this case, as required by PRC-006 Requirement R3, is 1,250 MW. Since DER output is not variable at this time, there is no concern of over-tripping or under-tripping the amount of necessary load to ensure safe recovery of frequency.
- **Spring Light Load (Daytime Hours with High DER Output):** During spring light load conditions around 12 noon on a spring day, gross load is at 3000 MW and solar PV DER output is around 1500 MW. Therefore, the net load is 1500 MW and the 25% deficiency studied in this case is only 375 MW. Since DER output is assumed at its maximum, there is concern of over-tripping or under-tripping the amount of necessary load to ensure safe recovery of frequency.
- **Spring Light Load (Daytime Hours with No DER Output):** During spring light load conditions around 12 noon on a cloudy spring day, gross load is at 3000 MW but solar PV DER output is at 0 MW. Gross and net load are 3000 MW and the 25% deficiency studied in this case is 750 MW. If only the aforementioned spring light load case with DER output assumed was modeled, then the amount of net load tripping would be short by 375 MW (750 MW – 375 MW). This could pose a risk of the UFLS program failing to operate due to the DER variability.
- **Spring Light Load (Nighttime Hours):** During spring light load conditions late in the night on a mild spring day, gross and net load are again 3,000 MW since solar PV DER output is at 0 MW. This matches the case with no DER output during the daytime hours (assumption made here that day and nighttime light load are the same), and the previously studied case can suffice.

The introduction of DERs, especially in high penetration, presents a need for increased studies for UFLS program design due to the variability and uncertainty of DER output on any given day in the future. Even with accurate forecast values, the variability poses challenges for assuring that the UFLS scheme will operate as necessary for any imbalance

[43] Assuming all feeders need to be selected beforehand at time of study and not to change seasonally. Historically, UFLS schemes were designed in a manner that could arm for all seasons making this a good assumption. To reiterate, increased variability on the amount of load shed per armed feeder will increase the total number of feeders armed in the case of a large imbalance between generation and load.

[44] Some electrical islands formed for summer peak loading conditions may include a high penetration of single-phase motor load composition that may have a higher impact during the daytime hours (opposed to the evening hours in the bullet). PCs are encouraged to use this list as an example when identifying the cases to consider when performing studies for UFLS program design.

presented. As shown above, if the assumption of DER on-line is made, there may be a risk of under-arming. Conversely, if the assumption of DER off-line is made, there may be a risk of over-arming during DER output conditions. Where the existence of the amount of DER is unknown, PCs should perform sensitivity studies that range from minimal DER output to a large penetration of DER output when designing a UFLS program.

Some entities have moved to adaptive UFLS program designs in the face of high DER penetration conditions as the only viable solution to ensure correct operation of UFLS at any given time. For example Hawai'i Electric Light (HELCO) has implemented an adaptive UFLS program that has seen successes and challenges with high penetrations of DER, which is described in more detail in Appendix C.

# Chapter 2: Impact of DER on UFLS Program Design Studies

As described in Chapter 1, DERs can have a significant impact on BPS frequency control and frequency response of the Interconnection. UFLS programs are built on long-term planning studies of expected future conditions, which often use interconnection-wide base cases as the starting point in which an islanded footprint for each PC is created. PCs will often adjust the dynamic models and operating conditions to represent conservative yet realistic assumptions of generation, load, transmission equipment, and DERs. Chapter 1 highlighted the effects that DERs can have on BPS frequency response; this chapter will focus on how those effects are represented in planning studies used to design the UFLS program. Following FERC Order No. 763, PCs will need to model DERs within their respective studied island network to account for the performance and potential tripping of DERs. Specifically, PCs should consider the following impacts of DERs when performing UFLS studies:

- Modeling DERs in the steady-state and dynamic case used for the UFLS study
- Appropriately allocating DERs to aggregate load representations
- Accurately performing any expected frequency- and voltage-related tripping from DERs in simulation
- Potential responsiveness of DER to changes in frequency.
- Variability and uncertainty in DER output
  - DER output masking the total gross load
- Selection of distribution circuits or end-use loads

## Recommended DER Modeling Framework

To account for the steady-state and dynamic effects that DERs can have on BPS performance during abnormal grid conditions, it is recommended that aggregate DERs be modeled in planning assessments using guidance proposed in previous NERC Reliability Guidelines (see **Figure 2.1**).[45] The DER modeling framework characterizes DERs as either utility-scale DER (U-DER) or retail-scale (R-DER). These definitions are intended to be adapted to specific TP and PC planning practices and specific DER installations, as needed. For reference, from the previous DER modeling recommendations, these definitions are provided here as a reference:

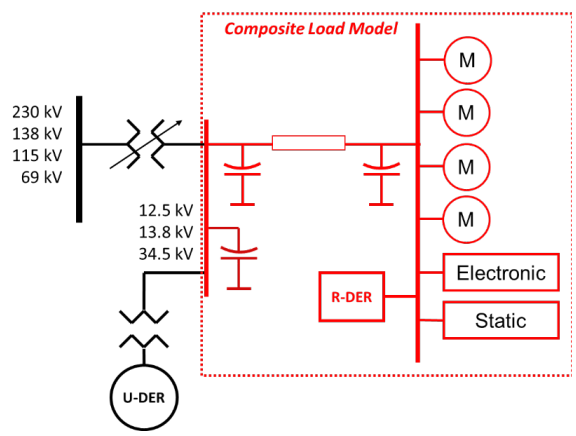



**Figure 2.1: DER Modeling Framework**

- **U-DER:** DERs directly connected to, or closely connected to, the distribution bus or connected to the distribution bus through a dedicated, non-load serving feeder.[46] These resources are typically three-phase interconnections and can range in capacity (e.g., 0.5 to 20 MW).
- **R-DER:** DERs that offset customer load, including residential,[47] commercial, and industrial customers. Typically, the residential units are single-phase while the commercial and industrial units can be single- or three-phase facilities.

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

[46] Some entities have chosen to model large U-DER that are connected to load-serving feeders as U-DER explicitly in the base case as well. This has been demonstrated as an effective means of representing U-DER as well, and is a reasonable adaptation of the definition above.

[47] This also applies to community DERs that do not serve any load directly but are interconnected directly to a single-phase or three-phase distribution load serving feeder. Also, U-DER that is not connected close to the distribution bus or on dedicated feeders.

Both U-DERs and R-DERs can be differentiated and modeled in power flow base cases and dynamic simulations. TPs and PCs have successfully adapted these general definitions for their system, and often refer to U-DER and R-DER for the purposes of modeling aggregate DERs. Aggregate amounts of all DERs should be accounted for in either U-DER or R-DER models in the base case, and TPs and PCs may establish requirements for modeling either individual large U-DER as well as aggregate amounts of the remaining DER as R-DER.

# Studied Operating Conditions for UFLS Studies

Many of the fundamental concepts of UFLS program design do not change with the introduction of DERs in the islanded network. PCs still need to determine the operating conditions and dynamic response of interconnected resources (including generation and load-side resources) that cause the most severe frequency deviation for a defined percentage deficiency between generation and load in their islanded system. However, determining these conditions requires close consideration of aggregate levels of DER particularly as DER penetration levels increase.

## Selecting Islanded Networks, Tripping Boundaries, and Study Techniques

Per Requirements R1 and R2 of PRC-006, each PC is required to "select portions of the BES (including portions of neighboring systems) that may form islands" and to "identify one or more islands to serve as a basis for designing its UFLS program". In many parts of the North American BPS, UFLS programs are regional in nature and as such the Regional Entity may conduct all or part of the reliability studies[48]. Choosing the PC area is the most logical and convenient island for study purposes for each PC. However, some areas may span multiple PC footprints (e.g., the northern part of the New England system with the New Brunswick system) and are therefore used in the same islanded system and coordinated among PCs.

The islanding boundary is critical to determine because it creates a complete island separated from the rest of the interconnected BPS for study purposes. Therefore, attention can be devoted to accurate modeling within the islanded network boundaries.

There are multiple ways to simulate the imbalance scenario, including but not limited to:

- **Reduced Power Flow Case Converting Tie Lines to Equivalent Loads:** A reduced power flow base case is created for each electrical island. All tie lines connecting the electrical island at the pre-defined island boundaries are replaced with equivalent loads or generators. In the dynamic simulation, those equivalent loads forming the electrical island and any additional BPS generation necessary to create the required load-generation imbalance are tripped simultaneously.
- **Islanding during Dynamic Simulation:** This approach uses the entire interconnection-wide or regional dynamic model rather than a reduced power flow model. The overall base case is configured with appropriate intertie flows into the PC area, and the electrical island is formed during the dynamic simulation by simultaneously tripping interties and any additional generation. Since this method uses the full interconnection-wide dynamic model with multiple islands formed, the simulations tend to run slow due to computation limitations in the commercial tools; therefore, this method may not be used by PCs for this reason.
- **Island in Power Flow Base Case:** In this case, the electrical island is the same as the PC area (i.e., islanded networks such as ERCOT) and this is reflected in the power flow base case. Therefore, the full amount of imbalance is created by tripping generating resources during the dynamic simulation.

[48] In some instances, it may be possible nearly all of the program design, including threshold setting, is done by the Regional Entity. This, however, does not alter the guidance this document sets forth for those conducting the studies and obtaining necessary information.

## Recommended Interpretation of Generation-Load Imbalance

Requirement R3 of PRC-006 states that each PC shall develop a UFLS program that meets a set of performance characteristics in simulations of underfrequency conditions resulting from an imbalance scenario[49] defined as:

$$imbalance = \frac{load - actual\ generation\ output}{load}$$

The term "load" is not capitalized[50] and therefore is subject to interpretation in PRC-006 regarding whether this term refers to gross load or net load in situations of DER penetration. A lowercase "load" term is only used in Requirement R3 of PRC-006-5 (although it shows up in other places in regional variances of the standard); however, how this term is used should be closely reviewed by PCs.

Consider how this equation is implemented in UFLS studies. The generation-load imbalance has historically been simulated by tripping boundary tie lines importing power to the island. This island can be formed in a single PC's boundary, or during the formation of an island with multiple PC's boundaries. These ties lines, referred to in the following equations, are based on the formed island for the study and are not necessarily (but can include) the interties for area to area connection or between PCs. They are the lines that connect the identified island in the study to other areas of the Interconnection. Any additional power needed to make up the imbalance will come from BPS generators within the island being tripped off-line at the same time as the tie lines are tripped. Therefore, historically this equation actually should be:

$$imbalance = \frac{load - (BPS\ generator\ output + (tie\ line\ imports - tie\ line\ exports))}{load}$$

Now consider the inclusion of DER into the scenario, which is differentiated from gross load. DER is inherently a generating resource that should be explicitly considered in the equation. This can be accounted for using the following equation:

$$imbalance = \frac{gross\ load - (BPS\ generator\ output + (tie\ line\ imports - tie\ line\ exports) + DER\ output)}{gross\ load}$$

With a fixed imbalance (i.e., 25%) set per the requirements of PRC-006, the equation can be rearranged to:

$$BPS\ generator\ output + (tie\ line\ imports - tie\ line\ exports) + DER\ output = 75\% * \ gross\ load$$

The combination of BPS generation output, net tie line interchange (imports–exports), and DER output needs to be reduced to 75% of the gross load to meet the requirements of PRC-006. To determine the worst case scenario (albeit more extreme than even the 25% imbalance itself), the reductions are typically prioritized using the following rules of thumb:

1. **Tie Line Imports and Exports:** The base case should be set up with reasonable expectations for imports and exports. Creating an artificial base case with heavy tie line imports that exceed any expected operating condition do not reflect a reasonable operating state and should not be used in simulation. However, the case can be set up to utilize the import capability to a reasonably justifiable level and exports can be minimized to the extent possible. Therefore, when the dynamic simulation trips the boundary lines of the islanded network, the reduction in tie line imports (less any exports) can be used to cover a portion of the deficiency.

[49] Note that this imbalance is limited to 25% in PRC-006 and may have regional variances.

[50] As in, does not refer to a term used in the NERC Glossary of Terms: https://www.nerc.com/files/glossary_of_terms.pdf

2. **BPS Generation Tripping:** The next resource that should be tripped are BPS-connected generating resources, and should generally be resources that are able to provide frequency response since this creates a reasonable yet conservative assumption. If non-frequency responsive resources were tripped, this would lean towards an optimistic assumption with additional frequency responsive resources on-line than may occur in reality. Therefore, the remaining imbalance should consist of tripping frequency-responsive resources or a mix of responsive and non-responsive resources, using engineering judgment.
3. **DER Tripping:** DERs should be tripped last as part of the imbalance created to satisfy the requirements of the standard. As described in the preceding bullet, these resources are not typically frequency responsive and therefore tripping them to create the imbalance will be an optimistic assumption. Further, legacy DERs may have a risk of tripping on underfrequency conditions prior to reaching UFLS threshold, which will exacerbate the imbalance during the dynamic simulation. This needs to be analyzed by the PC as part of the dynamic simulation results separately from creating the imbalance. This is described in subsequent sub-sections of this chapter.

Each PC (or entity performing the UFLS study) is encouraged to make judgement calls that are consistent with their system when creating the imbalance scenario to study their UFLS scheme. If this entails DER tripping as part of the imbalance, such decisions should be documented with technical rationale so that the impact of DER on the program design is fully captured in the program.

### *Example of System Setup using the Priority List*

Consider an example system with the following assumed conditions for study:

- Condition: Spring Light Load
- Time of Day: 12 noon
- Gross Load: 2,000 MW
- DER Output: 500 MW
- Imports: 300 MW
- BPS Generation: 1,200 MW

The PC needs to determine an imbalance for this study case, which is based on 75% of the 2,000 MW gross load; meaning that BPS generation and net intertie flows collectively must be reduced to 1,500 MW (i.e., reduced by 500 MW). In this case, imports are at 300 MW and will be cut as part of the contingency definition. Therefore, an additional 200 MW of BPS-connected generation would be tripped at the same time as the severance from the rest of the system. Alternately, the imports may be modified to 0 MW and an electrical island formed prior to the dynamic simulation, where then 500 MW of BPS-connected generation would be tripped.

> **Key Takeaway**
> Assuming net load for calculating the deficiency to study the performance of an island per PRC-006 may not fully test the robustness of the UFLS program.

Assuming net load for calculating the generation-demand imbalance to study the performance of an electrical island per PRC-006 may not fully test the robustness of the UFLS program and could lead to under-tripping of sufficient load to arrest severe frequency excursions.

## Selecting Appropriate Study Cases

There are not specific requirements in the latest version of PRC-006 that require a specific operating condition to be studied (i.e., season, demand levels, BPS-connected inverter-based resource levels, or DER levels). Many entities may currently use summer peak conditions since these are traditionally the most stressed scenario in terms of a

generation-load imbalance. However, electrical islands with high penetrations of inverter-based resources and DERs will likely change those most severe conditions. The risk of UFLS operation will likely increase during conditions of low gross load and high inverter-based resources (due to higher ROCOF, lower amount of on-line frequency responsive reserves, etc.). A one-size-fits-all approach likely will not work in the future, and PCs will need to evaluate which scenarios are most appropriate. Selecting an appropriate set of study cases is an important aspect in performing UFLS studies and developing a robust UFLS program. **Table 2.1** illustrates an example consideration of two distinct operating conditions.

| Table 2.1: Example Comparison of Study Case Scenarios | | |
|---|---|---|
| **Characteristic** | **Peak Summer Scenario*** | **Light Spring Scenario†** |
| Demand | Maximum | Minimum |
| Synchronous Generation | Relatively higher dispatch, units on-line | Relatively lower dispatch, units off-line |
| Synchronous Inertia | Higher | Lower |
| BPS-Connected Inverter-Based Generation | Likely moderate solar PV and wind outputs, may be more conservative based on time of day and other assumptions | High solar PV and wind output, high renewables scenario |
| DER | Moderate to low DER (likely solar PV) output | High DER (likely solar PV) output |
| Imbalance | Highest level of imbalance due to gross load being at its maximum | Lowest level of imbalance due to gross load being at or near its minimum |
| ROCOF | Relatively lower ROCOF, less ROCOF concern | Relatively higher ROCOF, high ROCOF concern based on Interconnection |
| DER Tripping | Less DER output so less potential magnitude of DER tripping with UFLS operations; possible DER tripping on frequency and ROCOF conditions | Higher DER output so greater potential magnitude of DER tripping with UFLS operations; possible DER tripping on frequency and ROCOF conditions |

* Peak Demand, Moderate Renewables Output, Moderate DER Output
† Light Demand, High Renewables Output, High DER Output

For each study case selected, an appropriate imbalance condition and setup of dynamic simulation will need to be conducted, and multiple study cases should be used to determine the worst-case frequency response[51] performance for the electrical island. In most cases, at least a summer peak load and a spring light load operating condition are used to perform UFLS studies to ensure that the UFLS program is able to securely operate under these diverse sets of operating conditions. As the penetration of DERs continues to increase, additional cases should at least be considered by the PC and potentially studied based on identified risks. These cases include, but are not limited to, the following:

- **Summer Peak Demand (Evening Hours):** Summer peak conditions often occur during the early or later evening hours when DER output may be significantly reduced due to solar irradiance at that time. For systems that are summer-peaking, this condition will mathematically result in the largest imbalance necessary to meet the percentage defined in PRC-006.
- **Winter Peak Demand (Nighttime Hours):** Systems with a winter peaking demand will need to consider these operating conditions as their highest peak gross demand conditions for the same reasons described in the summer peak demand case above.
- **Light Demand with High Renewables:** Light demand conditions typically occur during shoulder season, and most notably during the spring. Further, situations with high renewables output for BPS-connected inverter-based resources can drive low inertia operating conditions with the potential of high rate-of-change-of-

[51] As identified by the PC or entity performing the UFLS study for the UFLS program. Note that selection of "worst" here will vary between regions.

frequency (ROCOF).[52] This can pose a challenge for UFLS schemes to operate correctly. Regarding DER, there are two considerations that should be made:

- **Light Demand with High DER Output:** Systems with a notable penetration of solar PV DERs should consider studying daytime light demand cases coupled with high output from BPS-connected inverter-based resources. Ensure that a reasonable amount of BPS frequency responsive and spinning reserves are carried in the simulation to reflect realistic operating conditions, and ensure that BPS generators are dispatched at reasonable output levels.
- **Light Demand with Low DER Output (Nighttime Hours):** Systems with or without a notable penetration of solar PV DERs should also consider studying nighttime light demand hours (where solar PV DERs are off-line, where applicable) as an alternative dispatch scenario. It is possible that these conditions are prone to higher wind power output. Other dispatch considerations may exist that warrant an additional data point to ensure UFLS operates as designed.

As mentioned, these are example considerations that should be made when selecting simulation cases for UFLS studies. Multiple cases should be studied to ensure reliable and secure operation of the UFLS under different operating conditions.

### *Example of Study Case Selection and Creation*

Consider an example comparison between summer peak and light spring conditions, and how different system conditions affect case setup and generation dispatch assumptions. **Table 2.2** shows the CAISO base case setup from the 2019 CAISO Transmission Plan. The starting cases were modified to match imports to the 25% required generation-demand imbalance for each case; therefore, interties can be tripped during the contingency to match the required imbalance. This resulted in only a 3,500 MW change in tie line flows in the summer peak case, but a 19,500 MW change in the light spring case. Lastly, the percentage of local demand served by DER and BPS-connected internal island generation were calculated. In the summer case, DERs in the local island are only serving 0.5% of demand and will likely have little to no impact on UFLS. However, in the light spring scenario, DERs make up over 48% of the local island generation mix for the modified case from the light spring base case opposed to the 0.5% for the modified case built on the summer peak conditions. This illustrates how DERs can have a substantial impact to UFLS design, particularly during conditions when DER output is expected to be at or near its peak output conditions (which can often be coincident with low demand conditions, particularly for distributed solar PV).

**Table 2.2: Example Comparison of Study Cases using CAISO Base Case Data**

| Characteristic | Peak Summer Scenario | Light Spring Scenario |
|---|---|---|
| Time of Day | Hour Ending 19 | Hour Ending 13 |
| Gross Demand [MW] | 57,510 | 31,050 |
| DER Output [MW] | 280 | 15,050 |
| Pre-Contingency Case Imports [MW] | 17,840 | -11,860 (export) |
| BPS Generation On-line [MW] | 41,160 | 29,060 |
| | | |
| 25% Gross Demand Deficit | 14,378 | 7,763 |

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

| Table 2.2: Example Comparison of Study Cases using CAISO Base Case Data | | |
|---|---|---|
| **Characteristic** | **Peak Summer Scenario** | **Light Spring Scenario** |
| Modified Case Imports [MW] | 14,378 | 7,763 |
| Modified Case BPS Generation On-line [MW] | 44,622 | 9,437 |
| | | |
| DER as % of Gross Demand | 0.5% | 48.4% |
| Local BPS Generation as % of Gross Demand | 77.6% | 30.4% |

# Modeling DER Tripping

Modeling any tripping of aggregate DERs is an important aspect of performing UFLS studies. As described in Chapter 1, DER can trip for different reasons and each of those reasons will be described here regarding how to account for or model these potential initiators of DER tripping. The aspects worth considering include, but are not limited to, the following:

- **DER Tripping on Underfrequency Conditions:** DERs across the electrical island may trip if their terminal measurement of frequency falls below pre-defined threshold values. Trip thresholds are likely based on existing regional or local interconnection requirements or may be default values specified in equipment standards such as IEEE 1547. These thresholds can be modeled in the DER dynamic models or with supplemental dynamic models.
- **DER Tripping on High ROCOF Conditions:** During the initial onset of the frequency imbalance, ROCOF within the electrical island may be high, and may lead to tripping. Considerations for potential tripping on high ROCOF should be made; however, existing dynamic models may be limited in capturing aggregate DER tripping on ROCOF.
- **DER Tripping as Part of UFLS Operation:** Modeling considerations will need to be made to accurately represent the potential of DER tripping as part of the UFLS operations. Modeling potential DER tripping from UFLS operations will determine the appropriate modeling practices for power flow and dynamic models.

Each of these modeling considerations is described below in more detail.

## Dynamic Modeling of Aggregate DER Tripping on Underfrequency

As described above, the DER modeling framework recommends aggregate modeling of DERs in planning assessments, either as a U-DER or R-DER representation in the power flow base case and in dynamic simulations. U-DER are modeled with a generator record and can have an associated DER_A dynamic model applied; R-DER are accounted as part of the load record and can also have a DER_A dynamic model applied. The DER_A dynamic model includes frequency-related tripping, as described in NERC *Reliability Guideline: Parameterization of the DER_A Model*.[53] In the model, a filtered frequency signal is passed to frequency relay logic within the DER_A model. The frequency tripping logic is shown in **Figure 2.2**. If frequency tripping is enabled by the *ftripflag* parameter, voltage is above a defined threshold,[54] and frequency falls below the defined underfrequency trip setting,

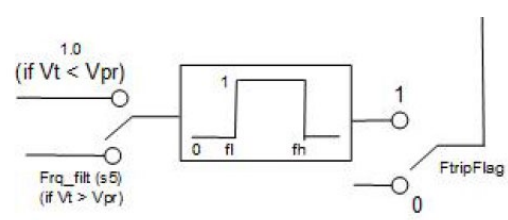



**Figure 2.2: DER_A Frequency Tripping Logic [Source: PSS®E]**

[53] https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability_Guideline_DER_A_Parameterization.pdf
[54] Low voltage inhibit logic prevents frequency passing to the relay model if terminal voltage is less than or equal to the defined threshold.

the full amount of DER modeled for that specific instance of the model will trip with a time delay set with the *tfl* and *tfh* parameters.

As DER trip off-line due to underfrequency, frequency will continue to decline. Therefore, reasonable modeling of potential DER tripping is important since it may exacerbate the generation-load imbalance. Sensitivity studies should consider any conservative assumptions on potential DER tripping to determine if this has any adverse impacts to the UFLS program.

## Modeling Potential DER Tripping on High ROCOF

As mentioned in Chapter 1, high ROCOF during electrical island conditions could cause legacy DERs to trip[55]. Since there are no requirements or standards to develop ROCOF protection models, PCs should use engineering judgement[56] to determine any potential risks that additional DER tripping on high ROCOF could pose to electrical island frequency control. There are currently no known dynamic models in commercially available software tools that can be applied to both U-DER (generator records) and R-DER (either as part of the load record or as a component in a modular dynamic load model) for ROCOF protection.[57]

Therefore, the best approach is for PCs to perform dynamic simulations and to identify the highest ROCOF observed during the simulation. If ROCOF exceeds a pre-determined threshold where DER may be prone to trip (based on engineering judgment), then the PC should determine an appropriate amount of DER to trip at that point in the simulation and re-run the simulation to see how this sensitivity affects frequency response of the electrical island. Sensitivity studies are recommended to ensure that any excess DER tripping does not affect performance of the UFLS program.

## Modeling DER Tripping as Part of UFLS Operation

Modeling considerations should capture potential tripping of aggregate DER as part of UFLS operations once frequency has fallen below UFLS thresholds. There are many different ways to model and represent this tripping in the dynamic simulations, and requires coordination between power flow and dynamics modeling practices. UFLS programs often have multiple load shed set points that trigger local load shedding relays based on pre-defined frequency trip settings. As described, this includes specific distribution feeders or individual large end-use customers based on the UFLS program design. In the power flow and dynamic models, the individual feeders or groups of loads are often lumped together as an aggregate load and may need to be separated or partially tripped in the studies based on utility practices.

Consider **Figure 2.3** to illustrate this concept. Assume that this system has U-DER modeled as individual generator records and R-DER included as part of the load record and composite load model (in dynamics). Assume that if U-DERs mainly are fed from the distribution substation and therefore are generally not tripped as part of the UFLS program. Therefore, there is no issue with modeling the consequential tripping of these resources as part of the UFLS operation. However, this is a concern for the R-DERs since some amount of R-DERs may be tripped when distribution circuits are tripped during UFLS operations. In this case, different

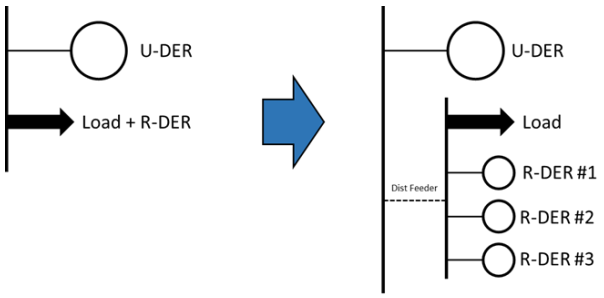



**Figure 2.3: Example Modeling of Aggregate DERs Tripping with UFLS**

[55] Additional ROCOF protections implemented by, or required by, the DP may also result in DER tripping.
[56] Discussions with equipment manufacturers that supply equipment to DER may prove useful in developing a ROCOF threshold.
[57] Some load shedding relay models such as *lsdt7* or *lsdt8* are able to model ROCOF-based tripping; however, these models are applied to load records and therefore will trip the load component in addition to any DERs. Therefore, these models are generally not well suited for capturing DER tripping for R-DER modeled as part of the composite load model.

amounts of DERs will be tripped at different UFLS operations based on the percentage of load tripped (assuming an equal distribution of R-DER across the various feeders).

Now assume that the load and R-DERs will be tripped at three stages (e.g., at 59.5, 59.1, and 58.7 Hz). An issue arises in the dynamics modeling of the R-DERs included as part of the load record and composite load model. The DER_A dynamic model trips the full amount of DER once the frequency trip threshold is crossed, and does not include staged trip settings in the dynamic model. Therefore, the R-DERs will need to be separated out into individual models that can be separately tripped. In the dynamic model, the frequency trip settings can be configured for each R-DER to trip once the pre-established thresholds are crossed. For example, R-DER #1 may trip at 59.5 Hz, R-DER #2 may trip at 59.1 Hz, and R-DER #3 may trip at 58.7 Hz.

Regarding the stand-alone load record (since the DER elements have been separated), load shedding relay models such as *lsdt7* or *lsdt8* can be used to trigger various levels of load tripping all combined into one dynamic load model record.

As mentioned, there are multiple ways this can be set up in the power flow and dynamics models; however, this modeling practice is described here as a reference for consideration.

## Performing Dynamic Simulations for UFLS Studies

As UFLS program design requires a Planning Coordinator level study to initiate the design of the UFLS program, the PC will need to make sure a few key parts in the dynamic simulation are maintained in order to effectively capture the impacts DER has to the design of the UFLS program. These considerations will provide a heightened confidence that the UFLS program captures the impact of DER. Key considerations for Planning Coordinators performing UFLS studies with aggregate DER represented include the following:

- Planning Coordinators should include dynamic models of both U-DER and R-DER. At a minimum, U-DER voltage and frequency trip models should be included[58].
- Planning Coordinators should ensure accurate modeling of BPS-connected generators, including:
  - On-line operating reserves
  - Governor response
  - Voltage and frequency trip protection settings
  - Over excitation limitations and under excitation limitations, if present
  - Power system stabilizers, if present
- Planning Coordinators should ensure that additional cases are tested that reflect load conditions other than Peak Load.

[58] Note that DER modeled as R-DER are usually operated at unity power factor without voltage control, and may trip at or above UFLS load shedding trip settings. Further, smart inverters with voltage and frequency control capabilities that can challenge that assumption.

# Chapter 3: Coordinating with UFLS Entities

PRC-006 includes the term "UFLS entity", referring to "all entities that are responsible for the ownership, operation, or control of UFLS equipment as required by the UFLS program established by the [PCs]." These entities may include TOs, DPs, or both. Requirement R3 describes that the PC, upon developing its UFLS program, will notify UFLS entities within its area of the program and a schedule for implementation by UFLS entities. Requirement R9 states that each UFLS entity shall "provide automatic tripping of Load in accordance with the UFLS program design and schedule for implementation…" for any PC areas in which it owns assets. UFLS entities are provided discretion regarding how specific levels of load are armed and automatically tripped to meet the requirements outlined by the PCs as part of the UFLS program. This leaves flexibility for UFLS entities to determine which distribution circuits, feeders, or specific loads will be selected. UFLS Entities often will consider excluding critical loads (e.g. hospitals) when selecting feeders with system elements to disconnect. With the growing penetrations of DERs, it is important for UFLS entities and PCs to closely communicate how specific loads or feeders are selected and to what degree DERs could impact effective UFLS operation. **Figure 3.1** shows the continuous feedback loop needed as DERs penetrations continue to increase.

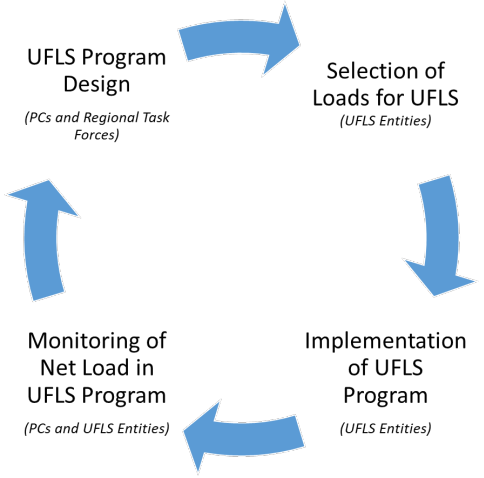



**Figure 3.1: Continuous Feedback Loop of UFLS Program Design**

There are key factors that should be considered by UFLS entities in coordination with their respective PCs when developing and implementing effective UFLS programs in the face of increasing DER penetrations. These include, but are not limited to, the following:

- Selection of loads participating in the UFLS program
- Impacts of DER aggregators or other DER management systems
- Coordination of any advanced DER controls (i.e., frequency response capability) with regional UFLS settings and BPS frequency control needs
- Coordination of UFLS with distribution-level hosting capacity analysis

These are described in more detail in the following subsections.

## Selection of Loads Participating in the UFLS Program

The primary focus or concern regarding the coordination between UFLS Program design and implementation is the selection of feeders or end-use load customers participating in the UFLS Program. UFLS studies are only required to be performed on a periodic basis; however, DER penetrations are rapidly growing in many areas of North America and can potentially impact the effectiveness of UFLS operations. An unexpected growth in DERs on a distribution circuit selected for participating in a UFLS program can reduce the effectiveness of the UFLS operation to ensure reliable operation of the BPS. Therefore, it is appropriate for the UFLS entities to monitor their net load armed for their UFLS program in order to ensure the targets are correct for a given snapshot in time.

> **Key Takeaway:**
> An unexpected growth in DERs on a distribution circuit selected for participating in a UFLS program can reduce the effectiveness of the UFLS operation to ensure reliable operation of the BPS.

For example, assume a UFLS entity has been assigned 50 MW of net demand that should be armed and automatically shed as part of UFLS operations. The

UFLS studies performed by the PC did not account for DERs in this area since penetrations were not significant. However, in the last few years, the DP has observed fairly significant DER growth on many of its feeders. The PC had previously only used peak summer conditions for UFLS studies, which assume peak demand around 6 PM. Therefore, during peak demand conditions, the UFLS would likely still operate as expected since DER output may be low at this time. However, during low demand, high solar DER output, low system inertia conditions, the DERs may reduce the net demand on those feeders. Assume now that instead of having 50 MW armed, the UFLS entity inadvertently is only arming 30 MW. The deficit of 20 MW of net demand armed will cause insufficient amounts of load shedding to ensure the UFLS operates as expected. Further, if this is observed across multiple DPs (i.e., UFLS entities), the issues may be further exacerbated across a wider PC footprint.

During the selection of loads participating in the UFLS program, UFLS entities, in particular DPs, should consider the following:

- PRC-006 does not specify which specific end-use loads, distribution circuits, or feeders should be chosen by DPs for inclusion in the UFLS program and automatic tripping if BPS frequency reaches these levels. That discretion is left to the DP based on their specific system needs and characteristics.
- Most commonly, the PC is specifying a net load quantity in terms of demand (MW) needed to be armed at the T-D interface. DPs should confirm with their PCs that the amount of arming is representative of a net demand quantity.
- Distribution circuits or feeders that have DERs intermixed along the circuit, resulting in variable net loading at the monitoring point (i.e., head of the feeder) inherently create more variability in the amount of net load that may be armed at any given point. Therefore, it is common practice for DPs to attempt to select circuits, loads, or feeders where DERs are not prevalent.
- As the penetration of DERs increases in any given area, the likelihood of identifying feeders with minimal DER impacts may be significantly reduced. Therefore, feeders with DERs may need to be used as part of UFLS programs. In these cases, close coordination between the DP and PC is needed. DPs and PCs should coordinate on at least the following:
    - DPs should confirm that the installed and forecasted DER penetrations used for simulations performed by the PC are correct. DP selection of UFLS-armed feeders or loads to meet the UFLS program objective at all times will increasingly become a challenge. Tripping feeders with high DER output will cause less net load to be tripped; tripping feeders with low DER output will cause more net load to be tripped. To further illustrate this point, feeders that export to the bulk power system should not be selected for UFLS arming as tripping the feeder would exacerbate the imbalance. This needs to be accounted for in studies conducted by the PC and in monitoring of feeder flows for the implementation of the UFLS program.
    - DPs should confirm that the simulations performed by the PC model aggregate DER with appropriate voltage and frequency trip settings. DERs that are expected to trip during voltage or frequency excursion events further complicate selection of UFLS-armed circuits, and may lead to unexpected generation loss during the contingency that could further exacerbate the underfrequency conditions.
    - DPs should clearly articulate which feeders are selected for UFLS arming and automatic tripping (that is simulated in the PC's studies), and identify any cases where DER variability could affect the net demand armed.
        - Variations of time of day, season, etc., should be considered by the DP when informing the PC of any variability in DER output affecting net loading of UFLS-armed circuits. The output of metering can be sent to the PC for use in the PC's study work for the PC to identify these variations.

- Targeting specific loads, circuits, or customers for inclusion in the UFLS program may require greater granularity in the future compared to past experience, particularly as the penetration of DERs for any given UFLS entity continues to increase.
  - Conventional UFLS relaying (i.e., on a circuit-level basis) may become obsolete or may require additional solutions when faced with increasing DER penetrations. For example, battery energy storage systems (BESSs) may be able to provide fast-responding net load reduction by providing either fast discharging capability or fast reduction of charging capability[59] when UFLS levels are reached. This may offset the need for tripping of end-use load customers in the future, and may help compensate for a depleting number of eligible UFLS feeders.
- Improve awareness of DER connected to their system and, to the extent possible, monitor real-time output of the aggregate DERs impacting the feeders armed for UFLS. The UFLS entity is encouraged to also provide the aggregated signal of the output to the RC and PC for situational awareness during frequency excursions and to help enhance modeling efforts for UFLS program design.

The considerations listed above are important for the DP to consider when selecting feeders or end-use loads for participating in the UFLS program; however, they are also relevant for PCs to consider as they design their overall UFLS program with increasing DERs across their PC footprint. PCs may consider working with their DPs to develop ranking criteria on feeder selection for UFLS programs, consider possible modifications to UFLS thresholds or trip levels, and establish regular communications with UFLS entities to ensure DERs are being sufficiently accounted for during UFLS program design. PCs, DPs, and entities governing distribution are encouraged to coordinate on the transfer of DER information necessary to assess the risk to the BPS for the purposes of designing a UFLS program. Appendix C describes a situation where the UFLS program in the HELCO footprint required an adaptive setting due to high DER penetration levels. This requires close coordination across the PC and DPs to implement these advanced types of tools.

## Impacts of DER Aggregators or Other DER Management Systems

DER management systems (DERMS) or DER aggregators are new functions that are surfacing across the industry in the face high penetrations of DERs. DERMS or other DER aggregators do not modify the electrical connection of DERs or other load modifiers (e.g., demand response); however, DERMS may modify the behavior of these resources to provide a specified or contracted response to support the grid. For example, DERMS may be used to provide frequency responsive reserves or contingency reserves or could be used for ramping or balancing, depending on the contracts or markets put in place that could enable this technology. While this is an evolving area, it will have an effect on UFLS operations and UFLS program design. Some questions that PCs and UFLS entities should consider include:

- How are the implementation and operation of DERMS or DER aggregators tracked and accounted for in UFLS studies?
- Which entity is sending any control signals to the DERMS in response to BPS disturbances?
- Is the DERMS configured or contracted to provide grid-supportive functions such as frequency response to underfrequency events?
- How will the response of a DERMS affect overall UFLS program design, and how is this modeled appropriately?

These questions all highlight the complexity of introducing DERMS or other aggregation components to the overall grid. Reliable operation of a UFLS program to avoid widespread outage conditions is a critical function of BPS safety

[59] The exact method depends on the battery's state of charge and if the battery is charging, idle, or discharging. It should be noted that the BA will need observability of any such devices that perform frequency service in order to perform their responsibility to maintain frequency.

nets and a critical element in reliable operation of the BPS. As such, it is anticipated that any operation of a DERMS or DER aggregator to provide frequency response will likely invalidate the feeders for use in UFLS programs.

## Coordination of UFLS Program with Possible DER Frequency Response

The inclusion or exclusion of feeders or circuits from participating in UFLS programs and potential automatic tripping during UFLS operations should not be confused with any prohibition of DERs from providing grid-supportive functionality or other essential reliability services. For example, if circuits are not chosen for UFLS operation due to increasing DERs, this should not affect the development of any interconnection requirements regarding those resources having frequency response capability and being able to provide that service to the BPS either now or in the future. This does mean, however, that the UFLS program design should reflect the changing nature of the grid.

UFLS is a safety net function for severe contingency events when an imbalance of generation and load requires a fast-responding and automatic disconnection of select end-use loads from the system to rebalance system frequency. Prior to reaching those UFLS frequency thresholds, all generating resources (including DERs, if able to respond) and end-use loads[60] can help arrest frequency declines. DERs and BPS-connected generation can increase active power output, if configured in a manner to do so, to support overall BPS frequency response. As mentioned above, DERMS or other aggregators may control many individual DERs in the future to provide this service to the BPS. Further, existing DERs participating in wholesale electricity markets may also be capable of providing these services to support BPS operations. These functions support overall frequency control and in some ways help mitigate the potential operation of UFLS in the first place. PCs and UFLS entities should ensure that DERs that are relied upon to support BPS frequency and provide essential reliability services are not impacted by UFLS relays and have adequate ride-through capability so that they are able to reliably provide these services. It is recommended to coordinate frequency capabilities and the availability of frequency response to the applicable BAs in addition to the PCs in order to carry out the BA's function to balance generation and load.

## Coordinating UFLS Programs with Distribution-Level Hosting Capacity

**Key Takeaway:**
State-level regulatory authorities should align hosting capacity analysis with UFLS program design to ensure that sufficient load, or load resources, are enabled to trip to arrest declining BPS frequency.

Some state-level regulatory authorities require DPs and TOs (UFLS Entities) to facilitate interconnection of DERs in areas of the distribution system with ample "hosting capacity," defined by the Electric Power Research Institute (EPRI) as "the amount of DER[s] that can be accommodated without adversely impacting power quality or reliability under existing control configurations and without requiring infrastructure upgrades."[61] According to EPRI, hosting capacity is a function of location, DER type, and circuit configurations (see **Figure 3.2**). Distribution circuits or feeders that already have DERs intermixed along the circuit have less available hosting capacity; distribution circuits or feeders that do not have DERs have more available hosting capacity.

[60] Either through inherent frequency sensitivity of direct-connected motor loads or through dedicated end-use loads providing frequency responsive services.

[61] https://www.esig.energy/blog-methods-applications-hosting-capacity/

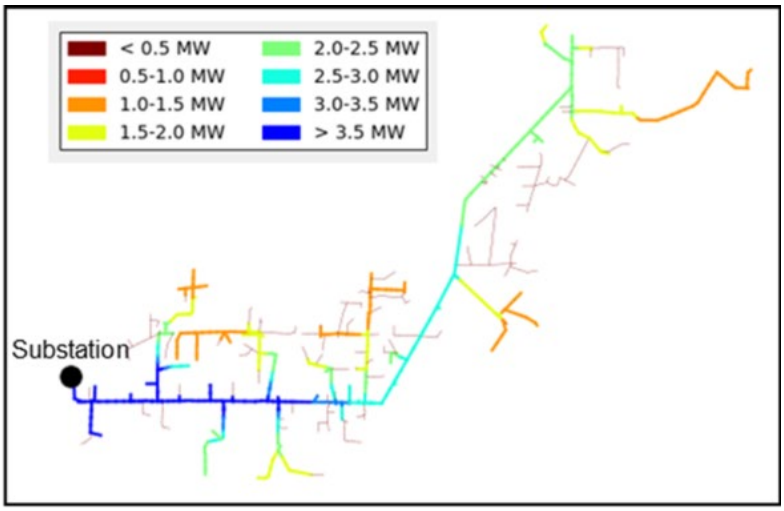



**Figure 3.2: Example Hosting Capacity Heat Map [Source: EPRI]**

Thus, state-level requirements facilitating the interconnection of DERs on feeders with hosting capacity (i.e., more load, less DER) will likely result in DER development on the same feeders that are designated for UFLS (again, more load, less DER). Greater levels of load enabled to trip on UFLS will in turn be required. PCs, UFLS entities, and state-level regulatory authorities should coordinate hosting capacity analyses with UFLS program design to ensure that interconnection of DERs does not inadvertently result in the degradation of UFLS required to support reliable operation of the BPS.

# Appendix A: UFLS Programs across North America

This Appendix compiles some of the presently effective UFLS program settings across North America, simply as a useful industry reference. **Table A.1** to **Table A.3** show the frequency set points and amount of net demand tripped when frequency reaches each set point for the Eastern, Western, and Texas Interconnections, respectively. Note that cells that are greyed out are simply not in effect for that specific entity.

**Table A.1: Various Eastern Interconnection UFLS Program Settings**

| Frequency Set Point (Hz) | NPCC* | | | PJM | | | | MRO/MISO | | | SERC |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | Peak ≥ 100 MW | 50 MW ≤ Peak < 100 MW | 25 MW ≤ Peak < 50 MW | MACZ | WCZ | CECZ | SCZ | 3-Step (15 UFLS Entities) | 5-Step (5 UFLS Entities) | 1-Step (9 UFLS Entities) | Target Load Shed |
| 59.6 | | | | | | | | | | | 7.4% |
| 59.5 | 6.5-7.5% | 14-25% | 28-50% | | 5% | | | | | | |
| 59.4 | | | | | | | | | | | 5.2% |
| 59.3 | 6.5-7.5% | | | 10% | 5% | 10% | 10% | 8.3-15.3% | 5.1-12.6% | 32.1-100% | |
| 59.2 | | | | | | | | | | | 5.2% |
| 59.1 | 6.5-7.5% | 14-25% | | | 5% | | | | | | |
| 59.0 | | | | | | 10% | 10% | 7.2-16.4% | 5.9-12.6% | 100% | 5.2% |
| 58.9 | 6.5-7.5% | | | 10% | 5% | | | | | | |
| 58.7 | | | | | 5% | 10% | | 6.3-13.1% | 4.7-10.7% | 100% | 6.3% |
| 58.5 | | | | 10% | | | 10% | 8.3-12.3% | 0.6-6.5% | 100% | |
| 58.4 | | | | | | | | | | | 4.3% |
| 58.3 | | | | | | | | 8.7-12.7% | 0.2-6.8% | 32.1-63.8% | |
| 58.2 | | | | | | | | | | | 2.2% |
| 59.6 (15 +/-.5s) | | | | | | | | | | | 2% |
| 59.6 (22 +/-.5s) | | | | | | | | | | | 3% |
| 59.5 (10s) | 2-3% | | | | | | | | | | |
| **Total % Shed** | **29.5-31.5%** | **28-50%** | **28-50%** | **30%** | **25%** | **30%** | **30%** | **28-43%** | **29-43%** | **32.1-100%** | **40-44%** |

*NPCC load is based on total TO, DP, and DPUF load in these columns. Also note that the Québec Interconnection has five threshold stages and four rate-of-change (slope) stages of load shedding.

| Table A.2: Western Interconnection[62] UFLS Program Settings | | | |
|---|---|---|---|
| **Frequency Set Point (Hz)** | **Coordinated Plan** | **NWPP Sub-Area** | **Southern Island Sub-Area** |
| 59.6 | | | .07% |
| 59.5 | | | 4.0% |
| 59.3 | | 5.6% | |
| 59.2 | | 5.6% | |
| 59.1 | 5.3% | | 2.8% |
| 59.0 | | 5.6% | |
| 58.9 | 5.9% | | 6.5% |
| 58.8 | | 5.6% | |
| 58.7 | 6.5% | | 7.4% |
| 58.6 | | 5.6% | |
| 58.5 | 6.7% | | 7.4% |
| 58.3 | 6.7% | | 7.3% |
| **Total % Shed** | **31.1%** | **28%** | **35.4%** |
| 59.3 (stalling) | 2.3% (15 sec) | 2.3% (15 sec) | 2.9% |
| 59.5 (stalling) | 1.7% (30 sec) | 1.7% (30 sec) | 2.1% |
| 59.5 (stalling) | 2.0% (1 min) | 2.0% (1 min) | 2.3% |

| Table A.3: Texas Interconnection UFLS Program Settings | |
|---|---|
| **Frequency Set Point (Hz)** | **ERCOT** |
| | **All DSPs** |
| 59.5 | |
| 59.3 | 5% |
| 59.1 | |
| 59.0 | |
| 58.9 | 10% |
| 58.7 | |
| 58.5 | 10% |
| 59.5 (10s) | |
| **Total % Shed** | **25%** |

[62] https://www.wecc.org/_layouts/15/WopiFrame.aspx?sourcedoc=/Reliability/Off-Nominal%20Frequency%20Load%20Shedding%20Plan.pdf&action=default&DefaultItemOpen=1

# Appendix B: AEMO Analysis of High ROCOF Conditions

System inertia has declined in South Australia since 2012 due to retirement of synchronous generation, as shown in **Figure B.1**. In August 2016, AEMO issued a report, *Future Power System Security Program Progress Report*, highlighting concerns over historical frequency response trends and system inertia. Specifically, the report described the possibility that the decline in system inertia, causing a rapid increase in ROCOF following large disturbances, may cause frequency to decline too rapidly in South Australia for "UFLS to produce a well-coordinated and well-graded disconnection of load to arrest the frequency" during historical "non-credible" separation events.[63,64,65] Under Australia's National Electricity Rules, 60 percent of expected demand must be available to shed "in manageable blocks spread over a number of steps within underfrequency bands from 49.0 Hz down to 47.0 Hz as nominated by AEMO."[66]

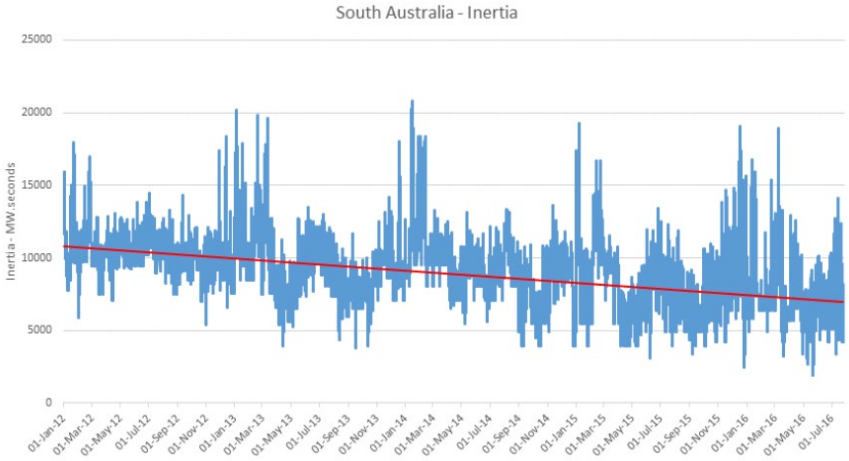



**Figure B.1: System Inertia in South Australia [Source: AEMO]**

A month later, on September 28, 2016 at 4:16 PM local time, South Australia's 1,826 MW of demand was supplied by 48% wind generation, 18% gas generation, and 34% electricity imports (limited at 650 MW).[67] **Figure B.2** shows the resource mix at the time prior to the disturbance. According to AEMO, tornados tripped a single 275 kV transmission line and a double circuit 275 kV line. This resulted in six voltage dips over a two-minute period on the South Australia grid, causing wind farms to enter into successive fault ride-through operations and subsequent reduction output of 456 MW over a period of less than seven seconds. The generation reduction resulted in imports of nearly 900 MW, exceeding the 650 MW limit, tripping the interconnector and islanding South Australia from the rest of the system. **Figure B.3** shows the transient and sustained power reductions from the wind plants during the sequence of events.

[63] The report is available here.

[64] http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/-/media/823E457AEA5E43BE83DDD56767126BF2.ashx.

[65] https://www.aemc.gov.au/sites/default/files/content//NER-v77-Chapter-04.PDF

[66] Note that the nominal frequency in the Australian power system is 50 Hz.

[67] http://www.aemo.com.au/-/media/Files/Electricity/NEM/Market_Notices_and_Events/Power_System_Incident_Reports/2017/Integrated-Final-Report-SA-Black-System-28-September-2016.pdf

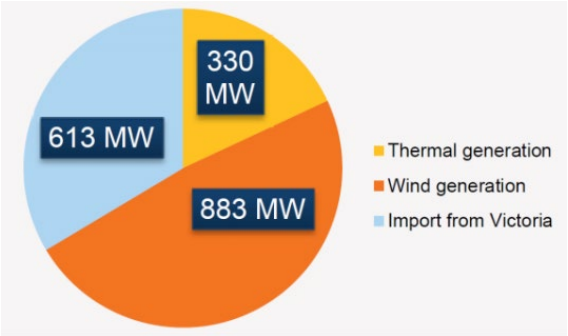



**Figure B.2: South Australia Generation Mix Pre-Event [Source: AEMO]**

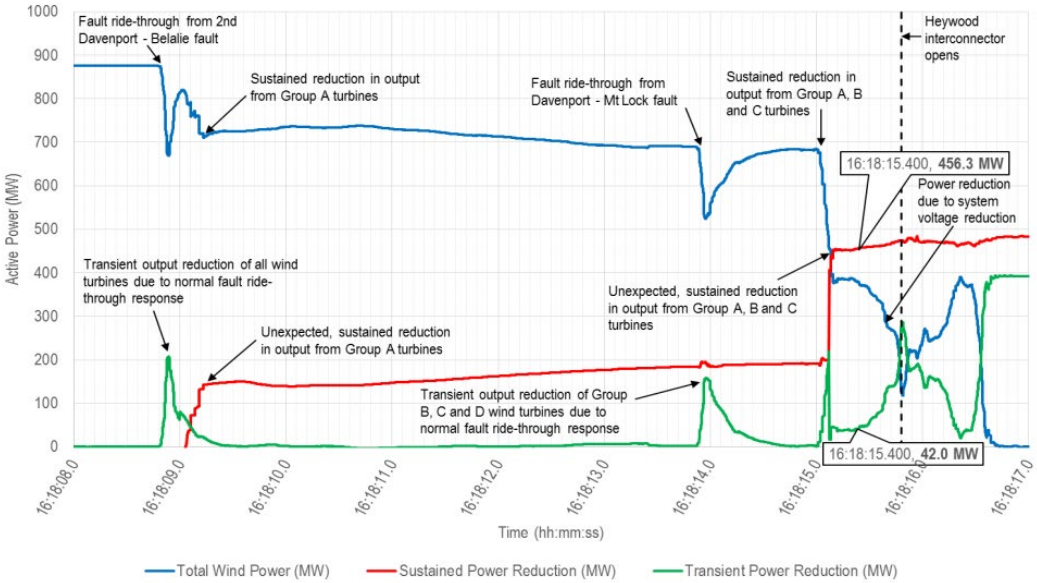



**Figure B.3: Sustained vs. Transient Power Reduction of Wind Plants during September 28, 2016 AEMO Disturbance [Source: AEMO]**

According to AEMO, ROCOF following separation of the South Australian system was 6.25 Hz/s (see **Figure B.4**), "too great for the UFLS scheme to operate effectively" as had been identified a month earlier. AEMO explained that the primary reason for frequency instability "was that, in the absence of any substantial load shedding, the remaining synchronous generators and wind farms were unable to maintain the islanded system frequency." The absence of inertial support and resulting high ROCOF caused by an unexpected large contingency event in South Australia caused the UFLS scheme to not operate.

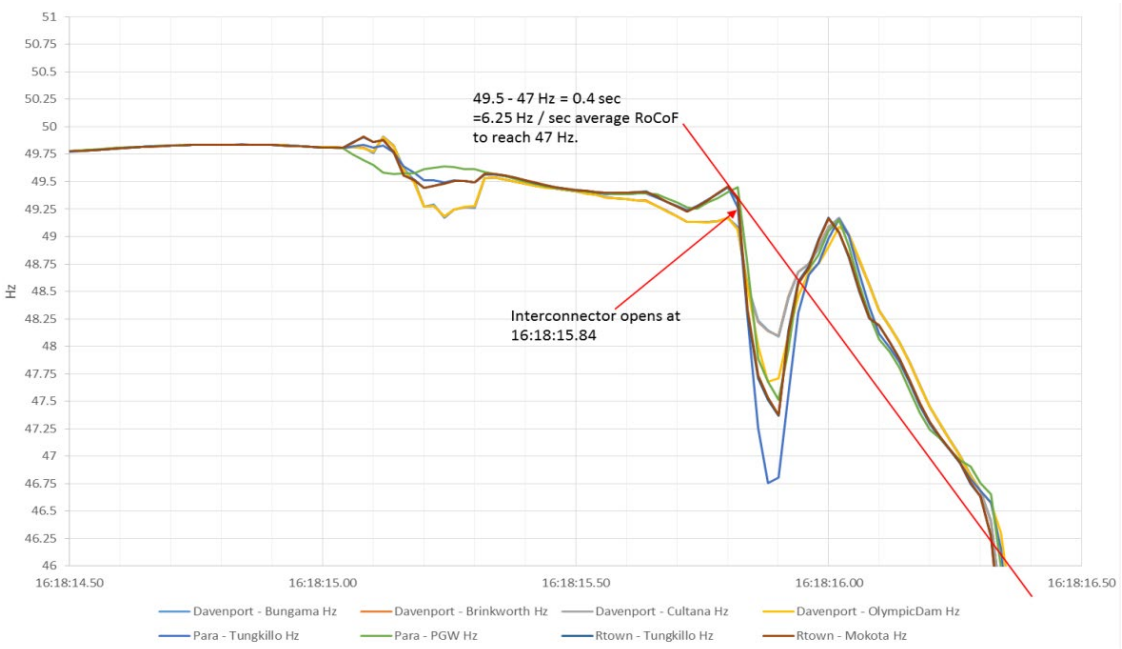



**Figure B.4: Frequency and ROCOF in Various SA Nodes Immediately Before the System Separation [Source: AEMO]**

After the blackout, AEMO identified a need for "sufficient inertia to slow down the [ROCOF] and enable automatic load shedding to stabilize the island system in the first few seconds." They have since implemented restrictions on the interconnector flow to ensure its loss (the largest expected contingency) does not result in a ROCOF exceeding 3 Hz/s. They have also created a minimum requirement for the number of on-line synchronous generators as they face critical inertia levels to support existing fast frequency response and primary frequency response capabilities.

Since this event, AEMO has begun a comprehensive work on UFLS specifically looking into the impacts of DER. **Figure B.5** demonstrates at a high level their emphasis on the importance to account for DER in underfrequency events. The net load disconnected from the system can vary depending on if the DER disconnects during the underfrequency event, worsening the frequency performance. As a result of their efforts, AEMO has implemented new network constraints to limit contingency sizes related to separation events in periods where the capabilities of UFLS to arrest system frequency are low. AEMO has also actively pursued a dynamic arming scheme to selectively disarm UFLS circuits with reverse flows in real time.[68]

[68] AEMO's work on this topic can be found here and here

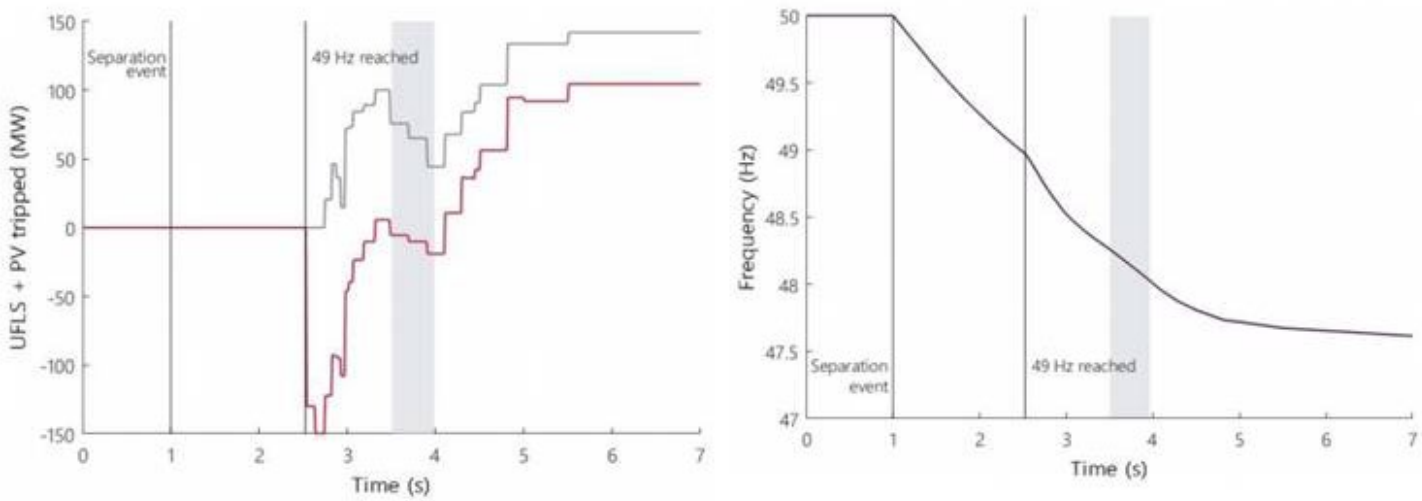



**Figure B.5 Example of UFLS Operation During a Period with High Distributed PV Generation [Source: AEMO]**

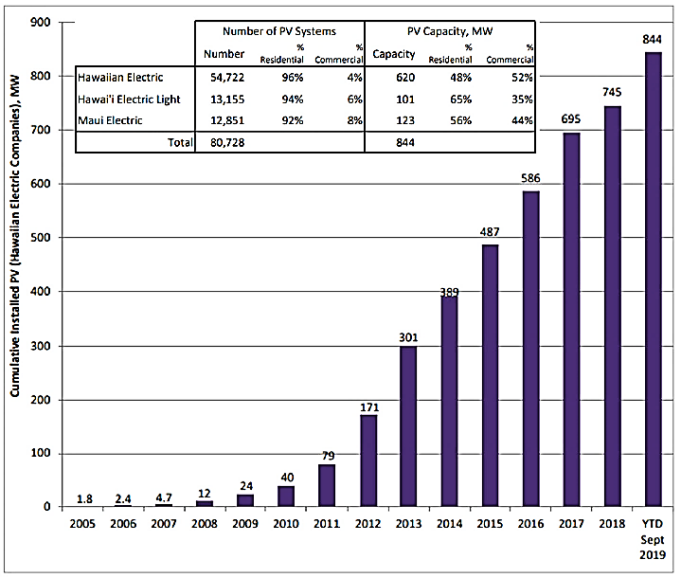
The South Australia experience demonstrates the importance of studying the impacts that decreasing system inertia can have on ROCOF and system frequency stability. While this example does not include DERs, DERs can and will contribute to decreasing system inertia. AEMO recently identified the importance of accounting for high levels of DERs in UFLS scheme design, suggesting the use of new "smart UFLS devices" like electric vehicles.[69]

System planning studies will need to ensure DERs are appropriately modeled such that their impact on system inertia can be appropriately captured. Inaccurate assumptions of sufficient inertial response can yield inaccurate simulation results of island-level performance during large underfrequency events. Therefore, PCs should ensure that off-peak demand conditions are also studied where local island system inertia may be at its lowest and ROCOF may be at its highest expected levels.

[69] http://www.aemo.com.au/-/media/Files/Electricity/NEM/DER/2019/Technical-Integration/Technical-Integration-of-DER-Report.pdf

# Appendix C: Hawai'i Electric Light Case Study – Adaptive UFLS

Hawai'i Electric Light (HELCO) has seen rapid adoption of DERs across its service territory on Hawai'i Island.[70] From 2011 to September 2019, the aggregate gross nameplate capacity of solar PV DERs in HELCO's service territory surged from 10 MW to 101 MW (see **Figure C.1**). The total nameplate capacity of DERs on Hawai'i Island is now twice as large as any other single generator on the Island, and nearly 50 percent of HELCO's historical peak load of 191 MW. The highest instantaneous penetration of DERs serving end-use load experienced by HELCO to-date is estimated to be in the excess of 80 MW. **Figure C.2** shows the widening range (greater variability) of average February net loads on Hawai'i Island's from 2011 to 2018.




| | Number of PV Systems | | | PV Capacity, MW | | |
|---|---|---|---|---|---|---|
| | Number | % Residential | % Commercial | Capacity | % Residential | % Commercial |
| Hawaiian Electric | 54,722 | 96% | 4% | 620 | 48% | 52% |
| Hawai'i Electric Light | 13,155 | 94% | 6% | 101 | 65% | 35% |
| Maui Electric | 12,851 | 92% | 8% | 123 | 56% | 44% |
| Total | 80,728 | | | 844 | | |

**Figure C.1: Solar PV DER Growth across HELCO [Source: HELCO]**

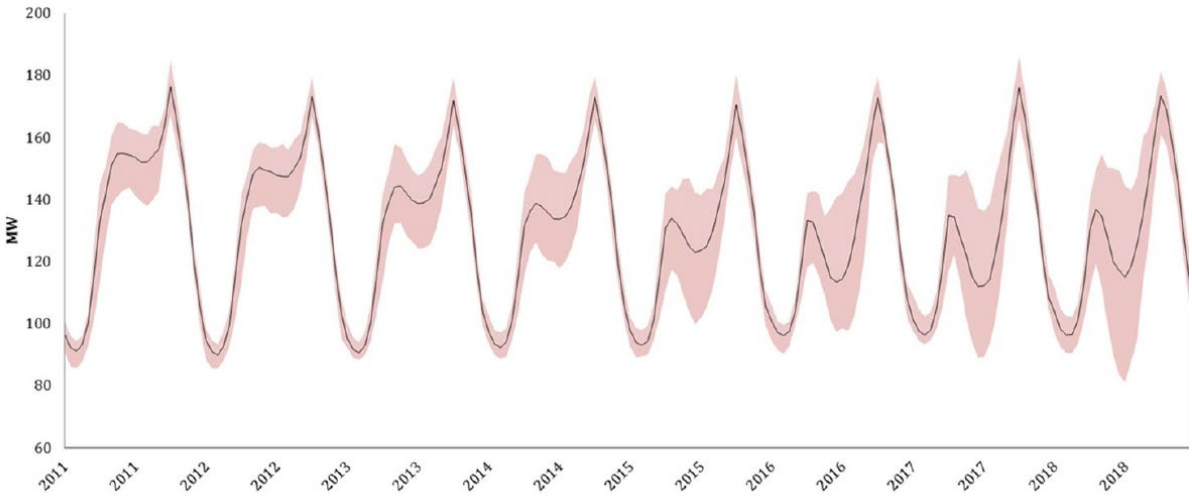



**Figure C.2: Impact of DER on Hawai'i Island's February Average Daily (Net) Load [Source: HELCO]**

As an islanded network, balancing supply and demand on Hawai'i Island has proven challenging, and HELCO currently relies on UFLS for a portion of its contingency reserves. Under high levels of DER penetration, reliable operation of its UFLS to maintain operation of the overall network during large power imbalances has been compromised. In 2014, HELCO conducted an initial study that determined its UFLS scheme was at risk of over-shedding load relative to the necessary amount per the specified requirements, leading to potential overfrequency conditions. The static UFLS scheme in use at the time was set to shed blocks of predetermined net load at the feeder-level based on the historical amount of load on the circuit. The assumption in the static scheme was that the amount of load on the circuits in the

[70] R. Quint, et al., "Transformation of the Grid: The Impact of Distributed Energy Resources on Bulk Power Systems," IEEE Power and Energy Magazine, vol. 16, iss. 6, pp. 35-45, October 2019. Available here

blocks generally matched the total system demand. However, this is no longer the case with increasing penetrations of DERs.

Net loading on each feeder is influenced by the amount of DER production, and feeders may even be exporting power to the system for many hours of the day. Tripping these feeders would result in additional loss of net energy. Further, the behavior of legacy DER installed prior to current interconnection requirements places additional considerations needed on UFLS program design. The loss of aggregate DERs at legacy frequency trip settings of 59.3 Hz adds to the net energy loss during underfrequency events and exacerbates the loss of generation contingencies. On the other hand, a larger portion of legacy DERs may also trip for high frequency conditions at 60.5 Hz. This could pose risks of DER tripping exceeding the largest single generator contingency. Due to the increased risks of overfrequency, a critical aspect of the UFLS design is now avoiding over-shedding of load and reaching the 60.5 Hz trip point for the larger portion of legacy DERs.

Recognizing that the development and installation of the new UFLS scheme would take time, the static UFLS scheme was modified to reduce the possibility of over-shedding load by creating an additional load shed block and reducing the load in each block. In addition, circuits that had been included in a both an instantaneous stage and a delayed ("kicker") stage, were assigned to only one stage to ensure even if the instantaneous stages operated to stabilize frequency for the initial disturbance the load in the delayed stages would still be retained if needed to return the frequency to 60 Hz.

Due to the rapid growth of solar PV DERs, HELCO identified a need for dynamic assignment of circuits to the UFLS scheme in real-time operations. The widespread variation of net load due to variability of DER output across the distribution system caused HELCO to re-evaluate the ability of a static UFLS program. In 2015, HELCO studied how an "adaptive" UFLS scheme might serve both to target load shed from distribution circuits with variable net load throughout the day, as well as to rapidly detect whether load shed is required on its system. Study results pointed to necessary changes to the static scheme to avoid over-shedding and under-shedding during different operating conditions. It was determined that HELCO would need to develop a custom application for an adaptive UFLS scheme to reflect both the amount of load shedding required and then dynamically assign circuits to the scheme stages. The application calculates the required amount of net demand required to be shed in real-time based on telemetered values from each distribution feeder circuit. Then, distribution circuits are automatically assigned to the underfrequency trip settings through communication to distribution circuit underfrequency relays. Further, HELCO determined that UFLS operations based on ROCOF may be required in addition to the frequency trip settings, and have planned to implement this feature in the future based on system needs. In all, over 40 substations required relay upgrades and real-time automatic controller installations. Around 78% of the distribution circuits, accounting for 70% of peak load, needed to be included in the scheme for its effective operation. Based on the urgency of the problem at hand, HELCO implemented the adaptive UFLS scheme in December 2017.

Settings for HELCO's adaptive UFLS program are shown in **Table C.1**, including the frequency and ROCOF trip settings, the percentage of net system demand to be tripped at each stage, and the expected time of operation after the frequency threshold is passed.

**Table C.1: HELCO Adaptive UFLS Load Shedding Scheme [Source: HELCO]**

| Stage | Setting [Hz] | % of Net System Demand [MW] | Time |
|---|---|---|---|
| df/dt* | 0.5/sec | 15% | 9 cycle relay plus breaker time |
| 1 | 59.1 | 5% | 8 cycle relay plus breaker time |
| 2 | 58.8 | 10% | 8 cycle relay plus breaker time |
| 3 | 58.5 | 10% | 8 cycle relay plus breaker time |
| 4 | 58.2 | 15% | 8 cycle relay plus breaker time |

| Table C.1: HELCO Adaptive UFLS Load Shedding Scheme [Source: HELCO] | | | |
|---|---|---|---|
| **Stage** | **Setting [Hz]** | **% of Net System Demand [MW]** | **Time** |
| 5 | 57.9 | 10% | 8 cycle relay plus breaker time |
| 6 | 57.6 | 20% | 8 cycle relay plus breaker time |
| Kicker 1a | 59.3 | 5% | 10 seconds |
| Kicker 1b | 59.5 | | 30 seconds |
| Kicker 2 | 59.5 | 5% | 20 seconds |

Stage 1 and stage 2 should sum to 15% of total system net load (maximum allowed load shedding for N-1 unit trips).
Stage 1 through stage 4 should sum to 40% of total system net load (maximum allowed load shedding for N-1-1 unit contingencies).
*Not currently active.

The program settings are static; however, they are based on the total net system demand that is continuously fluctuating. The allocation of distribution circuits to arm at any given time is dynamic and adapts to changing system conditions. The adaptive UFLS scheme selects which distribution circuits using a priority order, consisting of four categories:

1. Normal circuit (no tripping restrictions)
2. Restricted circuit (avoid tripping if possible)
3. Highly restricted circuit (last resort for tripping)
4. Not participating (do not trip)

Each distribution circuit is then assigned to blocks based on a participation factor of one through nine (see Table C.2), determined using additional factors like whether a circuit has a "hot line tag"[71] and how many times it has previously been tripped as part of UFLS operations.

| Table C.2: Customer Participation Prioritization [Source: HELCO] | | |
|---|---|---|
| **Customer Priority** | **Priority Description** | **Participation** |
| 1 | Normal circuit (no tripping restrictions) | 1 |
| | | 2 |
| | | 3 |
| 2 | Restricted circuit (avoid tripping if possible) | 4 |
| | | 5 |
| | | 6 |
| 3 | Highly restricted circuit (last resort for tripping) | 7 |
| | | 8 |
| | | 9 |
| 4 | Does not participate (do not trip) | 10 |

After calculating MW targets for each UFLS stage based on the calculated total system net load in real-time, the energy management system assigns distribution circuits to UFLS stages to achieve the required MW load shed targets. **Figure C.3** shows a summary display used in the HELCO EMS adaptive UFLS scheme.

[71] Which blocks remote reclosing, should the circuit be tripped.

UFLS STAGE DATA

System Load: 141.853
Total Target: 112.185
Total Available: 114.292

| Stage | Frequency | Percent | Target MW | Avail MW | Tol % | Tolerance | Delta MW |
|---|---|---|---|---|---|---|---|
| STAGE1 | 59.100 | 5.00 | 7.01154 | 6.82032 | 5.000 | 0.351 | 0.191 |
| STAGE2 | 58.800 | 10.00 | 14.02308 | 13.83560 | 5.000 | 0.701 | 0.187 |
| STAGE3 | 58.500 | 10.00 | 14.02308 | 13.34422 | 5.000 | 0.701 | 0.679 |
| STAGE4 | 58.200 | 15.00 | 21.03462 | 22.24468 | 8.000 | 1.683 | -1.210 |
| STAGE5 | 57.900 | 10.00 | 14.02308 | 14.21575 | 8.000 | 1.122 | -0.193 |
| STAGE6 | 57.600 | 20.00 | 28.04617 | 25.46988 | 25.000 | 7.012 | 2.576 |
| KICKER1 | 59.500 | 5.00 | 7.01154 | 6.79824 | 8.000 | 0.561 | 0.213 |
| KICKER2 | 59.300 | 5.00 | 7.01154 | 6.54598 | 8.000 | 0.561 | 0.466 |

**Figure C.3: Summary Display of HELCO Adaptive UFLS Scheme EMS [Source: HELCO]**

While the adaptive UFLS scheme has performed well against multiple events over the past few years, it has limitations including the extent of the contingencies which it is planned for. In July 2019 an over-shedding of load occurred when a storm caused a quickly occurring n-1-1 event that disconnected a power plant while it was generating 40 MW. The sudden loss of 40 MW (28% of load) was outside of the planning criteria applied in designing the UFLS scheme and resulted in the highest ROCOF experienced on the system to date (in excess of 2Hz/Second) the resulting load shed of nearly all the instantaneous stages caused frequency to reach 61.0 Hz (see **Figure C.4**). While the storm conditions did limit the solar generation at the time a still measurable and significant loss of solar generation in certain areas of the Island was observed due to the high frequency. This event demonstrates that even a fairly robust UFLS design will not always prevent significantly abnormal frequencies, and with DER production becoming a potentially significant portion of on-line generation it highlights the essential importance of grid-supportive interconnection requirements for DER, including expanded ride-through capabilities and control.

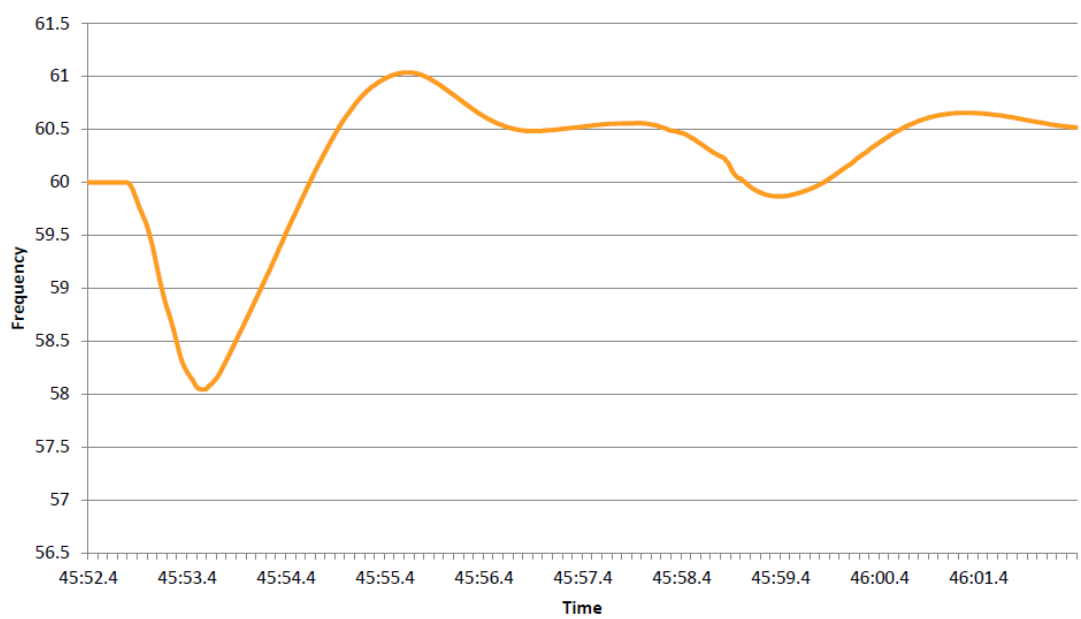



**Figure C.4: July 8, 2019 UFLS Event on Hawai'i Island [Source: HELCO]**

As a result of this event, HELCO identified additional improvements to the UFLS program including changes to UFLS block sizes, UFLS frequency thresholds, and enabling the ROCOF trip setting. The recommendation was for this to be implemented by the first quarter of 2020. In actual field implementation, it was found that the dynamic system behavior makes the ROCOF settings challenging and initial implementation resulted in a small load shed during normally cleared faults.

Given that the loss of aggregate DER with legacy frequency and voltage settings remains HELCO's largest contingency, HELCO has also identified a need for FFR from energy storage resources to reduce the incidence and impact of UFLS load shed. This FFR is procured through competitive bid.[72] The FFR storage resource is sized according to HELCO's resource plans and the level of aggregate DER with legacy trip settings. The resource providing this service is required to have configurable parameters, a proportional response to changes in frequency outside a pre-defined deadband, have capability to respond to over and underfrequency events, and be able to maintain established state of charge. HELCO is presently managing the increasing amounts of variable, inverter-based resources (particularly DERs) by procuring sufficient amounts of operating reserves and grid flexibility.

HELCO's experience with studying and implementing an adaptive UFLS scheme will prove invaluable to entities across North America as the BPS is faced with higher levels of aggregate DERs in the future.

72 https://www.hawaiielectriclight.com/documents/clean_energy_hawaii/selling_power_to_the_utility/competitive_bidding/20190822_final_stage_2_hawaii_variable_rfp.pdf

# Appendix D: Impacts of DERs on ISO-NE UFLS Islanding Study

Driven by state policies and private investments, DERs have steadily grown in the ISO New England (ISO-NE) region. As of December 2018, there were over 157,000 solar PV DERs in ISO New England under 5 MW, with the vast majority of installations under 25 kW installations, representing a total of 2,884 MW (see **Figure D.1**).[73] State-level distribution of solar PV DERs in ISO-NE in 2018 is shown in **Table D.1** Massachusetts constitutes about 65% of the total installed solar PV capacity in the New England region. The 2019 ISO-NE solar PV DER forecast indicates a much faster growth of solar PV installations across the New England region in the coming years. **Figure D.2** illustrates ISO-NE's solar PV forecasts and how existing integration of DERs has far exceeded forecasts over the past five years.

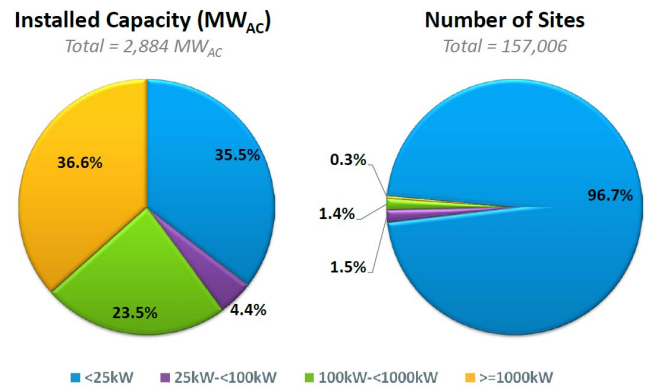



**Figure D.1: Installed Solar PV Capacity as of December 2018 in ISO-NE [Source: ISO-NE]**

**Table D.1: 2018 Solar PV DERs in ISO-NE, by State [Source: ISO-NE]**

| State | Installed Capacity (MW) | Number of Installations |
|---|---|---|
| Massachusetts | 1,871 | 90,720 |
| Connecticut | 464 | 35,889 |
| Vermont | 306 | 11,864 |
| New Hampshire | 84 | 8,231 |
| Rhode Island | 117 | 5,993 |
| Maine | 42 | 4,309 |
| **New England** | **2884** | **157,006** |

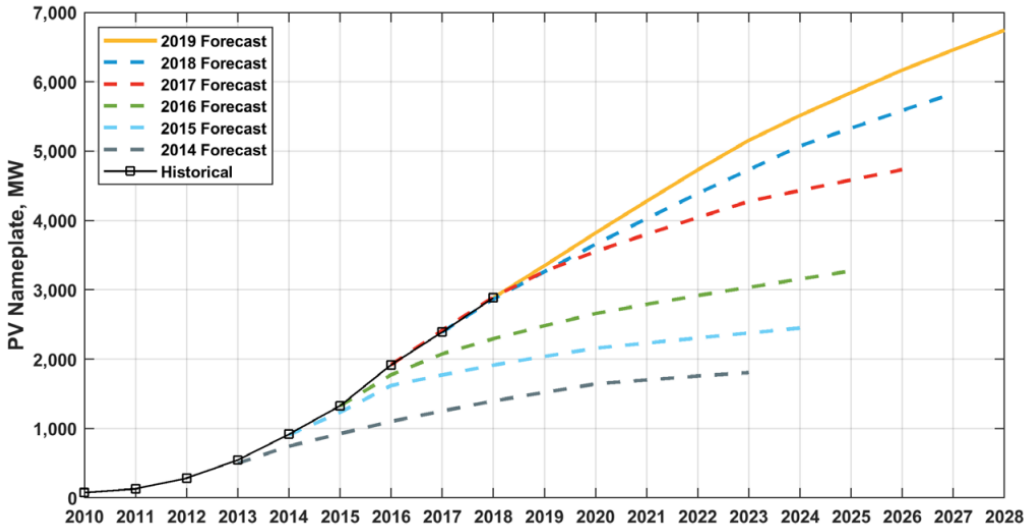



**Figure D.2: Reported vs. Forecasted Solar PV DER Growth [Source: ISO-NE]**

[73] ISO New England Final 2019 PV Forecast: https://www.iso-ne.com/static-assets/documents/2019/04/final-2019-pv-forecast.pdf

ISO-NE does not have direct visibility of the location or output of DERs since the majority of these resources do not participate in the ISO-NE wholesale markets. Nevertheless, ISO-NE has observed how DERs (in aggregate) have reduced system net load and even shifted the system peak load in some cases. As an illustrative example (see **Figure D.3**), ISO-NE reconstituted the total expected gross load on its system by adding the expected level of DER output to the measured net load for a peak summer day in 2018. On this day, the peak net load (red square) of approximately 26,000 MW was not only lower than the peak gross load (green circle) of approximately 27,000 MW, but it also shifted the net peak load time from 3 PM local time to 5 PM local time.[74] Given the projected growth of aggregate DER projected in the ISO-NE 2019 solar PV forecast, it is important to understand the increasing penetration of DERs in the ISO-NE footprint and the potential impacts this can have on BPS performance (particularly during underfrequency disturbances).[75]

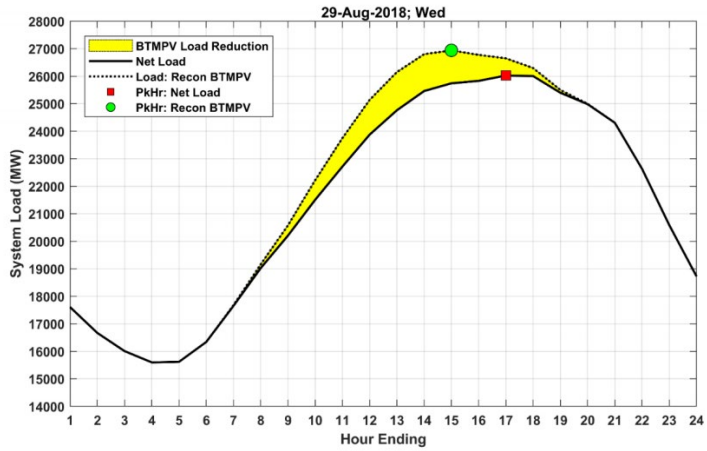



**Figure D.3: Solar PV DER Offsetting Net System Load during Summer Peak – August 29, 2018 [Source: ISO-NE]**

## NPCC Region UFLS Program

The Northeast Power Coordinating Council (NPCC) Directory 12[76] describes the implementation plan for UFLS programs in the NPCC region. With the adoption of PRC-006-NPCC-02, NPCC intends to retire Reliability Direction 12 in accordance with NERC Rules of Procedure; nevertheless, these values were in effect to determine system performance requirements at the time of the study. **Table D.2** shows the stages of UFLS operation, the percentage size of each UFLS tripping block, and operating times for load shedding actions. The NPCC UFLS program consists of five stages, with four stages having about 7 percent of load shed at each stage. The fifth stage is an anti-stall stage which sheds additional 2 percent load if the island frequency is below 59.5 Hz for more than 10 seconds.

**Table D.2: NPCC Region UFLS Program PRC-006-NPCC [Source: NPCC]**

| Stage | Threshold Setting [Hz] | Tripping Block Size [%] | Cumulative Load Shed [% of TO or DP Load] | Total Operating Time [s] |
|---|---|---|---|---|
| 1 | 59.5 | 6.5–7.5 | 6.5–7.5 | 0.3 |
| 2 | 59.3 | 6.5–7.5 | 13.5–14.5 | 0.3 |
| 3 | 59.1 | 6.5–7.5 | 20.5–21.5 | 0.3 |
| 4 | 58.9 | 6.5–7.5 | 27.5–28.5 | 0.3 |
| 5* | 59.5 | 2–3 | 29.5–31.5 | 10 |

Note: Total operating time is the load-weighted average for all load within a Balancing Authority area, with maximum deviation for any load limited to ± 50 ms.
* Anti-stall

[74] https://www.iso-ne.com/static-assets/documents/2019/03/a4_draft_2019_isone_annual_energy_and_summer_peak_forecast.pdf
[75] The results shown in this section do not represent the official results of ISO-NE as studies similar to this are being performed by SS-38 NPCC working group. However, the results do highlight some of the concerns that may need to be addressed with increasing DER penetration.
[76] Available here

# UFLS Program Design Studies Incorporating DERs

ISO-NE used a 2023 Summer Peak base case with ISO-NE gross load of 28,176 MW and 5,200 MW of DERs. Following DER modeling guidelines,[77] DERs were modeled as either R-DERs or U-DERs in the power flow base case. 2,200 MW were represented as R-DERs and 3,000 MW were represented as U-DERs. The load bus in the power flow base case was converted to six feeders, five feeders with R-DER resources and one feeder with U-DER resources (see **Figure D.4**). Key modeling assumptions were made:

- R-DERs are installed throughout the distribution system near the end-use loads and are located on feeders that may have UFLS relays. During underfrequency conditions, UFLS relays will trip feeders that include end-use load and R-DERs. End-use load and any co-located R-DERs are modeled to trip consistent with NPCC Directory 12 frequency set points and load shed requirements (per **Table D.2**).
- R-DERs are evenly split among the feeders, which was deemed a reasonable assumption since the objective of the study is to understand the impact of DERs on an islanded ISO-NE system; therefore, the distribution of DERs among feeders is not of concern.
- U-DERs are modeled separately from the R-DERs so that they can be differentiated from any DERs that may be tripped by the UFLS relays. U-DERs are not located on the distribution feeders, and therefore would not trip during operation of the UFLS relays.
- DERs are assumed to be compliant with IEEE 1547-2018, and assumed to meet the ISO-NE Source Requirements Document (SRD)[78] establishing DER settings requirements within the ISO-NE footprint (see **Figure D.5**).
- DER models are implemented as follows:
  - R-DERs are modeled using REGC_A and REEC_A dynamic models; voltage control is not used; constant real and reactive power mode (unity power factor) is assumed; and voltage and frequency tripping are modeled (see **Figure D.5**). Please note that R-DER trip along with the UFLS. The frequency settings are the same as the UFLS set points. This is to simulate the tripping of load and DER at the same time. In PSS/E version 33.12.1, the load and the DER cannot be modeled as a single composite load as in version 34 and above and hence the two components were split.
  - U-DERs are modeled using REGC_A, REEC_A, and REPC_A dynamic models; voltage control is included; plant controls are included; and voltage tripping is modeled (see **Figure D.5**).
    - Frequency trip settings for U-DER are much lower than the NPCC UFLS set points shown in **Table D.2** and have longer trip times; therefore, frequency tripping of U-DERs is not included. Please note that R-DER are part of the load and hence would trip with the load. The U-DER are separate and their frequency timer settings are more than the UFLS set points. For example, at 58.5 Hz, the trip setting is 300 seconds. The simulation is run for 60 seconds only before which the frequency has to go above 59.5 Hz. So U-DER frequency tripping has not been included.
  - Second generation renewable models were used at the time of study due to an implementation issue in the DER_A model, which has been resolved. Previous SPIDERWG reliability guidance on the choice of dynamic models representing aggregate DER should still be used when performing such studies.

[77] https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability_Guideline_DER_A_Parameterization.pdf
[78] https://www9.nationalgridus.com/non_html/ISO%20New%20England%20Source%20Requirement%20Document-2018-02-06.pdf

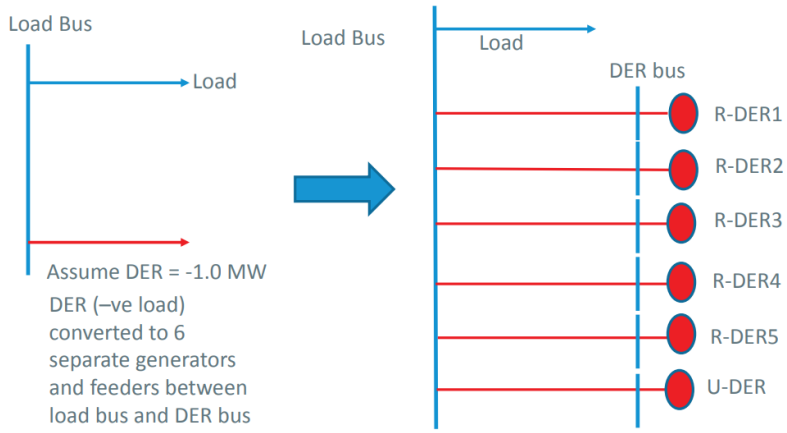



**Figure D.4: DER Modeling in Power Flow [Source: ISO-NE]**

| Shall Trip – IEEE Std 1547-2018 (2nd ed.) Category II | | | | | |
|---|---|---|---|---|---|
| Shall Trip Function | Required Settings | | Comparison to IEEE Std 1547-2018 (2nd ed.) default settings and ranges of allowable settings for Category II | | |
| | Voltage (p.u. of nominal voltage) | Clearing Time(s) | Voltage | Clearing Time(s) | Within ranges of allowable settings? |
| OV2 | 1.20 | 0.16 | Identical | Identical | Yes |
| OV1 | 1.10 | 2.0 | Identical | Identical | Yes |
| UV1 | 0.88 | 2.0 | Higher (default is 0.70 p.u.) | Much shorter (default is 10 s) | Yes |
| UV2 | 0.50 | 1.1 | Slightly higher (default is 0.45 p.u.) | Much longer (default is 0.16 s) | Yes |

| Shall Trip Function | Required Settings | | Comparison to IEEE Std 1547-2018 (2nd ed.) default settings and ranges of allowable settings for Category I, Category II, and Category III | | |
|---|---|---|---|---|---|
| | Frequency (Hz) | Clearing Time(s) | Frequency | Clearing Time(s) | Within ranges of allowable settings? |
| OF2 | 62.0 | 0.16 | Identical | Identical | Yes |
| OF1 | 61.2 | 300.0 | Identical | Identical | Yes |
| UF1 | 58.5 | 300.0 | Identical | Identical | Yes |
| UF2 | 56.5 | 0.16 | Identical | Identical | Yes |

**Figure D.5: Voltage and Frequency Trip Settings for DERs – ISO-NE SRD Requirements [Source: ISO-NE]**

Figure D.6 below shows the percentage of R-DER tripped and its associated frequency trip points. These percentages have been applied to all R-DER in the load flow case. The frequency trip settings for R-DER correspond with the UFLS program settings. This has been done to simulate the tripping of load as well as R-DER at the set points as dictated by the UFLS program.

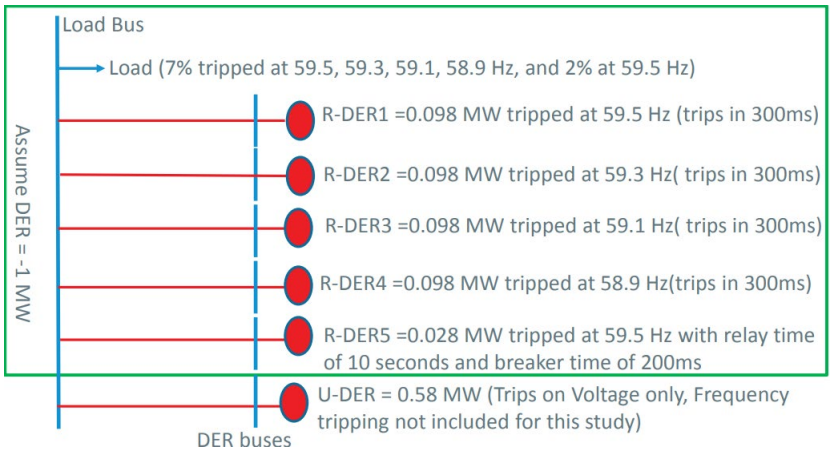



**Figure D.6: Load Shed and Assumed Split of R-DER and U-DER with trip settings**

## Impact of R-DER on Deficiency Calculations per PRC-006

ISO-NE assumes that DERs are evenly distributed across its system, which is deemed a practical modeling assumption for R-DER and U-DER since PRC-006 focuses on an electrical island-level impact. The UFLS program must meet specific underfrequency performance requirements caused by an imbalance defined as:

$$Imbalance = \frac{Load - Actual\ Generation\ Output}{Load}, of\ up\ to\ 25\%\ within\ the\ identified\ island(s)$$

As described in Chapter 2, if "load" is assumed as net demand, then the deficiency for analyzing the 2023 Summer Peak scenario would be 25% of 25,976 MW (28,176 MW of gross load minus 2,200 MW of R-DER), or 6,494 MW. If "load" is assumed as gross demand, then the deficiency would be 25 percent of 28,176 MW, or 7,044 MW. **Figure D.7** shows the electrical island frequency response for a simulated deficiency of each scenario. The simulation clearly shows that using gross load results in a deeper frequency nadir and a slower recovery in frequency (due to a larger deficiency). Further, the simulations here show that if ISO-NE used the 25% imbalance based on net demand, it would be compliant with the UFLS program requirements; however, assuming a 25% deficiency based on gross demand would result in simulations that do not meet the performance calculations (and additional load shedding would be required).

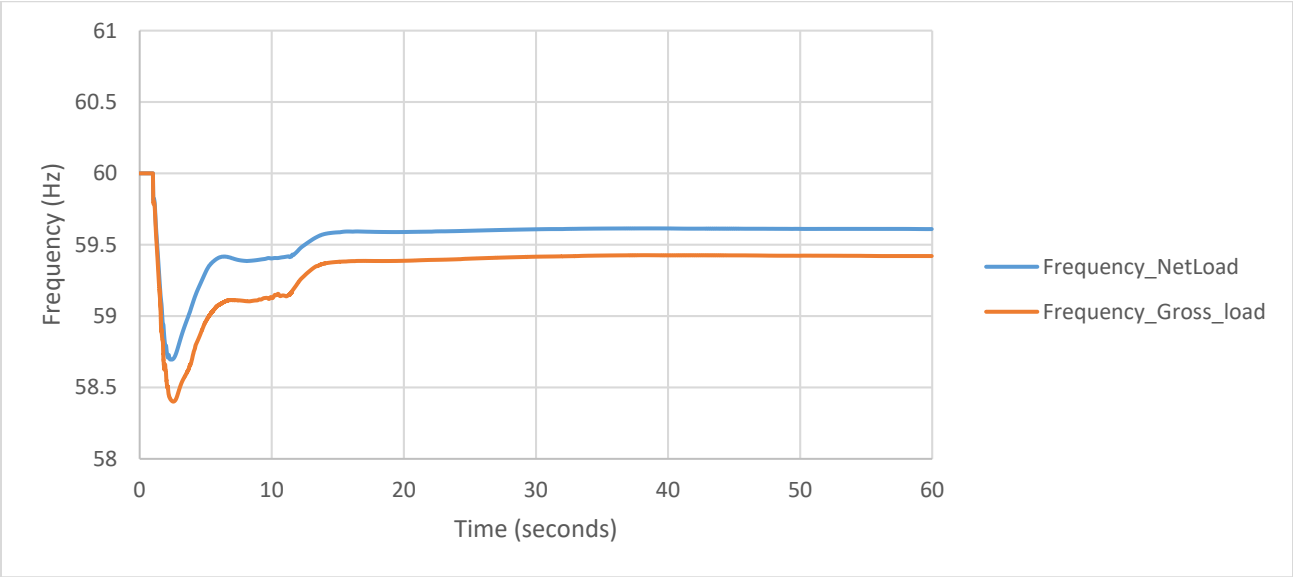



**Figure D.7: Net Load versus Gross Load**

## Tripping of U-DER Due to Voltage Fluctuations

Subsequent to frequency recovering above 59.5 Hz, the loss of load due to UFLS action causes the bus voltages to rise to a level and for a duration that may exceed the trip settings of U-DER causing U-DERs to trip. **Figure D.8** below shows the bus voltages at a U-DER location causing it to trip on voltage trip settings. The bus voltage exceeded 1.1 pu for more than 2 seconds and based on *Inverter Source Requirement Document of ISO New England (ISO-NE)*[79] Table-1 settings, U-DER tripped.

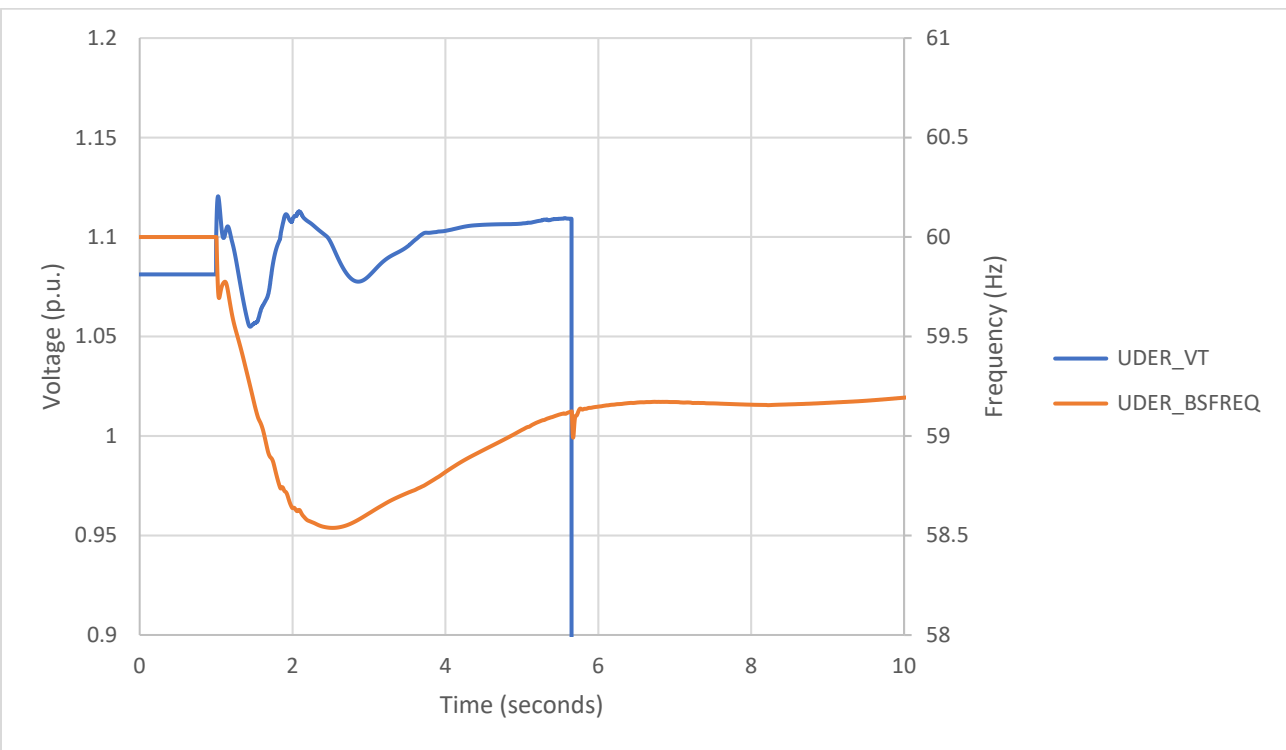



**Figure D.8: U-DER Tripping on Voltage Due to UFLS**

[79] https://www9.nationalgridus.com/non_html/ISO%20New%20England%20Source%20Requirement%20Document-2018-02-06.pdf

The loss of U-DER due to voltage trip settings further adds to the island generation deficiency. It is quite possible that due to this additional generation deficiency the island frequency may not recover above 59.5 Hz and hence may violate the requirements as shown in **Figure D.9** below.

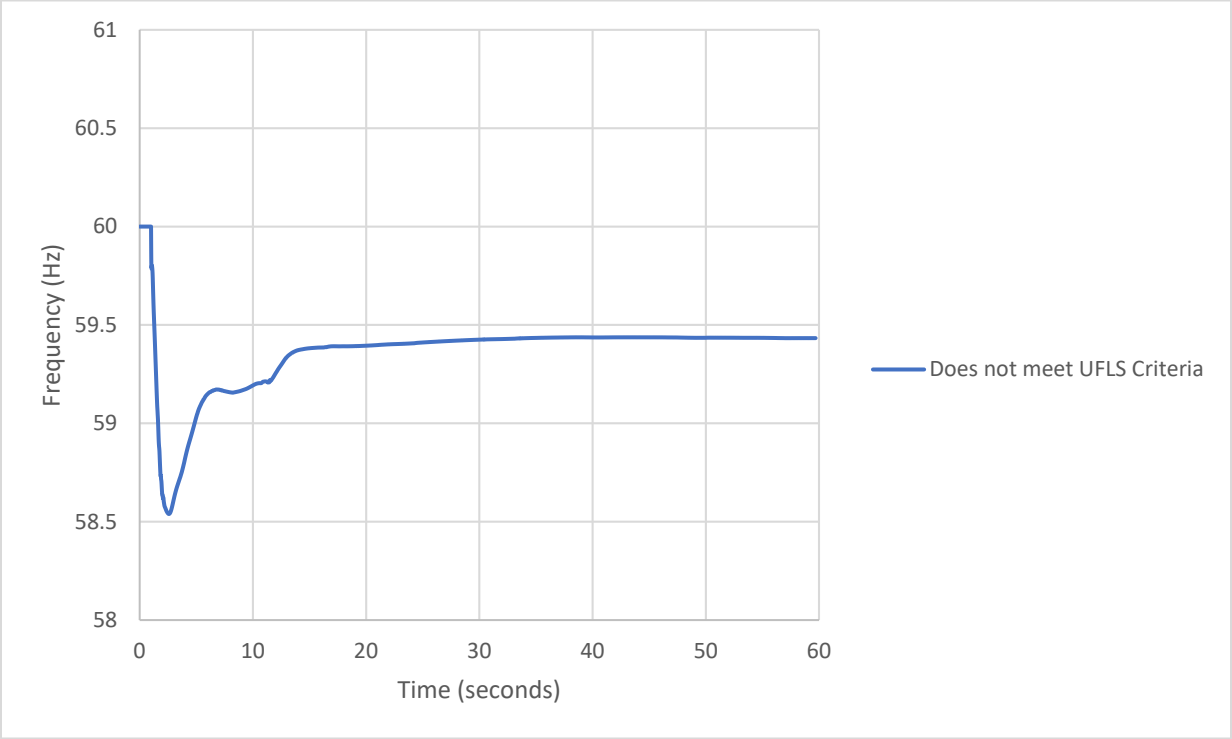



**Figure D.9: ISO New England Island Frequency Performance**

## UFLS Program Design with DER Impacts

High penetration of DERs in the system may require compensatory load shedding to make up for the loss of DERs during underfrequency conditions. Under NPCC Directory 12 requirements (now replaced by the Regional Reliability Standard PRC-006-NPCC Requirements), generating units shall not trip for underfrequency conditions in the area above the curve as shown in **Figure D.10** below.

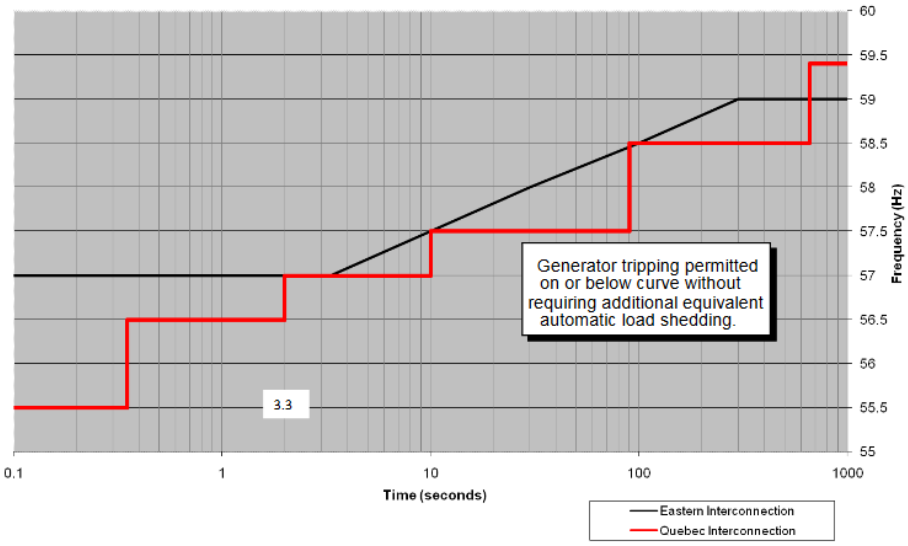



**Figure D.10: Standards for Setting Underfrequency Trip Protection for Generators**

If one considers the total R-DER that trips above the black curve in **Figure D.10** as a single aggregated unit, then additional compensatory load shedding may be needed to cover for the loss of R-DER. Including an additional compensatory load shedding percentage to cover for the loss of R-DER helps the island frequency to recover above 59.5 Hz and makes the UFLS program compliant. **Figure D.11** below shows the island frequency with compensatory load shedding.

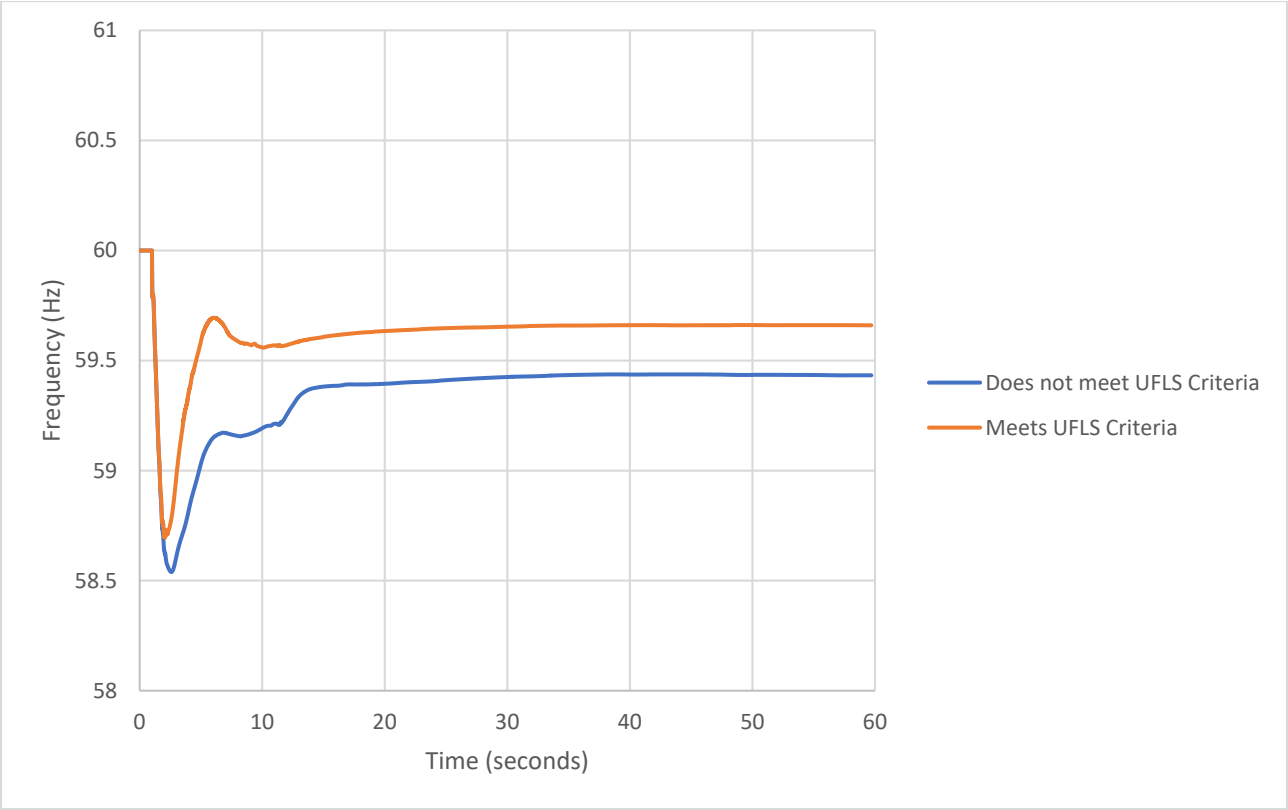



**Figure D.11: ISO New England Island Frequency with Compensatory Load Shedding**

# Contributors

NERC 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 SPIDERWG.

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|---|---|
| **Reliability Guideline** | Reliability Guideline: Recommended Approaches for UFLS Program Design with Increasing Penetrations of DERs |
| **Instructions** | **Please use this form to submit comments on the draft Reliability Guideline. Comments must be submitted w Recommended Approaches for UFLS Program Design with Increasing Penetrations of DERs Comments" in the comments should be provided within this form.**<br><br>Comments may be submitted by individuals or organizations. Please provide the requested information in Row Industry Segment and Region (if applicable) in Rows 7 and 8 and provide the requested contact information in R<br><br>If you have any questions regarding this process, please contact John Skeath (John.Skeath@nerc.net) |
| **Review Period** | July 12, 2021 - August 26, 2021 |

| Organization(s) | Page # | Line / Paragraph | Comment |
|---|---|---|---|
| Utility Services | 1 | 285-289 | Narrative references to colors in the figure are incorrect |
| Utility Services | 6 | 414 | missing word in sentence: "Therefore, a reasonable can be…" |
| Utility Services | 20 | 933-945 | In general, small DPs will not have the expertise or ability to conduct these activities. For example, a DP in ISO-NE is only expected to report the data for the peak hour from the previous year. Expecting a DP to conduct an analysis of the load on that feeder for various ambient conditions over the course of a year is unreasonable. The feeder load data could be provided to the PC in order to condict the analysis. Additionally, as many of the DPs are likely the recipients of the UFLS program requirements, not the planning agent or the entity creating the UFLS program, these DPs do not have the resources to conduct the types of studies suggested. If the DP is the UFLS planning or design agent, then the suggestion seems prudent, but in the case where the DP is being told what the program requirements are, there is no benefit for them to conduct the studies being suggested |

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| Thomas Foltz on behalf of American Electric Power | v | Preamble, pp. 87-98 | While the Preamble section does state that the contents of this Reliability Guideline are not considered "binding norms or parameters", it does not specifically state that the contents are not to be considered Reliability Standards. Such a distinction has been included the Preamble section of previous Reliability Guidelines and we recommend that it be added to this one as well. |
| Thomas Foltz on behalf of American Electric Power | Entire document, with page 20 serving as one example | Entire document, with lines 918 - 953 serving as one example | AEP appreciates the time and energy spent by the SPIDERWG to produce this Reliability Guideline. This guideline illustrates several gaps and potential failure points for entities and RTO/ISO's to consider when evaluating their UFLS programs, and will be extremely helpful in this regard. Having said that, while the guidance and recommendations provided are logical and sound, the premise of these recommendations do not take into consideration the jurisdictional hurdles that the industry faces today. The content in this Reliability Guideline includes multiple audiences and entities which would not be identified as Functional Entities, nor which would be obligated as such within NERC Standards. For example, there is no obligation for DER Owners/Operators to coordinate or report information to BPS owners/operators. The only visibility BPS owners/operators will have is if the DER owners participate in the market under a DER Aggregation pursuant to FERC Order 2222. Otherwise, knowledge of the mere existence of any DERs would be a significant hurdle in implementing the recommendations found within this Reliability Guideline. While the entire document contains guidance which would be problematic to execute, the bulleted list following the text "During the selection of loads participating in the UFLS program, DPs should consider the following" may prove either extremely difficult or even impossible for the DP to accomplish. As yet another example, the RG provides no recommendations for the State Commissions to encourage DER owners to report the needed information to those who are actually tasked |

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| Thomas Foltz on behalf of American Electric Power | Entire Document | Entire Document | While Reliability Guidelines encourage the reader to consider various recommended practices in the pursuit of BES reliability, these guidelines should avoid using language which, if taken out of context from surrounding text, may appear as directives or obligations. For example, phrases such as "should confirm" and "should clearly articulate" in this Reliability Guideline come across more as directives rather than recommended practices, and as such should be reworded in a manner more suitable for a Reliability Guideline. As one example, we believe it would be more appropriate for the text "During the selection of loads participating in the UFLS program, DPs should consider the following" to instead read "During the selection of loads participating in the UFLS program, DPs *may* consider the following." |
| California ISO | | Executive Summary and Introduction | Suggest to specify what is U-DER and R-DER when these terms are first used, not everyone may know that. It is explained in Chapter 2, but first mentioned in the Executive Summary. |
| California ISO | | Executive Summary and Introduction | Although an assumption that "R-DER, located on feeders, are usually on unity power factor without voltage control, and will trip at UFLS load shedding trip settings" is a conservative assumption. New DERs may have smart inverters with voltage and frequency control capabilities. However, if UFLS relays are located in the feeders where DER are connected together with load, DER will trip when the feeder trips. I suggest mentioning that. |

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| California ISO | | Executive Summary and Introduction | UFLS design is performed not only by PC, but also by WECC. WECC has the coordinated UFLS program in which WECC members participate. In the Western Interconnection, UFLS database is maintained by WECC. The WECC members provide updates of their UFLS relays and generation under-frequency relays. The studies of the WECC UFLS program are conducted by WECC UFLS Review Working Group. |
| California ISO | | Executive Summary and Introduction | The document should refer to PRC-006-5, which is the latest, not to PRC-006-3 as in Page 10. The cited requirements may be the same, but using the name PRC-006-5 and PRC-006-3 interchangeably may be confusing. It is better to provide plots from the Attachments of the Standard PRC-006-5, not PRC-006-3. Attachment A of the PRC-006-5 Standard doesn't have the plot with Thresholds for Setting Underfrequency Trip Protection for Generators shown in the Guideline from PRC-006-3. It is mentioned in the text of PRC-006-5, but the plot shown in the Guideline is not in the latest Standard. |
| California ISO | | Chapter 1 | Suggest to specify whether the DER discussed in the Guideline are Solar PV or other inverter-based resources. This is especially relevant when talking about system inertia. If the DER are not inverter-based, but, for example synchronous generators, they will not reduce system inertia and will not increase the Rate of Change of Frequency. |
| California ISO | | Chapter 1 | The Guideline should mention PRC-006-5, not PRC-006-3 |
| California ISO | | Chapter 1 | What were the settings on the DER tripping shown in Figure 1.2? |
| California ISO | | Chapter 1 | Please, spell out the abbreviations (for example, EPS), not everyone may know them. |

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| California ISO | | Chapter 1 | Suggest adding a point regarding composite load models to the discussion of the DER tripping for high or low voltages. Depending on how composite load is modeled in the dynamic stability data, there may be stalling of single-phase induction motors, and/or significant reduction in composite load following faults. Voltage trip setting of the DER should be appropriately modeled. In addition, large loss of load by composite load models may lead to UFLS not being activated, and may result in high voltages and high frequencies. With large loss of load by composite load model, DER may also trip for high voltages . |
| California ISO | | Chapter 1 | Suggest adding summer peak conditions with high DER output to the list of cases illustrating how DER affects UFLS arming. In this case, due to variability of DER, there may be a concern of under- or over-tripping of load, especially considering stalling of single-phase induction motors with faults. As said in Chapter 2, multiple cases need to be studied to develop UFLS programs. |
| California ISO | | Chapter 2 | The Guideline should cite PRC-006-5, not PRC-006-3 (Pages 11, 12, 14) |
| California ISO | | Chapter 2 | In Selecting Islanded Networks, I suggest adding that in WECC the studies, including selecting all the assumptions, are performed by WECC UFLS Review Group, not by individual PC. |

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| California ISO | | Chapter 2 | In the imbalance calculations, DER is considered to be generation and its output is counted together with generation connected to the bulk system. However, behind-the-meter DER are connected in the distribution system and in the studies are modeled as part of load. If behind-the-meter DER are counted as a part of load, then instead of the equation<br><br>Will be<br>BPS generation output + (tie line imports-tie line exports) = 75% * (gross load – DER output)<br>In these two cases, UFLS program will be different, with less deficiency if the load is counted as net demand. With the load counted as gross demand, there may be more UFLS needed, and the UFLS programs may not meet PRC-006 Standard. As said in this section, DER output is usually not reduced because they are not frequency responsive. Thus, it may make more sense to count them as a part of load and to consider net load, and not gross load. It is also not clear how are losses counted in the imbalance calculations. |
| California ISO | | Chapter 2 | Regarding modeling DER tripping on ROCOF, there are no ROCOF protection models, and it is not clear at which ROCOF DER may trip. The Guideline proposes to use engineering judgement, but doesn't give any recommendations. I suggest to add examples and provide some numbers at which ROCOF DER may trip. |
| California ISO | | Chapter 3 | It should be noted that in the Western Interconnection, UFLS entities provide data not to PC, but to WECC because WECC has UFLS program for the whole interconnection, not for individual PC. The PC within WECC participate in joint regional review of the UFLS program. |

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| California ISO | | Chapter 3 | The references should be to PRC-006-5, not to PRC-006-3. |
| California ISO | | Chapter 3 | The guideline needs to indicate from which % of DER, the DER should be modeled and not netted with load. |
| California ISO | | Chapter 3 | It will be beneficial if the Guideline provides more details on the battery storage impact on the UFLS, especially since the amount on battery storage in the distribution systems is rapidly increasing. |
| California ISO | | Appendices | Although Appendices have good examples of UFLS program designs, the Guideline looks more like a White Paper because it doesn't give definite recommendations how UFLS programs should be designed and which numbers and parameters to use. |
| Consumers Energy Company | vi. | 126-127 | The terms, "U-DER" and "R-DER" are first used here without defining them to distinguish vs. DER. "R-DER" was also used in line 330, still without definition. These terms are finally defined in lines 560 and 566, respectively. |

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| Consumers Energy Company | 1 | 264 | This lack of visibility in DER output may also apply to UFLS Entities, as they design their respective UFLS implementation. They may not be aware of DER's and their output, either in historical circuit loads or projected UFLS behavior. This can be a political / regulatory issue for these UFLS Entities. While they, and their regulators, likely have policies requiring notification of DER being planned / connected, those connecting DER may disregard such policies, reasoning that "my DER is too small to matter". |
| Consumers Energy Company | 5 | Footnote 29 | This behavior is endemic of older philosophies that premise that DER are antithetical to reliable system operation and should be disconnected whenever the system enters an abnormal mode to facilitate recovery using "traditional" resources. |
| Consumers Energy Company | 8 | 453-460 | Suggest that reference be made here to the FERC-mandated voltage ride-through characteristics. |
| Consumers Energy Company | 8 | 462 | Suggest that this section be augmented to address the issues noted above re: line 264 |
| Consumers Energy Company | 9 | 499 | I disagree with the premise here. Summer Peak Load (Evening Hours) – around 6 pm as noted on a hot summer day, will likely experience high levels of solar flux, resulting in high DER output. This is several hours prior to the setting of the sun in these conditions. I suggest this scenario be re-evaluated. |
| Consumers Energy Company | 14 | Table 2.1 | DER Output in Summer Peak Scenario (particularly solar PV) seems much more likely to be high as the defined time – 6 pm – is a time of still considerable solar flux at incident angles conducive to strong solar PV output. Thus, ROCOF is likely to be relatively higher, and higher possible DER tripping (particularly R-DER) is probable. |
| Consumers Energy Company | 19 | 863 | UFLS Entities often will consider "critical" loads, such as public safety, hospitals, etc. when selecting which system elements to disconnect. This may not be closely affiliated with DER penetration. |

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| Consumers Energy Company | | Additional Recommendation | Strongly emphasize that UFLS Entities MUST be aware of all DER connected to their systems, and, as much as possible, be aware of the real-time output of same. The UFLS Entities can then provide aggregated signals of total DER output to the RC and PC to help enhance the modeling efforts. Ideally, the aggregated DER output for R-DER should be based on each circuit, etc. that the UFLS is tripping as part of its UFLS program implementation. See Line 964 and following section. |
| Edison Electric Institute (submitted by Mark Gray) | N/A | N/A | General Comments:<br>The Reliability Guideline (RG) titled "Recommended Approaches for UFLS Program Design with Increasing Penetration of DERs" contains useful information that would benefit the industry and promote necessary discussion, but it should not be classified as a NERC Reliability Guideline. While the document would inform and educate many within the industry as a white paper, its value will be diminished as a Guideline because it lacks key elements of a guideline, including:<br>1. clear recommendations and guidance necessary to make the document actionable for entities trying to improve or otherwise analyze their UFLS program design in light of increased DERs.<br>2. metrics to measure whether this Reliability Guideline was effective. Reliability Guidelines, as of January 19, 2021, (under a FERC accepted NERC proposal, which defines the approach for evaluating all future NERC Reliability Guidelines) now obligates NERC to include "metrics specific to each Reliability Guideline." (See RSTC Committee Meeting Documentation dated March 3, 2021. Document titled "Evaluating Reliability Guideline Effectiveness Industry survey, Triennial Review and Metrics".) Accordingly, this Reliability Guideline should not be approved until necessary metrics are added.<br>For these reasons, we strongly encourage NERC to reclassify this document as a NERC White Paper. |

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| Edison Electric Institute (submitted by Mark Gray) | N/A | N/A | Additional General Comments:<br>In the event the document is not converted into a White Paper, we recommend that the following concerns be addressed and that the document is reposted for industry review and comment.<br><br>1. The document does not fully address the issues associated with high penetrations of renewable generation. While DERs are an issue, large wind and solar farms have a significantly greater impact on UFLS Systems.<br>2. DERs impact the amount of load that can be shed on certain feeders and recognize that TOP's/DP's may not have the ability to shed the amount of load originally identified due to the growing number of DERs in some areas.<br>3. Inertia is an important part of this issue but DERs are only part of that issue and should not be exclusively addressed. Significant amounts of DER can and do in some areas play a role in displacing synchronous generation, which can lower system inertia, however, large scale wind/solar farms also impact UFLS programs by displacing synchronous generation, which reduces system inertia and results in higher rate-of-change-of-frequency (RoCoF).<br>4. The document mentions Battery Energy Storage Systems as necessary to maintain system stability during frequency excursion to avoid tripping load but these issues are not yet clearly defined across the industry or in the document.<br>5. The document also does not provide clear guidance |

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| Edison Electric Institute (submitted by Mark Gray) | N/A | N/A | Additional General Comments (continued)<br>6. NERC should consider adding greater focus on providing guidance for the following entities<br>a. Transmission Planners (Long-Term) – Work in conjunction with the PC to study the effectiveness of UFLS programs for their area. Include studies under varying load and generation mixes, not just peak load (as described in the existing document). Determine maximum acceptable ROCOF to allow UFLS program to be effective. Study the impact of adding synchronous condensers, BESS's or automatic load restoration to see if they will cost effectively improve UFLS effectiveness.<br>b. Transmission Planners (Real-Time) – Administer the PC's UFLS program for their area. Monitor and trend historical load data to identify feeders most suitable for load shedding.<br>c. Transmission Operators – Monitor UFLS loads real-time to see if UFLS program is shedding enough load. Alarm if load levels are not sufficient. Report alarms to Real-Time Planner to add/subtract load from program if necessary. Monitor ROCOF real-time and alarm if greater than that provided by Long-Term Transmission Planning. Dispatch synchronous generation as needed to get ROCOF within limits. Use programmed SCADA poke-points to enable programmed relays to change settings groups to allow more/less load to be shed.<br>d. Transmission Owners – Program UFLS relays to operate per PC's UFLS program. Upgrade UFLS relays to microprocessor relays to take advantage of logic features that enable creation of more sophisticated UFLS schemes (e.g., ROCOF monitoring, changeable |

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| Edison Electric Institute (submitted by Mark Gray) | N/A | N/A | Additional General Comments (continued)<br>7. The document should also include guidance in these areas:<br>a. Brightline guidance defining the threshold that might trigger the need for more detail/dynamic T/D studies.<br>b. Clear guidance regarding how to treat U-DER and R-DERs that assist entities dealing with these issues while setting reasonable steps and expectations for modeling and planning studies that match entity impacts.<br>c. Recommendations that address the need for additional UFLS supervision such as voltage supervision, current supervision, or ROCOF supervision.<br>d. Recommendations that reduce UFLS time delays from 30 – 60 cycles to 5 – 10 cycles |

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| Edison Electric Institute (submitted by Mark Gray) | vi | 125 | The need for dynamic planning models should be clearly justified. The decisions on the need for this level of modeling should be left to the responsible entity and is generally outside of NERC's authority. |
| Edison Electric Institute (submitted by Mark Gray) | viii | 168 - 169 | EEI disagrees with this statement: "the UFLS Entities are expected to be able to accurately and quickly provide a firm amount of load disconnection. These two main expectations can be tested with the increase of DER, especially those DERs that are unknown to the PC or UFLS Entities." Guidance on tracking DERs on UFLS feeders should be provided emphasizing the importance of entities knowing and understanding UFLS impacts. What cannot be known with precision is how much output the DERs may be supplying at any given time. Moreover, treatment of DERs being used solely for local distribution should be considered as well as how to address the issues of modeling while also recognizing the lines between state and NERC jurisdiction. |

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| Edison Electric Institute (submitted by Mark Gray) | ix | 179 - 182 | On line 180, the document references a Notice of Proposed Rulemaking (NOPR), where it states that FERC was "persuaded…that Reliability Standard PRC-006-1 does not limit the resources that can be modeled in the UFLS assessments and that power system models used in UFLS assessments generally model all qualifying generation, including resources not directly connected to the bulk electric system" but the document does not provide a reference to that NOPR. Quotations should be referenced to allow readers to readily review the referenced document and context. |
| Edison Electric Institute (submitted by Mark Gray) | ix | 186 - 188 | EEI notes another quote from a FERC NOPR that is not referenced. In the document it states: FERC also highlighted that accurately predicting system performance is critical for UFLS program design simulations, and that "inaccurate models can lead to invalid conclusions which can be detrimental to the analysis and operation of the bulk electric system." The quote should be referenced. to allow for meaningful input. We do agree that inaccurate models can lead to invalid conclusions. That said, accuracy in the context of system model impacts to the BES need to be considered, meaning that the bulk modeling of DERs on a feeder should in most cases be sufficient to assess the expected impacts of DERs on a UFLS feeder because the output of a renewable cannot be modeled with precision |
| Edison Electric Institute (submitted by Mark Gray) | xi | 189 | EEI supports the statement that "reasonable representation of BPS generation, aggregate load, as well as aggregate DER is critical", however, aggregated DER in this context should be DERs that directly participate in the markets. For those not participating in markets, then modeling those DERs in with bulk load as offsets should be sufficient in most cases. |

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| Edison Electric Institute (submitted by Mark Gray) | xi | 238 - 240 | EEI notes that the statement – "If the quantity of DER is large enough to actually result in export to the bulk power system, isolation of the circuit as part of a load shed scheme could result in increasing, rather than reducing, system demand." While this is readily understood, guidance should be given to entities identifying how best to identify and address such impact. E.g., The responsible entity should be monitoring feeder power flows and if such situations are occurring then they should be locating a more suitable feeder rather than trying to model that feeder within the context of a UFLS program. |

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| Edison Electric Institute (submitted by Mark Gray) | xii | 247 - 251 | EEI disagrees with this statement: "Aligning with FERC Order No. 763, the planning assessments to develop a UFLS program rely on power system models that should suitably represent the expected system conditions facing the BPS in the future. This requires representing BPS-connected generating resources as well as end-use loads and DERs. Without appropriate accounting of the performance of these resources, PCs will be challenged in developing UFLS programs that are assured to operate appropriately for the expected frequency excursion event." While on the surface, the statement sound reasonable it makes assumptions regarding alignments to Order 763. In that Order, the Commission was persuaded that PRC-006 required the modeling of "the vast majority of qualifying generation to ensure the reliable operation of the bulk electric system" (see Order 763, P23). BPS connected resources continue to be modeled, while the vast majority of distribution level DERs are largely supporting local distribution and need to be considered differently from those resources directly connected to the BPS supporting the BES. EEI also believes that DER resources that are aggregated for the purposes of participating in the organized markets are being accurately modeled. This document seems to imply ALL DERs need to be modeled in order to ensure UFLS programs remains reliable. In many cases they can continue to be modeled as load offsets until they reach some tipping point. That said, UFLS feeders that have meaningful amount of DER should be tracked, and reported to the responsible PC so that more suitable |

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| Edison Electric Institute (submitted by Mark Gray) | 1 | 268 - 271 | Even assuming that ROCOF (rate of change of frequency) is slow enough for UFLS to operate effectively and that sufficient frequency responsive resources are available to arrest frequency decline, PCs will need to ensure appropriate modeling of aggregate DER UFLS trip settings that could exacerbate any underfrequency condition. This statement needs to be more clearly understood. First, if the program remains effective, it is unclear where the concern lies. Second, modeling of aggregated DER UFLS trip settings makes no sense in the context of a UFLS program. The purpose of a UFLS relay is to drop load to balance the loss of generating resources in order to maintain stability of the BES. If a UFLS feeder has a meaningful amount of DERs than any benefit of tripping the feeder is likely lost. This should be easy to track and reported through substation SCADA data. While this type of data would not track individual resources, it would provide useful information that would allow an entity to identify problem feeders already contained within a UFLS program. |
| Edison Electric Institute (submitted by Mark Gray) | 3 | 317 -318 | In the future, DERs may be able to provide fast frequency response (FFR) to support high ROCOF conditions during low synchronous inertia – EEI disagrees with this statement. While energy storage will be able to provide FFR, renewable generation (i.e., solar PV and small-scale wind DERs) will provide FFR they will normally operate at maximum available power. This leaves these resources without any spare capacity that could be used for this purpose. |
| Edison Electric Institute (submitted by Mark Gray) | 6 | 414 - 416 | Correct typos in this sentence: "Therefore, a reasonable can be to assume that DER will trip at 59.5 Hz within 2 seconds and at 57.0 Hz within 0.16 seconds." |

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| Edison Electric Institute (submitted by Mark Gray) | 8 | 488 - 489 | The statement that "[u]sing offline studies performed in the long-term planning horizon, as required per PRC-006-3, will become increasingly obsolete as the system rapidly changes operating conditions and expected net loading conditions." This statement appears to be overstated, assuming that all UFLS feeders will overtime have substantial amounts of DERs impacting the reliability of programs under PRC-006. |
| Edison Electric Institute (submitted by Mark Gray) | Various | 144, 1059,1100,1102, 1246 & 1403 | Typo - "under-frequency" should not be hyphenated or contain a space between under and frequency. |
| Edison Electric Institute (submitted by Mark Gray) | 27 | 1101 | Typo - delete the duplicate "the" |
| Edison Electric Institute (submitted by Mark Gray) | 30 | 1170 | Typo - delete the duplicate period. |
| Edison Electric Institute (submitted by Mark Gray) | 36 | 1297 | Correct typo "reture" to retune. |
| Eastern Interconnection Planning Collaborative - Frequency Response Working Group (FRWG) | General | General | Will this Reliability Guideline be subjected to evaluation metrics to determine industry adoption? If so, please describe within the document how these metrics will be detemined as well as how input is collected from industry. |
| Eastern Interconnection Planning Collaborative - Frequency Response Working Group (FRWG) | 6 | line 135: | the sentence is incomplete. |
| Eastern Interconnection Planning Collaborative - Frequency Response Working Group (FRWG) | 6 | lines 118-119: | This sentence is confusing consider revising. |
| Eastern Interconnection Planning Collaborative - Frequency Response Working Group (FRWG) | 6 | Lines 101-104 | The SPIDER scope document should not be considered as a specific "request" by the NERC RSTC. Additionally, the footnote link does not work. |
| Eastern Interconnection Planning Collaborative - Frequency Response Working Group (FRWG) | 6 | Lines 120 | Please include specific references to the mentioned "recent policy proposals and studies" in body of document or as a footnote. |
| Eastern Interconnection Planning Collaborative - Frequency Response Working Group (FRWG) | 6 | Lines 125 | Suggested word change from "should" to "are recommended to:". |

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| Eastern Interconnection Planning Collaborative - Frequency Response Working Group (FRWG) | 6 | Lines 125-135 | says "in general, PCs should" and then the first bullet point says "model DER separate from load". |
| Eastern Interconnection Planning Collaborative - Frequency Response Working Group (FRWG) | 6 | Lines 126-128 | This statement infers that dynamic models of U-DER and R-DER should be studied regardless of DER penetration levels, however, the Reliability Guideline's overall concern is the impact of high penetration of DER on UFLS programs. The guideline should have some discussion related to the increasing risk of UFLS impact based on percentage of DER penetration for a given system. |
| Eastern Interconnection Planning Collaborative - Frequency Response Working Group (FRWG) | 8 | line 145: | suggest changing "lack of generation" |
| Eastern Interconnection Planning Collaborative - Frequency Response Working Group (FRWG) | 8 | Lines 165-168 | The use of descriptors in these sentences do not accurately represent the referenced diagram. |
| Eastern Interconnection Planning Collaborative - Frequency Response Working Group (FRWG) | 9 | Figure I.1 middle blue box: | the words do not flow well "in order to use in event…", |
| Eastern Interconnection Planning Collaborative - Frequency Response Working Group (FRWG) | 9 | Line 189 | The descriptors in this sentence seem to be in conflict. |
| Eastern Interconnection Planning Collaborative - Frequency Response Working Group (FRWG) | 9 | Lines 825-828 | describes adaptive UFLS programs as a potential solution to high penetrations of DER. This is where you shed certain loads based on DER output conditions – it could be different for different times of day depending on DER output. |

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| Eastern Interconnection Planning Collaborative - Frequency Response Working Group (FRWG) | 11 | Lines 230-243 | This paragraph references that high levels or high DER production (3 separate times) can be impactful to UFLS programs, however, this reliability guideline doesn't make any attempt to establish/determine at what level of penetration does UFLS impact occur but simply implies that all DER should be modeled. It would be useful to industry for a discussion of this type to occur. |
| Eastern Interconnection Planning Collaborative - Frequency Response Working Group (FRWG) | 12 | Line 249 | Add clarity to level of DER representation |
| Eastern Interconnection Planning Collaborative - Frequency Response Working Group (FRWG) | 13 | Lines 258-259 | High levels of DER impact BPS frequency response, not increasing levels of DER. |
| Eastern Interconnection Planning Collaborative - Frequency Response Working Group (FRWG) | 13 | Lines 282 | Clarification |
| Eastern Interconnection Planning Collaborative - Frequency Response Working Group (FRWG) | 13 | Lines 285-288 | These statements contradict of the statements in Figure 1.1. Figure 1.1 shows that the blue line did not meet the UFLS criteria, while the orange line did meet the UFLS criteria. |
| Eastern Interconnection Planning Collaborative - Frequency Response Working Group (FRWG) | 14 | line 285-288: | The language says that orange line does NOT meet criteria, however in the Figure 1.1, it says orange line meets the criteria and blue line does not meet the criteria. |
| Eastern Interconnection Planning Collaborative - Frequency Response Working Group (FRWG) | 15 | Key Takeaway in blue box: | the first sentence appears to have repeated "BPS" and does not read well. |

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| Eastern Interconnection Planning Collaborative - Frequency Response Working Group (FRWG) | 15 | lines 317-318: | It would be a reliability risk to have DERs support ancillary services. If the BA is dependent on a home owner or set of home owners to maintain DERs such that they perform ancillary services, but the DER owner in fact does not maintain that equipment or goes on vacation and the DER is not operational, it would be a reliability risk. The concept of which resources provides ancillary services needs to determined that does not result in a risk to BPS reliability. Ancillary services are required both day and night not just during high solar output periods. Suggest removing these sentences that start "In the future". If DERs are load following, the internal islanding detection of the DER will not work. There are safety risks if DERs operate in an island with load. The only way for a DER to react to a low frequency event is if there is headroom for the DER, how does the DER owner get paid for providing ancillary services. How will the industry enforce headroom of DERS? Frequency support on the distribution system is too localized and may cause more tripping instead of less tripping of DER resources. Suggest that BA's have a requirement to identify resources that will support frequency and load following functions. These reliability resources should be connected to the BPS and not distribution. |
| Eastern Interconnection Planning Collaborative - Frequency Response Working Group (FRWG) | 15 | Lines 314-315 | Clarification and grammar correction |
| Eastern Interconnection Planning Collaborative - Frequency Response Working Group (FRWG) | 15 | Lines 323-325 | The AEMO event was not impacted by a high penetration of DER but simply an extreme event to demonstrate ROCOF, as stated in Appendix B. Using this event as an example in this Reliability Guideline implies that DER was an impact and misleads the reader. |
| Eastern Interconnection Planning Collaborative - Frequency Response Working Group (FRWG) | 16 | Lines 350-351 | Clarification to DERs that don't receive curtailment signals. |

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| Eastern Interconnection Planning Collaborative - Frequency Response Working Group (FRWG) | 17 | figure 1.4 : | there are two vertical axis without labels. Additionally a legend describing the two curves depicted is needed to avoid having to assume their meaning. |
| Eastern Interconnection Planning Collaborative - Frequency Response Working Group (FRWG) | 17 | line 370: | "increasing penetrations of legacy inverters" seems counterintuitive. Are "legacy inverters" increasingly being added to the system? |
| Eastern Interconnection Planning Collaborative - Frequency Response Working Group (FRWG) | 17 | Line 385 | Older, legacy DERs that are subject to early versions of IEEE 1547 may have a propensity to trip at frequencies closer to nominal while newer DERs compliant IEEE 1547-2018.29 |
| Eastern Interconnection Planning Collaborative - Frequency Response Working Group (FRWG) | 18 | lines 414: | The language is missing something, |
| Eastern Interconnection Planning Collaborative - Frequency Response Working Group (FRWG) | 20 | lines 454-456: | Having DERs perform voltage support is not as much a risk to the BPS as frequency support is, however real power is reduced when reactive power is put on the grid from IBRs, so a voltage event could result in a frequency event, it not careful. |
| Eastern Interconnection Planning Collaborative - Frequency Response Working Group (FRWG) | 20 | lines 463-464: | should not have DERs controlling frequency due to issues discussed earlier. |
| Eastern Interconnection Planning Collaborative - Frequency Response Working Group (FRWG) | 20 | lines 485-493: | BPS batteries will be much better at load following and frequency support. It eliminates many issues described in this this section. |
| Eastern Interconnection Planning Collaborative - Frequency Response Working Group (FRWG) | 20 | Lines 482-483 | Author is stating an opinion on that DER may have greater risks than BPS-connected VERs without clarification. |
| Eastern Interconnection Planning Collaborative - Frequency Response Working Group (FRWG) | 21 | line 501: | change PRC-006-3 to PRC-006-5. |

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| Eastern Interconnection Planning Collaborative - Frequency Response Working Group (FRWG) | 21 | lines 495-525: | Some consideration should be given to the fact that UFLS schemes were never intended to be load-level matched balancing schemes but rather a safety net to help avoid frequency declining low enough to cause more generation to trip offline which could cascade into a blackout. When considering DER impact to UFLS design, some deference should be given to understand the UFLS scheme is designed to be very conservative, in that the design requirement includes a large 25% load/generation imbalance as a design basis. This conservatively large imbalance was intended to account for load variation which occurs through all periods of the year, fully recognizing that it may not be capable of performing at the same level for all time periods, but should be able to perform sufficiently well to avoid cascading for most realistic generation loss events. Additionally, adaptive control schemes introduce added complexity and cyber vulnerabilities that come with widespread coordinated control. |
| Eastern Interconnection Planning Collaborative - Frequency Response Working Group (FRWG) | 21 | Line 520 | Clarification |
| Eastern Interconnection Planning Collaborative - Frequency Response Working Group (FRWG) | 21 | Lines 527-528 | Author implies that HELCO successfully implemented an adaptive UFLS program, however, descriptions in Appendix C indicate that HELCO expereinced challenges to their adaptive UFLS system and is considering other technologies. |
| Eastern Interconnection Planning Collaborative - Frequency Response Working Group (FRWG) | 22 | line 538: | change PRC-006-3 |
| Eastern Interconnection Planning Collaborative - Frequency Response Working Group (FRWG) | 22 | Line 532 | Clarification |
| Eastern Interconnection Planning Collaborative - Frequency Response Working Group (FRWG) | 22 | Lines 536-537 | Clarification |

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| Eastern Interconnection Planning Collaborative - Frequency Response Working Group (FRWG) | 23 | line 584: | change PRC-006-3 |
| Eastern Interconnection Planning Collaborative - Frequency Response Working Group (FRWG) | 24 | line 629: | This equation is more appropriately used when considering islands based on past islanding events or planned islands with controlled separation schemes. Arbitrary islands selected on the basis of testing UFLS scheme design, such as PC area islands which would never realistically form, do not necessarily benefit from simulating intertie based imbalance caused by tripping tie lines during simulations. |
| Eastern Interconnection Planning Collaborative - Frequency Response Working Group (FRWG) | 24 | line 634: | Again, this equation is more appropriately used with islands based on past events and intentional controlled islanding schemes. |
| Eastern Interconnection Planning Collaborative - Frequency Response Working Group (FRWG) | 24 | line 637: | Same comment as for line 634. |
| Eastern Interconnection Planning Collaborative - Frequency Response Working Group (FRWG) | 25 | lines 686-687: | PRC-006 was not originally written to consider season or demand levels because the very conservative design basis is a 25% imbalance on a peak load case. The standard was written to set the design basis at a conservative load level with a sufficiently large imbalance to provide reasonable assurance it would catch the system for realistic and reasonable loss of generation events during all seasons and load levels. It was never intended to be able to meet the performance requirements exactly during all seasons and load levels. The 25% imbalance at peak load levels represents some margin above what may be realistically needed to provide sufficient coverage at all load levels. |
| Eastern Interconnection Planning Collaborative - Frequency Response Working Group (FRWG) | 25 | lines 692-694: | Agree with the concept that the UFLS scheme should be tested for adequate levels of performance under different system conditions, but this is not the same as designing for these different load levels. |

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| Eastern Interconnection Planning Collaborative - Frequency Response Working Group (FRWG) | 27 | Line 735 | This example is confusing as it starts with an actual CAISO base case setup but then later identifies a hypothetical modified case. |
| Eastern Interconnection Planning Collaborative - Frequency Response Working Group (FRWG) | 28 | Line 759 | Word correction |
| Eastern Interconnection Planning Collaborative - Frequency Response Working Group (FRWG) | 29 | lines 790-803: | Further background is needed here to provide reference to DER ROCOF protection. Manufacturers should be able to provide this information for the purpose of determining the threshold of ROCOF which could lead to mass tripping of DER. |
| Eastern Interconnection Planning Collaborative - Frequency Response Working Group (FRWG) | 29 | lines 790-803: | As utilities retire synchronous machines, the turbines can be inexpensively converted to synchronous condensers maintaining inertia in the grid without burning carbon fuels. This would prevent reliability issues caused by high ROCOF. Utilities should be encouraged to do this type of conversion whenever possible. |
| Eastern Interconnection Planning Collaborative - Frequency Response Working Group (FRWG) | 32 | lines 949-953: | Any such devices will need to be able to be observable by the Balancing Authority and frequency response performance requires these BESS to not simultaneously be used for other services. |
| Eastern Interconnection Planning Collaborative - Frequency Response Working Group (FRWG) | 32 | lines 949-953: | If BPS BESSs are mostly charged and connected to the grid but not injecting any real power prior to a frequency event, they could respond to either a low or high frequency event by automatically going to the charging mode, or going to the injection mode. Inverters may need to be adjusted to accommodate this type of operation. |

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| Eastern Interconnection Planning Collaborative - Frequency Response Working Group (FRWG) | 33 | lines 988-991: | How do the entities responsible for frequency control per BAL-003 ensure that the DERs providing frequency support maintain and test their equipment to ensure the reliability of the BPS? The entities responsible for NERC BAL-003 should own and operate the equipment responsible for the essential reliability services. It is unjust to issue a fine to an entity responsible for BAL-003 when the parties responsible for maintaining equipment required for essential reliability services have zero responsibility for BAL-003. |
| Eastern Interconnection Planning Collaborative - Frequency Response Working Group (FRWG) | 34 | lines 1003-1004: | Why will the owners of the DER want to provide frequency support if they have to maintain headroom to do so. The DER owner will have less revenue or sales of energy if they have to maintain headroom. If the BA pays the DER owner to maintain headroom, who is responsible when the DER fails to provide frequency support due to lack of maintenance or a frequency event occurring at night? |
| Eastern Interconnection Planning Collaborative - Frequency Response Working Group (FRWG) | 35 | lines 693-694: | Doesn't read well "is an important aspect performing UFLS studies and developing a robust UFLS program" |
| Eastern Interconnection Planning Collaborative - Frequency Response Working Group (FRWG) | 35 | Appendix A | The AEMO event was not impacted by a high penetration of DER but simply an extreme event to demonstrate ROCOF, as stated in Appendix B. Using this event as an example in this Reliability Guideline implies that DER was an impact and misleads the reader. |
| Eastern Interconnection Planning Collaborative - Frequency Response Working Group (FRWG) | 41 | Line 1135 | Word correction |
| Eastern Interconnection Planning Collaborative - Frequency Response Working Group (FRWG) | 41 | Line 1149 | Word correction |
| Eastern Interconnection Planning Collaborative - Frequency Response Working Group (FRWG) | 41 | Line 1150 | Word correction |
| Eastern Interconnection Planning Collaborative - Frequency Response Working Group (FRWG) | 42 | line 1149: | It does not read well, |

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| Eastern Interconnection Planning Collaborative - Frequency Response Working Group (FRWG) | 42 | line 1156: | It does not read well "exporting power to the system during many parts of the day." |
| Eastern Interconnection Planning Collaborative - Frequency Response Working Group (FRWG) | 42 | Line 1167 | Word correction |
| Eastern Interconnection Planning Collaborative - Frequency Response Working Group (FRWG) | 44 | line 1219: | Does not read well: "it has limitation including.." |
| Eastern Interconnection Planning Collaborative - Frequency Response Working Group (FRWG) | 44 | line 1220: | Does not read well: |
| Eastern Interconnection Planning Collaborative - Frequency Response Working Group (FRWG) | 45 | lines 1241-1244: | Agree with these statements that FFR from storage resources is necessary. Battery storage devices seem to be the best solution for carbon free frequency response. BESS should be able to go from charging to injecting quickly providing the battery operator does not allow the BESS to be charged to its maximum capacity at any time and be charged enough to inject necessary real power. |
| Eastern Interconnection Planning Collaborative - Frequency Response Working Group (FRWG) | 33-34 | lines 995-1001: | Disagree that "all generating resources" are responsible to help arrest frequency declines. The BA must manage the essential reliability services by owning and controlling carbon free equipment that can reliably respond to voltage, frequency, and load following or the essential reliability services. Then if an instability occurs, it is the responsibility of the BA who has the expertise to prevent the instability. By not requiring those entities that have the expertise today to continue to maintain reliability and assume that entrepreneurs desiring to own generation resources will accommodate the reliability needs of the BPS will prove the reliability risk that it is. |
| Electric Reliability Council of Texas, Inc. (ERCOT) | vi | 128 | "will trip" seems a bit too strong here |
| Electric Reliability Council of Texas, Inc. (ERCOT) | viii | 145 | "..when a severe lack of generation is available to serve load causing frequency to fall rapidly..." seems awkward and not precisely correct |

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| Electric Reliability Council of Texas, Inc. (ERCOT) | viii | 157-158 | "...and are set above the highest expected set points for 157 generator underfrequency protection (most notable 57.5 Hz) to avoid frequency damage." UFLS set points and generator underfrquency protection could also be coordinated in time as well as frequency (i.e. generator protection may trigger at a higher frequency with a much longer time delay) |
| Electric Reliability Council of Texas, Inc. (ERCOT) | 5 | 367-370 | Language about "balance role" is a bit awkward: "As a resource providing generation to the BPS, playing a balance role in the balance of generation and load, loss of generation will exacerbate an underfrequency event and cause frequency to fall further." |
| Electric Reliability Council of Texas, Inc. (ERCOT) | 5 | 384-385 | This sentence appears to be incomplete. "Older, legacy DERs that are subject to early versions of IEEE 1547 may have a propensity to trip at frequencies closer to nominal while newer DERs compliant IEEE 1547-2018." |
| Electric Reliability Council of Texas, Inc. (ERCOT) | 6 | 390-391 | "Propensity" does not seem to be the word to use here. "...which can be used to determine the applicable propensity of DER to trip for underfrequency conditions associated with UFLS studies." |
| Electric Reliability Council of Texas, Inc. (ERCOT) | 6 | 414 | Typo/grammatical correction. "Therefore, a reasonable can be to assume…" |
| Electric Reliability Council of Texas, Inc. (ERCOT) | 10 | 537 | Typo/capitalization of acronym |
| Electric Reliability Council of Texas, Inc. (ERCOT) | 10 | 542 | Not sure why this is limited to BTM DER. It would seem applicable to all DER. Also, the bullet is a bit vague. Is the intent to ensure that appropriate amounts of DER are tripped based on UFLS relay deployment? |
| Electric Reliability Council of Texas, Inc. (ERCOT) | 13 | 655-661 | Prioritizing DER tripping last is definitely the worst case, but seems very unlikely and perhaps too extreme. A more plausible way to get to a 25% imbalance would be to experience the loss of a few large BPS generators such that the frequency decline additionally caused DER(s) with less robust frequency ride-through capabilty to trip. |

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| Electric Reliability Council of Texas, Inc. (ERCOT) | 14-15 | 700-733 | Cosidering sensitivities seems reasonble and prudent, but is there a possibiltiy that a single UFLS program is unable to meet the performance requirements of PRC-006 for all sensitivities? Where does that put an entity with respect to compliance? Standards such as TPL-001 do not require a CAP for violations in a single sensitivity case (or extreme event), but those concepts are not included in PRC-006. Will attempting to follow the reliabilty guideline potentially put entities in a no-win box with respect to PRC-006 compliance? Experiencing a 25% imbalance is already rare and extreme. To compound that with an absolute worst-case system condition while maintaining the same PRC-006 performance requirements seems like it may be too extreme. |
| Electric Reliability Council of Texas, Inc. (ERCOT) | 16 | 759 | Typo: "During the initial onset of the frequency imbalance, ROFOF..." |
| Electric Reliability Council of Texas, Inc. (ERCOT) | 18 | 852-853 | Grammatical correction to "Please note that R-DER, located on feeders, are usually on unity power factor without voltage control, and will trip at UFLS load shedding trip settings." Should be "operated at" in stead of "on" and use "may" instead of "will". |
| Electric Reliability Council of Texas, Inc. (ERCOT) | 19-21 | 896-962 | Most UFLS programs are specified to trip a set percentage of net load served from the transmission system (and typically this is assumed to be applicable at all times). UFLS entities can (and should) periodically monitor the amount of net load that is armed with UFLS relays against their total net load to ensure that UFLS targets are satisfied for specific snapshots in time and make adjustments as necessary. Actions such as this do not necessarily need to wait for a PC assessment per PRC-006 and are aligned with the R6 annual requiment to maintain UFLS models. Application of UFLS relays should not be a "set it and forget it" task that only gets reviewed when there is a PC assessment. |

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| Electric Reliability Council of Texas, Inc. (ERCOT) | 21-22 | 964-1004 | Any resources that are relied on to provide frequency response or other critical grid-support functions should be required to have adequate ride-through capability and should not be allowed to operate on ULFS feeders. |
| Electric Reliability Council of Texas, Inc. (ERCOT) | 21 | 985-991 | The intent of this paragraph is unclear. |
| Electric Reliability Council of Texas, Inc. (ERCOT) | 22 | 1003-1004 | It seems that this statement is getting into the realm of a market recommendation rather than a reliability recommendation. |
| Electric Reliability Council of Texas, Inc. (ERCOT) | 27 | 1101 | Typo: "The the net load disconnected…" |
| Electric Reliability Council of Texas, Inc. (ERCOT) | 32 | 1238 | Typo and missing words to the language "...behavior makes the ROCOF settings challenges and initial implementation resulted in a small shed during normally" |
| Electric Reliability Council of Texas, Inc. (ERCOT) | 34 | 1259 | Grammatical correction to the language "...vast majority under 25 kW installations, representing a…" |
| Electric Reliability Council of Texas, Inc. (ERCOT) | 35 | 1297 | Typo "…reture…" |
| Electric Reliability Council of Texas, Inc. (ERCOT) | 36 | 1327 | Typo "…following:" |
| Electric Reliability Council of Texas, Inc. (ERCOT) | 36 | 1337 | Typo/grammatical issue to the language "...frequency tripping of U-DERs is not been included." |
| Exelon | All | | Our reviewing SMEs did not have specific comments but did find the draft guideline to be informative. Exelon supports the continued development of this Reliability Guideline. |
| ISO New England | vi | 126 | Consider a footnote or something to explain what U-DER and R-DER are. |
| ISO New England | vi | 135 | seems like words are missing on this bulllet… |
| ISO New England | vi | 135 | Links to footnote documents don't work |
| ISO New England | xi | 221 | For ISO-NE, load shed is based on peak net load; not peak net demand. |

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| ISO New England | xi | 226 | PRC-006-NPCC-1 has been replaced by PRC-006-NPCC-2. |
| ISO New England | xi | 226 | In the chart, it is the peak load of the TO or distribution provider that provides load shedding. This reads as if it is New England's peak demand. Some clarification should be made. |
| ISO New England | 1 | 278 | insert the word "to"...critical importance to "accurately… |
| ISO New England | 1 | 282 | suggest including the word "exploratory" before the word "study". Some other word may be better. The reason: this isn't the official UFLS Study and the results here may incorrectly indicate an issue of non-compliance with our UFLS program. |
| ISO New England | 1 | 285 | The description of the lines is backwards. According to the legend on the plant orange meets criteria and blue does not. |
| ISO New England | 1 | 291 | Figure 1.1. needs to say what each of the axis represent. |
| ISO New England | 1 | 313-314 | bottom link does not open file |
| ISO New England | 3 | 315 | delete the last "s" on "perspectives" |
| ISO New England | 4 | 332 | Figure 1.3 does not show a 5 second window |
| ISO New England | 3 | 337 | Figure 1.2 needs to have labels for each axis |
| ISO New England | 4 | 340 | Figure 1.3 needs to have labels for each axis |

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| ISO New England | 5 | 368 | Word "balancing" seems more appropriate |
| ISO New England | 5 | 370 | How would penetrations of legacy inverters increase? An new installations should be meeting today's requirements. While footnote 29 says some new inverters are being installed to mimic old inverters, the inverters themselves are not legacy inverters. |
| ISO New England | 5 | 376 | The blue color shows voltage going to zero, yet this sentence says it is an overvoltage. |
| ISO New England | 5 | 380 | Figure 1.4 needs axis lables |
| ISO New England | 5 | 385 | There seem to be several words missing here. We think it should read "...DERs are compliant with IEEE 1547-2018. It also seemes like it should say something about the performance of IEEE 1547-2018 inverters at the end of the sentence. |
| ISO New England | 6 | 386 | typo with reference to IEEE 1548-2018 |
| ISO New England | 6 | 413 | The subject is singular "range" and verb is plural "are". Not sure which should be changed |
| ISO New England | 6 | 414 | Words are missing here - Therefore, a reasonable can be to assume that DER 414 will trip at 59.5 Hz within 2 seconds and at 57.0 Hz within 0.16 seconds |

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| ISO New England | 7 | 423 | insert space between IEEE and 1547 |
| ISO New England | 7 | 425 | "coordinate" should say "be coordinated" |
| ISO New England | 7 | 450 | Provide a reference so the reader knows what Category I, II, and III DER are. |
| ISO New England | 10 | 537 | capitalize the "s" in "UFLS" |
| ISO New England | 10 | 544 | It is not clear what frequency setpoints are being referred to. It could be of the UFLS program, but it could be of the DER, which is then redundant with the bullet above. |
| ISO New England | 10 | 553 | U-DER and R-DER should be defined on first use, rather than this deep into the document |
| ISO New England | 13 | 683 | Should this refer to load instead of DER? |
| ISO New England | 15 | 738 | This sentence says that the cases were set so that the imports were set to match the 25% generation-demand imbalance. However, the next sentence contradicts this for the light load case. |
| ISO New England | 16 | 759 | spelling...should be ROCOF not ROFOF |
| ISO New England | 23 | 1035 | In Table A.1, there needs to be a footnote to say that the amount of MW in this row for NPCC is the total TO, DP and DPUF total load. It looks like it is system load |
| ISO New England | 28 | 1107 | Figure B.5 doesn't seem to be discussed anywhere in the text |

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| ISO New England | 29 | 1121 | Appendix C title says Hawaii, but other locations in the report use Hawai'i. They should be the same throughout |
| ISO New England | 29 | 1128 | shouldn't this be figure C.1? |
| ISO New England | 30 | 1170 | delete extra period after sentence as shown |
| ISO New England | 30 | 1192 | Table C.1 is confusing. It appears as if almost all of these steps will happen at the same time. Are the times given in addition to the time from the step above? If they really are all acting at the same time, this is really one big stage, not multiple small stages. It should be clarified. |
| ISO New England | 32 | 1219 | add an "s" to "limitation" so that it says "limitations" |
| ISO New England | 32 | 1238 | insert "load" before "shed" |
| ISO New England | 35 | 1296 | Take out dash between Directory and 12.<br>PRC-006-NPCC-2 is an effective standard and NPCC intends to retire Directory 12. Correct the spelling of retire. |
| ISO New England | 35 | 1307 | The link for footnote 61 to NPCC standards does not work |
| ISO New England | 36 | 1317 | Delete dash between Directory and 12 for Directory 12. |
| ISO New England | 36 | 1337 | "has" instead of "is" |

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| ISO New England | 36 | 1343 | Consider removing the word "currently" |
| ISO New England | 40 | 1403 | Delete dash between Directory and 12 for Directory 12. |
| ISO New England | 42 | 1423 | Please only use ISO New England for company name |
| Michael Jones - National Grid | xi | 226 | We suggest changing PRC-006-NPCC-1 to PRC-006-NPCC-2. PRC-006-NPCC-2 has been effective since 4/1/2020 and replaced PRC-006-NPCC-1 which had an initial effective date of 7/1/2015. |
| Michael Jones - National Grid | 1 | 284 | We suggest deleting "meeting regional criteria" or replacing "meeting regional criteria" with "meeting the regional requirement." Note: PRC-006-NPCC-2 is the Regional Reliability Standard. PRC-006-NPCC was written with the intent to retire NPCC's Regional Reliability Reference Directory # 12 Under frequency Load Shedding Program Requirements. Please see PRC-006-NPCC-2 Requirement R1. |
| Michael Jones - National Grid | 1 | 285 | We suggest changing "criteria" to "requirement" Note: PRC-006-NPCC is the Regional Reliability Standard. We suggest not referencing Regional Criteria. In addition, please confirm if the "orange line" or the blue line should be referenced. |
| Michael Jones - National Grid | 1 | 288 | We suggest changing "criteria" to "requirement" PRC-006-NPCC is the Regional Reliability Standard. We suggest not referencing Regional Criteria. In addition, please confirm the "blue line" or the orange line should be referenced. |
| Michael Jones - National Grid | 3 | 315 | We suggest "perspectives" should be "perspective" |
| Michael Jones - National Grid | 6 | 414 | A word appears to be missing in the sentence, "Therefore, a reasonable can be to assume…" |
| Michael Jones - National Grid | 35 | 1295 | We suggest adding the word "Region" "NPCC Region UFLS Program" |
| Michael Jones - National Grid | 35 | 1296 | We suggest replacing "Directory 12" with "Regional Reliability Standard PRC-006-NPCC" |

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| Michael Jones - National Grid | 35 | 1297, 1298, 1299 | We suggest deleting, "Upon the adoption of PRC-006-NPCC-02, NPCC intends to reture Reliability Direction 12 in accordance with NERC Rules of Procedure; nevertheless, these values were in effect to determine system performance requirements at the time of the study." Note: NPCC Regional Reliability Standard PRC-006-NPCC-1 was also in effect at the time of the study, in addition to NPCC Regional Reliability Reference Directory #12. We suggesting not referencing the NPCC Regional Reliability Directory. |
| Michael Jones - National Grid | 35 | 1303 | We suggest referencing NPCC Region UFLS Program PRC-006-NPCC in the title of Table D.2 |
| Michael Jones - National Grid | 36 | 1317 | We suggest replacing "Directory 12" with "Regional Reliability Standard PRC-006-NPCC" |
| Michael Jones - National Grid | 40 | 1396 | We suggest changing "criteria" to "requirement" Note: PRC-006-NPCC is the Regional Reliability Standard. We suggest not referencing Regional Criteria. |
| Michael Jones - National Grid | 40 | 1399 | We suggest replacing "NPCC Directory #12" with "PRC-006-NPCC" |
| Michael Jones - National Grid | 40 | 1403 | We suggest replacing "NPCC Directory-12 requirements" with "NPCC PRC-006-NPCC requirements." For reference: Please see PRC-006-NPCC-2 page 8 of 23 (Figure 2). |
| Orange & Rockland Utilities, Inc. | 6 | 414 | Sentence starting with "Therefore" is not clear as far as meaning with word reasonable….. |
| ReliabilityFirst | 2 | 295- 315 | I would have expected to see the classical formula for calculating the ROCOF, or at least clear statements that the classical factors that determine the ROCOF are, system inertia, generation/load imbalance, and load damping response to declining frequencies. |
| ReliabilityFirst | 2 | 311 | There is some industry discussion about making the UFLS program more selective as to what loads to drop. Should there be at least a small mention of that within this report? |

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| ReliabilityFirst | 2 | 312 | This document should also cover that the less intentional delay in UFLS relay settings could also be part of the redesign. There are some entities in the Eastern Interconnection that have intentional delays of over 20 cycles. |
| ReliabilityFirst | 3 | 333 | Mentions a 5 second scale of Figure 1.3, but Figure 1.3 stops at 2.5 seconds? |
| ReliabilityFirst | 3 | 337 | The time scale of the figure is seconds. |
| ReliabilityFirst | 4 | 341 | The time scale of the figure is seconds. |
| ReliabilityFirst | 14 | 711 | In lines 704 and 705, these are cases to be considered, there is no need to reiterate appropriateness in at lines 711 and 719. |
| ReliabilityFirst | 23 | 1035 | Units of measure (MW) are missing from the table headings |
| ReliabilityFirst | 32 | 1222 | The loss of 40 MW being outside of UFLS planning criteria may seems odd/small to someone in the Eastern Interconnection. |
| ReliabilityFirst | 32 | 1226 | This statement leads the reader to make assumptions that may not match the study supporting this statement. Either the sentence should be removed or explained. (Was the 40 MW of generation lost solar or conventional? How would the total dispatch of generation on the island have changed if it had been less cloudy?) |
| SCS - Transmission Planning Department - SME/Team Lead - Jennifer Bell | Page 6 | line 135: | the sentence is incomplete. Suggested wording replace "Ensure that" with "Include". |
| SCS - Transmission Planning Department - SME/Team Lead - Jennifer Bell | Page 8 | line 145: | suggest changing "lack of generation" to " imbalance between generation and load". This is consistent with the phrasing on line 215. |
| SCS - Transmission Planning Department - SME/Team Lead - Jennifer Bell | Page 15 | Key Takeaway in blue box: | the first sentence appears to have repeated "BPS" and does not read well. Suggest changing "displaces BPS and BPS connected generation" to "displaces BPS connected generation". |
| SCS - Transmission Planning Department - SME/Team Lead - Jennifer Bell | Page 17 | line 370: | "increasing penetrations of legacy inverters" seems counterintuitive. Are "legacy inverters" increasingly being added to the system? |

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| SCS - Transmission Planning Department - SME/Team Lead - Jennifer Bell | Page 17 | figure 1.4 : | there are two vertical axis without labels. Additionally a legend describing the two curves depicted is needed to avoid having to assume their meaning. |
| SCS - Transmission Planning Department - SME/Team Lead - Jennifer Bell | Page 21 | line 501: | change PRC-006-3 to PRC-006-5. |
| SCS - Transmission Planning Department - SME/Team Lead - Jennifer Bell | Page 21 | lines 495-525: | Some consideration should be given to the fact that UFLS schemes were never intended to be load-level matched balancing schemes but rather a safety net to help avoid frequency declining low enough to cause more generation to trip offline which could cascade into a blackout. When considering DER impact to UFLS design, some deference should be given to understand the UFLS scheme is designed to be very conservative, in that the design requirement includes a large 25% load/generation imbalance as a design basis. This conservatively large imbalance was intended to account for load variation which occurs through all periods of the year, fully recognizing that it may not be capable of performing at the same level for all time periods, but should be able to perform sufficiently well to avoid cascading for most realistic generation loss events. Additionally, adaptive control schemes introduce added complexity and cyber vulnerabilities that come with widespread coordinated control. A better approach would be to consider the protection settings of the generation and load connected to the system. As synchronous machines are replaced with inverter-based resources, consideration should be given to whether the current level of performance required for UFLS design should be adapted to account for IBR ability to ride through much lower frequency excursions. Why not consider extending (widening) the frequency performance envelopes used in the design of UFLS schemes? |

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| SCS - Transmission Planning Department - SME/Team Lead - Jennifer Bell | Page 22 | line 538: | change PRC-006-3 to PRC-006-5. |
| SCS - Transmission Planning Department - SME/Team Lead - Jennifer Bell | Page 23 | line 584: | change PRC-006-3 to PRC-006-5. And every other place PRC-006 is mentioned in the guideline. |
| SCS - Transmission Planning Department - SME/Team Lead - Jennifer Bell | Page 24 | line 629: | This equation is more appropriately used when considering islands based on past islanding events or planned islands with controlled separation schemes. Arbitrary islands selected on the basis of testing UFLS scheme design, such as PC area islands which would never realistically form do not necessarily benefit from simulating intertie based imbalance caused by tripping tie lines during simulations. |
| SCS - Transmission Planning Department - SME/Team Lead - Jennifer Bell | Page 24 | line 634: | Again, this equation is more appropriately used with islands based on past events and intentional controlled islanding schemes. |
| SCS - Transmission Planning Department - SME/Team Lead - Jennifer Bell | Page 24 | line 637: | Same comment as for line 634. |
| SCS - Transmission Planning Department - SME/Team Lead - Jennifer Bell | Page 25 | lines 686-687: | PRC-006 was not originally written to consider season or demand levels because the very conservative design basis is a 25% imbalance on a peak load case. The standard was written to set the design basis at a conservative load level with a sufficiently large imbalance to provide reasonable assurance it would catch the system for realistic and reasonable loss of generation events during all seasons and load levels. It was never intended to be able to meet the performance requirements exactly during all seasons and load levels. The 25% imbalance at peak load levels represents some margin above what may be realistically needed to provide sufficient coverage at all load levels. |

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| SCS - Transmission Planning Department - SME/Team Lead - Jennifer Bell | Page 25 | lines 692-694: | Agree with the concept that the UFLS scheme should be tested for adequate levels of performance under different system conditions, but this is not the same as designing for these different load levels. Until the design based on peak load conditions fails to meet performance under other load conditions, the peak load design basis will still work. |
| SCS - Transmission Planning Department - SME/Team Lead - Jennifer Bell | page 29 | lines 790-803: | Further background is needed here to provide reference to DER ROCOF protection. Manufacturers should be able to provide this information for the purpose of determining the threshold of ROCOF which could lead to mass tripping of DER. |
| SCS - Transmission Planning Department - SME/Team Lead - Jennifer Bell | page 32 | lines 949-953: | Any such devices will need to be able to be observable by the Balancing Authority and frequency response performance requires these BESS to not simultaneously be used for other services. |
| SCS - Transmission Planning Department - SME/Team Lead - Jennifer Bell | page 44 | line 1220: | Does not read well: Delete the extra word 'for' at the end of the sentence that reads "contingencies for which it is planned for." |
| SCS - Transmission Planning Department - SME/Team Lead - Jennifer Bell | Page 6 | lines 118-119: | This sentence is confusing consider revising. |
| SCS - Transmission Planning Department - SME/Team Lead - Jennifer Bell | page 9 | Figure I.1 middle blue box: | the words do not flow well "in order to use in event…", the words "in order" could be removed without changing the meaning. |
| SCS - Transmission Planning Department - SME/Team Lead - Jennifer Bell | page 14 | line 285-288: | The language says that orange line does NOT meet criteria, however in the Figure 1.1, it says orange line meets the criteria and blue line does not meet the criteria. It appears the colors changed and the language associated with the figure needs to align. |

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| SCS - Transmission Planning Department - SME/Team Lead - Jennifer Bell | page 15 | lines 317-318: | It would be a reliability risk to have DERs support ancillary services. If the BA is dependent on a home owner or set of home owners to maintain DERs such that they perform ancillary services, but the DER owner in fact does not maintain that equipment or goes on vacation and the DER is not operational, it would be a reliability risk. The concept of which resources provides ancillary services needs to determined that does not result in a risk to BPS reliability. Ancillary services are required both day and night not just during high solar output periods. Suggest removing these sentences that start "In the future". If DERs are load following, the internal islanding detection of the DER will not work. There are safety risks if DERs operate in an island with load. The only way for a DER to react to a low frequency event is if there is headroom for the DER, how does the DER owner get paid for providing ancillary services? How will the industry enforce headroom of DERS? Frequency support on the distribution system is too localized and may cause more tripping instead of less tripping of DER resources. Suggest that BA's have a requirement to identify resources that will support frequency and load following functions. These reliability resources should be connected to the BPS and not distribution. |
| SCS - Transmission Planning Department - SME/Team Lead - Jennifer Bell | Page 18 | lines 414: | The language is missing something, maybe add "approach" after reasonable: "Therefore, a reasonable can be to assume that DER 414 will trip at 59.5 Hz" |
| SCS - Transmission Planning Department - SME/Team Lead - Jennifer Bell | Page 20 | lines 454-456: | Having DERs perform voltage support is not as much a risk to the BPS as frequency support is, however real power is reduced when reactive power is put on the grid from IBRs, so a voltage event could result in a frequency event, it not careful. |

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| SCS - Transmission Planning Department - SME/Team Lead - Jennifer Bell | Page 20: | lines 463-464: | Should not have DERs controlling frequency due to issues discussed earlier. BPS batteries can absorb real power (charging mode) and produce real power. These are the resources that need to perform frequency response. If BESSs are controlled by the BA, frequently tested, they can be depended on whereas DERs owned by home owners cannot be relied on for reliability. |
| SCS - Transmission Planning Department - SME/Team Lead - Jennifer Bell | Page 20: | lines 485-493: | BPS batteries will be much better at load following and frequency support. It eliminates many issues described in this this section. |
| SCS - Transmission Planning Department - SME/Team Lead - Jennifer Bell | Page 35 | lines 693-694: | Doesn't read well "is an important aspect performing UFLS studies and developing a robust UFLS program" maybe add the word "in" before performing. |
| SCS - Transmission Planning Department - SME/Team Lead - Jennifer Bell | page 29 | lines 790-803: | As utilities retire synchronous machines, the turbines can be inexpensively converted to synchronous condensers maintaining inertia in the grid without burning carbon fuels. This would prevent reliability issues caused by high ROCOF. Utilities should be encouraged to do this type of conversion whenever possible. |
| SCS - Transmission Planning Department - SME/Team Lead - Jennifer Bell | page 32 | lines 949-953: | If BPS BESSs are mostly charged and connected to the grid but not injecting any real power prior to a frequency event, they could respond to either a low or high frequency event by automatically going to the charging mode, or going to the injection mode. Inverters may need to be adjusted to accommodate this type of operation. |
| SCS - Transmission Planning Department - SME/Team Lead - Jennifer Bell | page 33 | lines 988-991: | How do the entities responsible for frequency control per BAL-003 ensure that the DERs providing frequency support maintain and test their equipment to ensure the reliability of the BPS? The entities responsible for NERC BAL-003 should own and operate the equipment responsible for the essential reliability services. It is unjust to issue a fine to an entity responsible for BAL-003 when the parties responsible for maintaining equipment required for essential reliability services have zero responsibility for BAL-003. |

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| SCS - Transmission Planning Department - SME/Team Lead - Jennifer Bell | page 33-34 | lines 995-1001: | Disagree that "all generating resources" are responsible to help arrest frequency declines. The BA must manage the essential reliability services by owning and controlling carbon free equipment that can reliably respond to voltage, frequency, and load following or the essential reliability services. Then if an instability occurs, it is the responsibility of the BA who has the expertise to prevent the instability. By not requiring those entities that have the expertise today to continue to maintain reliability and assume that entrepreneurs desiring to own generation resources will accommodate the reliability needs of the BPS will prove the reliability risk that it is. |
| SCS - Transmission Planning Department - SME/Team Lead - Jennifer Bell | page 34 | lines 1003-1004: | Why will the owners of the DER want to provide frequency support if they have to maintain headroom to do so. The DER owner will have less revenue or sales of energy if they have to maintain headroom. If the BA pays the DER owner to maintain headroom, who is responsible when the DER fails to provide frequency support due to lack of maintenance or a frequency event occurring at night? Essential reliability services need to be maintained by resources that are not intermittent in nature and are responsible for specific NERC reliability standards that are periodically audited and fined for non-compliance etc. |
| SCS - Transmission Planning Department - SME/Team Lead - Jennifer Bell | page 41 | line 1149: | It does not read well, may be missing a word after "of" "necessary amount of per the specified requirements" |
| SCS - Transmission Planning Department - SME/Team Lead - Jennifer Bell | page 42 | line 1156: | It does not read well "exporting power to the system during many parts of the day." should it say "many hours of the day, feeders are injecting power to the BPS"? |
| SCS - Transmission Planning Department - SME/Team Lead - Jennifer Bell | page 44 | line 1219: | Does not read well: "it has limitation including.." should it be "it has limitations including…" add an 's'. |

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| SCS - Transmission Planning Department - SME/Team Lead - Jennifer Bell | Page 45: | lines 1241-1244: | Agree with these statements that FFR from storage resources is necessary. Battery storage devices seem to be the best solution for carbon free frequency response. BESS should be able to go from charging to injecting quickly providing the battery operator does not allow the BESS to be charged to its maximum capacity at any time and be charged enough to inject necessary real power. PCs need to do studies to determine the amount of BESS required in their PC area for frequency support. This along with converting retired generation to synchronous condensers solves frequency support issues in a carbon free energy grid. |

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| SCS - Transmission Planning Department - SME/Team Lead - Jennifer Bell | 21 | 495-525 | Support the EIPC FRWG comments on this section: "Some consideration should be given to the fact that UFLS schemes were never intended to be load-level matched balancing schemes, but rather a safety net to help avoid frequency declining low enough to cause more generation to trip offline which could cascade into a blackout. When considering DER impact to UFLS design, some deference should be given to understand the UFLS scheme is designed to be very conservative, in that the design requirement includes a large 25% load/generation imbalance as a design basis. This conservatively large imbalance was intended to account for load variation which occurs through all periods of the year, fully recognizing that it may not be capable of performing at the same level for all time periods, but should be able to perform sufficiently well to avoid cascading for most realistic generation loss events. Additionally, adaptive control schemes introduce added complexity and cyber vulnerabilities that come with widespread coordinated control. A better approach would be to consider the protection settings of the generation and load connected to the system. As synchronous machines are replaced with inverter-based resources, consideration should be given to whether the current level of performance required for UFLS design should be adapted to account for IBR ability to ride through much lower frequency excursions. Why not consider extending (widening) the frequency performance envelopes used in the design of UFLS schemes? " |

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| SCS - Transmission Planning Department - SME/Team Lead - Jennifer Bell | 25 | 686-687 | Support the EIPC FRWG comments on this section: "PRC-006 was not originally written to consider season or demand levels because the very conservative design basis is a 25% imbalance on a peak load case. The standard was written to set the design basis at a conservative load level with a sufficiently large imbalance to provide reasonable assurance it would catch the system for realistic and reasonable loss of generation events during all seasons and load levels. It was never intended to be able to meet the performance requirements exactly during all seasons and load levels. The 25% imbalance at peak load levels represents some margin above what may be realistically needed to provide sufficient coverage at all load levels. " |

ithin the review period below to John Skeath (John.Skeath@nerc.net) with the words "Reliability Guideline:
subject line. Only comments submitted in this Microsoft Excel format will be accepted. Both general and specific

6. If comments are submitted on behalf of multiple organizations, list all organizations in Row 6. Please provide the
ows 9 and 10.

| Proposed Change | NERC Response |
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| Update the orange and blue references in the narrative to match the figure. | Change made as proposed |
| update language | Changed to "Therefore, it is reasonable.." |
| Consider the expertise of the DPs in regards to data collection and planning analysis. It may be more apporpriate for the PC to collect additional information that to place these types of obligations on a DP. | In the highlighted text, SPIDERWG does not identify a recommended practice for DPs to perform planning analysis, but that is the PC's role in the UFLS program design. Clarity added to the role PCs play in the planning analysis done in UFLS program design. Added a sentence detailing the sending of load data to the PC for analysis. |

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| Add text stating that contents of this Reliability Guideline are not to be considered as Reliability Standards or obligations. | Thank you for your comment. Text added based on comment. |
| Add text which acknowledges the various hurdles and challenges posed by attemting to obtain data from DER owners who are not Functional Entities nor have obligations thereof. | Thank you for your comment. Added a sentence to emphasize the coordination among various entities based on the comment. |

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| Revise any text which could be misconstrued as a directive or obligation, and instead, rephrasing to make it clear these are concepts and practices for consideration. Using words such as "may" rather than "should" or "will" may help in this regard. | Thank you for your comment. As per the Preamble, "Reliability Guidelines are not binding norms or parameters; however, NERC encourages entities to review, validate, adjuste, and/or develop a program with the practices set forth in this guideline." No changes made. |
| Specify what is U-DER and R-DER when these terms are first used. | Added a footnote for U-DER and R-DER terms and a link to the SPIDERWG terms and definitions document. |
| Mention that new DERs may have smart inverters with voltage and frequency control capabilities. However, if UFLS relays are located in the feeders where DER are connected together with load, DER will trip when the feeder trips. | Added a sentence in the new footnote referencing the voltage and frequency control. |

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| Refer to WECC also as an Entity that performs UFLS design. | PRC-006 does not have the regional entities (WECC) listed as the entitiy responsible for maintaining the UFLS database in Requirement R6. No changes made in area identified. Other changes related to this comment made in document. |
| Refer to PRC-006-5 | Changed instances that discussed history of standard as applicable. General reference changed to "PRC-006" and specific references changed to "PRC-006-5". Added sources of graphs. |
| Specify whether the DER discussed in the Guideline are Solar PV or other inverter-based resources. | Added sentences to clarify. |
| Refer to PRC-006-5 | Changed instances that discussed history of standard as applicable. General reference changed to "PRC-006" and specific references changed to "PRC-006-5" |
| Add settings on the DER tripping shown in Figure 1.2 | The reader is directed to Appendix D that contains a full set of study assumptions for this graph. |
| Spell out abbreviations | Spelled out Electric Power System the first time it is used. |

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| Add a point regarding composite load models to the discussion of the DER tripping for high or low voltages | Changes made based on comment and proposed addition |
| Add summer peak conditions with high DER output to the list of cases illustrating how DER affects UFLS arming. | Added a footnote to the Summer Peak Load bullet that discusses the possible impact with single-phase motor loads. SPIDERWG notes that this list is to be illustrative, and not exhaustive. |
| Refer to PRC-006-5 | Changed instances that discussed history of standard as applicable. General reference changed to "PRC-006" and specific references changed to "PRC-006-5" |
| Add that in WECC the studies, including selecting all the assumptions, are performed by WECC UFLS Review Group, not by individual PC | Changed text in Chapter 2 based on comment. |

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| Modify calculation | SPIDERWG's working definitions document lists DER as generation faciltiies and not as Load. The Reliability Guidleine proposes to take the "load" to mean gross load in the equation. No modification to calculations made. |
| Add examples and provide some numbers at which ROCOF DER may trip. | Added text that recommends a method for identifying ROCOF thresholds. Chapter 2 has text that explains no known dynamic model for ROCOF protection is suitable for DER. |
| Note that in the Western Interconnection, UFLS entities provide data not to PC, but to WECC | Footnote added to clarify some Regional Entities may perform all, or almost all, of the design work for a Regional Entity's area. |

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| Refer to PRC-006-5 | Changed instances that discussed history of standard as applicable. General reference changed to "PRC-006" and specific references changed to "PRC-006-5" |
| Indicate from which % of DER, the DER should be modeled and not netted with load. | SPIDERWG recommends the modeling framework where DER is separated from load when it is modeled per previously published Reliability Guidelines. SPIDERWG believes that each local area should be evaluated on a system-by-system basis for its impact to the particular system. No changes made. |
| Provides more details on the battery storage impact on the UFLS | Currently SPIDERWG is working on a modeling Reliability Guideline that covers BESS DER and its frequency response. Such models in simulation will impact the studies on UFLS; however, the SPIDERWG reiterates its guidance to UFLS entities to consider not choosing feeders that have beneficial aspects to avoid, or assist in, a fregeuncy excursion. |
| Provide definite recommendations how UFLS programs should be designed and which numbers and parameters to use | Appendix A is provided as a way to examine how current UFLS programs have been designed for industry reference. The SPIDERWG does not believe any particular set of recommendations will be suitable for all regions and all Interconnections. SPIDERWG reiterates that PCs should include multiple cases for study when designing their UFLS program to ensure such numbers in their UFLS program are appropriate in many different cases. |
| | Added a footnote for U-DER and R-DER terms and a link to the SPIDERWG terms and definitions document. |

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| | Thank you for your comment. Other comments added a recommendation to monitor the feeder flows, and SPIDERWG believes that such monitoring needs to occur. The SPIDERWG believes that the output of aggregate DER across a T-D interface cannot be ignored and agrees that it can be challenging to obtain an individual DER's output. No changes to bullet made. |
| | Thank you for your comment. Sentence added to footnote relating to comment. |
| | Thank you for your comment. Footnote added based on comment. |
| | Text added based on comment |
| | The list of cases here is an illustration to demonstrate that DER ouput can impact the UFLS program based on the PC's case used for simulation. Text added to emphasize that this list is a set of examples and will vary depending on the PC. |
| | Thank you for your comment. The SPIDERWG re-evaluated its example comparison of the operating cases in Table 2.1 and found that no change was needed in this example. Text added to table header to emphasize these are example conditions. |
| | Added sentence based on comment provided |

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| | Thank you for your additional recommendation. Added to list of recommendations. |
| EEI strongly encourages NERC to reclassify this document as NERC White Paper for the reasons provided in our General Comments. | Thank you for your comment. Metrics have been added to the document and recommendations are present in the posted draft at various sections as a way to provide the guidance on enhancing current UFLS studies. |

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| In the event the document is not converted into a White Paper, we recommend that the concerns contained in our Additional General Comments be addressed and that the document is reposted for industry review and comment. | Thank you for your comment. In response to this comment portion, 1) The scope of SPIDERWG focuses on impacts of DER, and while members may agree with the statement, it is more appropriate in the IRPWG to discuss large wind and solar farms, 2) Chapter 1 section on "Variabiliyt and Uncertainty of DER Output" covers this statement, 3) same response as in 1), 4) the document has no statement "Battery Energy Storage Systems as necessary to maintain system stability during frequency excursion to avoid tripping loady", but rather the technology "may be able to provide fast-responding net load reduction", 5) Chapter 2 sections include references that address all subparts (primarily the DER_A Parmeterization link, which it also has references that address the issues in its Appendix A, and the DER Modeling Framework section). |

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| In the event the document is not converted into a White Paper, we recommend that the concerns contained in our Additional General Comments be addressed and that the document is reposted for industry review and comment. | Thank you for your comment. In response to this comment portion, 6) Per PRC-006, the Transmission Planner is not listed. NERC has no Transmission Planner (long-term) or Transmission Planner (short-term) differentiation. Further, PRC-006's term "UFLS Entities" covers the other subparts and, when SPIDREWG thought more directed guideance was warrented, identified which of the UFLS Entities would be most aided. |

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| In the event the document is not converted into a White Paper, we recommend that the concerns contained in our Additional General Comments be addressed and that the document is reposted for industry review and comment. | Thank you for your comment. In response to this comment portion, 7a) SPIDERWG believes it is an incorrect approach to draw a brightline modeling criteria, especially for UFLS studies where such modeling can directly impact UFLS program design; 7b) Chapter 2 covers the recommended modeling framework that built on the industry vetted treatment of DERs as U-DER and R-DER; 7c) SPIDERWG has included a new recommendation for monitoring of flows that can constitute supervision in this sense. Further, this document also has examples that deal with monitoring of other quantities than frequency. SPIDERWG recommends against a one-size-fits-all approach to UFLS program design; 7d) Other comments have pointed out that the redesign for less intentional time delay may be a temporary solution to current changes. Further, SPIDERWG does not believe that a one-size-fits-all approach for UFLS relay settings (setpoints and timing) is appropriate and should be developed on an island by island basis |

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| Make it clear in the guide that decisions regarding the use of dynamic planning rest solely in the hands of the respnsible entity and is generally outside of NERC's Authority. | With regard to the portion of this comment touching on the scope of NERC's authority, Section 215(g) of the Federal Power Act provides NERC with authority to assess reliability and adequacy of the bulk-power system in North America. This activity may include guidance on recommended approaches or behavior in a given technical area for the purpose of improving reliability. Section 215(a)(2) and (d) of the Federal Power Act outline the scope of NERC's authority to establish Reliability Standards for the BPS, subject to Federal Energy Regulatory Commission review.<br><br>For the avoidance of confusion, NERC has added language which further highlights that, as reflected in the prior draft, the Planning Coordinator is typically the entity which studies conditions for UFLS, in coordination with other entities, such as the applicable Regional Entity, as appropriate. |
| Give consideration to softening the tone in the identified statement. Provide greater focus on providing useful guidance on tracking DERs on UFLS feeders. Provide clearer distinctions between aggregated DERs that are entered into the organized markets and DERs intended solely for distribution. Provide guidance on how best to meet entity needs for ensuring reliability while stradling the lines between state and NERC jurisdiction. | Thank you for your comment. The SPIDERWG reviewed PRC-006 and points specifically to R9 on how the UFLS entity is to provide load disconnection. Other comments have added a recommendation for UFLS entities regarding tracking of DER. SPIDERWG has added text to recommend UFLS entities to track and monitor aggregate DER output. SPIDERWG does not see a difference in tracking and accounting for aggregate DER depending on whether it is in an organized market or not. |

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| Reference the specific NOPR in the document. | Added reference to quoted text and the referenced NOPR the referenced text responds to. |
| Again reference the quotation to allow for meaningful input. | Reference is the same as the one above. Added text in-line to indicate. |
| EEI suggests that in many cases, modeling small DER resources as load offset would be sufficient in many cases. | Such a distinction contradicts guidance on using gross load and the modeling framework SPIDERWG recommends. SPIDERWG's modeling framework separates load from DER, and does not recommend netting DER with load. It is left up to the PC to determine the modeling threshold (i.e. penetration when to model) of DER. |

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| Guidance should be given to entities identifying how best to identify and address such impact. | Thank you for the comment. Added text in Chapter 3 section "Selection of Loads Participating in the UFLS Program". |

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| EEI does not support the statement identified and suggests that it be modified. | SPIDERWG reiterates that the PCs "should consider the following" when modeling DER in their studies used for UFLS. The distinction on market versus non-market does not apply when tripping of a feeder for implemenetation of the UFLS program design; however, text has been altered to generalize the points made in the comment and to emphasize that the studies "may require" modeling of these resources. |

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| Clearer discription of the identified problem is needed. EEI also questions the value of modeling DERs on UFLS feeders, rather efforts should be made to identify where this exists and select more suitable feeders. | Clarity added in new text that the "inadvertant tripping of DER post-UFLS action could exacerbate any underfrequency conditions". Also added a footnote referencing Appendix D where a simulation that considered the trip settings of aggregated DER. |
| The statement appears to be incorrect. Renewables/DERs are generally incapable of supplying FFR due to the manner they operate. This statement should be removed. | SPIDERWG identified that solar PV and wind are not the only DER. While SPIDERWG agrees that the majority of DER at this time operates in a way that does not allow capacity for FFR, SPIDERWG reiterates that DERs "may be able to" perform this service in the future. Granted, with changes to their operation. |
| EEI suggests: "Therefore, it is a reasonable can be to assume that these DERs will trip at 59.5 Hz within 2 seconds and at 57.0 Hz within 0.16 seconds." | Changes made based on this and other comments on the same sentence. |

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| The identified statement appears to be overstated, assuming that all UFLS feeders will overtime have substantial amounts of DERs impacting the reliability of programs under PRC-006. This statement should be modified or deleted. | Statement modified to enhance clarity on the point of long-term planning horizon studies being infrequent. |
| Correct typos | Changes made as proposed |
| Correct typo | Change made as proposed |
| Correct typo | Change made as proposed |
| Correct typo | Typo corrected |
| | Metrics section added |
| Suggested wording replace “Ensure that” with “Include”. | Change made as proposed |
| | Sentences revised based on comment. |
| The System Planning Impacts from Distributed Energy Resources (SPIDER) Scope Document, as approved by NERC's Reliability and Security Technical Committee (RSTC), identifies one of SPIDER's key activities to be "provide guidance on impacts that higher penetration of SER may have on system restoration, UVLS, and UFLS, and potential solutions or recommended practices to overcome any identified issues." | Changes made based on comment. |
| | Footnote added to link recent studies and enacted proposals. |
| "In general, Planning Coordinators performing UFLS studies are recommended to:" | SPIDERWG notes that the language "should" here is not binding. No change made based on comment. |

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| Our preference would be for the first bullet to read "if the system being studied has a certain level of DER penetration" instead of just saying all PCs should do this. What makes sense for higher penetration PCs may not make as much sense for lower penetration PCs. | The listed text could not be found in the lines identified; however, clarity edits made based on comment and proposed edition. |
| | Such detail is in Chapter 1 and referenced again in Chapter 2 for potential impact. New text was added in other comments on "high levels of DERs can impact BPS frequency response", which covers the discussion mentioned in the comment. |
| to " imbalance between generation and load". This is consistent with the phrasing on line 215. | Change made based on proposed edit. |
| There is an interchange of data between the Planning Coordinator (PC) and UFLS Entities. Each PC is expected to provide studies based on knowledge of load and generation data, and the UFLS Entities are expected to be able to provide a firm amount of load disconnection. | Change made as proposed |
| the words "in order" could be removed without changing the meaning. | Change made as proposed |
| "As this guideline will describe, a reasonsable representation of BPS generation, aggregate load, as well as aggregate DER is important for appropriate determination of UFLS programs moving forward." | Changes made to clarify statement |
| This makes sense from an engineering perspective, but I don't think PRC-006-SERC-02 R4 would allow it, as it requires the percentage of load shedding to be based on our previous year's coincident peak. "Peak Demand" is also used in PRC-006-SERC-02 R2.1. | The statement the comment refers to deals with the modeling of consequential tripping of DER modeled as R-DER due to UFLS operation of nearby feeders. It is not in reference to shedding different loads based on DER threshold, but the opposite. (DER tripping based on amount of load armed) |

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| | The NERC SPIDERWG intentionally did not choose a brightline threshold in terms of modeling DER. Rather, the SPIDERWG provided a modeling framework that can readily account for all DER in various components. Based on current industry forecasts and installed DER, the SPIDERWG believes that DER (modeled in aggregate) should be modeled and accounted for in reliability studies; the level of granularity is left, rightfully, to the PC. |
| "This requires representing BPS-connected generating resources as well as end-use load and DER at high penetration levels." | Sentence revised based on this and other comments. |
| "High levels of DER can impact BPS frequency response in at least the following ways:" | Change made as proposed |
| "….study by ISO-NE effectively summarizes the impacts DER may have on the study outcomes for UFLS." | Change made as proposed |
| In the figure, the blue line would not meet the criteria set for the ISO-NE operating as an electrical island as the deficiency caused by DER also tripping after UFLS action would not recover the frequency in time. So, ISO-NE tested a potential design change to their UFLS studies that compensated for the effect DER has on the island during these deficiencies, which resulted in the orange line that met the criteria. | Changes made as proposed |
| It appears the colors changed and the language associated with the figure needs to align. | Change made as proposed |
| Suggest changing "displaces BPS and BPS connected generation" to "displaces BPS connected generation". | Changes made to box to clarify |

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| | Thank you for your comment. Sentence added to emphasize that "future studies should take into consideration" the items raised in the comment. |
| "Alternatively, more UFLS tripping is not a desirable option from a reliability perspective,…" | Change made as proposed |
| Delete these sentences and remove/replace the AEMO event with a more suitable event for this Reliabilty Guideline. | The AEMO example is used to illustrate the imact extremely high ROCOF can have on the effectiveness of UFLS design. No change made |
| "DERs that are not under the control of the BA are not able to receive a curtailment signal and are typically programmed to provide maximum available power at all times." | Change made as proposed |

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| | Changes made based on comment. |
| | Changes made to text based on comment's question |
| Older, legacy DERs that are subject to early versions of IEEE 1547 may have a propensity to trip at frequencies closer to nominal than newer DERs compliant IEEE 1547-2018.29 | Chagne made as proposed |
| maybe add "approach" after reasonable: "Therefore, a reasonable can be to assume that DER 414 will trip at 59.5 Hz" | Changes made to clarity. Section identified in other comments. |
| | Thank you for your comment. The section identified for this comment does not deal with voltage support settings but rather for the tripping of DER due to voltage protection. No changes made. |
| BPS batteries can absorb real power (charging mode) and produce real power. These are the resources that need to perform frequency response. If BESSs are controlled by the BA, frequently tested, they can be depended on whereas DERs owned by home owners cannot be relied on for reliability. | Thank you for your comment. The section identified for this comment does not state that DERs should control frequency but that DERs are "not yet observable by, visible to, or controlled by the Balancing Authroity in their efforts to control BPS frequency". No changes made |
| | Thank you for your comment. SPIDERWG agrees that BPS batteries can assist in an underfrequency event; however, the point of large net load variability impacting UFLS design still holds. Changes made to make that point clearer. |
| "This, coupled with the lack of visibility of DER output, may pose risks to UFLS programs for systems with high DER penetration." | Change made based on proposed edit. |
| | Changed instances that discussed history of standard as applicable. General reference changed to "PRC-006" and specific references changed to "PRC-006-5" |

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| A better approach might be to consider the protection settings of the generation and load connected to the system. As synchronous machines are replaced with inverter-based resources, consideration should be given to whether the current level of performance required for UFLS design should be adapted to account for IBR ability to ride through much lower frequency excursions. Why not consider extending (widening) the frequency performance envelopes used in the design of UFLS schemes? | Added language to speak to the historic design of UFLS schemes. The UFLS design and program specifics are left to the PC. Sometimes this is in coordination with the applicable Regional Entity. Further, any changes to the PRC-006 standard are not suitable for inclusion in a Reliability Guideline. |
| "As mentioned, the introduction (and high penetration) of DERs presents…" | Changes made based on comment |
| "For example, Hawai'i Electric Light (HELCO) has implemented an adaptive UFLS program that has seen successes and challenges with high penetrations of DER, which is described in more detail in Appendix C." | Change made as proposed |
| to PRC-006-5. | Changed instances that discussed history of standard as applicable. General reference changed to "PRC-006" and specific references changed to "PRC-006-5" |
| "As described in Chapter 1, high penetration of DERs can…" | Changes made based on comment |
| "Chapter 1 highlighted the effects that a high penetration of DER can have on BPS frequency response and UFLS; " | Changes made based on comment |

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| to PRC-006-5. And every other place PRC-006 is mentioned in the guideline. | Changed instances that discussed history of standard as applicable. General reference changed to "PRC-006" and specific references changed to "PRC-006-5" |
| | Thank you for your comment. Sentences added to clarify the term "tie lines" in the equations for this and other comments. |
| | Thank you for your comment. Sentences added to clarify the term "tie lines" in the equations for this and other comments. |
| | Thank you for your comment. Sentences added to clarify the term "tie lines" in the equations for this and other comments. |
| | Thank you for your comment. After review of the surrounding text, SPIDERWG re-iterates that the "risk of UFLS operation will likely increase during conditions of low gross load and high inverter-based resources" as stated in the draft. |
| Until the design based on peak load conditions fails to meet performance under other load conditions, the peak load design basis should still work. | Thank you for your comment. SPIDERWG reiterates its guidance that "multiple cases should be studied to ensure reliable and secure operation of the UFLS under different operating conditions" |

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| Clearly identify if this example is an actual situation or a hypothetical scenario to not confuse the reader. | Added clarity and removed "hypothetical". Both the summer peak and light spring conditions are base cases, and references to modified case are to simulate the imbalance per PRC-006 |
| Change ROFOF to ROCOF. | Change made as proposed |
| | Thank you for your comment. Added a footnote that discussions with manufactorers is useful to determining this ROCOF threshold. |
| | Thank you for your comment. NERC agrees this can maintain grid inertia, and such maintaining of grid inertia will decrease ROCOF. However, this is outside the scope of this Reliability Guideline. No change to the section made. |
| | Thank you for your comment. Changes made based on comment. |
| | Thank you for your comment. Changes made based on comment. |

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| | Thank you for your comment. The response here does not count as compliance guidance. Further, the comment seeks compliance guidance and poses a potential answer. The NERC SPIDERWG does not provide compliance guidance and all such requests for compliance guidance for BAL-003 should be presented to the appropriate group. |
| Essential reliability services need to be maintained by resources that are not intermittent in nature and are responsible for specific NERC reliability standards that are periodically audited and fined for non-compliance etc. | The team appreciates the feedback on how DERs play a role in supporting reliability of the BPS. Changes made based on this and other comments. |
| maybe add the word “in” before performing. | Change made as proposed |
| Remove/replace the AEMO event with a more suitable event for this Reliabilty Guideline. | Thank you for your comment. After review of Apepndix B and its reference in Chapter 1, the text does not say this is a sample of DER impact to UFLS design. Rather, it is supporting the heightened risks on UFLS design during high ROCOF conditions and AEMO's resulting work from that event which included an investigation of DER on UFLS arming schemes as mentioned in the Appendix |
| Delete "the". | Change made as indicated with this and other comments |
| Delete "of". | Change made as indicated with this and other comments |
| Change "up" to "of". | Change made based on proposed edit. |
| may be missing a word after “of” “necessary amount of per the specified requirements" | Change made as indicated with this and other comments |

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| should it say “many hours of the day, feeders are injecting power to the BPS”? | Changes made based on proposed edit. |
| Delete "a". | No change made. Gramatically the list is proper with the word. |
| should it be “it has limitations including…” add an ‘s’. | Change made as proposed |
| Delete the extra word ‘for’ at the end of the sentence that reads “contingencies for which it is planned for.” | Change made as proposed |
| PCs need to do studies to determine the amount of BESS required in their PC area for frequency support. This along with converting retired generation to synchronous condensers solves frequency support issues in a carbon free energy grid. | Thank you for your comment. No changes made; however, the SPIDERWG points to the HELCO decisions in its Appendix as an example. |
| | Thank you for your comment. The text does not state that all generation resources are "responsible to help arrest frequency declines"; however, the text does state that "all generation resources (including DERs, if able to respond) and end-us loads can help arrest frequency declines". The text then gives exmaples of how DERs can help arrest frequency decline. No changes made. |
| change "will" to "may" | Changes made based on comment |
| Suggest changing to: "..when available generation is insufficient to serve load causing frequency to fall rapidly…" | Changes made based on this and other comments on the same sentence. |

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| Suggest changing to "...and are set to coordinate with generator underfrequency protection to avoid frequency damage." | Changes made as proposed |
| Suggest changing to: "As a resource providing generation to the BPS, the loss of DER generation will exacerbate any imbalance between generation and load in an underfrequency event and cause frequency to fall further." | Changes made as proposed |
| Suggest changing to: "Legacy DERs that are subject to early versions of IEEE 1547 may trip at higher frequency thresolds than newer DERs compliant IEEE 1547-2018." | Changes made based on this and other comments on the same sentence. |
| Suggest changing to: "...which can be used to determine appropriate DER underfrequency trip settings assumptions for use in UFLS studies." | Changes made based on comment. |
| Suggest changing to: "Therefore, it may be reasonable to assume…" | Changes made based on this and other comments on the same sentence. |
| Appears that "UFLs" should be "UFLS" | Changes made based on this and other comments on the same sentence. |
| Suggest changing bullet to: "Appropriately allocating DERs to aggregate load representations and ensuring approriate amounts of DER are tripped based on UFLS relay deployment" | Changes made based on comment. |
| | Added text based on comment. Commenter was part of drafting of text. |

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| | Thank you for your comment. The response here does not count as compliance guidance. Further, the comment seeks compliance guidance. The NERC SPIDERWG does not provide compliance guidance and all such requests for compliance guidance for PRC-006 should be presented to the appropriate group. Added text based on comment. |
| Appears "ROFOF" should be "ROCOF" | Change made as proposed |
| Suggest changing to: "Please note that R-DER, located on feeders, are usually operated at unity power factor without voltage control, and may trip at or above UFLS load shedding trip settings." | Change made as proposed |
| | Thank you for your comment. Text added based on this and other comments to monitor net load. |

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| | Text added based on comment. |
| | Altered text based on comment. |
| Suggest changing to: "PCs and UFLS entities should ensure that DERs that are relied upon to support BPS frequency and provide essential reliability services are not impacted by UFLS relays and have adequate ride-through capabiltiy so that they are able to reliably provide these services." | Changes made based on this and other comments on the same sentence. Change made based on proposed edit. |
| Delete repeated word. | Change made as proposed |
| Suggest changing to: "…behavior made the ROCOF settings challenging and initial implementation resulted in a small amount of load shed during normally…" | Change made as proposed |
| Suggest changing to: "...vast majority of installations under 25 kW, representing a…" | Change made as proposed |
| Appears that "reture" should be "retire" | Change made as proposed |
| Appears that "following" should be "follows" | Change made as proposed |
| Appears that "is not been included" should be "is not included" | Change made as proposed |
| | Thank you for your support of this Reliability Guideline |
| (See comment below regarding line 553) | Added a footnote for U-DER and R-DER terms and a link to the SPIDERWG terms and definitions document. |
| Ensure that additional cases reflecting other load conditions than Peak Load are considered. | Changes made based on proposed edit. |
| update links for footnote documents | Changes made based on proposed edit. |
| Change the word "demand" to "load". | Change made as proposed |

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| Change first sentence in the footnote to read, "See PRC-006-NPCC-2 for further information." | Change made as proposed |
| Amend second sentence of footnote 2 as, "Please note that Peak values are in MW of the TOs, DPs and DPUFs loads in New England. | Change made based on proposed edit. |
| Modeling aggregate amounts of DERs in BPS planning studies, particularly related to PC studies of UFLS program design per PRC-006-3, is of critical importance to "accurately predict system performance."21 | Change made as proposed |
| While each of the identified major impacts of DER can be explored in further detail, a high-level overview of a recent exploratory study by ISO-NE effectively summarizes the impacts DER have on the outcomes for UFLS. A more detailed report can be found in Appendix D. | Change made as proposed |
| Change description to match lines in Figure 1.1 | Change made as proposed |
| Add description of axis descriptions. Y = frequency (Hz), X = time (seconds) | Change made based on proposed edit. |
| update link for IEEE Power & Energy Society Technical Report | Change made based on proposed edit. |
| Alternatively, more UFLS tripping is not an acceptable option from a reliability perspectives, as the system undergoes continual change in terms of its generation mix. | Change made as proposed |
| Looking at the first few seconds of the same comparison in Figure 1.3, the recovery of the island frequency is also shown to be much slower with the increase of DER behind UFLS feeders. | Change made as proposed |
| Add description of axis descriptions. Y = frequency (Hz), X = time (seconds) | Change made as proposed |
| Add description of axis descriptions. Y = frequency (Hz), X = time (seconds) | Change made as proposed |

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| One key risk that DER, particularly legacy DER, may pose to BPS reliability during severe off-nominal frequency events is the potential for tripping off-line during the event. As a resource providing generation to the BPS, playing a balanceing role in the balance of generation and load, loss of generation will exacerbate an underfrequency event and cause frequency to fall further. | Changes made based on this and other comments on the same sentence. |
| describe in text inverters set to mimic old inverters with legacy settings | Changes made based on this and other comments on the same sentence. |
| Line 376: Add more language along the lines of "…an extended overvoltage condition resulting in tripping of the U-DER…"<br><br>Line 377: With the legacy DER tripping on overvoltage conditions after the UFLS action, a noticeable decline in frequency can occur. | Changes made based on comment |
| | Changes made based on comment. |
| The vintage of DER plays a key role in whether the resource is prone to tripping on underfrequency conditions. Older, legacy DERs that are subject to early versions of IEEE 1547 may have a propensity to trip at frequencies closer to nominal while newer DERs are compliant with IEEE 1547-2018 and will ride through a wider range of disturbances. | Changes made based on this and other comments on the same sentence |
| IEEE 1547-2018 are found in the Reliability Guideline: BPS-Perspectives on IEEE 15487-201830. | Change made as proposed |
| | Changes made based on comment. |
| Therefore, it may be reasonable can be to assume that DER will trip at 59.5 Hz within 2 seconds and at 57.0 Hz within 0.16 seconds | Changes made based on this and other comments. |

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| IEEE 1547-2018 | Change made as proposed |
| It also mentions that the settings should be coordinated with regional UFLS program design, | Change made as proposed |
| | Changes made based on comment |
| Chapter 1 highlighted the effects that DER can have on BPS frequency response and UFLS; this chapter will focus on how those effects are represented in planning studies per PRC-006-3. | Change made as proposed based on this and other comments on the same sentence. |
| Describe what specific frequency setpoints are applicable here | Altered bullet to enhance clarity as requested in comment. |
| Move up definition within the document | Added a footnote for U-DER and R-DER terms earlier in the document as well as a link to the SPIDERWG terms and definitions document. |
| Assuming net load for calculating the generation-demand imbalance to study the performance of an electrical island per PRC-006-3 may not fully test the robustness of the UFLS program and could lead to under-tripping of sufficient DER load to arrest severe frequency excursions | Change made based on proposed edit. |
| | Clarity added in new text to state that the imbalance was performed for each case. |
| DER Tripping on High ROCOF Conditions: During the initial onset of the frequency imbalance, ROFOF within the electrical island may be high, and may lead to tripping. | Change made based on comment. |
| NPCC*<br><br>*NPCC load is based on total TO, DP and DPUF load. Please also note that the Québec Interconnection has five threshold stages and four rate-of-change (slope) stages of load shedding. | Changes made based on proposed edit. |
| Add description in the text of what Figure B.5 is describing | Changes made based on comment. |

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| Use consistent language throughout document | Changes made based on comment. |
| Ensure that text refers to the correct Figure. | Changes made based on comment. |
| frequency to 60 Hz.. | Changes made based on this comment and others for the same sentence. |
| | Thank you for your comment. Changes made based on comment. |
| While the adaptive UFLS scheme has performed well against multiple events over the past few years, it has limitations including the extent of the contingencies for which it is planned for. | Change made based on this and other comments for the same sentence. |
| In actual field implementation, it was found that the dynamic system behavior makes the ROCOF settings challenges and initial implementation resulted in a small load shed during normally cleared faults. | Change made as proposed. |
| NPCC UFLS Program<br>The Northeast Power Coordinating Council (NPCC) Directory 12 describes the implementation plan for UFLS programs in the NPCC region. With Upon the adoption of PRC-006-NPCC-02, NPCC intends to retuire Reliability Directionory 12 in accordance with NERC Rules of Procedure; nevertheless, these values were in effect to determine system performance requirements at the time of the study. | Changes made as proposed |
| Update link | Change made based on proposed edit. |
| End-use load and any co-located R-DERs are modeled to trip consistent with NPCC Directory-12 frequency set points and load shed requirements | Change made based on comment. |
| Frequency trip settings for U-DER are much lower than the NPCC UFLS set points shown in Table D.2 and have longer trip times; therefore, frequency tripping of U-DERs is has not been included | Changes made based on this and other comments on the same sentence. |

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| Second generation renewable models were used at the time of study due to an implementation issue in the DER_A model, which has currently been resolved. | Change made based on comment. |
| Under NPCC Directory 12 requirements, | Change made as proposed |
| Kannan Sreenivasachar - Independent System Operator of New England ISO New England | Change made as proposed |
| Please change PRC-006-NPCC-1 to PRC-006-NPCC-2. | Change made as proposed |
| Please delete "meeting regional criteria" or replacing "meeting regional criteria" with "meeting the regional requirement." | Changes made as proposed |
| We suggest changing "criteria" to "requirement" | Change made as proposed |
| We suggest changing "criteria" to "requirement" | Changes made as proposed |
| We suggest changing "perspectives" to "perspective" | Change made as proposed |
| We suggest adding the word "assumption" | Changes made based on this and other comments on the same sentence |
| We suggest adding the word "Region" "NPCC Region UFLS Program" | Change made as proposed |
| We suggest replacing "Directory 12" with "Regional Reliability Standard PRC-006-NPCC" | Thank you for your comment. The text states that the values from Directory 12 "were in effect to determine system performance requirements at the time of study". No change made. |

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| We suggest deleting, "Upon the adoption of PRC-006-NPCC-02, NPCC intends to reture [retire] Reliability Direction [Directory] 12 in accordance with NERC Rules of Procedure; nevertheless, these values were in effect to determine system performance requirements at the time of the study." Note: NPCC Regional Reliability Standard PRC-006-NPCC-1 was also in effect at the time of the study. We suggesting not referencing the NPCC Regional Reliability Directory and simply reference the PRC-006-NPCC regional reliability standard. | Thank you for your comment. The text states that the values from Directory 12 "were in effect to determine system performance requirements at the time of study". No change made. |
| We suggest referencing NPCC Region UFLS Program PRC-006-NPCC in the title of Table D.2 | Change made as proposed |
| We suggest replacing "Directory 12" with "Regional Reliability Standard PRC-006-NPCC" | Thank you for your comment. The text states that the values from Directory 12 "were in effect to determine system performance requirements at the time of study". No change made. |
| We suggest changing "criteria" to "requirement" Note: PRC-006-NPCC is the Regional Reliability Standard. We suggest not referencing Regional Criteria. | Change made based on proposed edit. |
| We suggest replacing "NPCC Directory #12" with "PRC-006-NPCC" | Change made based on comment. |
| We suggest replacing "NPCC Directory-12 requirements" with "NPCC PRC-006-NPCC requirements." | Text added based on comment. |
| | Changes made based on this and other comments on the same sentence. |
| Add a statement about the factors the determine the ROCOF or add the formula. | Added a footnote based on comment. |
| redesigned to trip at lower frequencies, with less intentional time delay, and more selectively to accommodate higher ROCOF and avoid excessive shedding of loads served by DER. | Change made based on proposed edit. |

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| redesigned to trip at lower frequencies and with less intentional time delay to accommodate higher ROCOF | Text added based on this comment and the previous one mentioning intentional time delays |
| Label both axes of the graph, and have the graph and text match. | Change made based on this and other comments for the same sentence. |
| Label both axes of the graph | Change made as proposed. |
| Label both axes of the graph | Change made as proposed. |
| Remove the entire last sentence containing "if appropriate" at line 711, and the phrase "and should be studied where appropriate." from line 719. | Changes made as proposed |
| Provide definitions of Peak >= 100, 50 <= Peak < 100, etc. under NPCC (are these MW references) | Change made based on comment. |
| add (28% of load) | Change made as proposed |
| Remove the sentence "Had the solar generation been closer to what it is capable of the results would have been much worse" or provide the actual study results where full solar generation output occurred | Removed sentence based on proposed edit. |
| | Changes made based on this and other comments for the same sentence. |
| | Changes made based on this and other comments for the same sentence. |
| | Changes made based on this and other comments for the same sentence. |
| | Changes made based on this and other comments for the same sentence. |

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| | Changes made based on this comment. |
| | Changed instances that discussed history of standard as applicable. General reference changed to "PRC-006" and specific references changed to "PRC-006-5" |
| | See response to the same comment as submitted by the EIPC's FRWG. |

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| | Changed instances that discussed history of standard as applicable. General reference changed to "PRC-006" and specific references changed to "PRC-006-5" |
| | Changed instances that discussed history of standard as applicable. General reference changed to "PRC-006" and specific references changed to "PRC-006-5" |
| | Thank you for your comment. This exact comment was submitted by EIPC's FRWG. See response to comment there |
| | Thank you for your comment. This exact comment was submitted by EIPC's FRWG. See response to comment there |
| | Thank you for your comment. This exact comment was submitted by EIPC's FRWG. See response to comment there |
| | Thank you for your comment. This exact comment was submitted by EIPC's FRWG. See response to comment there |

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| | Thank you for your comment. This exact comment, although altered so the last sentence was the proposed change, was submitted by EIPC's FRWG. See response to comment there |
| | Thank you for your comment. This exact comment was submitted by EIPC's FRWG. See response to comment there |
| | Thank you for your comment. This exact comment was submitted by EIPC's FRWG. See response to comment there |
| | Change made based on this and other comments for the same sentence. |
| | Thank you for your comment. This exact comment was submitted by EIPC's FRWG. See response to comment there |
| | Thank you for your comment. This exact comment, although altered so the last sentence was the proposed change, was submitted by EIPC's FRWG. See response to comment there |
| | Change made as proposed |

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| | Thank you for your comment. This exact comment was submitted by EIPC's FRWG. See response to comment there |
| | Thank you for your comment. This exact comment, although altered so the last sentence was the proposed change, was submitted by EIPC's FRWG. See response to comment there |
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| | Thank you for your comment. This exact comment was submitted by EIPC's FRWG. See response to comment there |
| | Thank you for your comment. This exact comment was submitted by EIPC's FRWG. See response to comment there |
| | Change made based on this comment and others for the same sentence. |
| | Thank you for your comment. This exact comment was submitted by EIPC's FRWG. See response to comment there |
| | Thank you for your comment. This exact comment was submitted by EIPC's FRWG. See response to comment there |
| | Thank you for your comment. This exact comment was submitted by EIPC's FRWG. See response to comment there |

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| | Thank you for your comment. This exact comment was submitted by EIPC's FRWG. See response to comment there |
| | Thank you for your comment. This exact comment, although altered so the last sentence was the proposed change, was submitted by EIPC's FRWG. See response to comment there |
| | Change made based on this comment and others for the same sentence. |
| | Change made based on this comment and others for the same sentence. |
| | Change made based on this comment and others for the same sentence. |

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| | Thank you for your comment. No changes made to referenced text describing the statement on HELCO's determination of FFR from storage resources based on this comment. |

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| | Thank you for your comment. Please see NERC's response to the EIPC FRWG comment. |

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| | Thank you for your comment. Please see NERC's response to the EIPC FRWG comment. |

# Facility Ratings Task Force (FRTF) Scope and Next Steps

## Action
Approve

## Summary
The FRTF has developed a revised Scope document that includes a change in reporting structure. Rather than be a joint CCC/RSTC Task Force, the draft scope recommends the FRTF report to the RSTC. Transition of the FRTF to RSTC oversight continues to provide focus and technical expertise on Facility Ratings, including reliability risk to the grid, technical analysis and additional industry perspectives in problem statement definition. The FRTF also recommends adding additional technical expertise from the industry to the group for more robust discussion. The FRTF is seeking approval of the revised scope document.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

# Facility Ratings Task Force Revised Scope

December 16, 2021

## Purpose

The North American Electric Reliability Corporation (NERC) Reliability and Security Technical Committee (RSTC) is a standing committee that strives to advance the reliability and security of the interconnected BPS of North America by:

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

The NERC RSTC Facility Ratings Task Force (FRTF) will address risks and technical analysis associated with the FAC-008, *Facility Ratings Standards*. The potential areas this task force is evaluating relate to alignment of industry's processes and procedures to assess risk and analytics and prioritize resources with those processes and procedures that focus on prioritization of reliability risks and corresponding resources.

## Roles and Activities

Facility Ratings continue to be a source of discussion in the industry related to operational performance, enforcement actions and regulator views about future considerations. Future considerations related to facility ratings are more complex and consider use of utility assets in different manners as compared to a historical view. In order to effectively accommodate that type of conversation, the industry needs to assess the current processes and expectations to ensure the "basics" are covered. The RSTC, in its role serving as the technical expertise and executing the collaborative role with RISC to prioritize efforts related to BES risk response, will delegate responsibility to the FRTF to carry out activities to:

- Provide information to industry on the issues,
- Support industry readiness and success on this topic,
- Foster and facilitate discussions around the issues, risk and potential mitigations or course corrections, and
- Gather industry feedback around recommended solutions that are actionable by either registered entities or industry groups (membership forums, trade associations, technical committees, etc.).

The FRTF will report its work and deliverables to the RSTC, and the RSTC maintains ultimate responsibility for decisions and recommendations to NERC.

- The FRTF recommends the Facility Ratings Task Force transition oversight to the RSTC to continue to provide focus and technical expertise on Facility Ratings, including reliability risk to the grid, technical analysis, and additional industry perspectives in problem statement definition. Furthermore, we recommend adding additional technical expertise from the industry to the group for more robust discussion.
    - Consideration of implementing new specific cause codes in the availability data systems for tracking and trending of Facility Ratings vulnerabilities. New cause codes may include items such as discovery of changing elements, changes to the most limiting element, Facility Rating changes including de-rates as well as up-rates, de-ratings to equipment, inventory misses, identification of incorrect device ratings or settings, identification of field/inventory mismatches, etc. Causal code analysis will allow for quantification and better understanding of Facility Ratings risk.

- Through the ongoing efforts of the FRTF, the industry should seek understanding and quantifying Facility Ratings risk, however, this may represent a large project that is better served in phases, some of which maybe worked in parallel.
    - Conduct a field test with the industry to gather more information on Facility Ratings and risk analytics.
    - Focus reporting aspects first on changes to the most limiting element and derates.
    - Work with industry organizations to gather risk informed technical data to prioritize industry resources on responsiveness to the ERO's risk assessment.
- Industry input, as additional technical analysis occurs, related to the ERO Problem Statement around facility ratings.
- Gather detailed information on the Facility Rating performance issues.
    - Identify support needs and RSTC subcommittees or individual members that have the expertise to review the issues in support of the FRTF.
    - Reach to industry for input on potential readiness issues (e.g., trade associations, membership organization, compliance forums, registered entities, etc.).
    - Initiate or request FRTF discussions as issues are identified.
    - Identify issues representing specific concerns quickly and facilitate swift resolution or communications.
- Evaluate options for industry outreach.
- Develop suggested recommendations related to the issues.
- Present work outcomes to the RSTC for awareness.
- Determine appropriate path for recommendations to be considered and action taken.

## Membership

The FRTF membership will be comprised of RSTC members and observers appointed by the RSTC Chair.

1. Composition
   a. RSTC Members
   b. RSTC Active Participants (Observers)
2. Leadership
   a. The FRTF will be chaired with an RSTC member or RSTC Chair appointee.
3. Observers
   a. The FRTF Chair may invite observers to participate in meetings, which may include additional NERC or Regional Entity staff, as well as RSTC members. Observers may actively participate in the discussion and FRTF deliverables.

## Meetings

The FRTF meetings will be scheduled based on workload, as determined by the members. Meetings will be conducted by conference call. Meetings may also occur in conjunction with the regular RSTC meetings. The FRTF meetings will be open to other participants. The FRTF Chair will approve this participation and work with RSTC Chair for any necessary appointments.

# NERC Facility Ratings Task Force (FRTF)
## 2021 Year-End Report

## Executive Summary

Over the last few years, the industry and the ERO Enterprise have identified instances of discrepancies between documented Equipment, actual field conditions, and resultant Facility Ratings. Some of these discrepancies have resulted in the lowering of Facility Ratings and/or changes to the Most Limiting Element ("impactful") that determines the Facility Rating; while some of the discrepancies impact neither ("non-impactful"). Currently the Standard, and therefore the Compliance and Enforcement approaches, do not distinguish between impactful and the non-impactful discrepancies. Further, there is no distinction in the Standard between high "risk" Facility Ratings vs lower "risk" Facility Ratings. For these reasons, the joint task force under the NERC Reliability and Security Technical Committee ("RSTC") and the NERC Compliance and Certification Committee ("CCC") created the Facility Ratings Task Force ("FRTF") to provide additional insights to the ERO Enterprise and the industry. Additional technical and risk analytics will provide guidance for industry to prioritize resources ensuring reliability of the Bulk Electric System as well as an appropriate risk response. In conclusion of the work, the FRTF offers recommendations and next steps for existing NERC committees to address the path forward.

## Current Observations

There have been concerns raised about Facility Rating Methodologies considering specific equipment types that are not delineated in the existing Standard. This has been captured in guidance documents. The issues identified to date generally involve discrepancies between current field conditions and documented Equipment inventories and/or Facility Ratings. More specifically, the ERO reports that the discrepancies tend to occur as the result of the following:

- Lack of processes and controls to ensure changes in the field (emergency or otherwise) are being properly documented and communicated in order to update the Facility Rating.
- Lack of communication between parties responsible for determining Facility Ratings (i.e., substation and transmission).
- Insufficient processes and controls to ensure Facility Rating are accurate when facilities are commissioned or when Facility Ratings are otherwise initially determined.
- Insufficient processes and controls to ensure planned facility changes that resulted

in updated Facility Ratings are either implemented as planned or, if not, that the Facility Ratings are updated because of the planned changes with revisions to reflect current conditions.

In addition, industry highlighted the following opportunities to address the challenges below relative to the existing Standard.

- Need for recognition of different reliability risk levels associated with different BES elements.
- Need for consistent ERO interpretation, Guidance, and Compliance/Enforcement practices regarding FAC-008.
- Need for recognition of relationship between data discrepancies and reliability consequences, impactful and non-impactful data discrepancies.

Incorrect Facility Rating calculations have been performed because of missing, or incomplete assessments of the equipment identified within the Facility. For example, missing or incorrectly rated equipment includes jumpers and risers inside substations, bus bars, current transformers (including delta connected current transformers), circuit breakers, and transmission line conductors. Based on compliance monitoring activities, the ERO Enterprise has observed multiple contributing causes related to insufficient processes and lack of controls to prevent these discrepancies.

Also, as noted above, there is a need to provide for better collaboration of Facility Ratings between types of Registered Entities. There have been instances where differences between entities have resulted in incomplete or inaccurate modeling assumptions in the various Planning Coordinator and Transmission Planner assessments.

While the industry has matured to respond to the overall compliance requirements, we believe refinements are needed to further identify the reliability risk associated with discrepancies in facility ratings. Designing and implementing new specific cause codes could provide all stakeholders with a deeper understanding of Facility Ratings performance, clarity of materiality of the reliability risk to the grid and necessary actions and timing to reasonably resolve identified risks.

## Recommendations

To conclude the 2021 work of the FRTF, based on identified potential gaps and areas for improvement, there are numerous actions that are believed to be required and necessary to drive change to manage risk efficiently and effectively.

1. The FRTF recommends the Facility Ratings Task Force transition oversight to the RSTC to continue to provide focus and technical expertise on Facility Ratings, including reliability risk to the grid, technical analysis, and additional industry perspectives in problem statement definition. Furthermore, we recommend adding additional technical expertise from the industry to the group for more robust discussion.
    a. Consideration of implementing new specific cause codes in the availability data systems for tracking and trending of Facility Ratings vulnerabilities.

New cause codes may include items such as discovery of changing elements, changes to the most limiting element, Facility Rating changes including de-rates as well as up-rates, de-ratings to equipment, inventory misses, identification of incorrect device ratings or settings, identification of field/inventory mismatches, etc. Causal code analysis will allow for quantification and better understanding of Facility Ratings risk.

2. Through the ongoing efforts of the FRTF, the industry should seek understanding and quantifying Facility Ratings risk, however, this may represent a large project that is better served in phases, some of which maybe worked in parallel.
    a. Conduct a field test with the industry to gather more information on Facility Ratings and risk analytics.
    b. Focus reporting aspects first on changes to the most limiting element and derates.
    c. Work with industry organizations to gather risk informed technical data to prioritize industry resources on responsiveness to the ERO's risk assessment.

3. The NERC CCC will continue to communicate issues and recommendations regarding concerns about consistency or interpretation related to ERO Guidance, Compliance and Enforcement matters, publications beyond the standard language, etc.

4. The NERC CCC will continue to work with the ERO Enterprise on the risk-based compliance approach related to Facility Ratings in the following ways:
    a. Consideration for risk of each element – not all elements pose the same level of risk,
    b. Impactful versus Non-impactful data changes representing violations, and
    c. Registered entity's approach to self-identify and report impactful changes and controls.

## Background

In October 2019, the ERO Enterprise informed industry that concerns related to Facility Ratings were increasing and that patterns were emerging that required the industry to lean in to address an escalating risk profile. The description of the problem statement is as follows:

*The issues identified to date generally involve Facility Ratings calculations that are incorrect as a result of missing components and/or incorrect ratings for multiple types of components. As examples, the missing or incorrectly rated components include Elements such as jumpers and risers inside substations, bus bars, current transformers (including delta connected current transformers), circuit breakers, and transmission line conductors. The identified issues involve multiple causal factors relating to insufficient processes and lack of controls to prevent these discrepancies. More specifically, the*

*discrepancies tend to occur as the result of the following:*

*• Lack of processes and controls to ensure changes in the field (emergency or otherwise) are being properly documented and communicated in order to update the Facility Rating.*
*• Lack of communication between parties responsible for determining Facility Ratings (i.e., substation and transmission).*
*• Insufficient processes and controls to ensure Facility Rating are accurate when facilities are commissioned or when Facility Ratings are otherwise initially determined; and*
*• Insufficient processes and controls to ensure planned facility changes that resulted in updated Facility Ratings are either implemented as planned or, if not, that the Facility Ratings updated as a result of the planned changes are revised to reflect current conditions.*

*These recurring causes, coupled with the lack of mandatory detective controls such as periodic reviews of Facility Ratings, contribute to concerns that there are potentially more discrepancies on the system than what is currently known. Ultimately and in order to fully identify and mitigate the Facility Rating issues that may be present on the system, it is critical that entities perform their own self-assessments. Entities are encouraged, if an issue arises, to self-report potential noncompliance findings to Regional Entity.*

To clarify, Facility Ratings are required for certain facilities per NERC Reliability Standard FAC-008-3, Facility Ratings. Under the requirements, a Generator Owner must have documentation of its determination of Facility Ratings while a Transmission Owner must have a documented methodology for determining Facility Ratings. There has been substantive work across the industry on Facility Ratings related to processes, programs, frameworks, controls and best practices. Facility Ratings continues to be an area that is challenging and complex – for numerous reasons. The implied view is that all equipment and / or components are created equal from a risk perspective. From a system operating perspective, all elements on the grid are not equal (from an individualized registered entity view) even though the standard suggests that is the case. In addition, the current "blanket" application of the FAC-008-3 requirements can be costly to implement and thus requires a risk-based perspective to ensure these costs are providing corresponding reliability benefits. The cost implications are not a prohibition to adhere to standards, but a discussion to ensure that coveted technical resources are appropriately focused on the highest risk aspects of the process. In the end, solutions are needed that strengthen the reliability and the resilience of the grid. The current approach to Facility Ratings does not provide a straightforward way to implement a risk-based framework in the correlation of reliability and resiliency risks with adherence to the FAC-008-3 standard.

The NERC CCC formed a FRTF, which was expanded to include members from the NERC RSTC, to evaluate and work to propose alignment of the risk assessment and risk appetite related to Facility Ratings. The objective of expanding the FRTF to include

the RSTC targeted the incorporation of broader technical, risk-based perspectives into ongoing activities around the current FAC-008 standards. Some of the discussions that occurred have been informed broadly by the Facility Ratings Standards (FAC-008-3) filings and industry performance as evaluated under the CMEP including lessons learned. The potential areas where changes to approach should be evaluated relate to alignment of industry's processes and procedures, risk tolerance and the current body of regulations. The impact of those opportunities and risk analytics supported by technical analysis will directly translate to further compliance oversight discussions, institution of controls, assessments of risk, and prioritization of resources through NERC's Known and Emerging Risk Framework that translate to association of industry's processes and procedures that assist with focusing resources with corresponding reliability risks.

The FERC NOPR released in the staff report at the meeting on Thursday, November 19, 2020 could be a reason for broader concerns related to Facility Ratings. The NOPR suggests a move to dynamic Facility Ratings (from static) to maximize the capability of those facilities. This NOPR and the potential changes in the already complex issue of Facility Ratings make it even more critical that technical experts are involved in the evaluation of Facility Rating-related processes, procedures, risk analytics to ensure the path forward is based on a risk-based approach with common understanding of risk tolerance and acceptance. The recommendations hope to provide the RSTC a path to incorporate a fulsome view of Facility Ratings with technical basis for risk tolerances and ensure that industry's technical perspectives and expertise is carried into any future activities related to FAC-008-X, dynamic Facility Ratings or other topics which may occur going forward.

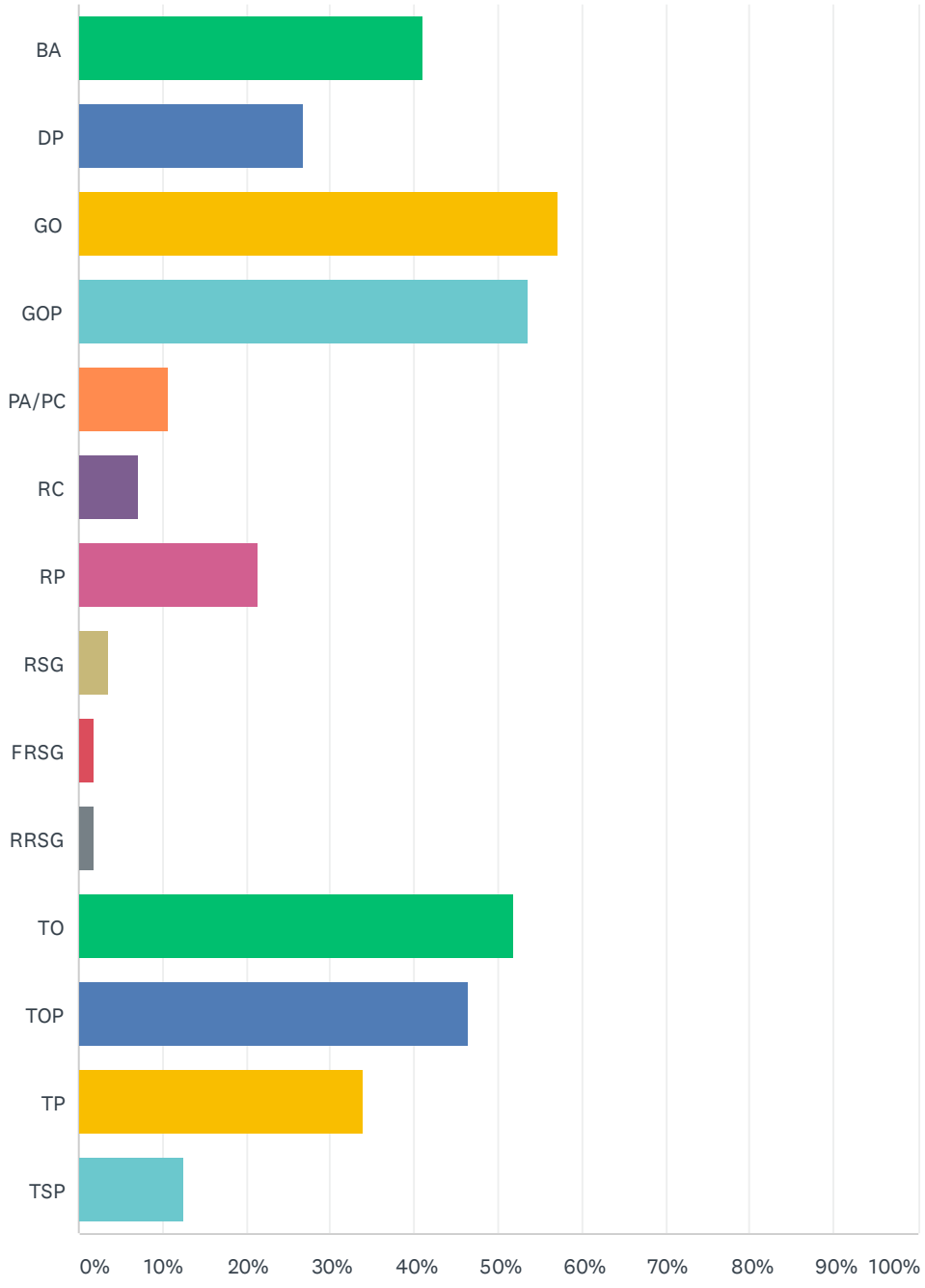
# Security Working Group (SWG)

## Action
Update

## Summary
The SWG will provide an update on its current work plan activities as well as the survey results for the Assessing Cyber Risk Team and NIST partnership survey.

# Q1 Applicability (Check all that apply)

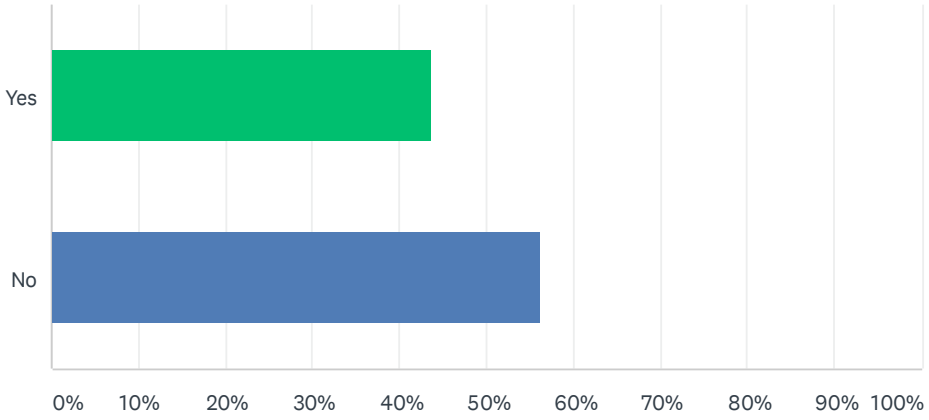
Answered: 56 Skipped: 0



| ANSWER CHOICES | RESPONSES | |
|---|---|---|
| BA | 41.07% | 23 |
| DP | 26.79% | 15 |
| GO | 57.14% | 32 |
| GOP | 53.57% | 30 |
| PA/PC | 10.71% | 6 |
| RC | 7.14% | 4 |
| RP | 21.43% | 12 |
| RSG | 3.57% | 2 |
| FRSG | 1.79% | 1 |
| RRSG | 1.79% | 1 |
| TO | 51.79% | 29 |
| TOP | 46.43% | 26 |
| TP | 33.93% | 19 |
| TSP | 12.50% | 7 |
| Total Respondents: 56 | | |

# Q2 Did your organization use the tool?

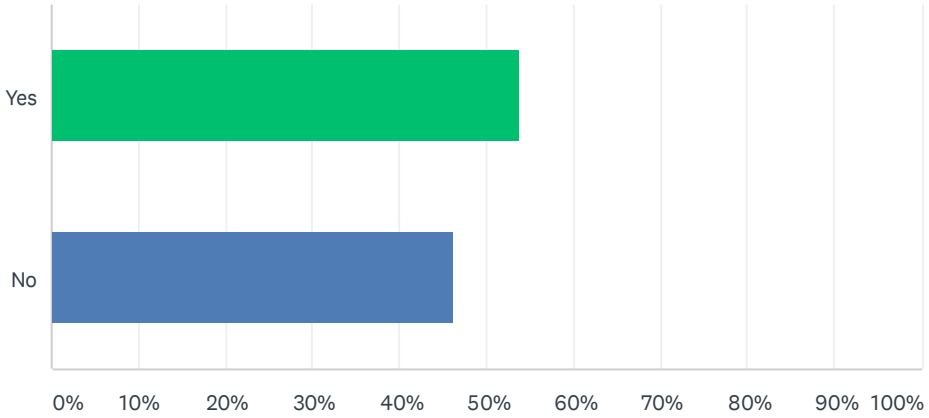
Answered: 16 Skipped: 40




| ANSWER CHOICES | RESPONSES | |
|---|---|---|
| Yes | 43.75% | 7 |
| No | 56.25% | 9 |
| TOTAL | | 16 |

# Q3 Did the tool identify gaps in your cyber security program?

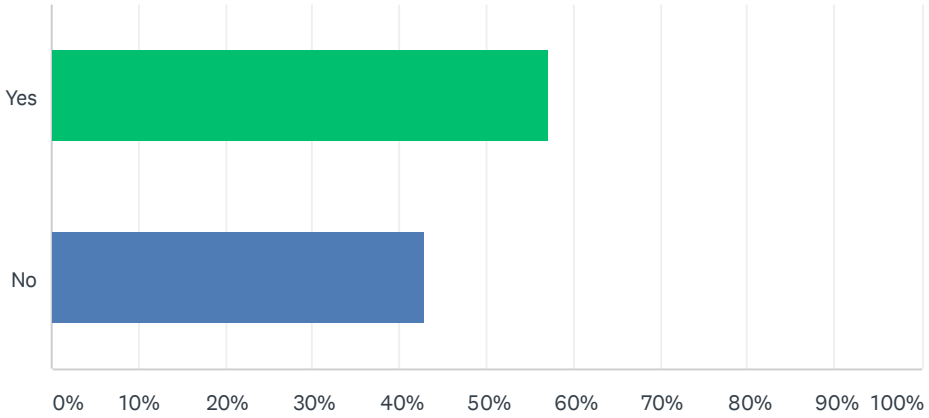
Answered: 13 Skipped: 43




| ANSWER CHOICES | RESPONSES | |
|---|---|---|
| Yes | 53.85% | 7 |
| No | 46.15% | 6 |
| TOTAL | | 13 |

# Q4 Did you make changes to your program to address the identified gaps?

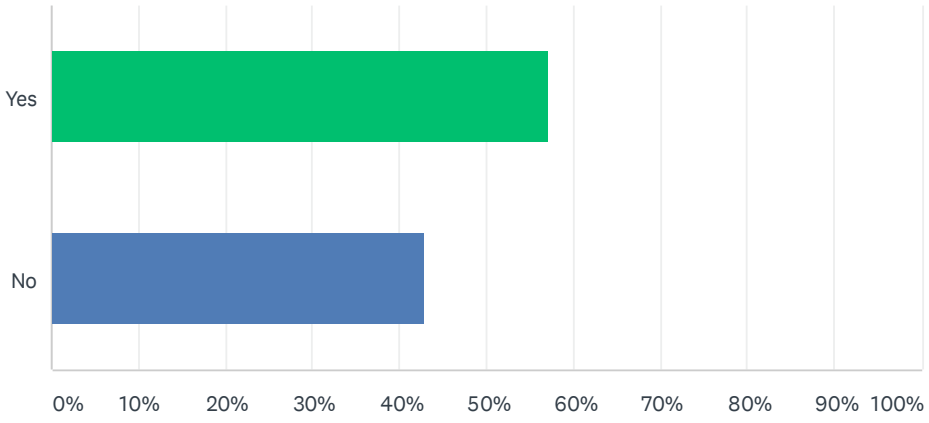
Answered: 14 Skipped: 42




| ANSWER CHOICES | RESPONSES | |
|---|---|---|
| Yes | 57.14% | 8 |
| No | 42.86% | 6 |
| TOTAL | | 14 |

# Q5 Was the tool helpful in developing annual or long term improvement plans?

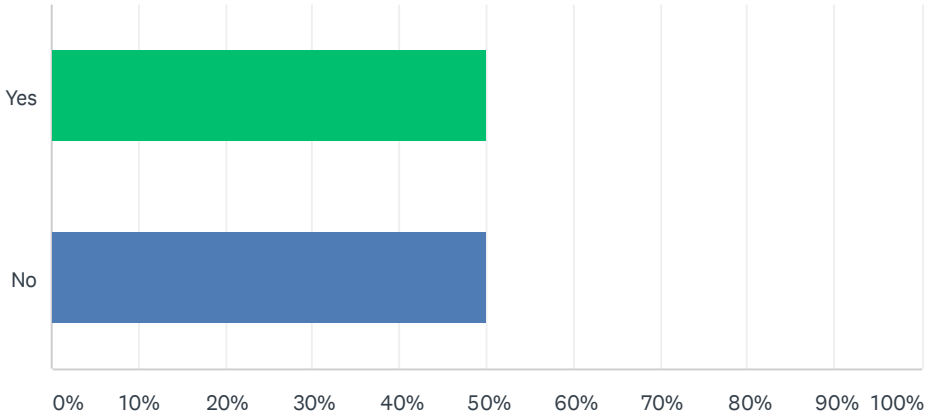
Answered: 14 Skipped: 42




| ANSWER CHOICES | RESPONSES | |
|---|---|---|
| Yes | 57.14% | 8 |
| No | 42.86% | 6 |
| TOTAL | | 14 |

# Q6 Was the tool easy to use?

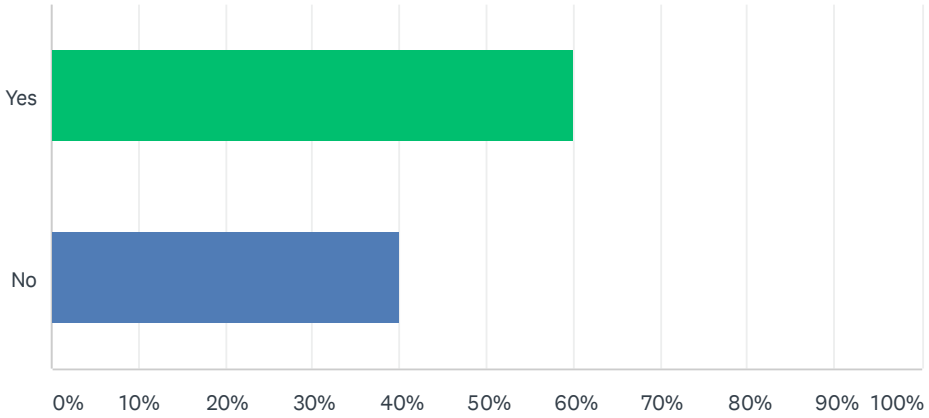
Answered: 10 Skipped: 46




| ANSWER CHOICES | RESPONSES | |
|---|---|---|
| Yes | 50.00% | 5 |
| No | 50.00% | 5 |
| TOTAL | | 10 |

# Q7 Did you utilize the job aid document?

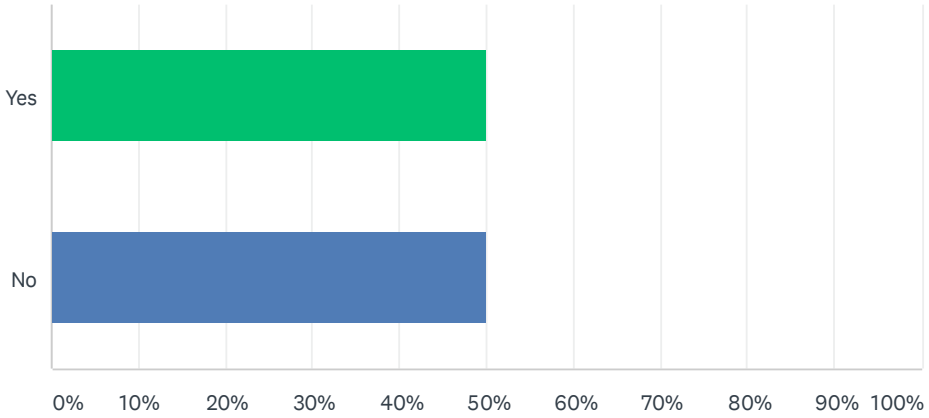
Answered: 10 Skipped: 46




| ANSWER CHOICES | RESPONSES | |
|---|---|---|
| Yes | 60.00% | 6 |
| No | 40.00% | 4 |
| TOTAL | | 10 |

# Q8 Did the tool adequately perform the functional intent?

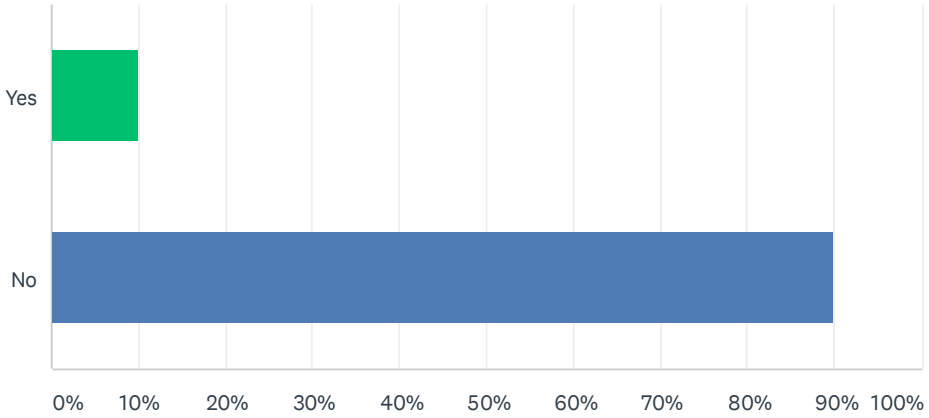
Answered: 10 Skipped: 46




| ANSWER CHOICES | RESPONSES | |
|---|---|---|
| Yes | 50.00% | 5 |
| No | 50.00% | 5 |
| TOTAL | | 10 |

# Q9 Were there any technical issues with the tool?

Answered: 10 Skipped: 46



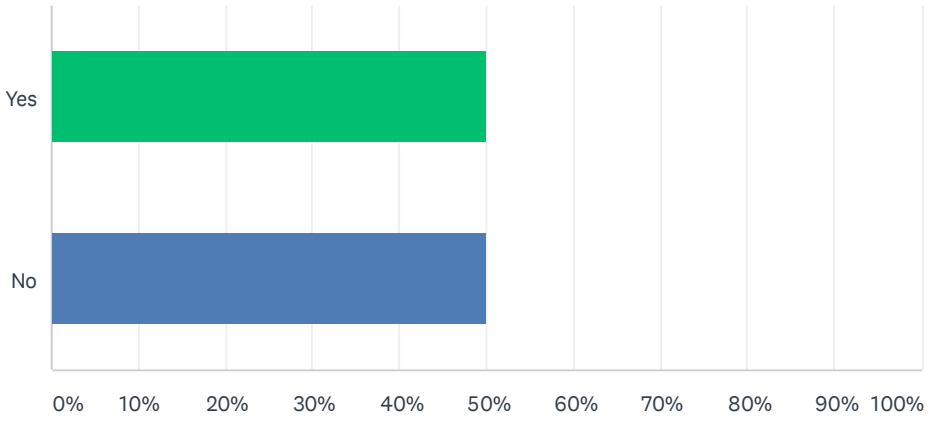

| ANSWER CHOICES | RESPONSES | |
|---|---|---|
| Yes | 10.00% | 1 |
| No | 90.00% | 9 |
| TOTAL | | 10 |

# Q10 If yes, please be descriptive in the issue(s)

Answered: 1 Skipped: 55

# Q11 Would an alternate format for import into automation tools such as a Governance, Risk and Compliance tool be useful?

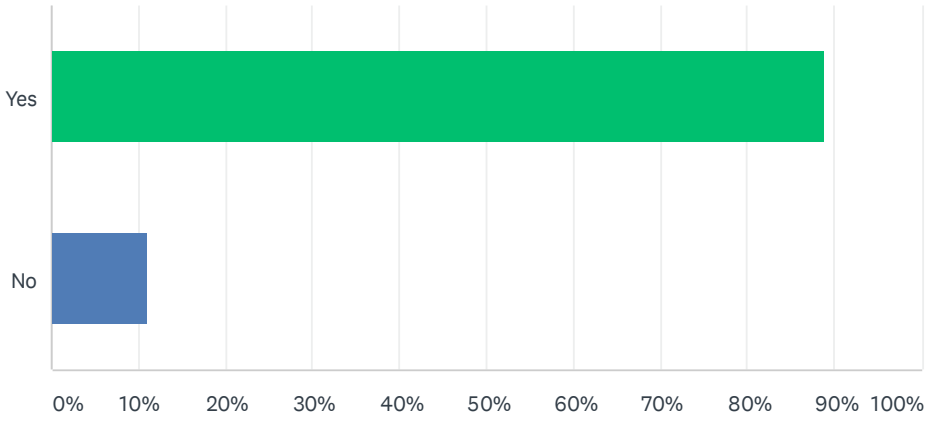
Answered: 8 Skipped: 48




| ANSWER CHOICES | RESPONSES | |
|---|---|---|
| Yes | 50.00% | 4 |
| No | 50.00% | 4 |
| TOTAL | | 8 |

# Q12 Would it be helpful to have the spreadsheet updated whenever relevant documents are revised (e.g., NERC Reliability Standards, NIST Cyber Security Frameworks, DOE C2M2)?

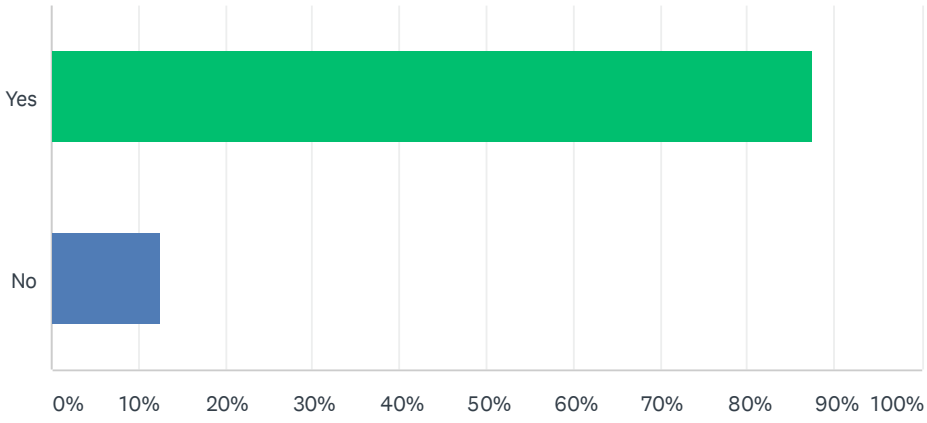
Answered: 9 Skipped: 47




| ANSWER CHOICES | RESPONSES | |
|---|---|---|
| Yes | 88.89% | 8 |
| No | 11.11% | 1 |
| TOTAL | | 9 |

# Q13 Will you continue to utilize the tool as an ongoing part of your program?

Answered: 8 Skipped: 48




| ANSWER CHOICES | RESPONSES | |
|---|---|---|
| Yes | 87.50% | 7 |
| No | 12.50% | 1 |
| TOTAL | | 8 |

## Q14 The SWG appreciates your time in responding to the survey, please provide additional feedback here.

Answered: 2 Skipped: 54

North American Transmission FORUM

*Community* *Confidentiality* *Candor* *Commitment*

**To:** NERC Reliability and Security Technical Committee (RSTC)

**From:** Roman Carter, Director-Peer Reviews, Assistance, Training and Knowledge Management

**Date:** November 18, 2021

**Subject:** NATF Periodic Report to the NERC RSTC (December 2021)

**Attachments:** NATF External Newsletter (October 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 NATF External Newsletter, which is also available on our public website: www.natf.net/news/newsletters .

## NATF Supply Chain Foundations, Next Steps, and ERO Support

Much progress has been made toward supply chain security since 2017 when, in response to the directives in the Federal Energy Regulatory Commission's (FERC) Order 829, the NERC board asked the North American Transmission Forum (NATF) and North American Generator Forum (NAGF) to develop white papers addressing best and leading practices in supply chain management.

Since that time, the NATF and NATF-led Industry Organizations Team (consisting of electric utilities, energy industry trade and forum representatives, suppliers, third-party assessors, and solution providers) have produced—and openly shared—work that is responsive to the NERC board's resolutions to address supply chain risk management issues. The NATF and the Industry Organizations Team's objectives are to further supply chain security through the identification and mitigation of risks; to converge the industry on information needed for that purpose; and to develop practices that are efficient, effective, and meet compliance requirements.

With those objectives in mind, the NATF's "Supply Chain Security Assessment Model," the "NATF Supply Chain Security Criteria," and "Energy Sector Supply Chain Risk Questionnaire" were developed. The Industry Organizations Team also developed guides for entities on understanding third-party assessments and using solution providers for third-party risk management. A series of webinars was conducted to share entities' methods for conducting risk assessments, and APPA (an Industry Organization Team member) developed a guide with input from other team members on supply chain risk management, including methods for conducting a risk assessment. Information on available products and services to identify and mitigate risks was provided in another webinar series.

As we reflect on these accomplishments, it is also an opportunity to look forward to what is needed to achieve the next level of maturity for these supply chain security efforts. Four key components are emerging for maturity:

- A process for evaluating and mitigating supply chain risks
- The information that is needed from suppliers to evaluate potential supply chain risks
- Entities' access to supplier information and other supply chain risk information

- Entities' ability to know their practices, if appropriately implemented, will meet compliance requirements

The first three have been achieved or are in progress. The NATF model provides the process, and the NATF criteria and questionnaire obtain the information needed from suppliers. The NATF criteria and questionnaire may be revised as needed through the associated industry-wide revision process that includes regulators, intelligence agencies (e.g., the E-ISAC), and suppliers. Regarding industry access to information, the NATF, EEI, APPA, and NRECA—with industry support—are embarking on activites to assess the need for and potential interest in a proposed central library concept, which is ultimately intended to streamline the collection and sharing of supply chain risk information.

The NATF has asked for assistance from the NERC board, NERC, and the Regions on the last component. ERO endorsement of the NATF and industry efforts conducted to support the 2017 NERC board request (specifically the NATF model, criteria, and questionnaire) would provide registered entities with added confidence that, if implemented appropriately, use of these tools is one way to meet compliance. NERC board recognition of the NATF's supply chain work and products as responsive to the 2017 resolution and ERO endorsement of the NATF model, criteria, and questionnaire will serve to further foster industry convergence on these methods to enhance security. More information will be provided for the February 2022 NERC board meeting.

## Winter 2021 Freeze Event

NATF staff and members have been reviewing the preliminary findings and recommendations from the FERC-ERO joint inquiry team's report on the 2021 winter freeze event. The NATF has been facilitating information exchange for members and discussing further options to support members without duplicating effort. The report will serve as input to help guide any specific NATF actions. One potential action is a joint NATF-NERC webinar for NATF members regarding recommendations from the inquiry.

## Facility Ratings

The NATF has been working with its members to socialize and review member implementation of facility ratings practices developed by a team of subject-matter experts from NATF member companies. A summary report on overall member implementation status as of April 2021 was provided by the NATF to NERC and regional entity leadership in August. The NATF is completing its third information collection from members to track ongoing status of practices implementation. The next summary report to the ERO will be provided in January/February 2022.

In addition, the NATF is updating its facility ratings practices document to incorporate a method to prioritize implementation of the practices based on relevant facility risk and note examples of internal controls for facility ratings processes. The revised document is now ready for member use.

## Value of NATF Peer Reviews

NATF review teams, comprising the members' own subject-matter experts, conduct periodic, confidential evaluations of NATF member organizations (which we refer to as the "host"). Each review consists of three to four days of interviews and observations, followed by a report that includes recommendations to the host member's executives and staff. Best practices from both the host and review team organizations are brought back to NATF practice groups for further sharing.

The NATF has conducted well over 100 peer reviews, offering significant value to members. To help understand the overall benefit of the program, NATF staff follows up with hosts at both the six-month and one-year marks to inquire about the status of recommendations offered (i.e., completed, partially completed, planned for future implementation, still under review, or plan to take no action). Recommendations members have completed, partially completed, or plan to complete in the future are considered “realized value,” meaning that implementation of the recommendations improves aspects such as member processes, procedures, readiness, safety, and, ultimately, transmission-system reliability and resilience.

To date, the NATF membership has provided peer-review hosts over 7900 recommendations, of which approximately 5700 have been completed or have planned action; the realized value is 72% at the one-year follow-up mark.

# North American Transmission Forum External Newsletter

October 2021

## NATF Posts Guidance for Entities Working with Solution Providers


The NATF has posted the "NATF Industry Collaboration: Using Solution Providers for Third-Party Risk Management" guide for industry use. The document clarifies the role of a solution provider and provides guidance for entities that are considering a solution provider's services to assist with evaluations of suppliers' cyber security practices. These services, such as gathering supplier information and providing analysis, can provide significant support for an entity's ongoing supply chain cyber security risk management.

The Industry Organization Team suppliers and solution providers jointly developed the document. They have provided entities with items to consider based on insights from both perspectives and, through the development of this document, strengthened the relationships between the two industries.

The document is available on the NATF Supply Chain Cyber Security Industry Coordination page.

***

## 2021 EPRI-NERC-NATF Planning and Modeling Virtual Seminar

The NATF is partnering with the North American Electric Reliability Corporation (NERC) and the Electric Power Research Institute (EPRI) to host a planning and modeling seminar focused on planning for a decarbonized grid. Subject-matter experts from across the industry will present on topics such as planning aspects of hybrid plants and bulk electric system storage, use of climate information for assessing the impacts of extreme weather events, and technology impacting the industry.

The seminar will be conducted over two days: November 3-4 from 1:00 p.m. to 4:00 p.m. eastern each day. See the event flyer for more information.

***

## New Product for NATF Members

The NATF is launching a new offering for members: NATF bulletins. As part of the NATF's value proposition to actively leverage the strengths of our individual members to make the entire membership stronger, the intent of an NATF bulletin is to improve and promote reliability, security, safety, and resilience through the sharing of actionable information. NATF bulletins share lessons learned and recommendations obtained by aggregating and analyzing member experiences and data to provide opportunities for members to learn without experiencing issues and events first-hand.

***

## Redacted Operating Experience Reports

We recently posted two new operating experience 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 resilience.

***

*For more information about the NATF, please visit www.natf.net.*

# TOCC Field Test Update

## Action
Information

## Summary
During the September RSTC meeting, the RSTC was presented with information regarding a proposed CIP-002 Transmission Owner Control Centers (TOCCs) Field Test. The Field Test document was sent to RSTC members for a comment period ending on Thursday, September 30, 2021. Comments were considered and incorporated into the TOCC Field Test document. The RSTC endorsed the Field Test document which was then approved by the Standards Committee (SC) for implementation. This agenda item will address the implementation of the Field Test for oversight by the RSTC.