Agenda
Reliability and Security Technical Committee

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

Attendee Webex Link: Join Meeting

AUDIO ONLY Dial-in: 1-415-655-0002 | Access Code: 172 206 5948

Call to Order

NERC Antitrust Compliance Guidelines and Public Announcement

Introductions and Chair's Remarks

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

Consent Agenda

2. **Minutes - Approve**
    a. June 10, 2020 RSTC Meeting*
    b. July 28, 2020 Closed RSTC Meeting*
3. **Past Executive Committee Action – Ratify**
    a. Executive Committee authorization to post *Reliability Guideline: Generating Unit Winter Weather Readiness* for a 45-day comment period by unanimous consent via e-mail ballot
    b. Executive Committee authorization to post *Guideline for the Electricity Sector: Supply Chain Procurement Language* for a 45-day comment period on August 4, 202 Transition Team conference call by unanimous consent
4. **Standards Authorization Request - Endorse**

  a. SAR for MOD-025-2 - Unit Verification and Modeling*
  b. Revisions to PRC-023-4 – Transmission Relay Loadability*

5. **Post Document for 45-day Comment Period - Authorize**
  a. Reliability Guideline: Gas and Electrical Operational Coordination Considerations*
  b. Reliability Guideline: DER Verification*

6. **Technical Documents - Approve**
  a. White Paper on Assessment of DER impacts on NERC Reliability Standard TPL-001*
  b. Reliability Guideline: DER Data Collection for Modeling in Transmission Planning Studies*

7. **Compliance Implementation Guidance – Endorse for Submittal to the ERO**
  a. Compliance Implementation Guidance: PRC-019-2*

Regular Agenda

8. **Remarks and Reports**
  a. Remarks – *Greg Ford, RSTC Chair*
    i. Subcommittee Reports and RSTC Work Plan*
    ii. Possible Misunderstandings of the Term "Load Loss" White Paper* - Seek Review Team
  b. Report of August 20, 2020 Member Representatives Committee (MRC) Meeting and Board Meeting – *Chair Ford*
  c. **Appoint** New Resources Subcommittee Leadership
  d. **Appoint** New Performance Analysis Subcommittee Leadership

9. **RSTC Transition Plan – Discussion and Action – *Chair Ford***
  a. Subgroup Organization Proposal* – **Approve** - *Chair Ford*
    i. Security Integration and Technology Enablement Subcommittee (SITES) Scope* - **Approve** - *Marc Child*
  b. RSTC Notional Work Flow Process document* – **Approve** - *Kayla Messamore*
  c. Subgroup Sponsors – *Chair Ford*
  d. Integrating Security Topics into RSTC Technical Groups* – **Endorse** - *Ryan Quint, NERC Staff*
  e. RSTC 2020 Calendar Review – *Stephen Crutchfield*

2020 Meeting Dates	Time	Platform
December 15, 2020 December 16, 2020	1:00 to 4:00 p.m. 1:00 to 4:00 p.m.	WebEx

10. NERC/IRC Whitepaper on Ensuring Energy Adequacy – Information - *Pete Brandien and Mark Lauby*

11. FERC/NERC Guide to Identify Supply Chain Vendors – Information – *Ryan Quint, NERC Staff*

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

13. Forum and Group Reports – Information

a. North American Generator Forum* – *Allen Schriver*

b. North American Transmission Forum* – *Roman Carter*

14. Chair's Closing Remarks

15. 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.

Meeting Minutes
Reliability and Security Technical Committee

June 10, 2020

Webinar

A regular meeting of the NERC Reliability and Security Technical Committee (RSTC) was held on June 10, 2020, via webinar. The meeting agenda and the attendance list are affixed as **Exhibits A** and **B**, respectively. The meeting presentations are posted in a separate file at RSTC presentations.

Meeting Highlights

1. The RSTC endorsed the 2020 State of Reliability Report.
2. The PPMVTF presented a white paper regarding gaps in Reliability Standard MOD-025. The group requested authorization to draft a SAR based on the white paper to revise MOD-025. The RSTC approved the white paper and authorized drafting the SAR.
3. The IRPTF presented four Standards Authorization Requests (SAR) for RSTC Endorsement. The RSTC endorsed all four SARs.
4. The RSTC Approved a revised Scope for the Resources Subcommittee.
5. The RSTC accepted the Security Guideline: BCSI Cloud Encryption.
6. The RSTC approved the Compliance Implementation Guidance: Cloud Solutions and Encrypting BCSI.
7. Chair Ford appointed Evan Shuvo as chair and Rajesh Nimbalkar as vice chair of the System Analysis and Modeling Subcommittee, both effective June 1, 2020.

RSTC Chair Greg Ford convened the meeting at 1:00 p.m. Eastern on Wednesday, June 10, 2020 and led introductions of RSTC members, observers and NERC staff..

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

Chair Ford reminded attendees to look around their office and evaluate actions in case of emergency. He noted that safety is always a priority.

Introductions and Chair's Remarks

Chair Ford provided the following remarks:

1. We have all faced challenges over the past few months with working remotely and social distancing and we are slowly returning to a more normal life.
2. This is a big day as it's the first meeting of the RSTC after the dissolution of the technical committees. A day that we have all have worked hard to bring to a reality.
3. The agenda is packed with a number of approval items of significant importance to industry; depending on how the timing plays out to complete those actions there is the possibility we may need to divert some non-action topics to next meeting.
4. Many of the items address risks resulting from the transformation of the grid, thus ensuring the system of the future will be reliable, secure and resilient.

5. The transition team has been working to ensure that we do not miss anything from the technical committees.
6. Looking forward to a productive transformation into the RSTC.

Consent Agenda

Chair Ford noted that the State of Reliability Report, which was on the Consent Agenda in the package that was provided before the meeting, has been moved to the Regular Agenda.

- Minutes* - Approve
    a. March 3-4, 2020 Critical Infrastructure Protection Committee (CIPC) Meeting*
        i. Note: Need to correct Andy Dodge's affiliation to FERC
    b. March 3-4, 2020 Operating Committee (OC) Meeting*
    c. March 3-4, 2020 Planning Committee (PC) Meeting* - Chair Ford noted that for the PC Minutes, the RSTC is affirming the approval completed by the PCEC in May 2020.
    d. March 4, 2020 RSTC Meeting*
- *Technical Report: BPS-Connected Inverter-Based Resource Modeling and Studies submitted by the IRPTF* – Affirm PCEC Approval

  Chair Ford noted that is an additional item for the Consent Agenda. The PCEC previously approved the Technical Report. Per the RSTC Charter, the RSTC can affirm that approval.
- *Motion to approve the Consent Agenda (minutes only) with correction to CIPC minutes made by Peter Brandien. The motion passed without dissent.*
- *Motion to affirm the PCEC action on the Technical Report made by Brian Evans-Mongeon. The motion passed without dissent.*

Regular Agenda

- State of Reliability Report (SOR) – Endorse – John Moura presented a summary of the SOR.

  Motion to endorse the 2020 SOR was made by John Stephens. The motion passed without dissent.
- Remarks and Reports
    e. Remarks – Greg Ford, RSTC Chair

    Chair Ford thanked Ken DeFontes for his participation and continued support from the Board.

        i. Subcommittee Reports included in agenda package*

        Chair Ford referenced the subgroup reports contained in the Agenda package and asked if anyone had any questions or comments. There was no discussion of the reports. Chair Ford noted that the reports were submitted in the format that was previously done for the CIPC, OC, and PC. In the future, we will develop a consistent reporting template for the RSTC.

ii. System Analysis & Modeling Subcommittee (SAMS) leadership. Per the RSTC Charter, the RSTC Chair appoints subgroup leadership. Chair Ford noted that the SAMS had recommended a chair and vice chair for the group. Chair Ford noted his concurrence and appointed Evan Shuvo as chair and Rajesh Nimbalkar as vice chair, both effective June 1, 2020.

f. Report of May 14, 2020 Member Representatives Committee (MRC) Meeting and Board Meeting

Chair Ford summarized the MRC and Board meetings:

MRC Meeting

iii. The MRC meeting focused on the policy input submitted regarding the Align tool and the ERO Secure Evidence Locker, good discussion and additional input was provided for the Board to consider in advance of its review for approval at the Board of Trustees meeting.

iv. Andy Dodge presented a regulatory update, providing a summary of the actions by FERC in response to the COVID-19 Pandemic, reviewed the order granting deferred implementation of certain NERC Reliability Standards, and delays on certain reliability and security related actions.

v. Lonnie Ratcliff provided a comprehensive presentation on cloud computing in lieu of the panel discussion that was to have occurred during the onsite meeting.

vi. John Moura presented summaries of the findings for both the Summer Reliability Assessment and the State of Reliability Report.

Board Meeting

i. The meeting opened with Jim Robb providing remarks on the COVID-19 ERO Enterprise Response, then Bruce Walker, Assistant Secretary, DOE provide an update on the recent DOE Executive Order and subsequent Task Force.

ii. There were two main approval items the most significant being the approval of the investment and funding strategy for the ERO Secure Evidence Locker and Align Delay costs. The second item was the approval of the Regional Delegation Agreement.

iii. Manny Cancel provided a summary of the actions by the E-ISAC respective to COVID-19.

iv. Chair Ford Ford presented on the RSTC Transition Plan – the presentation was very well received and the incredible work completed by the Transition Team and supported by the committee impressed the Board with Roy Thilly stating it was an extraordinary summary. I thank everyone for their input and look forward to the work of the RSTC and its impact.

v. NERC Board meetings will be via teleconference/WebEx for August 2020.

- RSTC Action Items Review

Vice Chair David Zwergel provided a brief summary of the RSTC Actions Items to date. He noted that several are closed and the remaining action items are on track.

- MOD-025 White Paper

  Shawn Patterson, Chair of the Power Plant Modeling Verification Task Force (PPMVTF) presented an overview of the white paper. The white paper was reviewed by the Planning Committee membership and all comments received by the PPMVTF have been addressed. The PPMVTF is requesting RSTC approval of the white paper and authorization to draft a standard authorization request (SAR) based on the white paper to revise MOD-025.

Question arose regarding the appropriate hand-off between a SAR and a standards drafting team. This is an item for further discussion.

Motion to approve the white paper was made by Carl Turner. The motion passed without dissent. Motion to authorize drafting a SAR based on the white paper was made by Carl Turner. The motion passed without dissent.

- Inverter-based Resources Performance Task Force (IRPTF) SARs

  Chair Ford called on Jeff Billo to present the four SARs developed by the IRPTF.

  g. IRPTF performed a review of all NERC Reliability Standards to identify potential gaps or needed clarifications related to inverter-based resources (IBRs)

  h. All identified issues were documented in the *IRPTF Review of NERC Reliability Standards Whitepaper*: https://www.nerc.com/comm/PC/InverterBased%20Resource%20Performance%20Task%20Force%20IRPT/Review_of_NERC_Reliability_Standards_White_Paper.pdf

  i. The PC and OC approved the whitepaper at their respective March 2020 meetings

  j. Based on the Whitepaper, IRPTF developed four SARs:

  i. **FAC-001-3 and FAC-002-2** should be revised to: (a) clarify which entity is responsible for determining which facility changes are materially modifying, and therefore require study, (b) clarify that a Generator Owner should notify the affected entities before making a change that is considered materially modifying, and (c) revise the term “materially modifying” so as to not cause confusion between the FAC standards and the FERC interconnection process;

  ii. **MOD-026-1** and **MOD-027-1** should either be revised or a new model verification standard should be developed for IBRs since these standards stipulate verification methods and practices which do not provide model verification for the majority of the parameters within an inverter-based resource. For example, the test currently used to comply with MOD-026-1 does not verify the model parameters associated with voltage control behavior during large disturbance conditions;

iii. **PRC-002-2** should be revised to require disturbance monitoring equipment in areas not currently contemplated by the existing requirements, specifically in areas with potential inverter-based resource behavior monitoring benefits;

iv. **VAR-002-4.1** should be revised to clarify that the reporting of a status change of a voltage controlling device per Requirement R3 is not applicable for an individual generating unit of a dispersed power producing resource, similar to the exemption for Requirement R4.

The IRPTF requests that the RSTC endorse all four SARs

A motion to endorse the FAC-001-3 and FAC-002-2 SAR was made by Peter Brandien. Robert Reinmuller seconded. Brian made a motion to revise the motion to have this SAR be tabled and ask the IRPTF to create Implementation Guidance regarding the term "materially modifying". John Stephens seconded this amendment. The revised motion failed 21-8. The original motion carried by 22-7

A motion to endorse the MOD-26-1 and MOD-027-1 SAR was made by Brian Evans-Mongeon. The motion passed without dissent.

A motion to endorse the PRC-002-2 SAR was made by Jeff Harrison. Seconded by Christine. Brian made a motion to revise the motion to have this SAR be tabled and ask the IRPTF to create Implementation Guidance. There was no second so the motion dies. The original motion passed without dissent but with one abstention (Brian).

A motion to endorse the VAR-002-4.1 SAR was made by Robert Reinmuller. The motion passed without dissent.

Chair Ford suggested having the RSTC EC prioritize the SARs we endorsed or authorized today.

- Resources Subcommittee Revised Scope

  Stephen Crutchfield reviewed the revisions to the scope document. The changes were primarily to remove language indicating the chair was a non-voting member and to change the reporting structure indicating that the RS no longer reports to the Operating Committee and now reports to the Reliability and Security Technical Committee.

A motion to approve the revised scope was made by Todd Lucas. The motion passed without dissent.

- Security Guideline: BES Cyber System Information (BCSI) Cloud Encryption

  Marc Child, CIPC Chair presented an overview of the Security Guideline and its development.

  - Education on cloud services and encryption
  - Foundational for understanding compliance complexities
  - Primer for scenario- specific compliance implementation guidance document
  - Approved by Compliance Input Working Group
  - Endorsed by CIPC Executive Committee

A motion to accept Security Guideline was made by Marc Child. The motion passed without dissent.

- Compliance Implementation Guidance: Cloud Solutions and Encrypting BCSI

  Marc Child, CIPC Chair presented an overview the guidance and its development.

  - CIP-004 and CIP-011 guidance
  - Expands on concepts presented in the primer, provides specific guidance on compliance evidence and controls
  - Leverages information gathered through partnerships with cloud providers
  - Exhaustive list of additional vendor-specific reference material
  - Approved by Compliance Input Working Group
  - Endorsed by CIPC Executive Committee

A motion to approve the Compliance Implementation guidance was made by Jody Green. The motion passed without dissent.

- Electromagnetic Pulse Task Force Update

  Chair Aaron Shaw presented and update on Electromagnetic Pulse Task Force (EMPTF) activities.

  Background:

  k. Electromagnetic Pulse (EMP) events may pose a risk to the reliability of the bulk power system (BPS)

  l. In March of 2019, NERC's Board of Trustees (Board) established an EMPTF to identify potential methods for promoting resilience to the EMP threat

  m. In November 2019, the EMPTF report to the Board included recommendations for NERC to address that would help mitigate the risk to the BPS from an EMP event

  EMPTF Recommendations for NERC

  n. Policy recommendations

  i. Establishing BPS performance expectations for a pre-defined EMP event

  ii. Providing industry and public education on EMPs

  iii. Coordination with other Critical Infrastructure sectors on EMP matters

  o. Research recommendations

  iv. Monitoring current research and report on national initiatives

  v. Identification of gaps in research that need to be closed to enable movement toward EMP performance requirements and/or guidelines

  vi. Develop industry specifications for equipment

  p. Vulnerability Assessment Recommendations

vii. Regular collaboration and coordination with Federal Government to procure and effectively disseminate information needed by industry

viii. Development of EMP vulnerability assessment methods and guidelines

ix. Development of guidelines to identify and prioritize hardening of critical assets

q. Mitigation Recommendations

x. Develop Guidance on EMP Mitigation

r. Response and Recovery Recommendations

xi. Establish national EMP notification system

xii. Coordinated response planning

xiii. Enhance operating procedures

xiv. Incorporate EMP events into industry exercises and training

xv. Strategies for supporting recovery

Next Steps:

- Scope document: to focus the EMPTF's efforts on recommendations from the Board report
- EMP Task Force priorities
  - Establish performance expectations
  - Provide guidance on asset hardening
  - Provide guidance to industry for supporting systems and equipment for recovery
- **Membership:** confirm current members will continue to participate and seek additional volunteers
- **Logistics:** schedule meetings and develop work plan documentation
- **NERC Coordinator:** Tom Hofstetter

- RSTC Transition Plan

s. Transition Team Activities

Kayla Messamore reviewed select topics from the Transition Team slides. This includes Governance, Processes and work plan creation. Subgroup Organization

Stephen Crutchfield noted that there were three sub-teams from the transition team that reviewed the CIPC, OC and PC work plans and organizations independently. These reviews were presented to the full transition team and a decision was made to look for more efficiency and effectiveness gains. The transition team is consolidating work plan task items and referencing them to the RISC risks and ERO Strategy items to help in this effort. The TT plans to develop a preliminary recommendation for subgroup structure in mid-to-late July and present it to the full RTSC in a closed session. This initial recommendation will be fully discussed during the September 15, 2020 RSTC meeting.

t. RSTC 2020 Calendar Review – Stephen Crutchfield reviewed the meeting dates below.

2020 Meeting Dates	Time	Location	Hotel
September 15, 2020	1:00 to 4:00 p.m.	Converted to a Call/Webex	None
December 15, 2020 December 16, 2020	1:00 to 5:00 p.m. 8:00 a.m. to 12:00 p.m.	TBD – Based on COVID-19 Guidelines	TBD

- Technical Committees Update

Vice Chair David Zwergel reviewed the actions taken by the CIPC, OC and PC since the March technical committee meetings.

CIPC:

a. Reviewed and submitted comments about the draft State of Reliability Report

b. Endorsed proposed implementation guidance, “Cloud Solutions and Encrypting BES Cyber System Information

c. Endorsed proposed security guideline, “Primer for Cloud Solutions and Encrypting BES Cyber System Information”

OC:

a. Actions since March 3-4, 2020 Meeting

b. Reviewed and submitted comments about the draft State of Reliability Report

c. Endorsed proposed implementation guidance, “Cloud Solutions and Encrypting BES Cyber System Information

d. Endorsed proposed security guideline, “Primer for Cloud Solutions and Encrypting BES Cyber System Information”

PC:

a. Endorsed the 2020 Summer Reliability Assessment

PCEC:

a. Approved March 2020 PC Meeting Minutes

b. Approved the *Technical Report: BPS-Connected Inverter-Based Resource Modeling and Studies* submitted by the IRPTF

c. Reviewed and approved the PC Work Plan with updates from subcommittees, task forces, and working groups

- Forum and Group Reports – Information
    a. North American Generator Forum

       Allen Schriver provided a brief summary of his written report which will be posted with the meeting presentations.

    b. North American Transmission Forum

       Roman Carter referred to his written report included in the agenda package. He noted a few highlights of the NATF work:

       i. Coordinating with NERC/DOE on Pandemic plan – v1 posted on web site.
       ii. Collaborate with regions on higher risk standards
       iii. EPRI/DOE/PNNL – v0 transmission resiliency model

- NERC Compliance

  Lonnie Ratliff provided a brief NERC Compliance update.

  Joint FERC/NERC Whitepaper

    - Why?
        - 2012 House Permanent Select Committee on Intelligence Report
            - Threats posed by foreign telecommunications companies
        - 2020 Executive Order on Securing US Bulk Power System
            - May 1, 2020
    - What?
        - Whitepaper to identify Network Interface Controllers
            - Malicious vendors
            - Others?
    - Who?
        - Compliance Input Work Group (CIWG) reviewed / provided input
        - CIWG possibly modify for industry

Next Steps:

- CIWG update whitepaper
- CIWG identify volunteer participants to:
    - Assess networks
    - Coordinate data collection
    - Sanitize data

    - Provide some type of sanitized analysis report to NERC/FERC

- Maintain document going forward?
    - Other?
- Chair's Closing Remarks/Adjournment

  Chair Ford thanked everyone for their participation. He noted that all discussions are appreciated and helpful for the actions taken by the committee today. Apologies for changes to materials and not getting them out early as we had hoped.

There being no further business before the RSTC, Chair Ford adjourned the meeting on Wednesday, June 10, 2020 at 4:25 p.m. Eastern.

Next Meeting
The RSTC will meet September 15, 2020 via webinar.

Stephen Crutchfield
Stephen Crutchfield
Secretary

Meeting Minutes
Reliability and Security Technical Committee

July 28, 2020

Webinar

A closed meeting of the NERC Reliability and Security Technical Committee (RSTC) was held on July 28, 2020, via webinar. The meeting agenda and the attendance list are affixed as **Exhibits A** and **B**, respectively.

RSTC Chair Greg Ford convened the meeting at 3:00 p.m. Eastern on Tuesday, July 28, 2020. Tina Buzzard, NERC staff, reviewed the procedures for the meeting, read the Antitrust Compliance Guidelines and confirmed quorum for the RSTC membership.

Introductions and Chair's Remarks

Chair Ford noted that the meeting today was to review the proposed organization of the RSTC that was developed by the transition team. Chair Ford reminded attendees to look around their office and evaluate actions in case of emergency. He noted that safety is always a priority.

Regular Agenda

- **RSTC Organizational Review Update and Recommendation** – Chair Ford reviewed the proposed organizational operating model and recommendation. The RSTC members asked questions regarding program areas, sponsors and the proposed elimination of the System Analysis and Modeling Subcommittee. At the conclusion of the discussion the Committee generally accepted the direction of the operating model but requested that the proposal be further enhanced with the recommendations from the discussion and brought back to the Committee for review at its September 15, 2020 meeting.

  In addition, RSTC Executive Committee members will reach out to Chairs of those subgroups that would be affected by the new organizational changes to ensure awareness prior to the presentation of the proposed organizational operating model and recommendations at the open, public meeting of the NERC Board of Trustees on August 20.

- **Chair's Closing Remarks/Adjournment -** Chair Ford thanked everyone for their participation and discussion.

There being no further business before the RSTC, Chair Ford adjourned the meeting on Tuesday, July 28, 2020 at 4:25 p.m. Eastern.

Next Meeting
The RSTC will meet September 15, 2020 via webinar.

Stephen Crutchfield

Stephen Crutchfield
Secretary

Agenda Item 4a
Reliability and Security Technical
Committee Meeting
September 15, 2020

Power Plant Modeling and Verification Task Force
SAR for the Revision of MOD-025-2

Action
Approve

Summary
The PPMVTF prepared a white paper documenting issues with MOD-025-2, concluding that the stated purpose of ensuring that accurate information on generator gross and net Real and Reactive Power capability and synchronous condenser Reactive Power capability is available for planning models used to assess Bulk Electric System (BES) reliability, is not being met by the standard. The PPMVTF recommends in the white paper that a SAR be drafted for the modification of MOD-025-2 and a standard drafting team be created to correct these issues.

The RSTC approved the white paper and authorized PPMVTF to draft a SAR for the revision of MOD-025-2 at their June 10, 2020 meeting. The task force has subsequently prepared a SAR that aligns with the white paper findings and is seeking RSTC approval to submit the SAR to the Standards Committee.

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:	MOD-025-2 Verification and Data Reporting of Generator Capability		
Date Submitted:	MM/DD/YYYY		
SAR Requester			
Name:	Shawn Patterson, Chair		
Organization:	NERC Power Plant Modeling Verification Task Force (PPMVTF)		
Telephone:	303-445-2311	Email:	spatterson@usbr.gov

SAR Type (Check as many as apply)

- ☐ New Standard
- ☒ Revision to Existing Standard
- ☐ Add, Modify or Retire a Glossary Term
- ☐ Withdraw/retire an Existing Standard
- ☐ Imminent Action/ Confidential Issue (SPM Section 10)
- ☐ Variance development or revision
- ☐ Other (Please specify)

Justification for this proposed standard development project (Check all that apply to help NERC prioritize development)

- ☐ Regulatory Initiation
- ☐ Emerging Risk (Reliability Issues Steering Committee) Identified
- ☐ Reliability Standard Development Plan
- ☒ NERC Standing Committee Identified
- ☐ Enhanced Periodic Review Initiated
- ☐ Industry Stakeholder Identified

Industry Need (What Bulk Electric System (BES) reliability benefit does the proposed project provide?):

The current industry need for this standards project is that industry implementation of MOD-025-2 has not resulted in useful unit capability data being provided for planning models of generating resources and synchronous condensers (i.e., the purpose statement of the standard). The primary reliability benefit of this project will be to correct these issues such that suitable and accurate data can be established through the verification activities performed by respective equipment owners. BPS planning assessments rely on accurate data, including machine active and reactive power capability, to identify potential reliability risks and develop mitigating actions for those risks.

The current MOD-025-2 verification testing activities require significant time, expertise, and coordination; however, they do not result in data that should be used by planners for modeling purposes. The current standard does allow for optional calculations to be performed to help facilitate better information sharing; however, calculations are not required nor can be used in many cases when auxiliary equipment limits or system operating conditions prohibit reaching the actual machine capability or limiters. This standards project will address these issues.

Requested information
Other benefits of this standards project to address issues with MOD-025-2 include, but are not limited to, the following: • Preventing over- or under-estimation of generating facility active and reactive power, which could lead to potential reliability risks or unnecessary and expensive solutions to mitigate • Identifying limitations within a generating facility that could constrain the resource from reaching the expected active/reactive capability at any given time • More clearly communicating the necessary data to be used for modeling the respective resources in steady-state power flow models • Ensure that the data users are part of the verification process to ensure that the necessary and usable data is provided and utilized appropriately • Ensure that raw test data alone is not used for resource modeling, but is analyzed, adjusted, and contextualized to account for measured system conditions • Coordinating with PRC-019 activities to develop a composite capability curve, inclusive of equipment capabilities, limiters, and other plant limitations to develop an appropriate capability curve • Ensuring that other means of verification (other than testing) can be more effectively leveraged to gather necessary and suitable data for verifying plant/machine capability
Purpose or Goal (How does this proposed project provide the reliability-related benefit described above?):
The intent of this standard revision project is to address the issues that exist with MOD-025-2 regarding verification and data reporting of generator active and reactive power capability (and any other relevant equipment capability). Currently, implementation of the standard rarely produces data that is suitable for planning models (i.e., the stated purpose of the standard). The vast majority of testing cases are limited by limits within the plant or system operating conditions that prohibit the generating resource from reaching its “composite capability curve” – the equipment capability or associated limiters. The goal of the proposed project is to: • Ensure that testing and other verification activities produce useful data for verification of plant active and reactive power capability • Ensure that the data is used by Transmission Planners and Planning Coordinators in an appropriate manner, with a sufficient degree of analysis prior to use • Ensure that the data is applicable and usable by the Transmission Planner and Planning Coordinator for reliability studies • Ensure Generator Owners appropriately identify limits within their generating resources (and synchronous condensers), and effectively communicate those limits to Transmission Planners and Planning Coordinators for the purposes of modeling these resources in reliability studies
Project Scope (Define the parameters of the proposed project):
The scope of this project is to modify MOD-025-2 to ensure that data provided through verification activities performed by applicable Generator Owner or Transmission Owners produce suitable data for

Requested information
the purposes of developing accurate planning models in Transmission Planner and Planning Coordinator reliability studies. The project should consider, at a minimum, the following: 1. Revisions to MOD-025-2 to ensure that verification activities produce data and information that can be used by Transmission Planners and Planning Coordinators for the purposes of developing accurate and reasonable plant active and reactive capability data (including possibly representation of the "composite capability curve" inclusive of capability and limiters, where applicable). 2. Ensure that each Planning Coordinator and the area Transmission Planners develop requirements for the Planning Coordinator area real and reactive capability data verification 3. Ensure that Generator Owners provide the data specified by the Planning Coordinator and Transmission Planners for the Planning Coordinator area 4. Ensure that verification activities can apply other methods beyond only testing (or real-time data) that allow plant capability information, protection settings, PRC-019 reports, and other documentation to also complement the verification activities 5. Ensure that data provided by the applicable Generator Owners and Transmission Owners is analyzed and used appropriately by Transmission Planners and Planning Coordinators 6. Ensure that the data provided by Generator Owners, if different from tested values, is acceptable to the Planning Coordinator and Transmission Planners with the standard providing guidance on acceptable reactive capability reporting if system conditions prevent reaching actual capability. 7. Ensure alignment of the MOD-025 standard with MOD-032-1 regarding data submittals for annual case creation and PRC-019-2 regarding collection of information that can be effectively used for verification purposes. Ensure activities across standards can be applied to effectively meet the purpose of these standards, and avoid any potential overlap or duplication of activities. This is dependent on the success of bullet number 1. 8. Ensure that equipment limitations are documented and classified as expected (e.g., system voltage limit reached) or unexpected (e.g., plant tripped or excitation limiter reached unexpectedly). In cases of unexpected limitations reached, ensure that the equipment owner develops and implements a corrective action plan to address this unexpected limitation.
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):
The NERC PPMVTF developed *White Paper: Implementation of NERC Standard MOD-025-2*[2] that recommends NERC initiate a standards project to address these issues with MOD-025-2. The white paper provides a detailed description and technical justification of the gaps that exist in MOD-025-2 and

[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.

[2] https://www.nerc.com/comm/PC/Power%20Plant%20Modeling%20and%20Verification%20Task%20Force/PPMVTF_White_Paper_MOD-025_Testing.pdf

Requested information
how the current standard may be leading to inaccurate data being used in BPS reliability studies. Further, the NERC PPMVTF *Reliability Guideline: Power Plant Model Verification and Testing for Synchronous Machines*[3] also describes in detail how testing activities per MOD-025-2 can lead to unusable data, and provides further guidance that a SDT could use to develop solutions to these issues.
Cost Impact Assessment, if known (Provide a paragraph describing the potential cost impacts associated with the proposed project):
The aforementioned NERC PPMVTF *White Paper: Implementation of NERC Standard MOD-025-2* includes an example of one Registered Entity's MOD-025 implementation costs (excluding cost of shifting the optimization of generation fleet assets due to minimum load testing requirements). The entity's average test cost was $1,259 (897 tests) and $4,326 per generator (261 generators). The verification testing of units generally results in transferring energy to a higher cost resource during the test period. Further, the data produced is often NOT suitable for planning studies, which does not serve the intended purpose of the standard and makes the added cost unjustified.
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 current MOD-025-2 was written around synchronous generation, although it is not specifically applicable only to synchronous generators. Therefore, the project should ensure the language is clear and concise regarding how to handle BES dispersed generating resources (e.g., wind, solar photovoltaic, and battery energy storage systems).
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):
• Generator Owner and Transmission Owner of synchronous condensers (asset owner that is in the best position to ascertain resource capability) • Transmission Planner and Planning Coordinator (user of the information provided by the Generator Owner; currently has no responsibility of ensuring accurate data per current MOD-025-2 standard)
Do you know of any consensus building activities[4] in connection with this SAR? If so, please provide any recommendations or findings resulting from the consensus building activity.
The NERC PPMVTF White Paper, approved by NERC RSTC, details the challenges with MOD-025-2. The team deliberated this subject for a significant amount of time, and have identified major issues with the standard that need to be addressed by an SDT. The PPMVTF believes that a significant revision to MOD-025-2 is needed, that testing activities are useful and should be retained, but that the activities can

[3] https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability_Guideline_-_PPMV_for_Synchronous_Machines_-_2018-06-29.pdf
[4] 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
focus on more effective means of collecting useful data for planning models. One dissenting opinion of PPMVTF membership believed the standard should be retired completely and not replaced with an alternative.
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 NERC standards development Project 2020-02 (Transmission-connected Dynamic Reactive Resources) SAR includes MOD-025-2, specifically addressing the applicability of transmission connected reactive devices in addition to generators and synchronous condensers. The SAR on PRC-019-2 submitted to NERC by the System Protection and Control Subcommittee is also related in that there is significant overlap of activities in PRC-019-2 and the development of planning models of machine capability. This SAR could be combined with those portions of those SARs to address this problem effectively.
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 are two key industry reference documents on this subject: 1. NERC *Reliability Guideline: Power Plant Model Verification and Testing for Synchronous Machines*[5] (July 2018) that provides recommended practices for synchronous machine capability testing. An appendix is devoted to MOD-025-2 testing, and highlights the challenges and inherent errors in MOD-025-2 to obtain useful data that can be applied for planning models. 2. NATF *Modeling Reference Document Reporting and Verification of Generating Unit Reactive Power Capability for Synchronous Machines*[6] (April 2015) that describes testing activities per MOD-025-2 and means of ensuring data is sufficient for planning studies. Neither industry reference document addresses the identified shortcomings of the standard described above and in NERC PPMVTF *White Paper: Implementation of NERC Standard MOD-025-2*.[7] These reference materials help industry understand how to implement the standards using best practices, but do not address the reliability gaps created by the standard requirements themselves which is leading to inaccurate data being used in planning assessments.

5 https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability_Guideline_-_PPMV_for_Synchronous_Machines_-_2018-06-29.pdf
6 https://www.natf.net/docs/natf/documents/resources/planning-and-modeling/natf-reference-document-reporting-and-verification-of-generating-unit-reactive-power-capability-for-synchronous-machines.pdf
7 https://www.nerc.com/comm/PC/Power%20Plant%20Modeling%20and%20Verification%20Task%20Force/PPMVTF_White_Paper_MOD-025_Testing.pdf

Reliability Principles	
Does this proposed standard development project support at least one of the following Reliability Principles (Reliability Interface Principles)? Please check all those that apply.	
☒	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☐	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
☒	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
☐	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.
☐	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.
☐	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☐	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.
☐	8. Bulk power systems shall be protected from malicious physical or cyber attacks.

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

Identified Existing or Potential Regional or Interconnection Variances	
Region(s)/ Interconnection	Explanation
N/A	None identified.

For Use by NERC Only

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

Version History

Version	Date	Owner	Change Tracking
1	June 3, 2013		Revised
1	August 29, 2014	Standards Information Staff	Updated template
2	January 18, 2017	Standards Information Staff	Revised
2	June 28, 2017	Standards Information Staff	Updated template
3	February 22, 2019	Standards Information Staff	Added instructions to submit via Help Desk
4	February 25, 2020	Standards Information Staff	Updated template footer

Revisions to PRC-023-4 – Transmission Relay Loadability

Action

Endorse

Background

The SPCS developed a PRC-023-4 SAR and requested NERC Planning Committee review in December 2018. The SAR was revised based on the comments.

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

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

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Standard Authorization Request (SAR)

Complete and please email this form, with attachment(s) to: sarcomm@nerc.net

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:	Revisions to PRC-023-4		
Date Submitted:	February XX, 2020		
SAR Requester			
Name:	Jeff Iler, Chair & Bill Crossland, Vice Chair (on behalf of)		
Organization:	NERC System Protection and Control Subcommittee		
Telephone:	Jeff: (614) 933-2373 Bill: (216) 503-0600	Email:	Jeff: jwiler@aep.com Bill: bill.crossland@rfirst.org
SAR Type (Check as many as apply)			
☐ New Standard ☒ Revision to Existing Standard ☐ Add, Modify or Retire a Glossary Term ☐ Withdraw/retire an Existing Standard		☐ Imminent Action/ Confidential Issue (SPM Section 10) ☐ Variance development or revision ☐ Other (Please specify)	
Justification for this proposed standard development project (Check all that apply to help NERC prioritize development)			
☐ Regulatory Initiation ☐ Emerging Risk (Reliability Issues Steering Committee) Identified ☐ Reliability Standard Development Plan		☒ NERC Standing Committee Identified ☐ Enhanced Periodic Review Initiated ☐ Industry Stakeholder Identified	
Industry Need (What Bulk Electric System (BES) reliability benefit does the proposed project provide?):			
Requirement R2, in PRC-023-4, requires applicable functional entities to set their Out of Step Blocking[1] (OOSB) elements to allow tripping for faults during the loading conditions prescribed by Requirement R1. A requirement to allow tripping in a Standard whose intent is to block tripping, has led to some entities disabling their OOSB relays. Disabling of these relays could lead to tripping during stable power swings causing an increased reliability risk. OOSB relays provide increased security by preventing relays from tripping for stable power swings. Preventing the tripping of transmission lines during these types of disturbances increases the reliability of the BES. Requirement R2 should be removed because it has been interpreted to restrict the setting of OOSB elements making compliance with PRC-026 more difficult. Attachment A exclusion 2.3 should also be removed. This exclusion is no longer needed and that exclusion has contributed to the confusion surrounding R2. Attachment A exclusion 2.3 has been			

[1] The term power swing blocking (PSB) is also used by industry to describe these elements

Requested information
interpreted as being in conflict with R2. Both R2 and Attachment A exclusion 2.3 are not needed in the Standard.
Purpose or Goal (How does this proposed project provide the reliability-related benefit described above?):
The purpose of the proposed project provides a reliability-related benefit by eliminating PRC-023-4 Requirement R2. This will eliminate entities disabling their OOSB elements unnecessarily. It will remove an unnecessary exclusion (Attachment A – 2.3) for relays that no longer need an exclusion.
Project Scope (Define the parameters of the proposed project):
The scope includes: • Retire Requirement R2. • Remove Attachment A, Item 2.3 exclusion with regard to the use of protection systems during stable power swings. • Make comporting changes to the standard as needed to address the retirement of Requirement R2 and to remove Attachment A, Item 2.3 exclusion. • Ensure that removing the Item 2.3 exclusion does not overlap or create a gap with intent of PRC-026 – Relay Performance During Stable Power Swings. • Making any administrative non-substantive corrections. • Modify the Supplemental Technical Reference Document, "Determination and Application of Practical Relaying Loadability Ratings Version 1", referenced in PRC-023-4, as needed to address the retirements and removal. Specifically, the Out of Step Blocking section.
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):
The PRC-023 standard is about setting protective relays so they do not limit transmission loadability, meaning they do not trip unnecessarily during heavy loading conditions while still being capable of detecting all fault conditions.[3] The intent of Requirement R2 is to ensure out-of-step blocking (OOSB) elements allow tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability. Requirement R2 is about ensuring OOSB elements allow blocked relay elements to trip reliably (i.e., if a three-phase fault occurs while OOSB is asserted) and not about ensuring protection systems do not limit transmission loadability. OOSB elements differentiate between power swings and three-phase faults. During a power swing, a OOSB element will typically block phase distance elements (i.e., Zone 1 & Zone 2 phase distance elements) from tripping. According to Requirement R2, a OOSB element must unblock the blocked phase distance elements for faults that occur

[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.

[3] PRC-023-4, Purpose: "Protective relay settings shall not limit transmission loadability; not interfere with system operators' ability to take remedial action to protect system reliability and; be set to reliably detect all fault conditions and protect the electrical network from these faults."

Requested information
during the loading conditions used to set the protective relay under Requirement R1. Also in the standard, Attachment A, Item 2.3 excludes protection systems intended for protection during stable power swings and is seen as contradictory with Requirement R2 because these protection systems are associated with the use of OOSB elements, whose primary purpose is to ensure phase distance elements don't trip during stable power swings. The apparent intent of Requirement R2 is to ensure that OOSB elements don't pick up, time out, and block distance elements from tripping for three-phase faults during the loading conditions described in Requirement R1. The protection engineer must ensure reliable fault protection and has various tools in modern microprocessor based relays to ensure the dependable unblocking of tripping elements during faults. Applying the loadability criteria while ensuring reliable fault protection is already an underpinning of Requirement R1.[4] For example, an engineer can apply the use of override timers[5] that are available in modern microprocessor relays or can add such timers to existing electromechanical relay elements. An engineer can also use advanced microprocessor-based zero-setting OOSB algorithms. Applying the loadability criteria to relay settings under Requirement R1 somewhat meets the intent of Requirement R2 because Requirement R1 mandates not limiting transmission loadability while maintaining reliable protection of the Bulk Electric System for all fault conditions. Additionally, Requirement R2 restrictively dictates the boundary setting of the OOSB element that starts the OOSB timer which has the overall effect of reducing the slip rate for which the OOSB element will correctly block. This results in decreasing the security of the protection scheme and increasing the chance that a misoperation of a distance element will occur for power swings that are faster than the allowable slip rate. Requirement R2 also impacts the ability to comply with NERC Reliability Standard PRC-026 (Relay Performance During Stable Power Swings) in that it affects the application of OOSB relaying that is integral to the purpose of PRC-026, which is "[t]o ensure that load-responsive protective relays are expected to not trip in response to stable power swings during non-Fault conditions". Attachment A, 2.3 was included for protection systems that intentionally trip during power swing disturbances, such as intentional islanding schemes. Florida was cited as an example of where these schemes were employed. Research has indicated that these schemes no longer exist and there is no need for a power swing tripping exclusion. Requirement R2 was added to PRC-023 in version 2 after filing version 1 with FERC.[6] FERC observed that Attachment A item 2 in PRC-023-1 was a requirement and that it needed to be included in the requirements section of a standard with the appropriate violation risk factors and violation severity levels.

[4] PRC-023-4, "R1. Each Transmission Owner, Generator Owner, and Distribution Provider shall use any one of the following criteria (Requirement R1, criteria 1 through 13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability **while maintaining reliable protection of the BES for all fault conditions**. Each Transmission Owner, Generator Owner, and Distribution Provider shall evaluate relay loadability at 0.85 per unit voltage and a power factor angle of 30 degrees."
[5] OOSB relays with override timers will allow the OOSB blinder that starts the timer to be set beyond the loadability region prescribed by the standard. The OOSB relay would unblock after a predetermined delay should an unlikely three-phase fault occur.
[6] See FERC Order 733 para 244 https://www.ferc.gov/whats-new/comm-meet/2010/031810/E-5.pdf

Requested information
The original SDT included the "warning" in Attachment A item 2, with regards to OOSB, in reference to the OOSB timer. Some OOSB schemes employ an outer and an inner impedance blinder with a timer that is used to determine the rate of change of apparent impedance to differentiate between a fault (fast change) and a swing (slow change). The timer starts timing when the impedance passes through (is less than) the outer blinder. If the impedance does not pass through the inner blinder (is less than), before the timer setting, the OOSB will declare a swing and block the phase distance elements from tripping. The SDT wanted to inform entities that they could experience loading conditions that would result in an impedance that was between the OOSB blinders for a long period of time that would result in the blocking of the phase tripping elements indefinitely. This condition could exist at any time regardless of a relay loadability requirement. Therefore, this should not be a requirement associated with PRC-023. It is good engineering practice to ensure your relays will operate properly for all conditions they are expected to experience. This should not be a requirement in a relay loadability Standard. OOSB elements are included in the Relay Performance During Stable Power Swings Standard PRC-026-1. PRC-026-1 already includes the language "while maintaining dependable fault detection" in regards to OOSB supervision. Attachment A item 2.3 excludes "Protection systems intended for protection during stable power swings". This exclusion is referencing "Protection systems installed specifically to separate portions of the system that are experiencing stable power swings relative to each other in order to maintain desirable performance relative to voltage, frequency, and power oscillations"[7]. These Out of Step Tripping (OOST) protection systems are better addressed in the standard for power swings, PRC-026.
Cost Impact Assessment, if known (Provide a paragraph describing the potential cost impacts associated with the proposed project):
Should reduce cost to Registered Entities by eliminating the compliance monitoring of a requirement that is addressed by another standard. Revising the exemption should not have a significant impact on cost.
Please describe any unique characteristics of the BES facilities that may be impacted by this proposed standard development project (*e.g*. Dispersed Generation Resources):
Transmission facilities that use OOSB functionality and that experience significant oscillations (i.e., power swings) has the benefit of ensuring the system remains intact where separation of portions of the transmission system could occur due to power swings.
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 Owner, Generator Owner, and Distribution Provider

[7] See Project 2010-13.1 Phase 1 of Relay Loadability: Transmission Draft 1 Relay Loadability Standard Consideration of Comments https://www.nerc.com/pa/Stand/Project%202010131%20Phase%201%20of%20Relay%20Loadability%20Trans/Consider_Comments_1st_Draft_Relay_Loadability_Std_09Jan07.pdf

Requested information
Do you know of any consensus building activities[8] in connection with this SAR? If so, please provide any recommendations or findings resulting from the consensus building activity.
N/A
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)?
PRC-026 – Relay Performance During Stable Power Swings (Note: Project 2015-09 – Establish and Communicate System Operating Limits is proposing modifications to PRC-026 due to revisions to the definition of System Operating Limit).
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.
N/A

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

[8] 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	
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
N/A	

For Use by NERC Only

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

Version History

Version	Date	Owner	Change Tracking
1	June 3, 2013		Revised
1	August 29, 2014	Standards Information Staff	Updated template
2	January 18, 2017	Standards Information Staff	Revised
2	June 28, 2017	Standards Information Staff	Updated template

Reliability Guideline: Gas and Electrical Operational Coordination Considerations

Action
Authorize posting for 45-day public comment period.

Background
Reliability Guideline: Gas and Electrical Operational Coordination Considerations was approved by the NERC Operating Committee on December 13, 2017. Coordination of operations between the gas and electric industries has become increasingly important over the course of the last decade. The electric power sector's use of gas, specifically natural gas-fired generation, has grown exponentially in many areas of North America due to increased availability of gas, potentially more competitive costs in relation to other fuels and a move throughout the industry to lower emissions to meet environmental goals. With increased growth in gas usage comes greater reliance and associated risk due to the dependency that each industry now has on the other. The operational impact of these dependencies requires gas and electric system operators to actively coordinate planning and operations. The goal of the coordination is to ensure that both the gas and electric systems remain secure and reliable during normal, abnormal and emergency conditions.

Per the RSTC Charter, all Reliability Guidelines are to be reviewed on a three-year cycle.

Summary
The Reliability Guideline: Gas and Electrical Operational Coordination Considerations was approved by the NERC Operating Committee on December 13, 2017. Per the RSTC Charter, all Reliability Guidelines are to be reviewed on a three-year cycle. The Operating Reliability Subcommittee and Electric-Gas Working Group will coordinate a comment period, review and update for the Reliability Guideline. These two groups are seeking authorization to post the document for a 45-day public comment period.

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Reliability Guideline

Gas and Electrical Operational Coordination Considerations

Applicability:

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

Preamble

It is in the public interest for the North American Electric Reliability Corporation (NERC) to develop guidelines that are useful for maintaining or enhancing the reliability of the Bulk Electric System (BES). The Technical Committees of NERC- the Operating Committee (OC), the Planning Committee (PC) and the Critical Infrastructure Protection Committee (CIPC) – are, per their charters authorized by the NERC Board of Trustees (Board) to develop Reliability (OC and PC) and Security (CIPC) Guidelines. Guidelines establish voluntary codes of practice for consideration and use by BES users, owners, and operators. These guidelines are developed by the technical committees and include the collective experience, expertise and judgment of the industry. Reliability guidelines do not provide binding norms or create parameters by which compliance to standards is monitored or enforced. While the incorporation and use of guideline practices is strictly voluntary, the review, revision, and development of a program using these practices is strongly encouraged to promote and achieve the highest levels of reliability for the BES. Nothing in this guideline negates obligations or requirements under an entity's regulatory framework (local, state or federal) and all parties must take those requirements into consideration when developing any of the guidance detailed herein.

Background and Purpose

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

Guideline Content:

A. Establish Gas and Electric Industry Coordination Mechanisms

B. Preparation, Supply Rights, Training and Testing

C. Establish and Maintain Open Communication Channels

D. Intelligence and Situational Awareness

E. Summary

A. Establish Gas and Electric Industry Coordination Mechanisms

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

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

- Exchanging real-time operating information in both verbal and electronic forms (e.g., pipeline company informational postings) of actual operating conditions on specific assets on specific pipelines.

- Outage planning for elements of significance to include sharing detailed electric and gas asset scheduling information on all time horizons and coordinating outages of those assets to ensure reliability on both the gas and electric systems. This coordination should include if possible face-to-face coordination meetings.

- Sharing normal, abnormal and emergency conditions in real-time and ensuring each entity understands the implications to their respective systems. This should include gas and electric entities proactively reaching out to the operators of stressed gas systems to discuss the impacts, adverse or otherwise, of their expected or available actions. Under extreme gas system operating conditions, understand the direct impacts to electric generation assets when gas pipelines are directed under force majeure conditions.

- The sharing of non-public operating information between the electric operating entity and LDC, intrastate pipelines, and gathering pipelines is not covered under FERC Order 787. For this reason, individual communication and coordination protocols should be considered with each LDC and intrastate pipelines within the footprint of the operating entity. Understanding the conditions under which an LDC or intrastate pipeline would interrupt gas-fired generation is of particular importance and incorporating this information into operational planning will assist in identification of potential at-risk generation. Setting up electronic/email alerts from each LDC or intrastate pipeline as to the potential declaration of interruptions is one key means of real time identification of potential loss of generation behind the LDC city gate or meter station on an intrastate pipeline.

- Coordinating Procurement Time Lines

  - Operating entities may want to consider changing next day operating plan scheduling practices to align more efficiently with gas day procurement cycles. The gas and electric industries operate on differing timelines for the Day Ahead planning processes and in real-time, with the electric day on a local midnight to midnight cycle. The gas industry process operates on a differing timeline with the operating day beginning at 9 a.m. Central Clock Time and uniform throughout North America. This difference in operating days can lead to inefficient scheduling of natural gas to meet the electric day demands. In many instances throughout North America, the electric industry has moved the development and publishing of unit commitments and next day operating plans in order to ensure that generation resources have the ability to procure and nominate natural gas more efficiently to better meet the scheduling timelines of the gas industry. In addition, the gas industry has adjusted some of its nomination and scheduling practices to allow for more efficient scheduling that meets the needs of the electric system. Coordinating and modifying scheduling practices using more effective time periods may allow for a higher level of pipeline utilization, but more importantly, may provide the early identification of constraints that could require starting gas generation with alternate fuels, or using non-gas-fired facilities for fuel diversity to meet the energy and reserve needs of the electric system.

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

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

B. Preparation, Supply Rights, Training and Testing

- Assessments
  - Preparing the gas and electric system for coordinated operations benefits from up front assessments and activities to ensure that when real-time events occur, the system operators are prepared for and can effectively react. Preparation activities that may be considered include the following:
    - Developing a detailed understanding of where and how the gas infrastructure interfaces with the electric industry including:
      - Identifying each pipeline (interstate and intrastate) that operates within the electric footprint and mapping the associated electric resources that are dependent upon those pipelines.
      - Identifying the level and quantity of pipeline capacity service (firm or interruptible; primary/secondary) and any additional pipeline services (storage, no-notice, etc.) being utilized by each gas-fired generator.
      - Developing a model of and understanding the non-electric generation load that those pipelines and LDCs serve and will protect when gas curtailments are needed.
      - Identifying gas single element contingencies and how those contingencies will impact the electric infrastructure. For instance, although most gas side contingencies will not impact the electric grid instantaneously, they can be far more severe than electric side contingencies over time because gas side contingencies may impact several generation facilities. When identifying gas system contingencies, the electric entity should consider what the gas operator will do to secure its firm customers. This could include the potential that the gas system will invoke mutual aid agreements with other interconnected pipelines and this may involve curtailment of non-firm electrical generation from the non-impacted pipeline to aid the other.
      - Understanding how gas contingencies may interact with electric contingencies during a system restoration effort.
      - An additional example of appropriate actions to consider as part of the assessment phase of preparation is provided as a Natural Gas Risk Matrix[1].
- Emergency Procedure Testing and Training
  - Consider the development of testing and training activities to recognize abnormal gas system operating conditions and to support extreme gas contingencies such as loss of compressor stations, pipelines, pipeline interconnections, large LNG facilities, which can result in multiple generator losses over time. Particular attention should be focused on any gas related contingency that may result in an instantaneous generation loss.

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

  - Consider the addition of electric and natural gas coordination and interdependencies training to educate and exercise RCs, BAs, TOPs, and GOPs during potentially adverse natural gas supply disruptions.
  - If voltage reduction capability exists within your area, practical testing and training should be considered as part of seasonal or annual work plans.
  - The use of manual firm load shedding may be required for beyond criteria extreme gas and or electric contingencies. Consideration should be given to practicing the use of manual load-shedding in a simulated environment. These simulations should also be used as part of recurring system operator training at a minimum. The use of tabletop exercises can be a valuable training aid, but wherever possible, consideration should be given to using an advanced training simulator that employs the same tools the operators would use to accomplish the load shedding tasks.
  - Consider the development of and drill on internal communication protocols specific to potential natural gas interruptions.
- Generator Testing
  - Consideration should be given to adopting generator testing requirements for dual fuel auditing. Some items to consider when establishing a dual fuel audit program are:
    - How often should the audits be conducted and under what weather and temperature conditions.
    - Verify sufficient alternate fuel (e.g., fuel oil) inventory to ensure required generation response and output. As part of this assessment, ensure that the stored fuel is fully burnable as well since the full volume of the tank may not be pumpable at very low inventories.
    - Capacity reductions on alternate fuels.
    - Understanding the exact time it takes to startup, switch to alternate fuel, ramp to and operate at full capacity, ramp down and resource shut down. Additional consideration should be given for those assets which require a shutdown in order to swap to an alternate fuel source.
    - The operating entity should consider any environmental constraints the generator under test must meet in order to swap to and operate on the alternate fuel.
- Capacity and Energy Assessments
  - Consideration should be given to the development of forward looking capacity analyses with which the electric industry is familiar but applying the impacts of fuel restrictions that may occur due to pipeline constraints or other fuel delivery constraints such as LNG shipments or liquid fuel delivery considerations. In order to conduct these types of assessments, the analysis needs to consider the LDC loads within the region. The weather component of the assessment should consider normal, abnormal and extreme conditions (i.e., Gas Design Day, which is the equivalent to the highest peak that the pipeline was designed for). This capacity assessment can be on several time horizons including; Real-time, Day Ahead, Month Ahead and Years into the future.

These assessments should consider pipeline maintenance, known future outages, construction and expansion activities as well as all electric industry considerations, including known or potential regulatory changes, which are normally analyzed.

- In addition to a capacity assessment that represents only a single point in time, consideration should be given to the development of a seasonal, annual or multiannual energy analysis that uses fuel delivery capability/limitations as a component. Such assessments can be scenario based, simulate varied weather conditions over the course of months, seasons and/or years, and consider the same elements as discussed in the capacity analysis. The output of the assessments should determine whether there is the potential for unserved energy and/or determine the ability to provide reserves over the period in question.

- Winter Readiness Reviews
  - Recent system events have magnified the need to ensure that seasonal awareness and readiness training is completed within the electric industry including System Operators, Generator Operators and Transmission Operators. Seasonal readiness training for winter weather could include reviews and training associated with dual fuel testing, emergency capacity and energy plans, weather forecasts over the seasonal period, fuel survey protocols and storage readiness. Other areas that require attention in winter readiness reviews include reviewing and setting specific operational expectations on communications protocols. Finally, any winter readiness seminars should include individual generator readiness such as ensuring adequate fuel arrangements are in place for unit availability, adequate freeze protection guidelines are in place, understanding access to primary and secondary fuels and testing to switch to alternate fuels, ensuring all environmental permitting is in place for the fuel options available to the asset, and making sure that the Balancing and Transmission Operators are kept apprised of the unit availability.
- Extreme Weather Readiness Reviews
  - Seasonal readiness reviews for extreme summer weather events (e.g., Gulf of Mexico hurricane) could include response to potential natural gas supply limitations and corresponding decreases in natural gas deliveries that may impact electric generation. Many of the same benefits as winter readiness exercises can be realized with the added benefit of exercises under summer operating conditions when electric loads are higher than winter loads.

C. Establish and Maintain Open Communication Channels

- Industry Coordination
  - In the long and short term planning horizons, regularly scheduled meetings between the gas and electric industries should be held to discuss upcoming operations including outage coordination, industry updates, project updates and exchange of contact information.
  - Operating entities should consider the development of a coordinated and annually updated set of operational and planning contact information for both the gas and electric industries. This information should include access to emergency phone numbers for management contacts as

well as all control center real-time and forecaster desks for use in normal, abnormal and emergency conditions.

- Gas and Electric emergency communication conference call capability should be considered between the industries such that operating personnel can be made available from both industries immediately, including off hours and within the confines of the individual confidentiality provisions of each entity. Electric sector personnel should periodically monitor pipeline posted information and notices.

- Emergency Notifications to Stakeholders
  - Operating Entities may want to consider proactive notifications to stakeholders of abnormal and or emergency conditions on gas infrastructure to ensure widespread situational awareness and obligations associated with dispatch relationships in the electric sector. An example of a notification used for generators in New England appears below:

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

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

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

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

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

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

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

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

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

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

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

While these types of efforts are still in their infancy they should be explored depending upon the particular circumstances of each entity's Region.

D. Intelligence and Situational Awareness

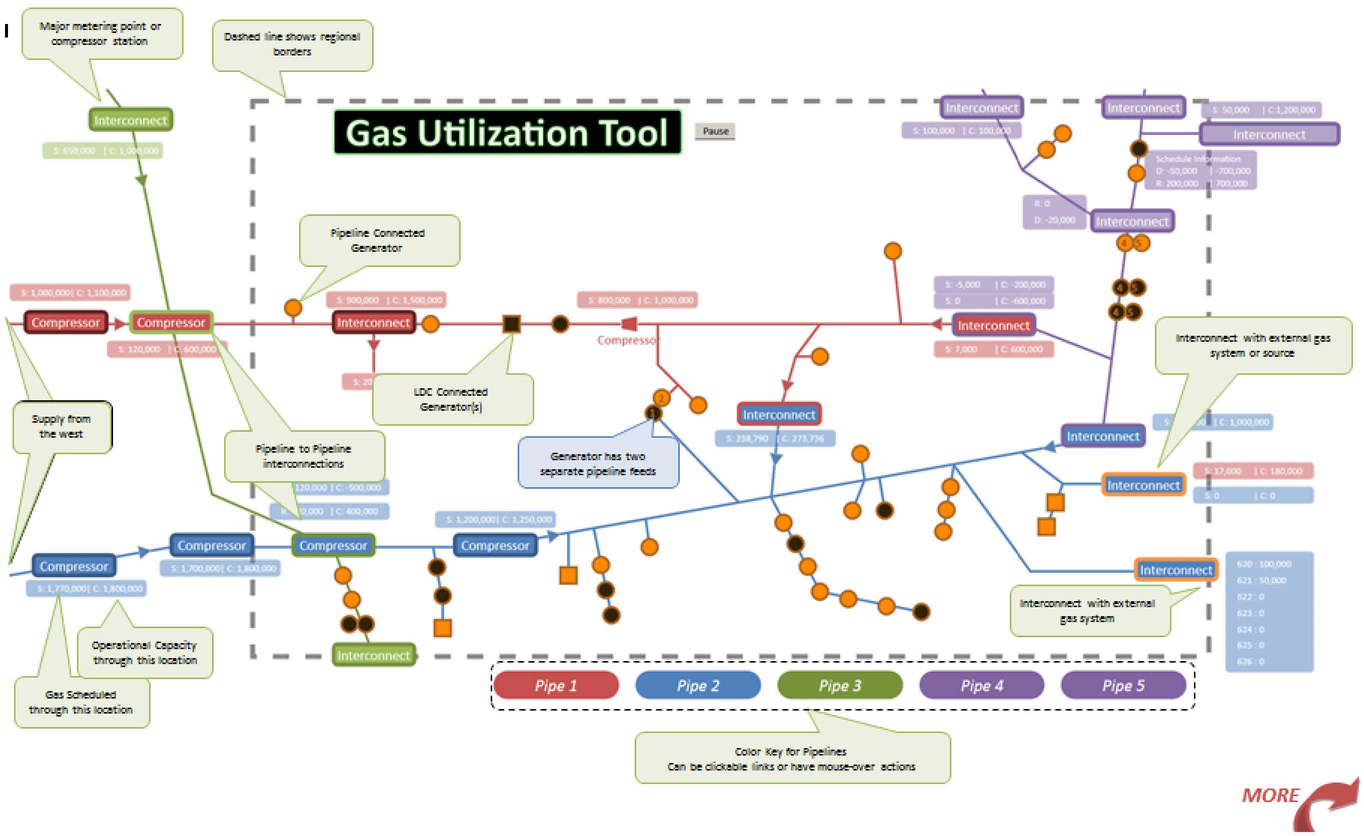
- Fuel Surveys and Energy Emergency Protocols
  - Energy emergency procedures and fuel surveys can be important tools in understanding the energy situation in a region. The surveys can be used to determine energy adequacy for the region's electric power needs and for the communications and associated actions in anticipation or declaration of an energy emergency[2]. Interestingly, the fuel surveys[3][4] will most likely focus on the fuel availability of other types of fuels if the gas infrastructure is the constrained resource.
- Fuel Procurement
  - Operating entities should consider evaluating each electric generator's natural gas procurement and commitment to determine fuel security for the operating day.
    - The electric operating entity can collect publicly available pipeline bulletin board data and compare the gas procurement for individual generators against the expected electric operations of the same facility in the current or next day's operating plan. An example of this type of data collection appears below with the data helping to determine if enough fuel is available to meet an individual plant or in aggregate an entire gas fleet's expected operation for the current or future day. The report can indicate whether a fuel surplus or deficit exists by asset or for an entire pipeline. If sufficient gas has not been nominated and scheduled to the generator meter, assessments can be done to determine the impact on system operations and the operating staff may call the generator to inquire as to whether the intention is to secure the requisite gas supply to match its expected dispatch plus operating reserve designations.

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

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

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

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



<u>Notes</u>:

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

<u>Possibilities</u>:

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

E. Summary

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

Reliability Guideline: DER Verification

Action

Authorize posting for 45-day public comment period.

Background

With the rapid growth of distributed energy resources (DERs) across many areas of North America, and new power flow and dynamic modeling practices being developed to accommodate these resources into the planning process,[1] focus turns to ensuring that the models used to represent aggregations of DERs are verified to some degree. DER models used in BPS planning assessments are used to represent either large utility-scale DERs (U-DERs) individually or aggregate amounts of many retail-scale DERs (R-DERs).[2] Verification of these models, at a high level, entails developing confidence that the models reasonably represent the general behavior of the installed equipment in the field (in aggregate). Since DER models used in planning studies often represent an aggregate behavior of hundreds or even thousands of individual devices, guidance is needed for Transmission Planners (TPs) and Planning Coordinators (PCs) to effectively perform an appropriate level of model verification to ensure that transmission planning assessments are capturing the key impacts that aggregate amounts of DERs can have on BPS reliability.

This guideline provides TPs and PCs with tools and techniques can be adapted for their specific systems to verify that the aggregate DER models created are a suitable representation of these resources in planning assessments. The first step in DER model verification is collecting data and information regarding actual DER performance (through measurements) to BPS disturbances or other operating conditions. Measurements of DERs (individual or aggregate) are currently sparse, and this guideline recommends practices for ensuring adequate data are collected for larger utility-scale DERs as well as capturing the general behavior of aggregated retail-scale distributed resources. This guideline discusses when model verification is triggered, as well as how to understand the mix of different DER characteristics. This guideline describes differences between verifying the model response for aggregate R-DERs and larger U-DERs. Describing the recommended DER model verification practices can also help TPs, PCs, and Distribution Providers (DPs) understand the types of data needed for analyzing DER performance for these purposes both now and into the future as DER penetrations continue to rise. As has been observed in past large-scale disturbances, the response of DERs to BPS disturbances can significantly impact overall reliability of the BPS.[3]

Summary

SPIDERWG asks the RSTC to authorize this *Reliability Guideline: Model Verification of Aggregate DER Models used in Planning Studies* for a 45-day industry commenting period as per the approval process for Reliability Guidelines.

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

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

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

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Reliability Guideline

Model Verification of Aggregate DER Models used in Planning Studies

September 2020

RELIABILITY | ACCOUNTABILITY

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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. T*he 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

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

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

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Executive Summary

With the rapid growth of distributed energy resources (DERs) across many areas of North America, and new power flow and dynamic modeling practices being developed to accommodate these resources into the planning process,[1] focus turns to ensuring that the models used to represent ~~aggregate amounts~~aggregations of DERs are verified to some degree. DER models used in BPS planning assessments are used to represent either large utility-scale DERs (U-DERs) individually or aggregate amounts of many retail-scale DERs (R-DERs).[2] Verification of these models, at a high level, entails developing confidence that the models reasonably represent the general behavior of the installed equipment in the field (in aggregate). Since DER models used in planning studies often represent an aggregate behavior of hundreds or even thousands of individual devices, guidance is needed for Transmission Planners (TPs) and Planning Coordinators (PCs) to effectively perform an appropriate level of model verification to ensure that transmission planning assessments are capturing the key impacts that aggregate amounts of DERs can have on BPS reliability.

This guideline provides TPs and PCs with tools and techniques can be adapted for their specific systems to verify that the aggregate DER models created are a suitable representation of these resources in planning assessments. The first step in DER model verification is collecting data and information regarding actual DER performance (through measurements) to BPS disturbances or other operating conditions. Measurements of DERs (individual or aggregate) are currently sparse, and this guideline recommends practices for ensuring adequate ~~amounts of~~ data are collected for larger utility-scale DERs as well as capturing the general behavior of ~~aggregate amounts of~~aggregated retail-scale distributed resources. This guideline discusses when model verification is triggered, as well as how to understand the mix of different DER characteristics. This guideline describes differences between verifying the model response for aggregate R-DERs and larger U-DERs. Describing the recommended DER model verification practices can also help TPs, PCs, and Distribution Providers (DPs) understand the types of data needed for analyzing DER performance for these purposes both now and into the future as DER penetrations continue to rise. As has been observed in past large-scale disturbances, the response of DERs to BPS disturbances can significantly impact overall reliability of the BPS.[3]

Key Findings

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

- **Visibility and Measurement:** Verification of DER models requires measurement data to capture the general behavior of these resources. For R-DERs, data is most useful from the ~~distribution~~high-side of the transmission-distribution (T-D) interface, most commonly ~~at~~ the T-D transformers. For U-DERs, this may be at the point of interconnection of each ~~larger~~ U-DER.
- **Aggregation of U-DER and R-DER Behavior:** Verification of aggregate DER models becomes more complex when both U-DER and R-DER are modeled on the distribution system with different performance capabilities and operational settings, and verification practices will need to adapt to each specific scenario.
- **Data Requirements:** Data requirements vary between steady-state and dynamic model verification; however, both steps are critical to developing a useful aggregate DER model. DER verification practices should ensure that both steady-state and dynamic modeling are supported.
- **Event Selection:** A relatively large disturbance on the BPS (e.g., nearby fault or other event) is the most effective means of dynamic model verification; however, these events are not necessarily the only trigger of

Commented [JN1]: Is it assumed that U-DERs are connected to the BPS and R-DERs are connected to the distribution system? If so, we may want to clarify this. A clear definition of each type would be helpful. What is the delineation between the two types? Is it a size (i.e. 1 MW) or percentage of load on a circuit or transmission connected transformer?

Commented [JS2R1]: The SPIDERWG Coordination group has defined the U-DER and R-DER term in the definitions document for more specificity. However, both U-DER and R-DER are connected to the Distribution system. U-DER is modeled at the distribution bus and R-DER is modeled across an impedance connected to the distribution bus.

Added link to SPIDERWG terms and definitions.

Commented [JN3]: How would load masking be accounted for if the measurement is taken at the T-D transformer? In most instances, the amount of DER is less than the load consumed and only reduces net load at the distribution circuit or substation.

Is it expected to measure each DER individually and aggregate the distributed generation total at the transformer?

Commented [JS4R3]: In the document, we call out specific monitoring for larger U-DER installations based on group discussion as they have a larger impact at the modeled distribution bus. Looking at Appendix B, the load is also modeled in aggregate at that bus, so the load would be accounted for in the playback to verify the set of models.

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

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

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

model verification. It should be noted that aggregate model verification is not a one--time exercise. Since system loads and DER output levels keep changing, as and when more events happen and the measurement data becomes available the verified models should be checked to ensure that they indeed can replicate the other events that have happened in the system.

- **Concept of Verified Models:** ~~Creating~~ Developing an aggregate DER model is not equivalent to having a verified model[4]. ~~This is true for all sets of models, and is not exclusive to aggregate DER models.~~ ~~A~~A verified model ~~is not always~~should not be expected to be ~~equivalent~~ usable ~~to a model useful~~ for all ~~a specific~~ types of planning stud~~y~~ies. A developed aggregate DER model for the positive sequence simulation tools ~~is one that is proposed to represent~~is ~~the expected equipment~~a mathematical representation at a given location. Whereas, ~~V~~verification of th~~is~~ise ~~simulation~~ model is an exercise that entails comparing the ~~proposed~~ model performance to the actual equipment performance during staged or grid events and tuning relevant parameters to match the model behavior with actual field response. ~~Creating~~ Developing a model useful for study, based on information attained through model verification, requires engineering judgement.[5]

Recommendations

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

- TPs and PCs should ~~E~~encourage DPs and other applicable entities that may govern DER interconnection requirements to revise interconnection requirements to ensure both ~~high-speed and low-speed~~high and low time-resolution data collection. ~~The expected data, as outlined in this guideline, is not necessarily as detailed as any recommended data collection requirements for BPS-connected resources.~~The expected data, as outlined in this guidance, is not necessarily more refined than any recommended data required for BPS-connected resources.
- TPs, PCs, TOs, and other applicable entities that may govern DER interconnection requirements should coordinate with DPs to determine the necessary measurement information that would be of use for the purposes of DER modeling and model verification, and jointly develop requirements or practices that will ensure this data is available.
  - This collaboration should include a minimum set of necessary data for performing model verification.
  - This collaboration should include a procedure where other models, rather than current models, can be verified with additional data should a more accurate representation be required.
- TPs and PCs should coordinate with their TOs, TOPs, and DPs to gather measurement data to verify the general behavior of aggregate DER[6]. Relevant T-D interfaces should be reviewed using data from the supervisory control and data acquisition (SCADA) system or other available data points and locations.

[4] This is true for all sets of models, and is not exclusive to aggregate DER models.

[5] A verified model may not be enough for a particular study as study conditions may be different than verified conditions (e.g., future years, different time of day).

[6] SPIDERWG is actively developing guidance on how this coordination should take place to ensure reliability of the BPS.

Commented [JN5]: May want to add a bullet here that mentions that the verified model would be used to extrapolate and determine expected performance of a future state where additional DER is added to the system.

Commented [JS6R5]: SPIDERWG Verification team does not necessarily agree with the idea that a verified model is the same as one useful for future studies. These verified models CAN be used, but require engineering judgement based on the study conditions for any changes to meet the study's scope. For instance, a verified model at 1 PM does not have the same available power for a Solar PV DER as the available power at 10 AM for some installations.

Commented [PM7]: Should this be high resolution and low resolution instead of speed

Commented [JS8R7]: Yes, this should be resolution versus speed.

Commented [MJ9]: I don't know what this means specifically and what action is needed both from the PC and then the DP once they receive this sort of "Encouragement". Please make this into something that is actionable by both parties.

Commented [JS10R9]: Added a phrase to specify what "encouragement" we are asking for as well as who does the "encouragement"

Commented [JN11]: Does this guideline not cover BPS connected resources? If so , it needs to me made more clear that this guideline is specific to non-BPS DER.

Commented [JS12R11]: Yes, this guideline is focused on DER, which by SPIDERWG definitions does not include BPS connected devices.

Commented [MJ13]: There is some coordination that does happen in an effort to collect data for what is assumed to be aggregate R-DER (rooftop solar and small solar and storage facilities). What additional coordination is expected here as the reality is that not everything will be accounted for? Can we be more granular regarding the "coordination" to some extent. What additional coordination is specifically needed?

Commented [JS14R13]: Added "measurement" to specify the amount of data. From discussions in SPIDERWG, the only coordination so far is nameplate capacity and similar set points. We are asking for coordination of high and low resolution measurement data in order to verify the planning models. Additionally, this recommendation attempts to point to the Coordination subgroups major Reliability Guideline.

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Introduction

Many areas across the BPS in North America are experiencing an increase in the penetration of DERs, and TPs and PCs are adapting their long-term transmission planning practices to accommodate these relatively new resources into their reliability studies. Aggregate amounts of DERs should be modeled and reflected up to the BPS level when performing these studies. BPS fault events in 2018[7] highlighted the growth of DERs in California and the potential impact these resources can have on BPS performance during grid disturbances. Rapidly growing penetrations of DERs across North America have sparked the need for modeling the aggregate behavior of DERs, and in some instances the individual behavior of larger U-DERs, to a suitable degree to incorporate into BPS planning studies, much like how TPs and PCs currently account for aggregated load. SPIDERWG has provided recommended practices for DER modeling.[8,9] These guidance materials provide TPs and PCs with recommendations for modeling aggregate amounts of DERs. However, some degree of uncertainty is involved when applying assumptions or engineering judgement in the development of the model. Therefore, this guideline tackles the need for verification practices after aggregate DER models are developed to ensure that the models used to represent DERs are in fact representative of the actual or expected behavior. Verification of models is paramount to obtaining reasonable and representative study results. The goal is for TPs and PCs to gain more confidence in their aggregate DER models and utilize them for BPS planning studies.

There will inherently be lag between the time in which steady-state and dynamic models for DERs are created and when verification of these models using actual system disturbances and engineering judgement can take place. However, this should not preclude the use of these models in BPS reliability studies. Engineering judgment can be used in the interim to develop reasonable and representative DER models that capture the key functional behaviors of DERs. Explicit modeling of aggregate amounts of DERs is strongly recommended,[10] versus netting these resources with load, as the key functional behaviors are different.

Difference between Event Analysis and Model Verification

While some of the same data may be used between event analysis and model verification, especially dynamic model verification, the two procedures are not necessarily the same. Event analysis seeks to comprehensively understand the disturbance and to identify the root cause of the event. The data needed to execute event analysis typically includes as a vast array of event logs, dynamic disturbance recordings, pre-contingency operating conditions, and other forms of documentation. The pre-contingency operating condition and the dynamic disturbance recordings captured during these events can be used for steady-state and dynamic model verification. This document is intended to help TPs and PCs ensure DER model fidelity using data from actual system disturbances. Model verification's purpose is to add fidelity to models. While some recorders can be used in the same process as event analysis, the processes are quite different.

Recommended DER Modeling Framework

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

Commented [PSJ15]: Placing this sub-section before the DER modeling framework sub-section may improve the readability.

Commented [JS16R15]: Swapped based on recommendation.

Commented [PSJ17]: In my opinion this sub-section should be towards the end of the Introduction section.

Commented [JS18R17]: Kept here as flow is DER model framework into process of verification.

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

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

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

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

or aggregate amounts of smaller R-DERs spread across a distribution feeder[11]. The steady-state model for these resources is placed at a single modeled distribution bus, with the T-D transformer modeled explicitly in most cases. The modeling framework is reproduced in Figure I.1. This guideline uses modeling concepts consistent with the recommended modeling framework previously published and used by industry on recommended DER model verification practices. Please refer to the aforementioned guidelines for more information.

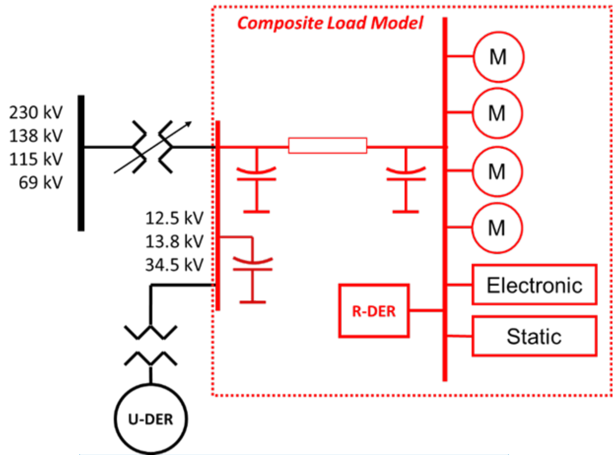

Figure I.1: DER_A Modeling Framework

~~Difference between Event Analysis and Model Verification~~

~~While some of the same data may be used between event analysis and model verification, especially dynamic model verification, the two procedures are not necessarily the same. Event analysis seeks to comprehensively understand the disturbance and to identify the root cause of the event. The data needed to execute event analysis typically includes as a vast array of event logs, dynamic disturbance recordings, pre-contingency operating conditions, and other forms of documentation. The pre-contingency operating condition and the dynamic disturbance recordings captured during these events can be used for steady-state and dynamic model verification. This document is intended to help TPs and PCs ensure DER model fidelity using data from actual system disturbances. Model verification's purpose is to add fidelity to models. While some recorders can be used in the same process as event analysis, the processes are quite different.~~

Guide to Model Verification

Model verification first requires an adequate model be developed, and then for an entity to gather data to match the model performance with that information. Model verification of the models used in planning studies occurs when ~~utilizing~~ TPs and PCs utilize supplemental information to verify ~~against~~ parameters in ~~the~~their transmission model used ~~by TPs and PCs~~ in their high fidelity studies. The process begins with a perturbation on the system resulting in a visible performance characteristic from devices. Such data is stored and sent[12] to the TP/PC for use in validating their set of representative models of those devices. The process continues with the PC perturbing their model and storing

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

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

Commented [MJ19]:

Commented [JS20R19]: Unsure on change recommended, no change made.

Commented [JS21]: Levetra/Pubs, this is getting cut off, please help.

Commented [PSJ22]: It may be better to give the DER_A model diagram here.

Commented [JS23R22]: I agree that clarity always helps for assisting the guideline points; however, the linked DER_A Parameterization guide already has those sections detailed out and we point to those products rather than reproduce what is in them.

Commented [PSJ24]: Placing this sub-section before the DER modeling framework sub-section may improve the readability.

Commented [JS25R24]: Swapped based on recommendation.

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the outputs[13]. Those model outputs and the measured outputs are compared and if a sufficient match based on the TP/PC procedures, the verification procedure stops. If not, small tuning adjustments are made to verify the set of models as it relates to the measured data. It is anticipated that verification of planning models incorporating aggregate DER take more than one of these perturbations. An example of model verification can be found in Appendix B, which details an example using the playback models to verify a set of DER models.

Three Phase versus Positive Sequence Model Verification

The majority of planning studies performed by TPs and PCs use RMS[14] fundamental frequency, positive sequence simulation tools.[15] Hence, steady-state powerflow and dynamic simulations assume[16] a balanced three-phase network, which has conventionally been a reasonable assumption for BPS planning (particularly for steady-state analysis). Therefore, this guideline focuses on verification of the models used for these types of simulations. However, other simulation methods may be used by TPs and PCs, based on localized reliability issues or other planning considerations. These studies, using more advanced or detailed simulation models, may require more detailed three-phase ~~modeling~~ simulation methods~~tools~~ such as three-phase RMS dynamic simulation, electromagnetic transient (EMT~~)~~), or co-simulation ~~tools~~. Those ~~tools~~ methods require more detailed modeling data and verification activities. However, DER model verification using those ~~tools~~ methods is outside the scope of this guideline as the majority of the planning studies are based on the RMS fundamental frequency and positive sequence quantities.

Data Collection for Model Verification of DERs

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

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

Considerations for Distributed Energy Storage

Recent discussions regarding the expected growth of energy storage, particularly battery energy storage systems (BESSs), relate to both BPS-connected and distribution-connected resources. This guideline focuses ~~solely~~ on the distributed BESSs where energy storage is concerned. Other documents coming from the NERC IRPTF are dealing with BPS-connected devices and their impact, which includes BPS-connected BESSs. Many of the recommendations regarding data collection and model verification of aggregate DERs ~~can~~ also ~~apply~~applies for distribution-connected ~~BESSs~~BESSs~~, and this~~. This guideline covers this in more detail throughout where distinctions on distribution-connected BESS can be more informative. ~~between BESS and other types of DER can be informative.~~

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[13] Practices may change related to the software changes, which is similar to the current load model verification practices. SPIDERWG is reviewing and recommending simulation practice changes regarding to DER in other work products.

[14] Root-mean-square

[15] This is different from three-phase simulation tools used by DPs to capture things like phase imbalance, harmonics, or other unbalanced effects on the distribution system.

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

Commented [PSJ26]: It may be better to rename this as "Scope of Guideline"

Commented [JS27R26]: Title of heading not changed as other titles do not clarify the discussion of the section as well as this one.

Commented [RD28]: Should probably first include three phase RMS dynamic simulations like in OpenDSS and/or GridLab-D…co-simulation and EMT can then follow

Commented [JS29R28]: Added text in the sentence.

Commented [MP30]: Aggregated models may not require EMT type modeling because that are approximate models by definitions. EMT should be reserved for individual equipment modeling where it makes far more sense. E.g. we do not require EMT model of aggregated DER.

Commented [JS31R30]: Agreed, added a sentence to return back to pos sequence and ensure this guideline provides guidance on those.

Commented [PSJ32]: In my opinion this sentence is a very key information and should be included in the Guide to Model verification section.

Commented [JS33R32]: Added some language in the above section that mimics the idea, but isn't a direct copy.

Commented [MJ34]: From our experience, this is actually happening today. Some TSPs are actually requiring PMUs to be installed for DERs being interconnected at 75 – 100 MW or above. Is the group thinking about requiring something above and beyond this for monitoring devices?

Commented [JS35R34]: In the monitoring devices chapter, we discuss the types of recording devices. We are not requiring more than what is similarly seen at the BPS connected devices, except with the monitored location at high side of the T-D interface, or at the POI of U-DERs where capable. We are encouraging entities here to allow for monitoring devices to be placed on the distribution system.

Commented [JN36]: Why would you not include BPS connected energy storage as well? Doesn't the guideline cover BPS connected U-DERs? If it doesn't, it may need to be made more clear in the introduction that this guideline is only for DERs not connected to the BPS.

If BPS connected DER is covered by another guideline, it may be good to call that out here.

Commented [JS37R36]: This guideline does not cover BPS connected devices as the DER definition comments above. Added a sentence to reference the IRPTF conversations regarding BPS connected devices.

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Chapter 1: Data Collection for DER Model Verification

The data and information needed to create a steady-state and dynamic model for individual or aggregate DERs is different that the data and information used to verify those models. TPs and PCs should work with their DPs to collect information pertaining to existing DERs, and also work with the DP and other applicable entities to forecast future levels of DERs for planning studies of expected future operating conditions. The NERC *Reliability Guideline: DER Data Collection for Modeling in Transmission Planning Studies*[17] describes the types of data and information necessary to create a suitable steady-state and dynamic model for DERs used for planning studies. On the other hand, data used for DER model verification focuses more on the actual performance of aggregate or individual DERs that can used to compare against model performance.

Before describing the verification process in subsequent chapters, this chapter will first describe the data and information used for verifying the DER model(s) created.

Data Collection and the Distribution Provider

Key Takeaway:
The "source" of the DER data may come from other entities than a DP, such as a DER developer. It is intended that clear coordination between DPs, TPs, and PCs highlight the needs required to collect the data from the "source".

DPs are the most suitable entity to provide data and information pertaining to DERs within their footprint since DPs conduct the interconnection studies and may have access to the measurements necessary to perform DER model verification. Applicable entities that may govern DER interconnection requirements states, upon their review of interconnection requirements for DERs connecting to the DPs footprint, are encouraged to ensure DPs are capable of collecting data for model verification purposes as unverified models have an impact on BPS studies. This impact compounds on itself as the DER penetration in a local area grows; however, access to measurements for verifying model performance alleviates those study impacts. Sometimes the actual "source" of the data is a DER developer or other distribution entity, who is not a functional NERC entity. TPs, PCs, and Transmission Owners (TOs) are encouraged to coordinate with DPs and respective DER developers, generators, owners, or other distribution entities related to DER in order to develop a mutual understanding of the types of data needed for the purposes of DER modeling and model verification. Coordination between these entities can also help develop processes and procedures for transmitting the necessary data in an effective manner. Two of the primary goals of this guideline are to help ensure that DPs, TPs, PCs, and TOs understand the types of data needed to successfully verify DER models, and to provide recommended practices for gathering this data and applying it for verification purposes. It is intended that with clear coordination on the needs for the data, the best "source" of this data will become apparent.

DER model verification starts with having suitable data available for DERs to make reasonable engineering judgments regarding how to model the aggregate behavior of DERs. There is no one-size-fits-all method to this effort; entities should coordinate with each other to develop solutions most applicable for their specific systems and situations. However, common modeling practices and similar data needs will exist, and these are discussed in this chapter in more detail.

Monitoring Requirements in IEEE 1547

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

[17] Guideline found here (Review hyperlink upon completion)

Commented [LG38]: Considering the current MOD-032 SAR, will this language be in alignment with the standard?

Commented [JS39R38]: The MOD-032 SAR parrots the change from LSE to DP, so yes, the language is in agreement. Additionally, the MOD-032 SAR asks to change to dynamic and steady-state data for aggregate DER, which is concurrence with this language.

Commented [DK(TD-140]: DER developers build and sell DER plants. They typically do not own or operate the plants. So it is more likely to request data from DER generators/owners or utility companies.

Commented [JS41R40]: Added language to address the comment

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in 2018 to address the proliferation of DER interconnections. Both IEEE 1547-2003[18] and IEEE 1547-2018[19] standards are technology neutral. The monitoring requirements for both standards are presented here:

- **IEEE 1547-2003:** The IEEE 1547-2003 standard, applicable for DER installations installed prior to the full adoption and implementation of IEEE 1547-2018,[20] included provisions for DERs with a single unit above 250 kVA or aggregated more than 250 kVA at a single Point of Common Coupling (PCC) to have monitoring for active power, reactive power, and voltage. However, the standard did not specify any requirements for sampling rate, communications interface, duration, or any other critical elements of gathering this information. Further, DER monitoring under this requirement was typically through mutual agreement between the DER owner and the distribution system operator. Therefore, it is expected that data and information for these legacy DERs is likely very limited (at least from the DER itself). For legacy R-DERs, this may pose challenges in the future for DER model verification and BPS operations.
- **IEEE 1547-2018:** The IEEE 1547-2018 standard places a higher emphasis on monitoring requirements and states that "the DER shall be capable of providing monitoring information through a local DER communication interface at the reference point of applicability….The information shall be the latest value that has been measured within the required response time." Active power, reactive power, voltage, current, and frequency are the minimum requirement for analog measurements. The standard also specifies monitoring parameters such as maximum response time and the DER communications interface. Therefore, larger U-DER installations will have the capability to capture this information, and DPs are encouraged to establish interconnection requirements that make this data available to the DP (which will be applicable to distribution and BPS planning and operations).

Information and data can be collected for the purposes of DER model verification from locations other than at the DER PCC. This is particularly true for capturing the behavior of aggregate amounts of R-DERs. However, particularly for larger U-DER installations, this type of information can be extremely valuable for model verification purposes.

Recording Device Considerations

This section specifies considerations for applicable entities that may govern DER interconnection requirements regarding recording devices. In addition to the information that the IEEE 1547-2018 standard requires to monitor, event-driven capture of high-resolution voltage and current waveforms are useful for DER dynamic model verification. These allow the key ~~functions~~responses of fault ride-through, instability, tripping and restart to be verified. It is recommended that the built-in monitoring capabilities of smart inverter controllers or modern revenue meters are fully explored by relevant entities since they may provide similar data as a standalone monitor. These meters may also be able to monitor power quality indices.

> **Key Takeaway:**
> Recording capabilities will vary on IEEE 1547-2003 and IEEE 1547-2018 compliant DER. It is critical to understand these capabilities when considering additional recording devices.

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

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

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An example of a recording device is the Power Quality meters (PQ meters), which are a type of measurement device used in a multitude of applications including compliance, customer complaint troubleshooting, and incipient fault detection. These devices are programmable to record voltage and current waveforms during steady-state conditions as well as during system events. These types of measurement devices record both RMS and sinusoidal waveforms at many different sample rates and are IEC code compliant on their RMS and sinusoidal samplings. These types of meters are viable when capturing the aggregate performance of DER on the BPS depending on the placement of the device, and can function as a standalone meter or as part of a revenue meter. TPs and PCs should collaborate with applicable entities that may govern DER interconnection requirements ~~regarding recording devices~~ and the DP, regarding recording devices, so that these recording devices accomplish the objectives of each entity~~, as capturing this performance is not only useful to the TP~~. The improved model quality and fidelity will benefit all the stakeholders. ~~It is recommended that new DER installations have some sort of smart meter capability[21] so that explicit output levels of DER can be collected.~~

> ~~**Key Takeaway:**~~
> ~~Recording capabilities will vary on IEEE 1547-2003 and IEEE 1547-2018 compliant DER. It is critical to understand these capabilities when verifying DER models.~~

Placement of Measurement Devices

Selecting measurement locations for DER steady-state and dynamic model verification depends on whether TPs and PCs are verifying U-DER models, R-DER models, or a combination of both. The following recommendations should be considered by TPs, PCs, and DPs when selecting suitable measurements for DER model verification:

- **R-DER:** An R-DER model is an aggregate representation of many individual DERs. Therefore, the aggregate response of DERs can be used for R-DER model verification. This is suitably captured by taking measurements of steady-state active power, reactive power, and voltage at T-D interface[22]. ~~Note that such a measurement would include the combined response from the load and the R-DER.~~ This may be acquired by measurements at the distribution substation for each T-D transformer bank or along a different distribution connected location[23].
- **U-DER:** U-DER models represent a single (or group of) DER; therefore, the measurements needed to verify this dynamic model must be placed at a location where the response of the U-DER (or group of DER) can be differentiated from other DERs and load response. For U-DER connecting directly to the distribution substation (even through a dedicated feeder), the measurements for active power, reactive power, and voltage can be placed either at the facility or at the distribution substation. For verifying groups of DERs with similar performance, measurements capturing one of these facilities may be extrapolated for verification purposes (using engineering judgment). Applicable entities that may govern DER interconnection requirements should consider establishing capacity thresholds (e.g., 250 kVA in 1547-2003) in which U-DER should have monitoring equipment at their Point of Connection (PoC) to the DP's distribution system.
- **Combined R-DER and U-DER:** Situations where both U-DER and R-DER exist at the distribution system may be quite common in the future. Where possible, the response of U-DERs (based on DER modeling practices) should be separated from the response of R-DERs and end-use loads. Measurement locations at the T-D

> **Key Takeaway:**
> Measurement locations of DER performance depend on the type of DER model (U-DER vs. R-DER) being verified. Aggregate R-DER response can be captured at the T-D interface, whereas explicit model verification of U-DER models may require data at specific larger DER installations.

~~[21] Possibly something like PG&E has as seen Here~~

[22] Note that such a measurement, expectedly, could include the combined response from the load and the R-DER; however, this will not undermine the accuracy of the model verification since the model framework also includes both load and resource components as described in the DER model framework sections.

[23] While uncommon, measurement data along a distribution feeder can replace data at a T-D interface. Entities are encouraged to pursue the location that is easiest to accommodate the needs of all entities involved.

Commented [MJ42]: It's not clear what is intended here. Someone is going to have to pay for these recording devices and it's not apparent how a recording devices placed with the objective of verifying a model developed by the TP is also going to be beneficial for the DP or the DER developer.

Commented [JS43R42]: SPIDERWG understands that there is a cost associated with this equipment, but as this is a reliability guideline, we are focused on the reliability benefit of these recording devices, which benefit all stakeholders as improved model fidelity and quality allows for accurate studies.

As accurate studies feed the ability to optimize the transmission and distribution system, these allow for rates to be set that the DP/DER developer is highly interested in.

Commented [PM44]: Included this line here since the next bullet point talks about separating load and U-DER response. It is important to mention that the measurements for RDER will include load response as well and both needs to be verified together

Commented [JS45R44]: Included.

Commented [JN46]: These measurements will be affected by load downstream of the T-D interface. Is the load modeled separately from the DER or are they modeled together at this interface? If they are modeled separately, how are the two separated, unless metered at each individual DER?

Commented [JS47R46]: See Parag's clarification on the load. They are separated based on the modeling practices, currently emphasized to separate R-DER from Load in the framework; however, the measurement will account for both aggregate load and aggregate DER. The separation occurs based on metered U-DER in the next section.

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interface are recommended in all cases, and additional measurements for capturing and differentiating U-DERs may also be warranted.

As described, the type of DERs and how they are modeled will dictate the placement of measurement devices for verifying DER models. Figure 1.1 illustrates the concepts described above regarding placement of measurement locations for capturing the response of R-DERs, U-DERs, or both. In the current composite load model framework, specific feeder parameters are automatically calculated at initialization to ensure voltage at the terminal end of the composite load model stays within ANSI acceptable voltage continuous service voltage. These parameters represent the aggregated impact of individual feeders, as~~,~~ indicated by the dashed box in Figure 1.1. Each of the highlighted points in Figure 1.1 pose a different electrical connection that this guideline calls out. At a minimum, placement at the high or low side of the transformer provides enough information for both steady-state and dynamic model verification. For U-DER, it is suggested that monitoring devices are placed at their terminal as shown in Figure 1.1. ~~(indicated in Figure 1.1 at the high side connection)~~. While other locations are highlighted, they are not necessary for performing model verification when the two aforementioned locations are available; however, they may be able to replace or supplement the data and have value when performing model verification.

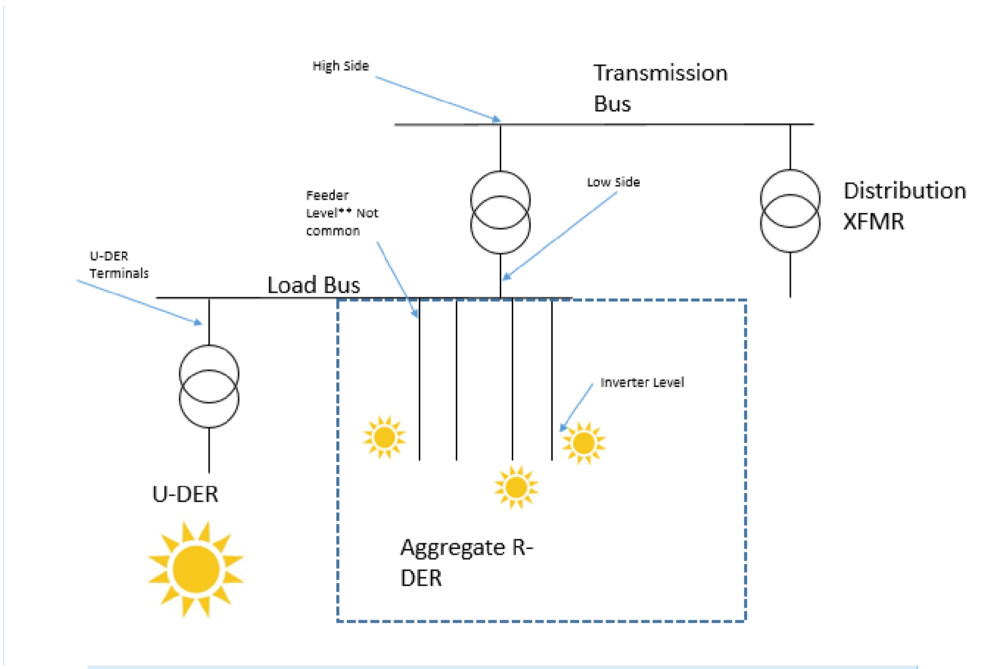

Figure 1.1: Illustration of Measurement Locations for DER Model Verification

Measurement Quantities used for DER Model Verification

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

- Steady-state RMS voltage (Vrms)
- Steady-state RMS current (Irms)

Commented [PM48]: In the current composite model, the feeder parameters are not automatically calculated. The guidance (reflected in the default parameters) is to choose the feeder parameters such that a voltage drop of 4-6% is achieved from the feeder head to the feeder end, and the X to R ratio is 1. These feeder parameters are automatically adjusted during initialization if and only if the voltage at the terminal of the composite load components fall below 0.95 pu, which is the ANSI acceptable voltage continuous service voltage level

Commented [JS49R48]: Changes made in text

Commented [RD50]: Minor comment: the figure doesn't actually indicate the feeder parameters or the equivalent that is being calculated.

Commented [JS51R50]: Changes made in text.

Commented [LG52]: This is good for people to know so that they know they don't have verify feeder parameters all the time. I would ask the group to consider a more rural scenario when U-DER and R-DER will be mixed together on the same line to the substation. Wouldn't we want to verify the impedance of a "long" distribution line? Especially if the revenue meters are at the customer site and not the substation.

Commented [JS53R52]: It would be hard to verify just the feeder parameters by using field tests or measurement data from these feeders. This scenario can fall under the method for checking model parameters of the composite load record.

In scenarios where the aggregate feeder needs to be represented explicitly (i.e. outside the composite load model), this would break away from the current modeling practices, and would be covered under adjustments to models to verify measurements at the T-D interface.

Commented [MP54]: We need to make sure that the terminology for what is modeled as UDER and what is modeled as RDER be harmonized with the modeling sub-group.

Commented [JS55R54]: Both documents use the Coordination team's definitions for modeling with one notable exception that Reigh Walling brought up. If it makes sense for a U-DER to be modeled as R-DER if some of the installations are across long impedances. This deviation is an explanation of engineering judgement when it does not make sense to model alongside other closer U-DER.

Commented [JS56]: Need to genericize the figure (not just Solar PV) – Pubs, can you assist?

Commented [BM57]: Is this recommending different measuring devices for the sole purpose of validating models? Please clarify

Commented [JS58R57]: We are recommending that devices be placed for the purpose of verifying models; however, we encourage entities to coordinate to accomplish as many tasks as needed for this device. This content describes the verification aspect.

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- Active power (W)
- Reactive power (~~VARS~~Vars)
- ~~Apparent power (VA)~~

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

- ~~Instantaneous voltage (V)~~
- ~~Instantaneous current (I)~~
- RMS[24] voltage and current (Vrms, Irms)
- ~~RMS current (Irms)~~
- Frequency (Hz)
- Active power (W)
- Reactive power (~~VARS~~Vars)
- ~~Apparent power (VA)~~
- Harmonics[25]
- Protection Element Status
- Inverter Fault Code

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

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

Based on the types of measurements desired, preferred, and helpful, Table 1.1 provides a summary between the steady-state and dynamic recording devices. Each of the measurements above is categorized in Table 1.2 as necessary, preferred, or helpful to assist in device selection. For dynamic data capture, Digital Fault Recorders (DFRs) and distribution Phasor Measurement Units (PMUs) are two high resolution devices that are useful in capturing transient events, but are not the only devices available to record these quantities. In some instances, already installed revenue meters may provide this RMS information[26].

Table 1.1: Recording Device Summary

Topic	Steady-State	Dynamic
R-DER		
Useful Location(s) of Recording Devices	High-side or low-side of T-D transformer(s); individual distribution circuits[27] (see Figure 1.1)	

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

[25] These measurements should collect the Total Harmonic Distortion (THD) and Total Demand Distortion (TDD) at the T-D interface. These levels should be consistent with IEEE standards (IEEE std. 519 for example) and such standards refer to the upper harmonic boundary for measurement.

[26] These devices can also offer different measurement quantities as well. See Chapter 6 of NERC's Reliability Guideline on BPS connected inverter devices here. While DERs are different in treatment of performance, the measurement devices discussed there can be used on the high side of the T-D transformer for similar data recording

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

Commented [BM59]: Is it really necessary to specifically measure the kVA/MVA of a unit if you are also measuring the active and reactive power? Also, is this just the magnitude or both the magnitude and angle of the kVA/MVA?

Commented [BM60]: A Positive Sequence RMS dynamic model would not need instantaneous V/I measurements. I do agree that an EMT model would though. Can we clarify this?

Commented [JS61R60]: Moved to calculate/report section to clarify these are not needed to verify positive sequence RMS dynamic models.

Commented [PSJ62]: It may be good to include the minimum sampling rate of the measurements required to do the verification.

Commented [JS63R62]: We left out sample rate as it is up to the entities decision for these measurements. TPs/PCs should be cognizant of the sample rate to see if the measurement is suitable for the type of verification used. (i.e. not using 10 minute data for dynamic verification).

Commented [RD64]: Three phase or single phase? Or as applicable?

Commented [JS65R64]: As applicable, determined under the coordination of transmission and distribution entities' needs.

Commented [BM68]: Same question as above.

Commented [JS69R68]: See response to comment above

Commented [RD66]: Fundamental frequency RMS or true RMS?

Commented [JS67R66]: Added footnote to clarify

Commented [BM70]: Should we specify out to which harmonic? I think there was discussion before that an IEEE standard requires designing out to the 50th harmonic but someone was having problems with even higher harmonics. I may be mis-remembering though.

Commented [JS71R70]: Added footnote to reference IEEE std 519 for harmonics. SPIDERWG Verification subgroup emphasizes that transmission entities and distribution entities should coordinate to ensure that needs are met with the recording device. As a device that stops at 50th harmonic may be suitable in some ...

Commented [RD72]: Up to which order? And on which side ...

Commented [DK(TD-173R72]: Agreed. The harmonic ...

Commented [JS74R72]: See response to above comment

Commented [PM75]: Should we require harmonic ...

Commented [JS76R75]: See above comment

Commented [DK(TD-177]: For event oscillography capture ...

Commented [JS78R77]: Added "systems" to allow for ...

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Examples of Recording Devices	Resource side (SCADA) or demand side (~~,~~ Advanced Metering ~~System~~ Infrastructure (AMI~~S~~)) devices	DFR, distribution PMU, or other dynamic recording devices.
Minimum Set of Measurements	Active Power, Reactive Power	Frequency, RMS Voltage, Active Power, Reactive Power
Additional Preferred Measurements	RMS Voltage	RMS Currents
Measurements Helpful if Available	Frequency, Apparent Power, Steady-State Current	Harmonics
U-DER		
Useful Location(s) of Recording Devices	Point of interconnection of U-DER; distribution substation feeder to U-DER location; aggregation point of multiple U-DER locations, if applicable (see Figure 1.1)	
Examples of Recording Devices	DP SCADA or AMS; DER owner SCADA	DFR, distribution PMU, modern digital relay, or other dynamic recording devices[28].
Minimum Set of Measurements	Active Power, Reactive Power	Frequency, RMS Voltage, Active Power, Reactive Power
Additional Preferred Measurements	RMS Voltage	RMS Currents
Measurements Helpful if Available	Frequency, Apparent Power, Steady-State Current	Protection Element Status, Harmonics, ~~Fault~~ Disturbance Characteristics[29]; Sinusoidal Voltage and Currents

In regards to protection quantities, the identified U-DER protection device statuses coupled with an inverter log from a large U-DER device helps in determining what protective function impacted the T-D interface and to verify that such performance is similar in the TP's set of models. This type of information become more important to understand as penetration of large DER increases in a local area, especially if such protection functions begin to impact the T-D interface.

Steady-State DER Data Characteristics

As Table 1.2 summarizes the measurement quantities needed, preferred, and helpful if available, entities that are placing recording devices will need to decide upon the sample rate and other settings prior to installing the device. Table 1.2 summarizes the many/ aspects related to utilizing steady-state data for use in model verification. As the steady-state initial conditions feed into dynamic transient simulations, the steady-state verification process feeds into the dynamic parameter verification process. With the focus on BPS events, the pre-contingency operating condition and the dynamic disturbance recordings captured during these events can be used for steady-state and dynamic model verification. This is a unique process different from steady-state verification of seasonal cases in the base case development process. The considerations in Table 1.2 can be applied to both seasonal case verification as well as pre-contingency operating condition verification.

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

[29] This can be a log record from a U-DER characteristic, or a record of how certain types of inverters reacted to the BPS fault. This is different from event codes which are applied from the BPS perspective and including this information can assist with both root cause analysis as well as verification of aggregate DER settings.

Commented [SR79]: Inverter data?

Commented [JS80R79]: Added clarification on what is referred to by this term.

Commented [BM81]: Same question as above about the kVA/MVA

Commented [JS82R81]: See response above, here we are highlighting the helpfulness of this measurement and contrasting it with the minimum set (of P and Q).

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Commented [DK(TD-183]: Modern digital relays also come with PMU capabilities and can be enabled for data streaming. PQ meters and digital relays have event reporting capability for event analysis.

Commented [JS84R83]: Added to list

Commented [PM85]: its fairly easy to convert sinusoidal currents to RMS. Also since we need the fundamental frequency RMS it may be better to have actual sinusoidal measurements and convert them to RMS

Commented [JS86R85]: Added to helpful if available items.

Commented [DK(TD-187]: GSP timing would be useful for wide-area validation studies.

Commented [JS88R87]: Added to list. Also, assuming GPS instead of GSP.

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Table 1.2: Steady State DER Model Verification Data Considerations	
Topic	**Key Considerations**
Resolution	High sample rate data is not needed for steady-state model verification. For example, one sample every 10 minutes, can be sufficient.[30] SCADA data streams come in at typically 2 to 4 seconds per sample~~.~~; however, these speeds are not always realizable.
Duration	Largely, a handful of instantaneous samples will verify the dispatch of the DER and load for each Interconnection-wide base case. Further durations nearing days or weeks of specific samples may be needed to verify U-DER control schemes, such as power factor operation, load following schemes, or other site-specific parameters. For these, TPs and PCs are encouraged to find an appropriate duration of data depending on their needs for verification of their steady-state models.
Accuracy	At low sample rate, accuracy is typically not an issue. Measured data should have relatively high accuracy and precision. Data dropouts or other gaps in data collection should be eliminated.
Time Synchronization	Time synchronization of measurement data may be needed when comparing data from different sources across a distribution system (or even across feeder measurements taken with different devices at the same distribution substation). Many measurement devices have the capability for time synchronization, and this likely will become increasingly available at the transmission-distribution substations. In cases where time synchronization is needed, the timing clock at each measurement should be synchronized with a common time reference (e.g., GPS)[31] to align measurements from across the system.
Aggregation	Based on the modeling practices for U-DER and R-DER established by the TP and PC,[32] it may be necessary to differentiate DERs for the purposes of accounting in the power flow model. This includes separating out the MW values for U-DER and R-DER and having sufficient measurement data to capture each type in aggregate.
Dispatch Patterns and Data Sampling	Different types of DERs are often driven by external factors that will dictate when these resources are producing electric power. For example solar PV DERs provide cyclic energy during times of solar irradiance, wind resources provide output during times of increased wind, and BESSs may inject~~or~~ or consume energy based on market signals or other factors. In general, these recommendations can apply to sampling measurements for these resources: • Solar PV: Capture sufficient data to understand dispatch patterns during light load daytime and peak load daytime operations; nighttime hours can be disregarded since solar PV is not producing energy during this time. • Wind: Capture output patterns during coincident times of high solar PV output (if applicable), as well as high average wind speeds. • BESSs: BESSs should be sampled during times when the resource is injecting and during times when the resource is consuming power.

Commented [BM89]: Shouldn't this say "2 to 4 samples per second"?

Commented [JS90R89]: No. See comment below, these timeframes were provided and checked by Verification subgroup to be valid.

Commented [JN91]: This is not always the case. Some scada measurements only come in every 15 minutes due to being connected via cellular.

Commented [JS92R91]: Based on Verification discussions, these were the time bands TPs said their SCADA steam had. Added clarification that these speeds are not always the case

Commented [PSJ93]: Correct spelling from injector to ***inject***

Commented [JS94R93]: Change made as suggested

[30] The resolution needs to be able to reasonably capture large variations in power output over the measurement period.

[31] https://www.gps.gov/

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

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Post-Processing	Depending on where the measurement is taken some post-processing will need to be done to determine if the DER is connected to point on transmission that is not it normal delivery point. Not taking this into consideration makes DER mapping to BES model susceptible to inaccurate DER connection points. These same mappings apply to the dynamic model verification process.
Data Format	Microsoft Excel and other delimited data formats are most common for sending or receiving steady-state measurement data. Other forms may exist, but are generally also delimited file formats.

Verifying ~~operating~~ the operation mode for DER ~~voltage and current~~ may require more complex measurements and it is best to work with the applicable entities that may govern DER interconnection requirements and the DP to determine the best placements of devices to verify BES interaction characteristics. It is beneficial to include steady-state current and voltage waveforms to this effect, especially for inverter-based DER.

Dynamic DER Data Characteristics

Dynamic recorders uses in capturing the transient conditions of an event have differing data considerations than the steady-state recorders. The data characteristics and considerations typically discussed in dynamic recording of measurements are found in Table 1.3. In comparison to steady-state measurements, dynamic data measurements require a faster ~~sample~~ sampling rate with the trade-off that the higher fidelity sampling is only for a shorter time period. The data captured from dynamic disturbance recorders can be used for the purposes of dynamic model verification.

Table 1.3: Dynamic DER Model Verification Data Considerations

Topic	Key Considerations
Resolution	~~The RMS positive sequence, fundamental frequency dynamic models use a time step on the order of one-quarter of an electrical cycle.~~ Typically, the BPS planning models look at responses of less than 10 Hz, so the sampling rate of the measuring devices should be adequate to capture these effect. Therefore, ~~measurement data for DER dynamic model verification should have a resolution~~ a resolution on the order of 1-4 milliseconds is recommended to be above the Nyquist Rate for these effects. ~~[33]~~ For reference, typical sampling rates recording devices can report at 30-60 samples per second continuously, with some newer technologies sampling up to 512 samples per cycle on a trigger basis.

~~[33] For cases where EMT model verification is needed, much higher resolution data would be required.~~

Commented [LG95]: Why would operating voltage be needed in a steady state model? Typically, these devices for R-DER will be modeled at the voltage of the aggregation and U-DER is modelled at nameplate voltage. I would consider removing this

Commented [JS96R95]: Changes made to clarify based on group discussion with commenter.

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Commented [RD97]: The footnote is misplaced and unnecessary

Commented [JS98R97]: Deleted footnote.

Commented [JN99]: Should there be a minimum number of samples per cycle in order to detect harmonics? The reason I ask is that most PMUs and other measurement devices specify it in samples per cycle instead of milliseconds.

Commented [JS100R99]: Added some references to get samples per second and cycle for some devices.

Commented [DK(TD-1101]: For reference, typical sampling rate for DFR, PQ meters, and relays range from 4-128 points per cycle. 512 per cycle is offered by newer models.

Commented [JS102R101]: Added text for this reference.

Commented [PM103]: I think we should re-word this by saying that the model responses we want to model is in the range of <10 Hz and the sampling rate of measuring devices should be adequate to capture these effects properly. Therefore, a sampling rate of 1-4 ms is suggested.
The time step of simulation is adjustable based on the smallest time constant modeled. For a double cage IM this time constant is t'' which is 0.0021 which means the time step used internally for the cmld is at most 5.2500e-04. PSSE and PSLF does this internal time-step division.

Commented [JS104R103]: Reworded this in verification group discussions

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Triggering	Dynamic recording devices will need to have their triggers set in order to record and store their information. Some important triggers to have are such that a BPS fault is detected or that nearby protection relays assert a trigger to the device to record. This generally shows up as the following: • Positive sequence voltage is less than 88~~70~~% of ~~operating voltage~~the nominal voltage • Over-frequency~~Overfrequency~~ events[34] ~~above 60.1 Hz.~~ • ~~Under Frequency Events~~Under-frequency events ~~under a few hundred mHz below nominal frequency~~ Although higher trigger values can be used to obtain more data, some of those triggering events may not be useful in verifying the large disturbance dynamic performance of BPS models. ~~that may not be a BPS fault.~~ In the case, both R-DER and U-DER terminals are expected to ~~behave~~ have the same as electrical frequency ~~is highly pervasive in AC synchronized systems~~.
Duration	~~The duration dynamic measurements capturing DER response to grid events should generally be up to around 20 to 30 seconds. Sometimes longer windows are needed to capture the event.~~Event duration requirement depends on the dynamic event to be studied. For short dynamic events such as faults, 1-2 seconds time window is common. For long events such as frequency response, the time window can range from a few seconds to minutes. ~~.~~
Accuracy	Dynamic measurements should have high accuracy and precision, and any gaps in the recorded data should be minimized and eliminated.
Time Synchronization	Dynamic measurements should be time synchronized to a common time reference (e.g., GPS) so that dynamic measurements from different locations can be compared against each other with high confidence that they are time aligned. This is essential for wide-area model verification purposes.
Aggregation	Based on the modeling practices for U-DER and R-DER established by the TP and PC,[35] it may be necessary to differentiate DERs for the purposes of accounting in the power flow model. This includes separating out the MW values for U-DER and R-DER and having sufficient measurement data to capture each type in aggregate.
Data Format	Similar to the Steady-state data, the dynamic data formats typically come in a delimited file type such that Microsoft Excel can readily read in. If it does not come in a known Excel format, ASCII[36] files are typically used that would be converted into a file format readable in Excel. However, other files types, such as COMTRADE[37], are also widely used by recording devices and can be expected when requesting dynamic data from these recording devices.

Commented [BM105]: This seems a bit low. Would a better value be 88% to match up with IEEE 1547?

Commented [JS106R105]: Change made as suggested.

Commented [DK(TD-1107]: Frequency variation can vary from interconnection to interconnection. It is up to DPs to determine the over and under frequency thresholds

Commented [JS108R107]: Added footnote to accommodate comments from last meeting to address per Interconnection

Commented [JN109]: How would high resolution monitoring be implemented for smaller behind the meter distributed resources? At the substation level, changes in load can cause fluctuations (triggers) just as much as DER.

Commented [JS110R109]: SPIDERWG recommends this monitoring be at the T-D interface for aggregate R-DER devices. While load can perturb the measurement, that might be a good trigger for verification of the load model (opposed to the DER model). In either case, the TP/PC is made aware in the changes that these triggering events may not be useful for higher trigger values with high resolution data.

Commented [DK(TD-1111]: Only continuous recording devices like PMU and DFR can have 20-30 seconds event duration. PQ meters and relays typically have an event window less than 2 seconds.

Commented [JS112R111]: Changes were made by other commenter to account for these device limitations in continuous recording.

Commented [PM113]: this duration of measurements is typically not available from DFRs. Should we specify MicroPMU's or devices of that nature that has data logging capabilities with required resolution for long periods

Commented [JS114R113]: Changes made as suggested.

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[34] These events are typically at +/- 0.05 Hz around the 60 Hz nominal; however, this value should be altered for each Interconnection appropriately based on the amount and types of events desired to be used for BPS model verification.

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

[36] ASCII stands for American Standard Code for Information Interchange as a standard for electronic communication.

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

Chapter 2: DER Steady-State Model Verification

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

System Conditions for DER Model Verification

System Conditions for DER Model Verification Steady state verification procedures can use slower data records and does not need events to verify the steady state data. An example of this is that other studies can provide an insight into the local region. When conducting short circuit studies, an entity found that an aggregation of DER was incorrectly modeled. In this scenario the aggregation occurred with R-DER and was modeled on the nearest BPS bus and not modeled at the correct voltage level. This was affecting the powerflow solution at the modeled BPS transformer and cause increased LTC activity in the powerflow model. The entity solved the issue in their studies by verifying the location of the resource, the connection voltage, and analyzed its path the BPS bus to get appropriate impedances between the R-DER and BPS transformer. It is recommended that other entities utilize this approach where appropriate to create an accurate steady-state DER model~~Steady state verification procedures can use slower data records and does not need events to verify the steady state data. An example of this is that other studies can provide an insight into the local region. When conducting short circuit studies, an entity found that an aggregation of DER was affecting the powerflow solution at the modeled BPS transformer when the solution software was behaving abnormally. The entity solved the issue in their studies by verifying the steady state aggregate DER model and it is recommended that other entities utilize this approach where appropriate~~.

There are a few conditions that the TP should ensure is verified in their set of models and each is to be verified systematically when the data becomes available. A set of important conditions to verify, accounting for gross demand and aggregate DER output, include the following[38]:

- DER output at a (gross or net) peak demand condition
- DER output at some off-peak demand condition

At each of these points, the collected active and reactive power will help verify the steady-state parameters entered into the DER records. ~~Voltage and frequency data~~Voltage measurements will also help inform how the devices operate based on the inverter control logic, voltage control set points, and how ~~that~~ these aggregate~~s~~ to the T-D interface.

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

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

Commented [BM115]: This document refers to the steady state model fairly often but it doesn't actually define what a steady state model consists of (IE a negative load or an explicit generator). I don't think it is in the scope of this document to lay out the DER model but it should point to where the preferred definition of a steady state or dynamic DER model is housed.

Commented [JS116R115]: Added another sentence to refer to introduction section that contains the links and framework. Highlighted key point of explicit generator records.

Commented [BM117]: Not sure the end of this sentence makes sense. Maybe revise to "and is the starting point around which dynamic models initialize"

Commented [JS118R117]: Change made as suggested.

Commented [RD119]: This is not at all useful unless either a reference is provided or more information is provided.

Commented [JS120R119]: Information provided per comment above.

Commented [RD121]: How was it verified?

Commented [JS122R121]: Information provided per comment above

Commented [RD123]: What is the approach?

Commented [JS124R123]: Information provided per above comment

Commented [LG125]: Consider revising to "System Conditions for DER Model Verification Steady state verification procedures can use slower data records and does not need events to verify the steady state data. An example of this is that other studies can provide an insight into the local region. When conducting short circuit studies, an entity found that an aggregation of DER was incorrectly modeled. In this scenario the aggregation occurred with R-DER and was modeled on the nearest BPS bus and not modeled at the correct voltage level. This was affecting the powerflow solution at the modeled BPS transformer and cause increased LTC activity in the powerflow model. The entity solved the issue in their studies by verifying the location of the resource, the connection voltage, and analyzed its path the BPS bus to get appropriate impedances between the R-DER and BPS transformer. It is recommended that other entities utilize this approach where appropriate to create an accurate steady-state DER model."

Commented [JS126R125]: Change made as suggested, given that this was your section

Commented [LG127]: We didn't ask for frequency in steady-state before so we shouldn't mention it here.

Commented [JS128R127]: Deleted as recommended.

Commented [LG129]: Not sure how much value this provides in the steady-state realm

Commented [JS130R129]: Altered, but see Brad's comments on voltage settings in steady state records for certain conditions.

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Temporal Limitations on DER Performance

> **Key Takeaway:**
> Time dependent variables impact the dynamic capability of the DERs in the aggregation. TPs should separate maximum nameplate capacity and maximum dynamic capability during the event during dynamic model verification.

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

Commented [BM131]: Don't know if "average" is the right word here. I think "minimum" might be better thinking of the parabolic shape of a PV profile. For a sunny day the irradiance would hit the minimum level required to output the maximum allowable power twice, once when the sun is coming up, the other when it is going down. Between those times the irradiance is higher than that needed for full output.

Commented [JS132R131]: You are right. Change made as suggested.

Steady-State Model Verification for an Individual DER Model

> **Key Takeaway:**
> The large majority of U-DER facilities are s~~S~~olar PV, and behave generally like other BPS s~~S~~olar PV IBR resources. This predictable performance should be included when gathering data for model verification purposes.

The objective of steady state verification of DER installations is to verify the correlations between active power, reactive power, and voltage trends. The responses below in Figure 2.1 demonstrate how a DER device characteristics may change in the day to day responses. Compare that response with the total load response in Figure 2.2. While the data contained here demonstrates the controllability aspects of the DER resource over a long period of days, much of this data can be inferenced based off irradiance data taken close to the facilities; however, this particular site had a few controllability settings to verify, namely load following settings.

Commented [PSJ133]: I think the term solar PV IBR resource (in the Key Takeaway box) should be clarified. Does this refer to the inverter based resources on the bulk power system?

Commented [JS134R133]: Clarified as we are trying to make that connection in terms of the parabolic PV resource profile.

Commented [PSJ135]: Why does the power output from DER become negative? Is this the load as seen by the distribution system?

Commented [JS136R135]: It is not the load, but at the terminals of the resource, the negative value is based on that particular entity's way of tracking it (negative indicates production from the resource that could flow back to transmission system).

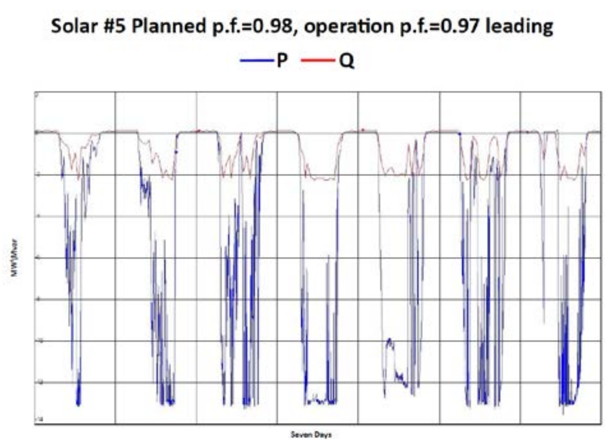

Figure 2.1: Load Following U-DER Response

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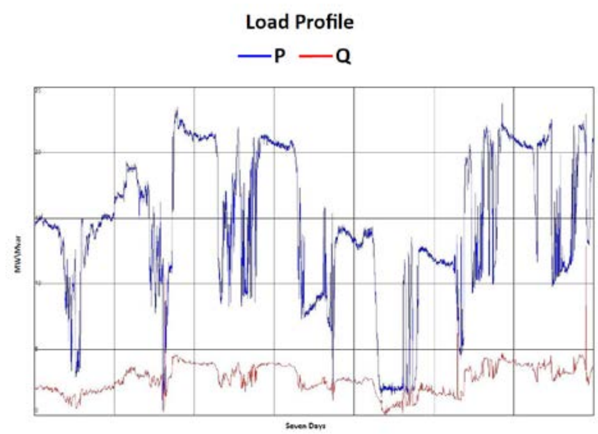

Figure 2.2: Load Response near the U-DER

In the steady state, the points required could be verified based on day 4 only. To reiterate, the P and Q relationships could be verified by simply providing that one day. To verify the load following setting, day 5 provides valuable information regarding the load following settings In addition, it is important to know that these measurements came from two different electrical locations (at the terminals of the U-DER device and at the T-D interface for the load) and such separation allows for the steady-state verification process to be easier. Each TP/PC should consult with the DP to ensure the data required to verify their facility as part of the modeled aggregation is submitted. Care shall be taken to ensure that the data will be used for its intended purpose of model verification and will not be misused or shared outside of the DPs and other distribution entities intended use; however, it is graphs like these that allow TPs to verify the P, Q, and V characteristics in their steady state models. If there isn't data measurements like Figures 2.1 and 2.2 made available, by asking questions of the DP and applicable entities, the TP is able to adjust their set of planning models to account for any changes to the DER aggregation from the submitted model. Table 2.1 highlights some of these important questions.

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

Data Collected	Anticipated Parameters	~~Specific DER parameters~~
~~How many DER installations~~What is the aggregated operational characteristics of DERs [39] at substation within specified time domain?*	This will help set the maximum power output of all DER represented in the verification process. This ~~assumes that the count of inverters is indicative of the size of installations. i.e. 5 installations of 5 MW for a total of 25 MW~~accounts for the aggregated ~~coincidental capacity~~coincidental capacity potential of the resources.	~~Pmax~~

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

Commented [BM137]: Not sure what this table is specifically asking for? Steady state parameters for the powerflow model? Or just data points in general? Why list PMAX twice? The interconnection location is important as well, but maybe this table assumes one already knows where the DER is located, but not the parameters around it?

Commented [JS138R137]: Changed Table title, delete third column, and added location as a separate row. This is asking, when measurements are not available, ways to verify the steady-state dispatch of the BPS model.

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Commented [SR139]: Many interconnection issues and working groups around the country focus on the operating profiles, which is very important with AC coupled storage, so that nameplates are not simply stacked if the DERs do not operate in this manner.

Commented [JS140R139]: Changes kept to emphasize this point.

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What is the point of interconnection (i.e. transmission substation) where the aggregate DER connects to?	This will identify which load/generator record in the powerflow set of data to attribute the aggregate DER capacity and generation in the set of BPS models.	
What is the magnitude and type of aggregated coincidental load connected to the transmission substation?**	This data point will assist in determining how the overall model set will perform when adjusting both the DER model and load model at the substation.	~~Pmax, Pgen~~
What reactive capability is supplied at the DER installations?	This will assist in determining the maximum reactive output of all DER represented in the verification process. This question can also be asked of the aggregate load response.	~~Qmax, Qmin~~
Minimum power of DER***	For non-solar related DER devices such as microturbines or BESS, this parameter provides the minimum required output of the DER resource in transient stability.	~~Pmin~~

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

Battery Energy Storage System Performance Characteristics

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

It is recommended to utilize a single DER model for aggregate U-DER, but some complexities or modeling practices may dictate otherwise. ~~A prime E~~ Eexamples for moving to ~~two~~ separate ~~models~~ aggregations is related to the frequency or voltage regulation settings. Some modeling practices aggregate each technology type separately; however, the benefit of a single DER model for each U-DER allows for a one to one relationship in any measurements provided. ~~for a DER BESS providing a load following service next to a DER facility that is at power factor control. There exists many complex control interactions between those facilities, and a single measurement location may not be able to capture all the steady-state parameters for modeling in order to capture the unique aspects of BESS opposed to other DERs.~~ The TP and PC is recommended to use engineering judgement and readily available information to determine if these ~~BESS~~ considerations are necessary for their models and alter their verification practices accordingly.

Steady-State Model Verification for Aggregate DERs

The verification of multiple facilities at they pertain to the aggregation is a more complex process than modeling a single U-DER facility due to the variety of different controls and interactions at the T-D interface ~~When there is only~~

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Commented [PM141]: Load keeps varying throughout the day. Do we need peak or off peak or coincident measurements when DER is being measured? Also how does it help determine PMAX and PGEN. This is not very clear and an example will help

Commented [JS142R141]: Addressed by adding "Aggregated coincidental" in the question. Third column of table is removed.

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Commented [LG143]: In general, I feel a diagram may be very useful here to convey what we are trying to say. There is currently a lot of things in flux with BESS and conveying the information about the characteristics and modelling intricacies can be hard to follow in text, especially to readers that have not been exposed to this.

Commented [JS144R143]: A diagram was determined in the 7/27/20 discussion to not be useful here. The information here is to address the complexity of different resource aggregations behaving differently. We call out aggregate BESS as their aggregate impact at the T-D interface is made up of charge/discharge controllers that operate, for the most part, independently of one another. The guidance remains the same: monitor large U-DER and the T-D interface. BESS just means you need to be aware of any charge/discharge interactions that can mask load or other DER output.

Commented [BM145]: Not sure this is a problem but it might be useful to discuss the type of aggregation. I think aggregating U-DER according to the WECC Solar plant modeling guideline is good, but lumping individual U-DER projects together in steady state would be a mistake since they could have different steady state voltage control schemes.

Commented [JS146R145]: Changed the following in order to accommodate this point.

Commented [BM147]: This section assumes that measured data is available on a transformer and DER level. Is this always the case?

Commented [JS148R147]: It is not always the case, but follows from the Chapter 1 placement of devices for both U-DER and R-DER modeled. We recommend each U-DER be monitored/distinguished from the R-DER and in all cases have measurements at the T-D interface.

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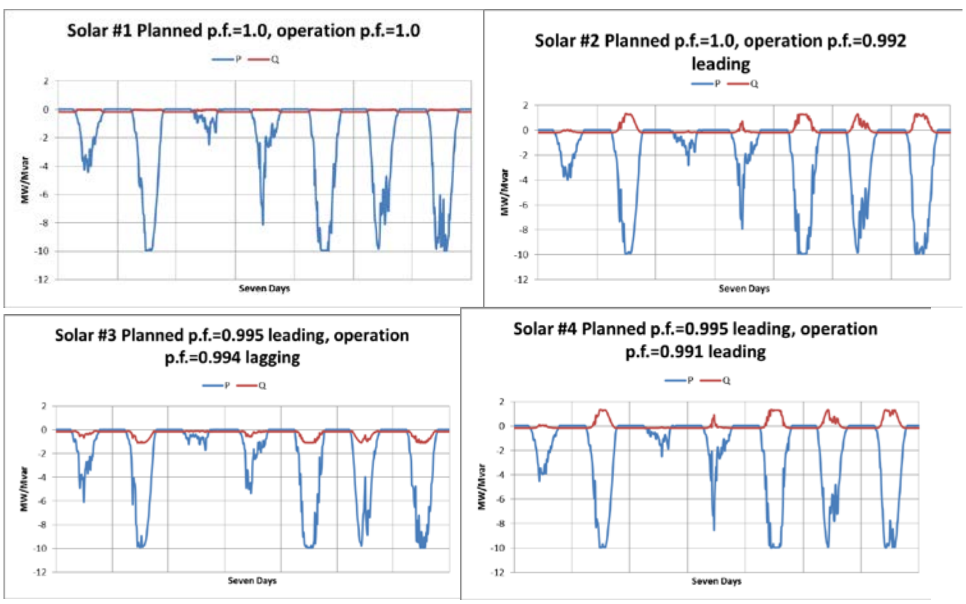
~~one large U-DER facility in the aggregate DER model the process is simpler. Adding to the complexity will be the verification of multiple facilities as they pertain to the aggregation~~. When modeling both U-DER and R-DER at the T-D interface some assumptions help the verification process. Most legacy DERs (IEEE 1547-2013) may operate at constant power factor mode only and typically are set at unity power factor, making this a safe assumption. The IEEE 1547-2018 standard has introduced more DER operating modes such as volt-var, watt-var or volt-watt and this may require reaching out to the DP to verify as the settings could be piecewise~~.~~ or the functionality may not even be used.~~ ~~ More complex control schemes will require more than a cursory review of settings. Additionally, if there are any load following behaviors, it is preferable to collect each day in a week to capture load variation. It is preferable to monitor each individual U-DER location in order to aggregate the impacts of the data, while leaving the monitoring of R-DER at the high side of the T-D interface.

Figure 3.3 shows an example from a 44 kV feeder measurements. The four solar plants, each rated 10 MW, and one major industrial load are connected to the feeder at different locations. All solar plants were planned to operate at constant power factors at either unity or leading. The leading power factor requirement was to manage voltage rise under high DER MW outputs travel through a long feeder with lower X/R ratio. The data show that the third solar plant's reactive power output was opposite to the planned direction (lagging vs. leading). The second solar plant also could not maintain unity power factor as planned. Figure 2.3 also plots the industrial load profile and the total feeder flow measured at terminal station. Based on this, the steady state verification of the DER should reflect the aggregation of all four of those facilities as it is reflected at the T-D interface. Here, the TP is able to verify the aggregate of the U-DER solar facilities as the P and Q flows from these facilities were recorded. Additional confirmation of steady-state voltage settings would require the voltages at these locations, and is recommended to supplement these graphs.



Commented [LG149]: Consider revising to "The verification of multiple facilities at they pertain to the aggregation is a more complex process than modeling a single U-DER facility due to the variety of different types of technologies."

Commented [JS150R149]: Slightly altered, but kept the main point as this is a transitioin sentence.

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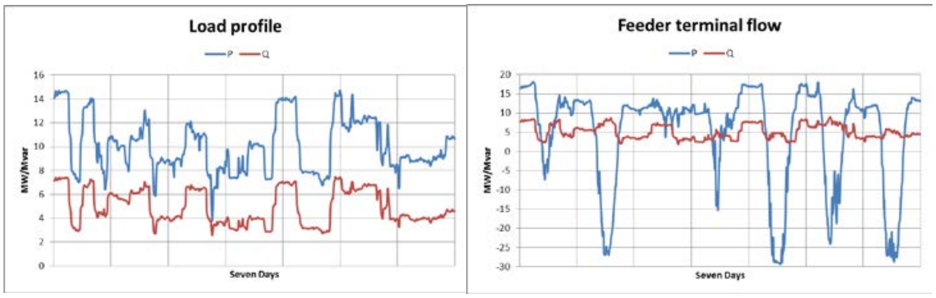
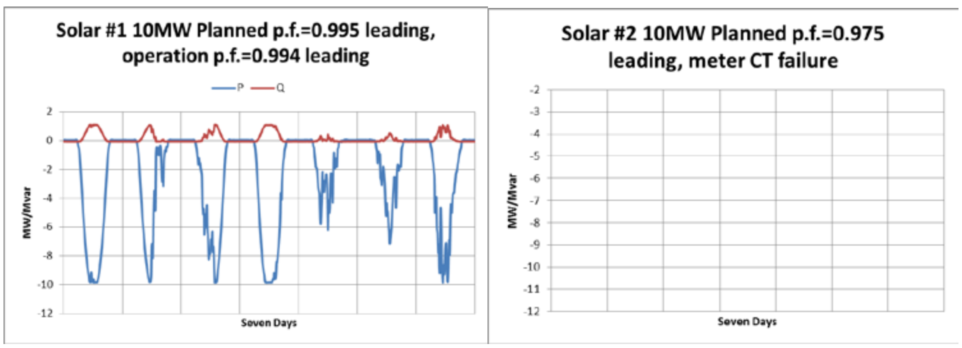


Figure 2.3: Active and Reactive Power Measurements from U-DERs, Load, and Substation

Figure 2.4 shows another 230kV station-wide measurement. Power trends from eight monitored DERs connected to 44kV feeders supplied from the station are plotted in the figure. The meter at Solar #2 was out of service in the week due to failed CT. Note the 6th solar DER is a behind the meter installation, the 7th is a biomass DER and the 8th is aggregation of three solar DERs and load[40]. The last two plots in Figure 3.4 are measured from two paralleled 230kV-44kV step-down terminals. It can be seen that nearly zero MW transferred across the transformers under high DER outputs. The Mvar flow steps were result of shunt capacitor switching at the 44kV bus of the station. Based on each of these monitored elements, the powerflow representation should capture the active power, reactive, power, and voltage characteristics as seen across the modeled T-D transformer. While not provided in the figures, the voltage at these locations should be used when verify the voltage characteristics in the model This process may require baseline measurements to determine gross load values in addition to coordination of substation level device outputs in relationship to the load and DER as evident in this example with the capacitor bank switching, DER, and load output affecting the T-D transformer.



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

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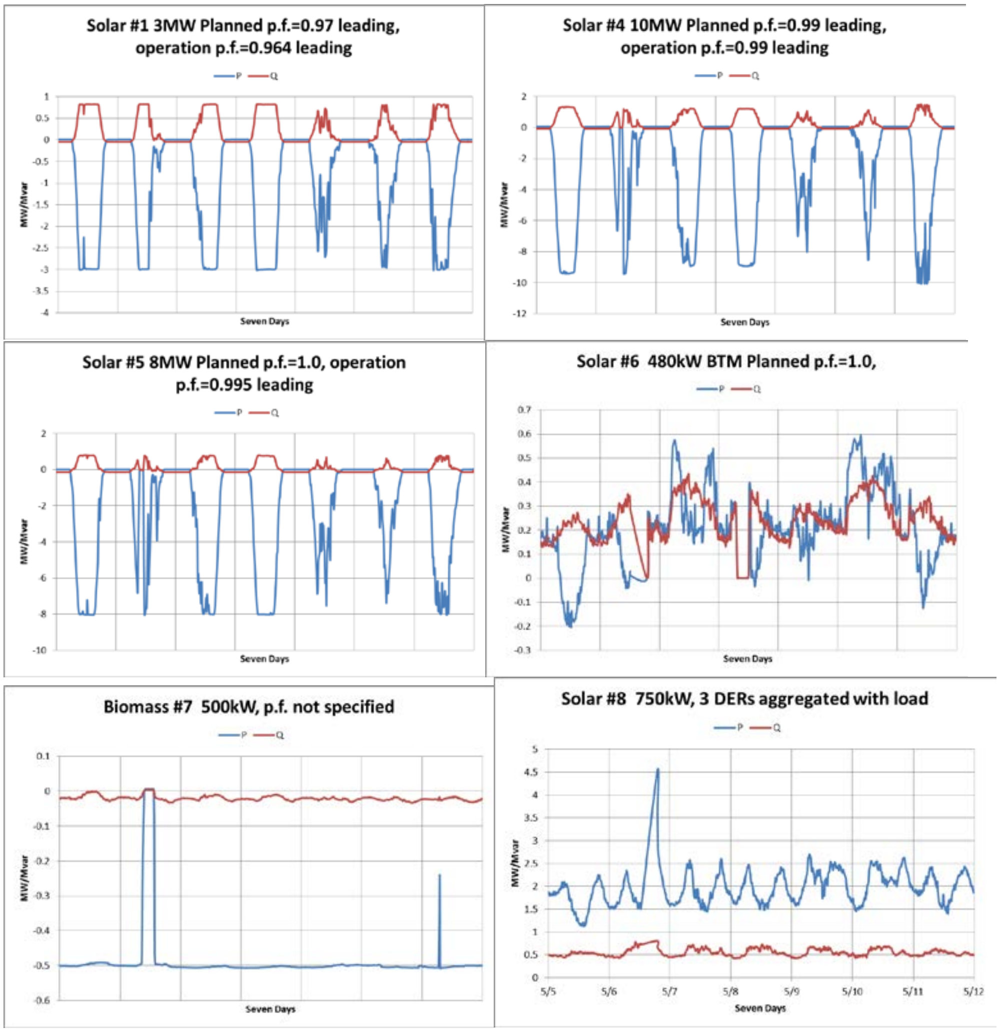

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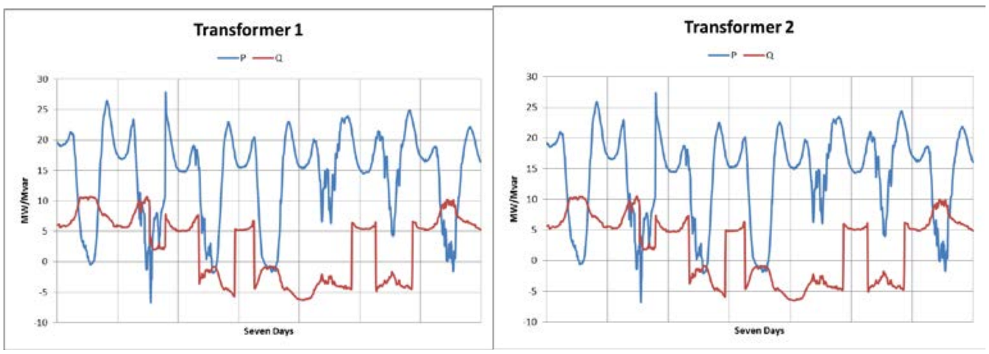

Figure 2.4 Active and Reactive Powers Measured from Various DERs and Substation Transformers

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

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

Once the model contains both aggregate U-DER and R-DER, the dispatch of the U-DER and R-DER becomes difficult to verify in the steady state records with only one measurement at the T-D interface. With measured outputs of all U-DER aggregated at the substation, a TP is able to verify the MW and MVAR output between the two aggregations so long as the gross load of the feeder is known. Figure 2.5 details a high level of the U-DER and R-DER pertaining to the distribution transformer as seen in a planning base case. Additionally, with voltage measurements pertaining to the U-DER, the whole set of active power, reactive power, and voltage parameters can be verified to perform as according to the steady state operational modes. Note that this process will inherently vary across the industry as performance and configuration on the distribution system varies. In general, the verification of the steady state P, Q, and V characteristics will need measurements of those quantities and which of the DER model inputs that measurement pertains to (i.e. the U-DER or R-DER representation). As each model record represents an aggregation of DER facilities, note that more data will help refine the process. Additionally, some modeling practices have more than one generator record for different aggregations of DER technology types, namely for U-DER. The increase of generator records when modeling DER increases the importance of monitoring individual large U-DER facilities in order to attribute the correct steady state measurements to the planning models. ~~–~~In general, when viewing measurements from a T-D bank, assumptions will be required to categorize the U-DER response in relationship to the R-DER response

Commented [BM151]: Again, I don't think we should recommend aggregating the U-DER's since they can have different steady state voltage control schemes. Some could be in PF control, others in voltage control. These aren't always small plants either, they can be 20-30MW's. I think U-DER steady state outputs should be verified on an individual plant basis.

Commented [JS152R151]: Added some text below to stress this modeling practice.

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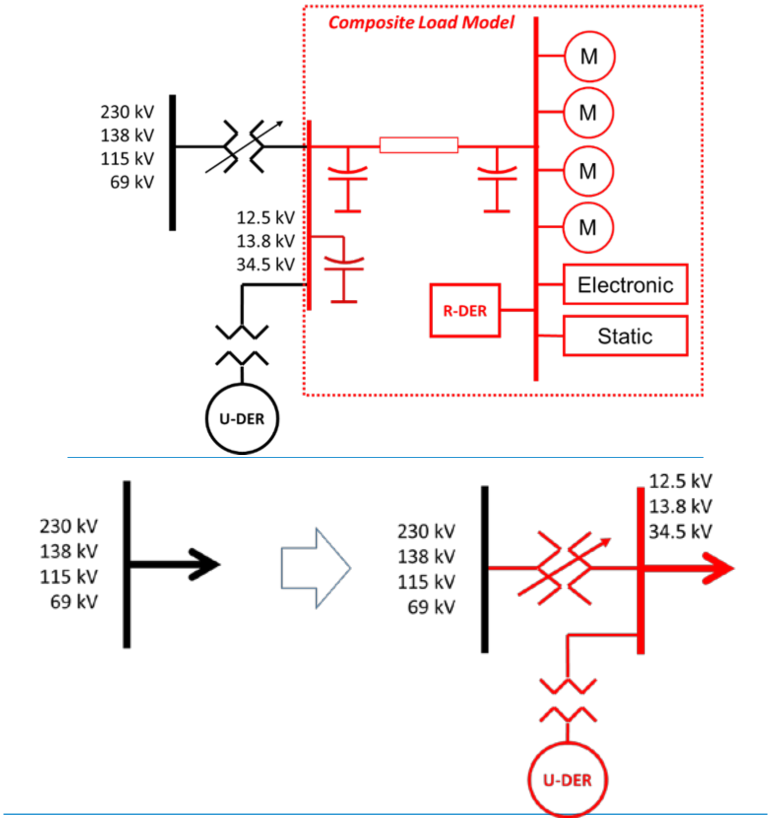

Figure 2.5 Aggregate U-DER and R-DER Steady-State High Level Representation

Commented [RD153]: The diagram does not specify R-DER. Would be good to include R-DER in the diagram. The reader may not know what the arrow at the 12.5kV bus is supposed to denote

Commented [JS154R153]: Changed figure to include both modeled types.

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Chapter 3: DER Dynamic Model Verification

This section covers the verification of the aggregate DER model for use in dynamic simulations. Generally speaking, the primary initiating mechanism for verification of dynamic models are BPS level events. Historic events may be used to verify the performance of equipment online during the event. The majority of dynamic model verification occurs when using recorded BPS level events as a benchmark to align the model performance. If the DP/TP/PC has access to the commissioning tests, the availability of these results is also useful in DER model verification as some commissioning tests demonstrate the dynamic capability of the devices.

Event Qualifiers when using DER Data

Some qualifiers should be used when selecting the types of events used in model verification due to the varying nature of events. Because of the many aspects of events, the following list should be considered when performing verification of the DER dynamic model:

- Utilization of measurement error in calculations regarding closeness of fit
- Separation ~~from~~ of DER response from load response in events, both in steady state and dynamics performance
- Reduction strategies to simplify the system measurements to the models under verification

Because of event complexity, some events simply will not have any value in verifying the DER models and thus will have no impact to increasing model fidelity. Such considerations are:

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

Even with previously verified models for one event, additional events will also provide TPs additional assurance on the validity of the dynamic DER model. One of the most telling aspects on this would be that the Event Cause Code is different between verified model and new event and such differences impact model performance. Based on the above factors, it is crucial to the model verification process that each recorded event have sufficient detail to understand the event cause and the DER response in order to link the two. Such documentation should be considered in order to ensure future procedures are beneficial to the verification of the model.

Individual DER Dynamic Model Verification

If the TP/PC determines there are sufficient amounts of aggregate DER in a study area, then models should adequately represent dynamic performance of aggregate DER. U-DER and R-DER differ in that dynamic performance characteristics of individual installations of U-DER are practically accessible, while the dynamic performance characteristics of individual installations of R-DER are not. Thus, though this section focuses on the dynamic performance of U-DER, many of the same performance characteristics may be inferred under engineering judgment to apply to R-DER[41]. With data made available, model verification can occur. See Figure 3.1 for a high-level representation of U-DER topology with load and other modeled components. The composite load model here contains a modeled R-DER input; however, in this section the composite load model is considered to not include that input.

[41] In the model framework, the U-DER facilities are connected to the low side bus of the T-D transformer as they are generally close to the substation with a dedicated feeder. In cases where this is not the case, the TP should consider moving that DER facility from the classification of U-DER to R-DER in the modeled parameters if the facility is sufficiently far away from the substation that the feeder impedance affects the performance of the large DER facility.

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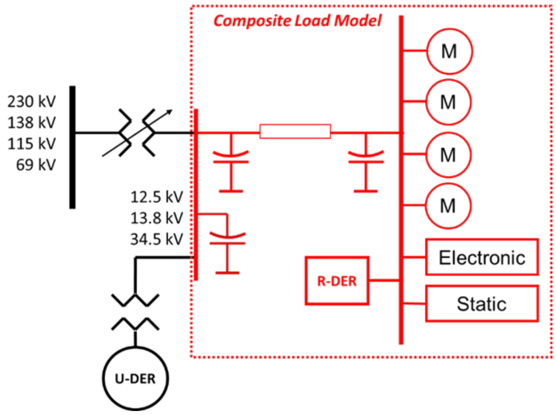

Figure 3.1 High Level Individual U-DER and Load Model Topology

Dynamic Parameter Verification without Measurement Data

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

In the instances where measurement data is not made available to the TP for use in model verification, the TP is capable of verifying a portion of their dynamic models by requesting data from the DP or other entities that is not related to active and reactive power measurements, voltage measurements, or current measurements. A sample list of data collected and anticipated parameter changes is listed in Table 3.1. This list of parameters is not exhaustive in nature~~. and~~This table should be altered to address the modeling practices the entity uses in representing U-DER in their set of BPS models, and should be used only as an aide in determining those parameters required for the dynamic performance verification as the model and system changes between the initial model build and the current set of models. These parameters can be used to help adjust the model in order to assist in performing the iterative verification process. As the DER_A model is one of the few current generic models provided for representing DER, those parameters are listed to assist the process. These parameters can come from a previous model in addition to a data request. An important note is that requesting the vintage of IEEE 1547[42] inverter compliance will provide the TP information adequate to ensure their model was correctly parameterized to represent a generic aggregation of those inverters. This is especially true of higher MW DER installations as these are more likely to dominate the aggregation of DER at the T-D interface. This method is not intended to replace measurement based model verification, but rather supplement it where measurements are not currently available.

Table 3.1: DER Dynamic Model Data Points and Anticipated Parameters		
Data Collected	**Anticipated Parameters**	**Example DER_A parameters**

[42] Or other equivalent applicable equipment standard

Commented [RD155]: Or equivalent applicable standard.

Commented [JS156R155]: Added footnote on this.

Commented [BM157]: Should this only be referring to the R-DER? I think U-DER should have their own explicit models developed using the WECC Solar Plant modeling guideline using the 2nd gen renewable models.

Commented [JS158R157]: This should be representing both R-DER and U-DER. While we understand the 2nd generation models are useful for IBR DER, this does not always mean entities will use explicit modeling of U-DER. The framework allows for aggregate models on U-DER and we want to address those here.

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What vintage of inverters represented?	This will provide a set of voltage and frequency trip parameters.	Voltage: vl0,vl1,vh0,vh1,tvl0,tvl1,tvh0,tvh1 Frequency: Fltrp,fhtrp,tfl,tfh
		Overall: Vrfrac
How much of DER trips during voltage or frequency events?	This data point, in combination with the data point above will help determine the total MW of capacity that trips with regard to voltage or frequency. The answer can take into account other known protection functions that trip out the distribution feeder or other equipment not related to the inverter specifications, or can represent choices made inside the vintage.	vrfrac

Commented [JS159]: Change not accepted as the verification of BPS planning models do not need to know if the inverters are compliant with current DP practices.

Dynamic Parameter Verification with Measurement Data Available

The preferred method for dynamic parameter verification is the matching of model performance with field measurement data. Per FERC Order No. 828, the Small Generator Interconnection Agreement (SGIA) already requires frequency and voltage ride through capability and settings of small generating facilities to be coordinated with the transmission service provider.[43] And per FERC Order No. 792, metering data is also provided to the transmission service provider.[44] Thus, the TP/PC have access to data for verification of U-DER dynamic performance for units applicable to the SGIA. In utilities with larger penetrations of DER, more prescriptive language may exist to supplement the SGIA. Data at the low side of the transformer provides the minimum amount of data to perform the process, but the measured data at the U-DER terminals also can provide a greater insight into the behavior of installed equipment and the TP can perform a more accurate aggregation of such resources. If the DP has data that would help facilitate the verification process and such data is not cumbersome to send to the TP/PC, the data[45] should be sent in order to verify the aggregated impact of the U-DER installations in the BPS Interconnection base case set of models.

While the SGIA provides benefits for the TP/PC in obtaining data for applicable units, not all of the DER facilities will be under the SGIA. See Table 3.2 to get an understanding of the amount of resources ISO-NE considers as DER[46]. For the representations here, the Solar PV Generation not participating in the wholesale market is 1532 MW while 858 MW participates and is SGIA applicable. In this region, reliance on the SGIA alone will only gather a third of the installed Solar PV DER. In addition, generation from other sources totals 1351 MW, which includes fossil fuel, steam, and other non-Solar renewables as the fuel source for the DER. Based on this table, roughly 22% of all DER applicable to the SPIDERWG Coordination Group's definitions would be verified if only those facilities under the SGIA would be verified. While the SGIA does play a role in the data collection, reliance on the SGIA alone could result in significant data gaps.

Table 3.2: New England Distributed energy Resources as of 01/01/2018

[43] Order No. 828, 156 FERC ¶ 61,062.
[44] Order No. 792, 145 FERC ¶ 61,159.
[45] E.g. measurements from a fault recorder, PQ meter, recording device, or device log.
[46] The full ISO-NE letter can be found here.

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DER Category[47]	Settlement Only Resource Nameplate Capacity [MW]	Demand Resource (DR) Maximum Capacity [MW]	Total DER Capacity [MW]
Energy Efficiency	-	1765	1765
Demand Resources (excluding behind-the-meter DG capacity)*	-	99	99
Natural Gas Generation	26	331	357
Generation using Other Fossil Fuels	75	268	344
Generation using Purchased Steam	-	19	19
Non-Solar Renewable Generation (e.g. hydro, biomass, wind)	523	126	649
Solar PV Generation participating in the wholesale market	810	48	858
Electricity Storage	1	-	1
Solar PV Generation not participating in the wholesale market	-	-	1532
Total DER Capacity	1436	2656	5625
Total DER Capacity/ Total Wholesale System Capability**	4.1%	7.5%	15.9%

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

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

Aggregate DERs Dynamic Model Verification

Similarly to verifying U-DER, the model of an aggregation of U-DER and R-DER will be conducted similarly, with the same one to many concerns discussed for steady-state verification.[48] Detailed in Figure 3.2 is a complex set of graphs that represent R-DER and U-DER, along with load, connected to a 230 kV substation to the response of an electrically close 115 kV three phase fault. As evident in the figure, it is only applicable to collect multiple terminal locations of

[47] Note that these categories are from ISO-NE and may not conform to the working definitions used by SPIDERWG related to DER (e.g., energy efficiency is not considered a component of DER under the SPIDERWG framework)
[48] Please see an example in *Duke Energy Progress Distributed Energy Resources Case Study: Impact of Widespread Distribution Connected Inverter Sources on a Large Utility's Transmission Footprint,* EPRI, Palo Alto, CA: 2019, 3002016689

Commented [RD160]: Can also reference EPRI Public report which showed DER_A model validation with event measurement data:

Duke Energy Progress Distributed Energy Resources Case Study: Impact of Widespread Distribution Connected Inverter Sources on a Large Utility's Transmission Footprint, EPRI, Palo Alto, CA: 2019, 3002016689

Commented [JS161R160]: Added reference.

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data when more than a single U-DER installation is modeled at the substation in the aggregation to ensure adequate measurements are available for the TP to verify their models.

Under a 115 kV system three-phase fault, the entire station sees the voltage profile[49], which details a roughly 15-20% voltage sag at the time of the fault. The voltage of the 230kV substation returns to normal after the fault; however, the current contributions across the distribution transformers changes. At the 44kV yard all four solar installations rode through the fault with increased current injection during fault. The load was not reduced after the event even with it providing reduced current during the fault. Aggregated current at T3 shows total current unchanged after fault but big increase during fault. This is different from traditional fault signature as reduced current during fault is expected when the fault is outside of the station.

At the 28 kV side the two solar plants could not ride through and shut down. In addition, increased load current after fault clearing can be seen in T1/T2, which is impossible in the traditional station representation without DER. This demonstrates that the pickup of the load was across the T1/T2 transformers. Based upon this figure, it can be determined that the dynamic model parameters should reflect the response of the aggregate, and that may look different depending on how the Transmission Planner decides to model this complex distribution substation into the planning models. In summary, with metering at each U-DER[50], large load and station terminals, we have enough information for verification of the complex models that represent these DERs.

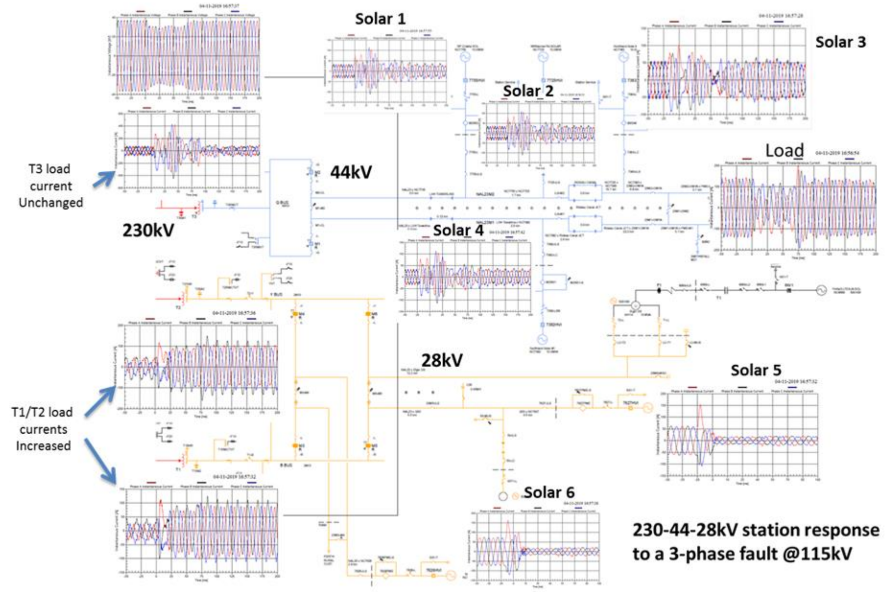

Figure 3.2: 230 – 44 -28 kV Substation Response to a 115 kV Three Phase Fault

Dynamics of Aggregate DER Models

Similar to the process for individual DER models, the aggregation of R-DER and U-DER models pose just a few more nuances in the procedure. As the framework shows, the U-DER inputs and the R-DER inputs both will feed into the substation level measurement taken. This poses a challenge where the number of independent variables in the

[49] Left top corner of the figure
[50] Note that some required monitoring at the end of the feeder

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process are lower than the number of dependent outputs in the set with only one device at the T-D bank. As such, techniques that relate the two dependent portions of the model will be of utmost importance when verifying the model outputs. Figure X.X describes the overall dynamic representation of U-DER modeled DER and R-DER modeled DER with respect to the T-D interface, and Similar to Table 3.2, the same number of data points can help to verify the parameters in the DER model associated with the resource. However, a few additional points help with attributing the total aggregation towards each model as seen in Table 3.3.

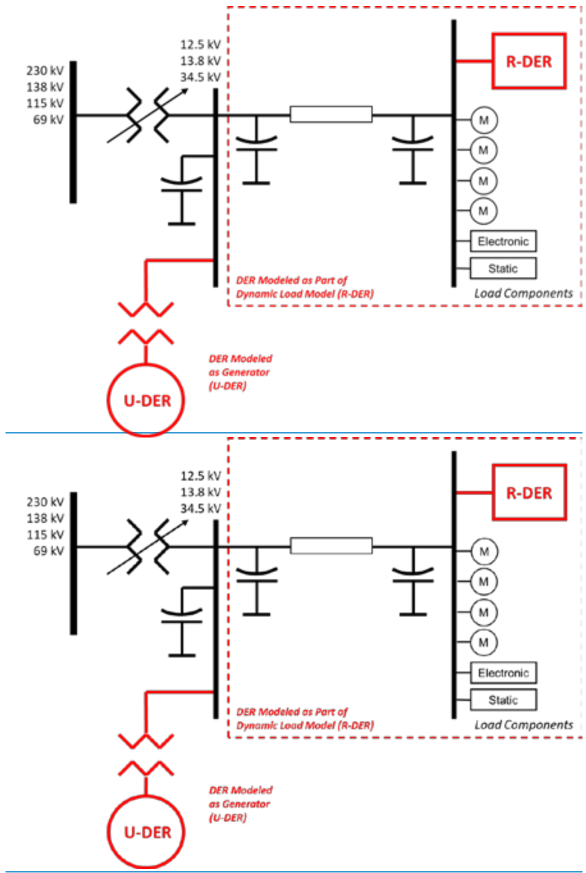

Figure X.X: Aggregate DER Dynamic Representation Topology Overview

Table 3.3: DER Data Points and Anticipated Parameters			
Data Collected	**Data Measurement Location**	**Affected Representations**	**Anticipated Parameters**
Ratio of U-DER and R-DER inverter output*	Substation level	Relative Size of U-DER and R-DER Real Power output	Pmax in U-DER model, Pmax in R-DER model

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Ratio of DER to Load*	Substation Level	Relative size of Load model to U-DER and R-DER outputs	Pload in Load model, Pmax in DER models
Distance to U-DER installations	Substation Level to U-DER installation	Resistive loss and Voltage Drop	Voltage Drop / Rise parameters, Xe
Mean distance to R-DER installation	Substation level to calculated mean	Resistive loss and Voltage Drop	Feeder, Voltage Drop / Rise Parameters.

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

Most notably, the last two rows of the table detail a way to help separate the R-DER and U-DER tripping parameters and voltage profiles seen at the terminals of the inverters. Should any of the above data be restricted or unavailable, following the engineering judgments in the *Reliability Guideline: DER_A Parameterization*[51] will assist in identifying the parameters to adjust based on inverter vintages. However, the data answers in Table 4.1 are not a supplement for measurement data taken at the U-DER terminals or at the high side of the T-D transformer. With the measurements available and the data in Table 4.1, the TP or PC can make informed tuning decisions when verifying their models.

Initial Mix of U-DER and R-DER

Key Takeaway:
Relative sizes between load, U-DER, and R-DER can guide TPs and PCs on which portion of the aggregation to adjust during model verification.

In the model representation, the ratio of U-DER and R-DER is significant as the response of the two types of resources are expected to be different considering with relationship to specific voltage dependent parameters. As many entities do not track the difference in modeled DER if tracking DER at all, it is expected that the initial verification of an aggregate U-DER and R-DER model to require more than simply the measurements at the location in order to attribute model changes. TPs and DPs are encouraged to coordinate to assist in getting a proper ratio of the devices in the initial Interconnection-wide base case. In the future, there exists a possibility that the interconnecting standard for U-DER may be different than R-DER. If such standards exist, the TP/PC should verify the mix of U-DER and R-DER are representative of the equipment standards pertaining to the type of DER.

Battery Energy Storage System Performance Characteristics

With regard to BESS, the performance of both aggregate U-DER and R-DER is doubly as complicated in the BESS plus U-DER example. As highlighted in that section, control mechanisms exist that could cloud and complicate the interaction of different DER types when utilizing a singular dynamic model, but could perform adequately for steady-state DER model verification. With respect to adding in modeled R-DER and assuming retail scale connected BESS devices, it becomes even trickier to understand. Including R-DER modeled BESS devices proves to mix not only between two different DER control schemes, but also with the load. Additionally, contracts with R-DER BESS can pose challenges to obtain parameters or measurements for use in dynamic model verification[52]. It then becomes harder to separate the response of load and DER as a charging BESS system can mask increased DER output for R-DER modeled devices, and the ride-through characteristics of the aggregate BESS DER and the aggregate R-DER modeled solar PV DER can be different. In turn, model verification can become computationally complex just to attribute the response to U-DER BESS, other U-DER, R-DER BESS, other R-DER, or load in the model. TPs and PCs are encouraged to utilize engineering judgement and to coordinate with the DP and other available resources to attribute the response characteristics of load, BESS, and other DER types when performing the model verification for situations like the above.

[51] https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability_Guideline_DER_A_Parameterization.pdf
[52] As many of the dynamic parameters from OEMs are largely considered proprietary

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Parameter Sensitivity Analysis

As with most models, certain parameters in the DER_A model may impact the model output depending on the original parameterization. Trajectory sensitivity analysis (TSA), a type of sensitivity analysis varying the parameters of a model, quantifies the ~~level of trajectory change from a model when small changes are made to individual parameters~~sensitivity of the dynamic response of a model to small changes in their parameters.[53] While TSA is commonly ~~used in academia,~~ implemented differently across multiple organizations, certain software packages include ~~them~~ a basic implementation. Among them are~~including~~ MATLAB Sensitivity Analysis Toolbox[54] and MATLAB Simulink. ~~In addition, EPRI is developing a tool utilizing TSA focused on load modeling.[55]~~ TSA analysis with respect to verifying DER_A dynamic model parameters can be found in Appendix A.

TSA is one of many methods for TPs and PCs to gain understanding of the sensitivity of the dynamic model to small changes in model parameters; however, this is not a required step in model verification nor a required activity for tuning dynamic models. Further, due to TSA linearizing the response of the dynamic model around the operating point, it may not account for changes in operating modes in the DER dynamic model and may not account for needed changes in flags or other control features in the model. Furthermore, some parameters in models may prove to be more sensitive than others, but are not well suited for adjustments. One such example are transducer time delays that can greatly impact the response of the device, but other parameters are more likely to be changed first. Additionally, the numerical sensitivity of particular parameters is not important for a TP to verify the aggregate DER dynamic model, but their impact on the dynamic response of the model is. It is encouraged that multiple set of parameters for DER models be tested against dynamic measurements when performing parameter analysis. ~~Therefore~~Because of all these qualifications, use of TSA should be supervised by strong engineering judgment.

Summary of DER Verification

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

- Location of Voltage, Frequency, Power, or other quantity with respect to the electrical terminals of the DER devices
- Relationship of the DER devices with respect to end use demand as well as other DER devices in the aggregation[56]
- Accurate and robust metering equipment on the high or low side of the T-D transformer as well as equipment near the large DER terminals

With those three bullets in mind, TPs and PCs are encouraged to begin utilizing measurements for steady-state or dynamic model verification of DER. Since all DER generators can be tested,[57] the DER models will likely be tuned over time to represent the growth of DER in a specific area. Like BPS device models, operational considerations and adjustments are required to perform the study conditions. In order to change a verified model to the study conditions, the following items should be considered:

- Time of day, month, or year[58]

[53] Hiskens, Ian A. and M. A. Pai. "Trajectory Sensitivity Analysis of Hybrid Systems." (2000).
[54] https://www.mathworks.com/help/sldo/sensitivity-analysis.html
~~[55] https://www.epri.com/#/pages/product/3002003349/?lang=en-US~~
[56] This is particularly true of BESS DERs
[57] Nor should they be absent a technical analysis and justification
[58] Irradiance and other meteorological quantities are affected by time and some DER types are dependent upon this weather data

Commented [MP162]: For the sake of simplicity let us just call it sensitivity analysis and mention that it is the sensitivity of the entire dynamic response. This is fairly well known among transmission planners. TSA on the other hand sounds quite esoteric.

Commented [MP163]: This statement needs to be modified. This has been done extensively for the composite load model during the NERC LMTF and WECC MMWG activities by MEPPI. This is also routinely done by EPRI and other folks to identify key model parameters required for a variety of sensitivity studies. Albeit, the methods for performing sensitivity analysis is different the ones referred here.

Commented [JS164R163]: Altered to emphasize more "common" packages, but not focusing on the academic portion. Emphasized the changes of practices/implementation in entities (as evident in the comment)

Commented [MP165]: EPRI has a tool for parameter estimation called LMDPPD. However, we do not have a tool for trajectory sensitivity analysis.

Commented [JS166R165]: Removed.

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- Electrical changes between verified model and study model[59]
- Sensitivity considerations on the study[60]

Future Study Conditions

TPs and PCs should see future and other guidance from the SPIDERWG that details the study concerns with DER and how to change the model to reflect those study conditions. It is likely that not all the same parameters changed in the models to obtain a verified model will be adjusted for study conditions. For example, a study sensitivity may try and determine the impact of updating all legacy DER models on a distribution system. For such a study, tripping parameters will likely change; however, the penetration will not for that specific study. These type of considerations are not applicable when verifying the DER model; however, they are to be considered when performing a study with a verified DER model.

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

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

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Appendix A: ~~Trajectory~~ Parameter Sensitivity Analysis on DER_A Model

Trajectory sensitivity analysis is one of the methods to correlate the linear sensitivity of dynamic model parameters to the ~~output~~dynamic response of a~~output of the~~ model. These types of calculations can help the TP understand these relationships during the tuning of dynamic model parameters. When verifying model performance, it is crucial to understand how the parameters affect the simulation output in order to match measured quantities.

If a parameter has significant influence on the trajectory of the dynamic model output, the corresponding trajectory sensitivity index will be large. It is common for certain parameters to have a significant influence on the trajectory of a particular disturbance or system condition and negligible influence in other disturbances or conditions. Before starting the parameter calibration procedure, it is critical to identify the candidate parameters in order to reduce the computational complexity of the problem. In this study the measurement was the active and reactive power at the DER bus.

To quantify the sensitivity of parameters, a full parameter sensitivity analysis on DER_A model was carried out by performing the calculation on each of the parameters of DER_A,~~using (1)~~ and the resulting parameter sensitivity indexes are summarized in Table A.1. Simulations were performed in PSS®E and utilize one of the sample cases (savnw) as a model basis. The DER-A model was added to the system, and each of the DER-A parameters were altered by +/- 10% and the event simulated was a three phase 500 kV fault on the line between buses 201-202. Parameters of the DER_A model not listed in Table A.1 had a trajectory sensitivity of zero.~~Simulations were performed in PSS®E~~. It should be noted that the sensitivity calculation depends on the operating point in the simulation, and that the DER A model is an aggregated model. Both of these indicate that this calculation itself requires engineering judgement to determine if those parameters are justified to be changed. For instance, the Trv parameter is not a great candidate to change in the verification of the DER dynamic model even though it has a high sensitivity and impacts the simulation output greatly. The parameters that are good candidates to change are those that adjust the section of the dynamic performance that is needing to adjust (i.e. before, during, or after the fault) in the verification process and that the parameter under adjustment makes sense to adjust. To help illustrate this, take the Trv example in Figure A.1. While this constant has high sensitivity, it is less likely to be altered as other parts of the DER-A model that are likely to change between the initial model build and the installed equipment. Additionally, the graphical change for this calculation for Imax, Pmax, and Tiq are found in Figures A.2 to A.4, respectively.

Table A.1: Parameter Sensitivities for the DER_A model			
Parameter	**Value**	**Sensitivity**	**Description**
Trv~~trv~~	0.02	High	voltage measurement transducer time constant
Tiq~~tiq~~	0.02	Low	Q-control time constant
Pmax~~pmax~~	1	High	Maximum power limit
Imax~~imax~~	1.2	High	Maximum converter current
Vl~~vl~~	0.49	High*	inverter voltage break-point for low voltage cut-out
Vl~~vl~~	0.54	High*	inverter voltage break-point for low voltage cut-out
vh0	1.2	High*	inverter voltage break-point for high voltage cut-out
vh1	1.15	High*	inverter voltage break-point for high voltage cut-out
Tg~~tg~~	0.02	High	current control time constant (to represent behavior of inner control loops
Rrpwr~~rrpwr~~	2	High	ramp rate for real power increase following a fault
Tv~~tv~~	0.02	High*	time constant on the output of the multiplier

* indicates this variable is affected only when the voltage trip flag (VtripFlag) is enabled

Commented [JS167]: Follow up with Shahrokh on

- Variation of the params (+/=%?)
- More detail on contingency (type of fault etc.)
- More on expected performance and setup of the analysis.

Commented [JS168R167]: Added the detail in text.

Commented [RD169]: What is this (1)? An equation?

Commented [JS170R169]: Yes, but was taken out in the review as it clouded the very generic thing we wanted to say.

Commented [RD171]: Apologies for saying this, but this entire section does not provide much information to a reader. It is too high level and there are many nuances associated with the trip parameters. Additionally, the relation of pmax and imax also includes nuances. This appendix needs to either have a lot more information or needs to be removed. In its present state, it has the potential to misrepresent information too.

Commented [JS172R171]: Adjust for aggregate model of DER Adjust for certain parameters are limits, and are not quantified by a linearized analysis.

Commented [RD173]: Apologies for saying this, but this entire section does not provide much information to a reader. It is too high level and there are many nuances associated with the trip parameters. Additionally, the relation of pmax and imax also includes nuances. This appendix needs to either have a lot more information or needs to be removed. In its present state, it has the potential to misrepresent information too.

Commented [JS174R173]: Adjust for aggregate model of DER Adjust for certain parameters are limits, and are not quantified by a linearized analysis.

Commented [JS175]: See if Shahrokh can provide a visualization of one parameter adjustment.

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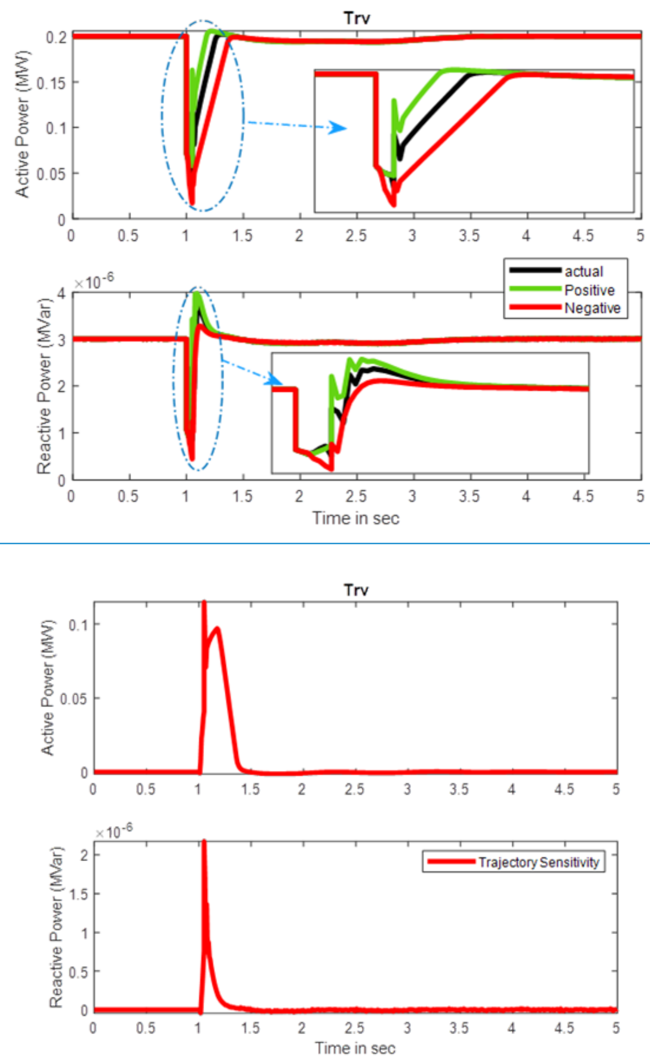

Figure A.1: Simulation Output and the Resulting TSA Calculation on Trv[61].

[61] The reader is cautioned that this graph and following graphs are not matching measurement data to simulation output; however, it is comparing a set parameter adjustment back to the original model output for the same contingency. As expected, as you increase the time constant for the inverter to react for a voltage dip due to a BPS fault, the inverter may not see the dip in time, and decreasing the time constant means the model will react quicker to voltage changes. See the block diagram in Figure A.4 that shows the Trv constant, which demonstrates why this phenomenon exists.

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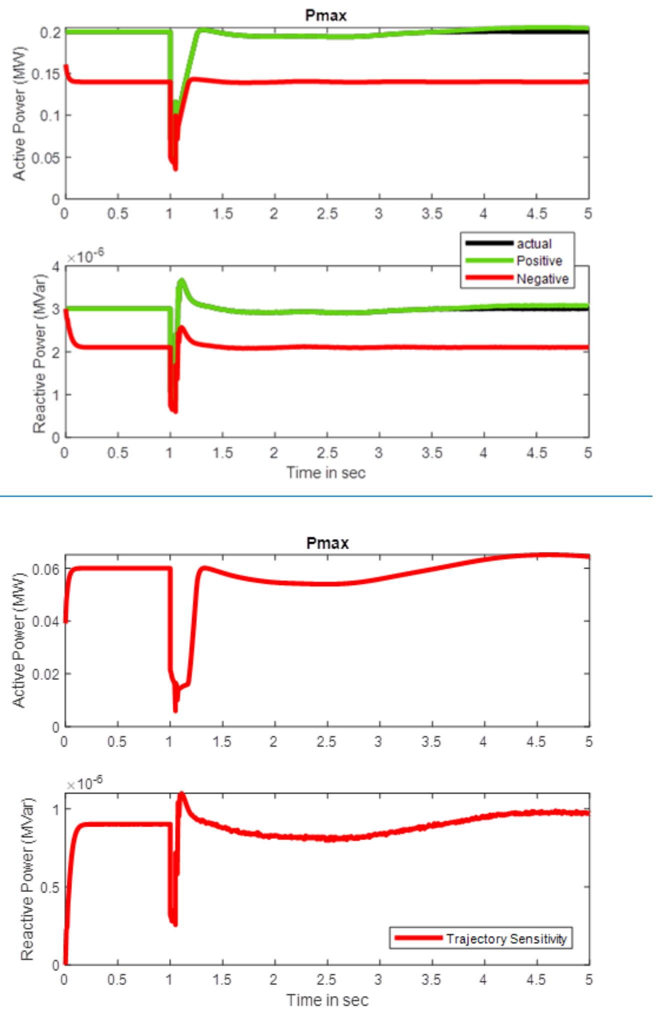

Figure A.2: Simulation Output and the Resulting TSA Calculation on Pmax.

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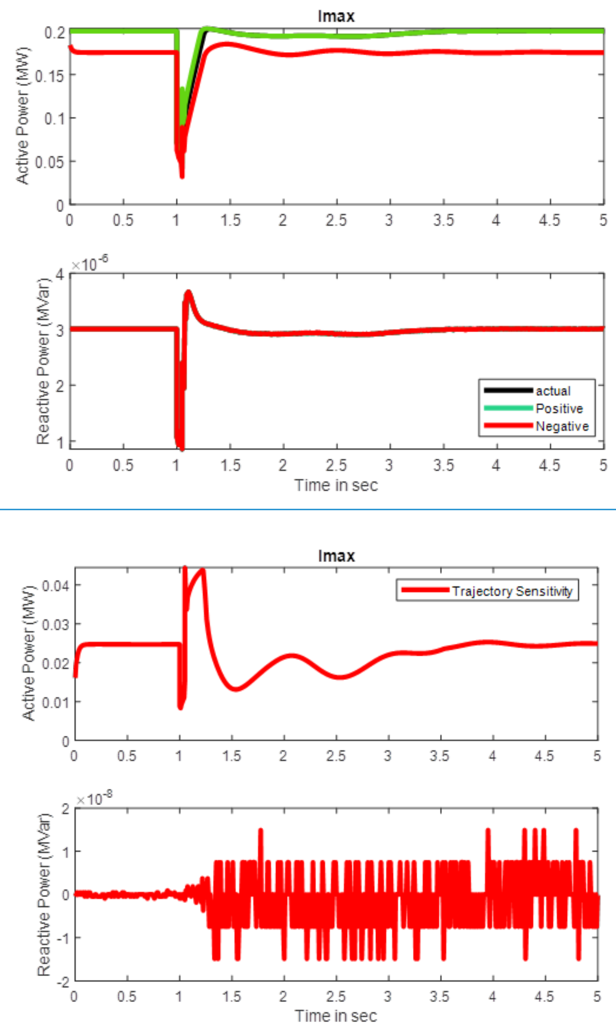

Figure A.3: Simulation Output and the Resulting TSA Calculation on Imax

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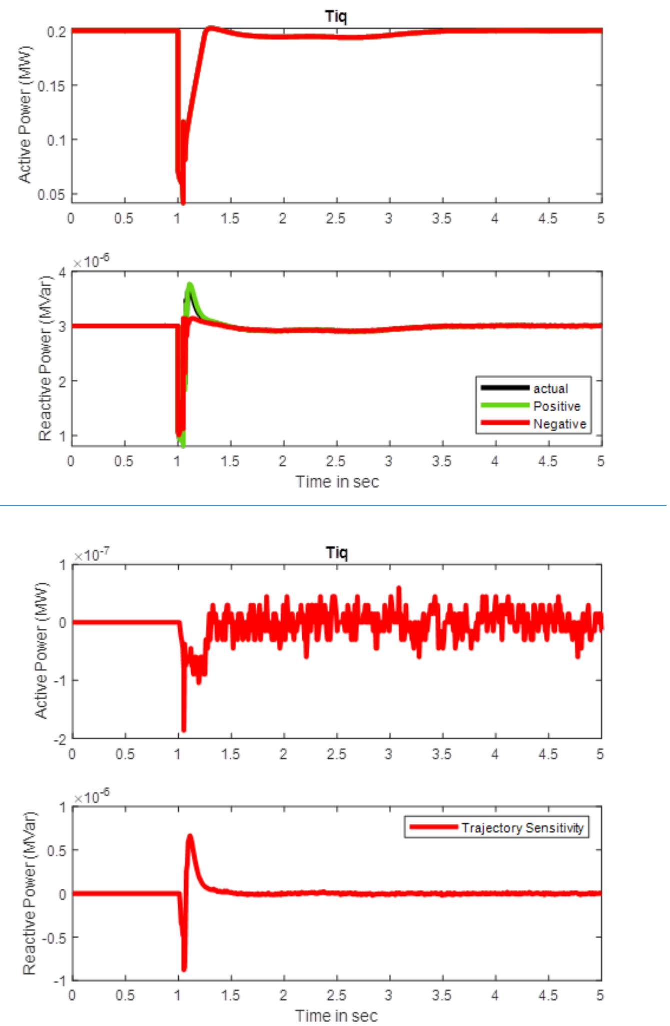

Figure A.4: Simulation Output and the Resulting TSA Calculation on Tiq.

Highly sensitive parameters have a relatively higher trajectory sensitivity and parameter values closer to zero are not as sensitive. Dynamic model control flags can affect the parameter sensitivity and therefore need to be carefully selected (e.g., PfFlag, FreqFlag, PQFlag, GenFlag, VtripFlag and FtripFlag). Figure A.5~~1~~ shows where these flags are located with respect to the DER_A dynamic model.

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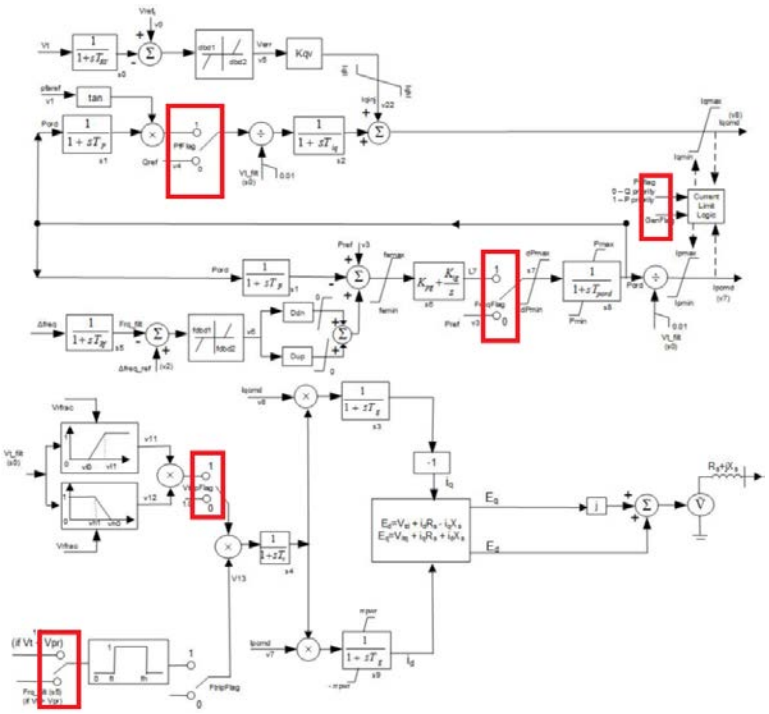

Figure A.5~~1~~: DER_A Control Block Diagram in PSS®E [Source: Siemens PTI][62]

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[62] PSSE model Documentation

Appendix B: Hypothetical Dynamic Verification Case

To assist in developing more complex verification cases and to demonstrate how certain aspects of the Reliability Guideline stated in Chapters 3 and 4, the SPIDERWG set up a sample case with hypothetical measurements and hypothetical parameters. This appendix demonstrates the model verification starting from a common load representation. This assumes that the load record that models the distribution bank, feeders, and end use customers is represented as a single load off the transmission bus and has already been expanded to the low side of the T-D bank for dynamic model verification. A generic load expansion for that single load record is used alongside the DER_A model. The example has the monitoring device at the high side of the T-D interface, and the verification monitoring records are set up with the monitoring at that location. If the monitoring devices were on the low side of the transformer, the model results would also need to reflect that.

Commented [RD177]: If this is the case, can the obtained values of DER_A also be hypothetical?

Commented [JS178R177]: Yes

Model Setup

In Figure B.1, a Synchronous Machine Infinite Bus (SMIB) representation that describes the modeled parameters is provided. The infinite bus is used to model the contributions from a strong transmission system and is used to vary both Voltage and Frequency at the high side of the transformer; however, the measurement location is assumed to be the high side of the transformer as per the recommendations in this Reliability Guideline. The TP/PC should determine the equivalent impedance in order to determine the system strength in that area. This example assumes a stiff transmission system at the load bus, modeled as a jumper.

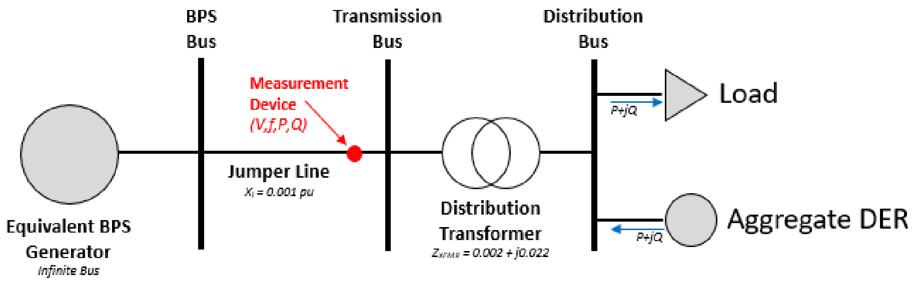

Figure B.1 Simulation SMIB Representation for High Level Aggregate U-DER

To populate the parameters in the representation, Table B.1 provides the numerical parameters assumed in the setup of the powerflow and Table B.2 contains the default parameters utilized in the composite load representation at that bus. The XFMR MVA rating is 80 MVA, and the study assumes that the transformer values have been tested upon manufacturing and is verified at the installation of the T-D bank.

Table B.1: Steady State Parameters for Study

Input Name	Value
Load	60+30j MVA
Aggregate DER	10+1j MVA

In order to parameterize the Composite load model, the parameters in Figure B.2 were used and are assumed to represent the inductor motors and other load characteristics. This example is set to verify the dynamic parameters of the aggregate DER, and assumes the impacts were separated from the load response and is fully attributed to the DER. The list of parameters that were provided in the original model were is found in Figure B.2 and lists the starting set of parameters in the simulation. The supplied measurements from the hypothetical DP to the hypothetical TP were taken at the high side of the distribution transformer as indicated in Figure B.1.

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In this example, the following models[63] were used to play in and record the buses at each system. Each model was chosen to assist in either retrieving simulation data from the files, inputting measurement data, or characterizing the dynamic transient response of the load or aggregate DER in Figure B.1.

- Plnow – Used to input measurement data available for use in the dynamic simulation. Time offset of zero for using all data in the file.
- Gthev – Used to adjust the voltage and frequency at the BPS bus in order to play-in the Frequency and Voltage signals
- Imetr – Used to monitor the flows at the high end of the T-D transformer where the measurement location is. This model records P, Q, and amperage.
- Monit – Used to monitor convergence and other simulation level files when debugging software issues.
- Vmeta – Used to tell the dynamic simulation to capture all bus voltages
- Fmeta – Used to tell the dynamic simulation to capture all bus frequencies
- Cmpldw – Used to characterize the Load model
- Der_a – used to characterize the Aggregate DER model

```
#
lodrep
cmpldw     102 "LOWSIDE"  13.8  "1"   :  #9   mva=-1 /
 "Bss"   0  "Rfdr"  0.01  "Xfdr"  0.01  "Fb"  0.75/
 "Xxf"   0.00  "TfixHS"  1  "TfixLS"  1  "LTC"  0  "Tmin"  0.9  "Tmax"  1.1  "step"  0.00625  /
 "Vmin"   1.025  "Vmax"  1.04  "Tdel"  30  "Ttap"  5  "Rcomp"  0  "Xcomp"  0  /
 "Fma"   0.167  "Fmb"  0.135  "Fmc"  0.061  "Fmd"  0.113  "Fel"  0.173  /
 "PFel"   1  "Vd1"  0.7  "Vd2"  0.5  "Frcel"  1  /
 "Pfs"   -0.998  "P1e"  2  "P1c"  0.566  "P2e"  1  "P2c"  0.434  "Pfreq"  0  /
  "Q1e"  2  "Q1c"  -0.5  "Q2e"  1  "Q2c"  1.5  "Qfreq"  -1  /
 "MtpA"   3  "MtpB"  3  "MtpC"  3  "MtpD"  1 /
 "LfmA"  0.75  "RsA"  0.04  "LsA"  1.8  "LpA"  0.12  "LppA"  0.104  /
 "TpoA"  0.095  "TppoA"  0.0021  "HA"  0.1  "etrqA"  0  /
 "Vtr1A"  0.7  "Ttr1A"  0.02  "Ftr1A"  0.2  "Vrc1A"  1  "Trc1A"  99999  /
 "Vtr2A"  0.5  "Ttr2A"  0.02  "Ftr2A"  0.7  "Vrc2A"  0.7  "Trc2A"  0.1 /
 "LfmB"  0.75  "RsB"  0.03  "LsB"  1.8  "LpB"  0.19  "LppB"  0.14  /
 "TpoB"  0.2  "TppoB"  0.0026  "HB"  0.5  "etrqB"  2  /
 "Vtr1B"  0.6  "Ttr1B"  0.02  "Ftr1B"  0.2  "Vrc1B"  0.75  "Trc1B"  0.05  /
 "Vtr2B"  0.5  "Ttr2B"  0.02  "Ftr2B"  0.3  "Vrc2B"  0.65  "Trc2B"  0.05 /
 "LfmC"  0.75  "RsC"  0.03  "LsC"  1.8  "LpC"  0.19  "LppC"  0.14  /
 "TpoC"  0.2  "TppoC"  0.0026  "HC"  0.1  "etrqC"  2  /
 "Vtr1C"  0.65  "Ttr1C"  0.02  "Ftr1C"  0.2  "Vrc1C"  1  "Trc1C"  9999  /
 "Vtr2C"  0.5  "Ttr2C"  0.02  "Ftr2C"  0.3  "Vrc2C"  0.65  "Trc2C"  0.1 /
 "LfmD"  1  "CompPF"  0.98  /
 "Vstall"  0  "Rstall"  0.1  "Xstall"  0.1  "Tstall"  9999  "Frst"  0.2  "Vrst"  0.95  "Trst"  0.3  /
 "fuvr"  0.1  "vtr1"  0.6  "ttr1"  0.02  "vtr2"  0  "ttr2"  9999  /
 "Vc1off"  0.5  "Vc2off"  0.4  "Vc1on"  0.6  "Vc2on"  0.5  /
 "Tth"  15  "Th1t"  0.7  "Th2t"  1.9  "tv"  0.025
#
models
#
monit        1 "INF    "  115.00 "1 " : #9  9999.00
vmeta        1 "INF    "  115.00 "1 " : #9  0.0 0.0
fmeta        1 "INF    "  115.00 "1 " : #9  0.0 0.0 0.050000
#
plnow       1 ! ! "1 " : #9 0.0
gthev       1 ! ! "1 " : #9 .0001  .001 1 2 10 10
#
imetr     101 ! ! "1 "        1 ! !  "1 "  1 : #9 "tf" 0.0
#
#

der_a   102 "LOWSIDE" 13.8 "U " : #9 mva=11 /
"trv" 0.02 "dbd1" -99 "dbd2" 99 "kqv" 0 "vref0" 0 "tp" 0.02 "pflag" 1 /
 "tiq" 0.02 "ddn" 0 "dup" 0 "fdbd1" -99 "fbdb2" 99 "femax" 0 "femin" 0 /
"pmax" 1 "pmin" 0 "frqflaq" 0 "dPmax" 99 "dPmin" -99 "tpord" 0.02 "imax" 1.2 /
"pqflag" 1 "vl0" 0.44 "vl1" 0.45 "vh0" 1.2 "vh1" 1.19 "tvl0" 0.16 "tvl1" 0.16 /
 "tvh0" 0.16 "tvh1" 0.16 "vrfrac" 0 "fltrp" 59.3 "fhtrp" 60.5 "tfl" 0.16 /
"tfh" 0.16 "tg" 0.02 "rrpwr" 0.1 "tv" 0.02 "kpg" 0 "kig" 0 "xe" 0.25 "typeflag" 1 /
 "vfth" 0.8" "iqh1" 0 "iql1" 0
#
#
```

Figure B.2 Starting Set of Dynamic Parameters

[63] PSLF v21 was used to perform this example and the PSLF model names are listed.

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Model Comparison to Event Measurements

The event that was chosen to verify these set of models was a fault that occurred 50 miles away from the measurement location, and such fault caused a synchronous generator to trip offline. The measurements demonted here are simulation outputs from a different set of parameters and are assumed to be the reference P and Q measurement for verification purposes. For the purposes of illustration, the event is assumed to be a balanced fault[64]. The event is detailed in the first set of graphs in Figure B.3. The active power and reactive power measurements are taken at the high side of the T-D transformer corresponding to Figure B.1. In order to ensure that the load model was performing as anticipated during the event, the active powers from the load are recorded in Figure B.4, and demonstrate two separate distinctions in the process. Firstly, that the load model responds similarly between the measurement values and the reported model. Secondly, that the changes and adjustments to the DER model do not impact the response in a way that would misalign the model with the measurements.

Commented [RD179]: The previous page says that the measurements were hypothetical. Does this relate to the same sentence?

Commented [JS180R179]: yes

[64] TPs/PCs should be cognizant that unbalanced faults may not closely match the positive sequence simulation tools. This may be a source of mismatch that does not warrant modification in dynamic model parameters.

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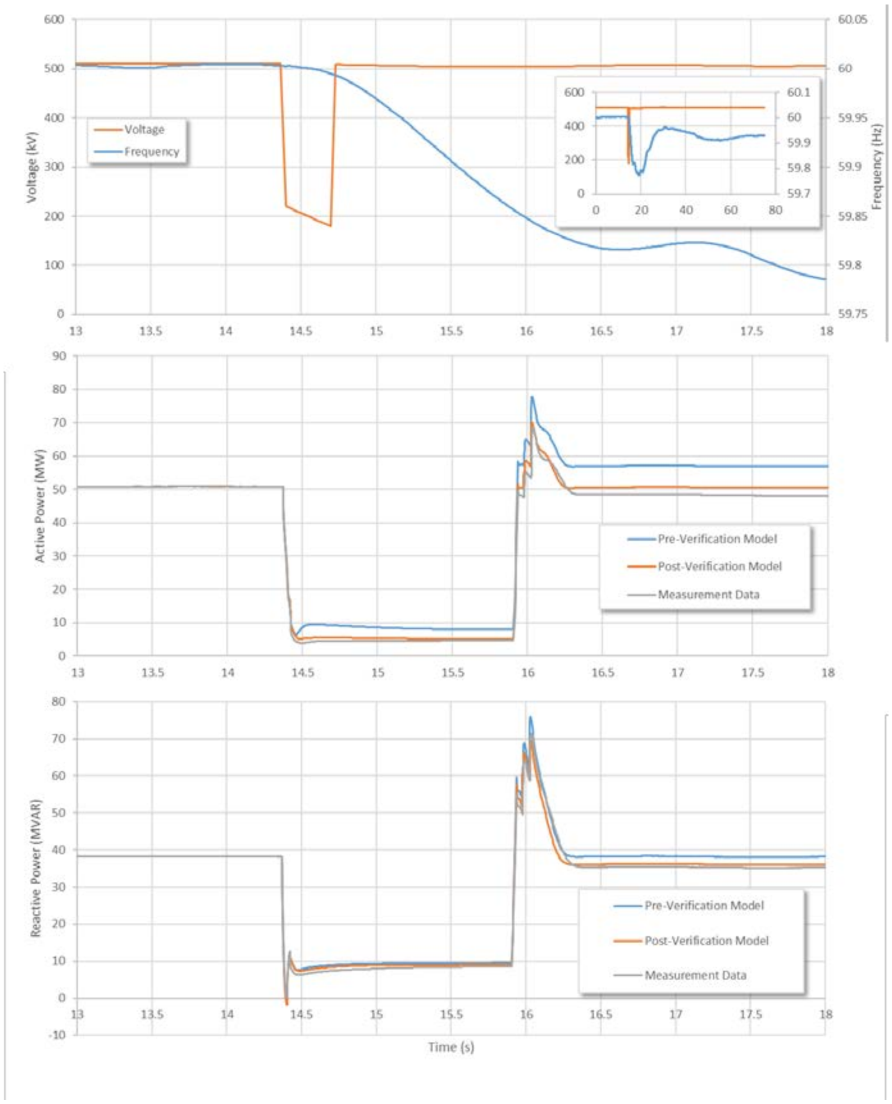

Figure B.3 Voltage, Frequency, Active, and Reactive Power Measurements

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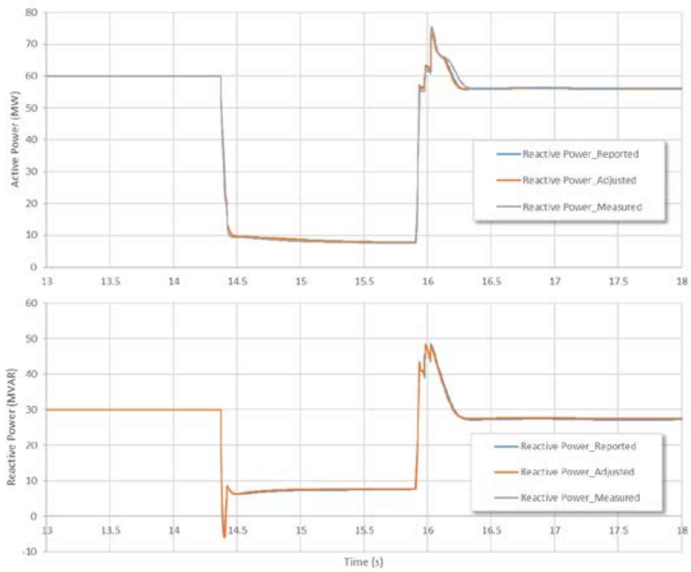

Figure B.4 Active and Reactive Power of Load Model

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

Table B.2: DER Parameter Changes		
Parameter Name	**Previous Value**	**New Value**
Vrfrac	0	0.2
Vfth	0.8	0.4
Vl0	0.44	0.35
~~Kpg~~	~~0~~	~~0.1~~
~~Kig~~	~~0~~	~~10~~
Tvl0	0.16	0.75
Tvh0	0.16	0.75

Commented [PSJ181]: Was the parameter adjustment for the DER_A model done using some optimization algorithm that minimized error between model output and measured output. A reference to the method used would be useful.

Commented [JS182R181]: All was hypothetical and no optimization algorithm was used. A simple "eye" for clarity as this was an example of what we are talking about to tuning parameters.

Commented [RD183]: The newer IEEE 1547 standard requires this to be 0.3 and it only relates to disabling frequency trip values. What was the implication of changing this value?

Commented [JS184R183]: Qualified above as everything existing in simulation based on 6/16/2020 conversation

Commented [RD185]: Initial values of 0.45 and 0.44 for vl1 and vl0 are too restrictive.

Commented [RD186]: Did this also include making the frqflag = 1 to enable the frequency control loop? What were the values Ddn and Dup?

Commented [RD187]: Did this also include making the frqflag = 1 to enable the frequency control loop? What were the values of Ddn and Dup?

Commented [JS188R187]: Qualified above as everything existing in simulation based on 6/16/2020 conversation

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Commented [RD189]: What was the basis for changing this value?

Commented [JS190R189]: Qualified above as everything existing in simulation based on 6/16/2020 conversation

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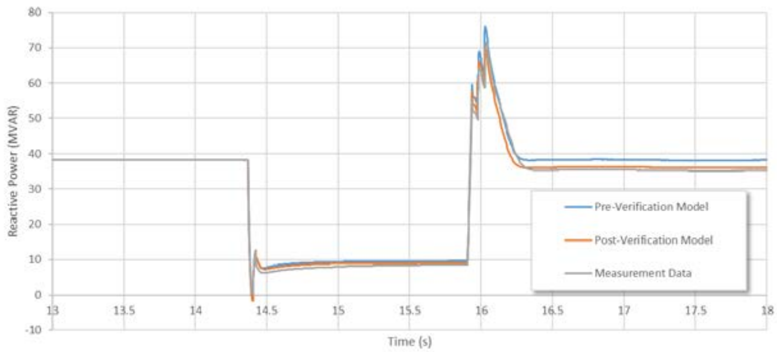

Figure B.5 Active Power of Model versus Measurements after Parameter Adjustment

After the adjustments were made in Table B.2 and simulating the model response, the active power is looked at closely, reproduced in Figure B.5, to determine the effect of the changes. Based on the closeness of fit, the verification process ends and the model is now verified against this particular event's performance. If the TP/PC determines that this verification closeness of fit is not adequate, the process would iterate again with more fine adjustments made until the entity has confidence in how the model behaves relative to the event measurements. As this process only used one event, it is highly recommended that the post-verification model be confirmed by playing back another event, if available.

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Appendix C: Data Collection Example

Specific types of BPS events have demonstrated a characteristic response in load meters, which has been attributed to DER response;[65] however, a majority of TPs or PCs may not know the types of system level measurements and practices when looking to verify a set of models. This appendix provides TPs and PCs with an example of DER response to BPS events. It also suggest methods or ideas to consider when using the event data collected for verifying aggregate DER models in planning studies.

IESO DER Performance Under BPS Fault Conditions

DER responses to transmission grid disturbances are typically not in scope of DER commissioning tests; therefore, it is more practical to verify DER dynamic performance through naturally occurred events. An example of the performance expected can be found in **Figure C.1,** which shows an example of U-DERs responding to a 500kV single-line-to-ground fault in Ontario. More than 30 DER meters recorded interruptions upon the fault and **Figure C.1** highlights seven locations as far as 300km from the fault location (voltage and current waveforms side by side, with nameplate MW indicated). The DERs were all installed under the IEEE 1547-2003; therefore, most of them tripped offline following the voltage dips induced by the fault. At Site B and Site G additional current waveforms from other solar plants connected to the same substations are included for comparison. The DER current outputs varied significantly due to different control strategies for the controllers, which experienced similar voltages at PoC.

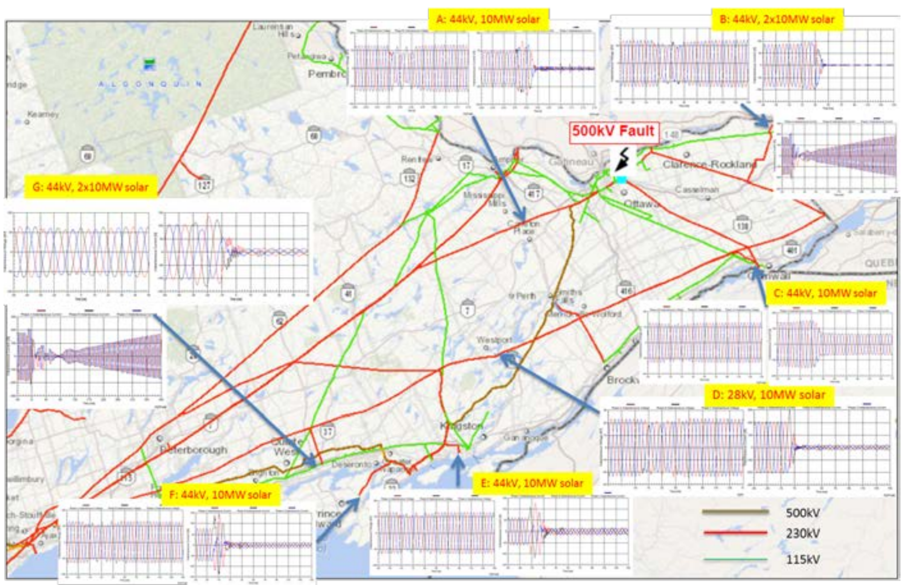

Figure C.1 Solar U-DER Voltage and Current Waveforms for a 500kV Fault

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

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

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

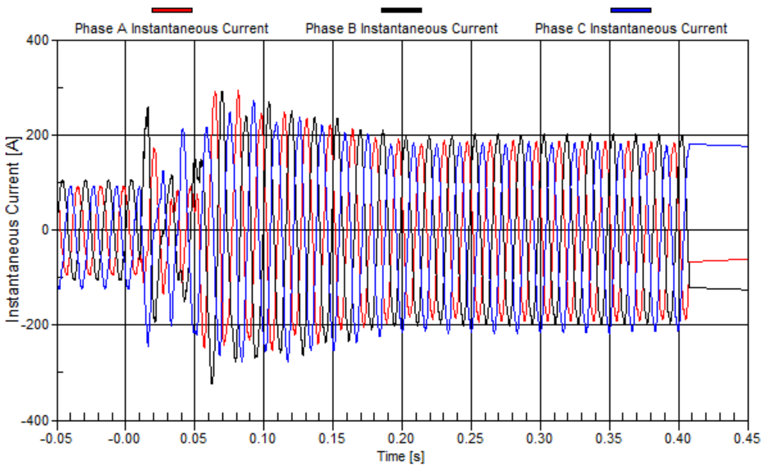

Figure C.2 Current waveforms from 230/44kV transformer at Site B

DER operating logs show various reasons that may initiate DERs shutdown, such as under/over-voltage, frequency deviations or current/voltage unbalance. A common feature associated with such initiating causes is an arbitrarily short time delay, yet some designs employ instantaneous shutdown. The IEEE 1547-2003 standard allows for protection delay settings as short as zero seconds, but such small time delays have caused premature generation interruptions under remote BPS grid events. In most cases, the DERs would have been able to ride through the disturbances if the decisions of gating off inverter were reasonably delayed.

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

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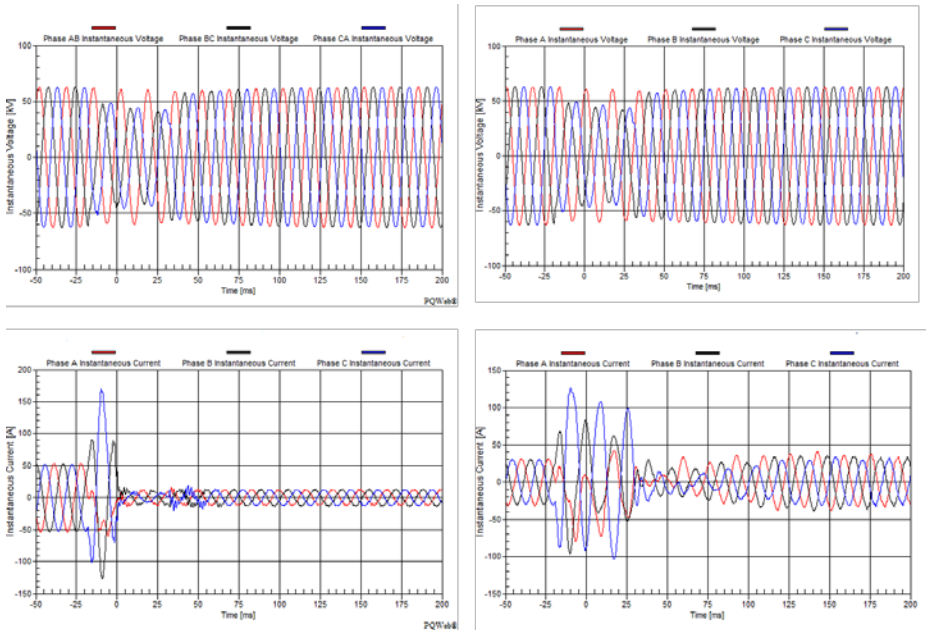

Figure C.3 Comparison of Two Adjacent Solar Plants' Responses to the Same 500kV Fault (top: voltage, bottom: current)

Installation data may suggest the overall majority of DERs are solar generators, but wind turbines connections in distribution system are also common in some utilities. Operation records show that wind DERs may experience similar interruptions as solar under BPS disturbances. Figure C.4 and Figure C.5 show Type IV and Type III wind plants responses to a common 500kV bus fault, respectively. While the wind plants are connected at different locations and voltage levels (28kV vs. 44kV), both shut down under the BPS fault. Figure A.6 shows load current increase measured from one out of two paralleled 115kV/44kV step-down transformers as a result of wind generation loss in the 44kV feeders. In this event insufficient time delay (shorter than transmission fault clearing time) for voltage protection designed under 1547-2003 was confirmed to be the cause of shutdown. Such issue is expected to diminish with the new 2018 standard revision, which requires at least 160ms time delay to accommodate transmission fault clearing.

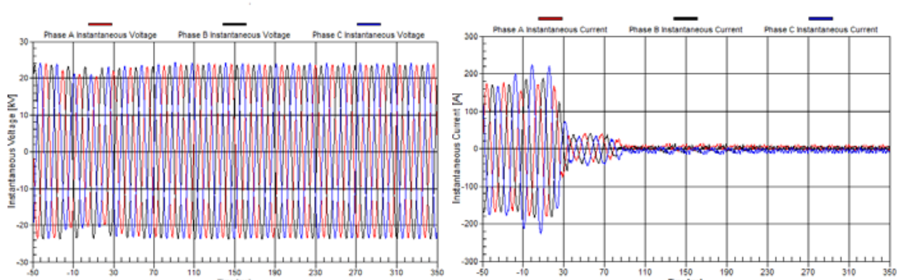

Figure C.4: Type IV Wind Plant (28kV/10MW) Response to 500kV Single-Line-to-Ground Fault

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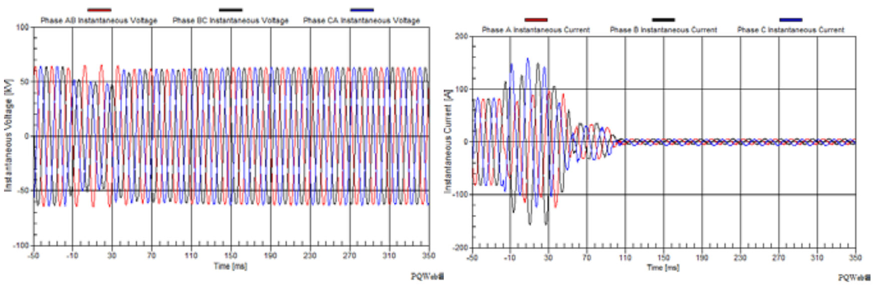

Figure C.5: Type III Wind Plant (44 kV/10 MW) Response to 500kV Single-Line-to-Ground Fault

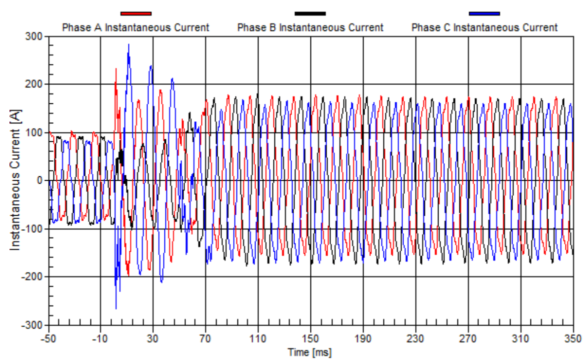

Figure C.6: Load Current Increase at a 115 kV/44 kV Transformer after Loss of Wind Generation

April-May 2018 Disturbances Findings

In the Angeles Forest and Palmdale Roost disturbances, a noticeable amount of net load increase was observed at the time of the disturbances.[66] DERs were verified to be involved in the disturbance using a residential rooftop solar PV unit captured in the Southern California Edison (SCE) footprint about two BPS buses away from the fault through a 500/220/69/12.5 kV transformation. The increase in net load identified in both disturbances signified a response from behind-the-meter solar PV DERs; however, the availability, resolution, and accuracy of this information was fairly limited at the time of the event analysis. **Figure C.7** shows the CAISO net load for both disturbances. It is challenging to identify exactly[67] the amount of DERs that either momentarily ceased current injection or tripped offline using BA-level net load quantities. Note that these measurements were taken at a system-wide level and represent many T-D interfaces, while the above IESO example is for specific T-D interfaces.

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

[67] The ERO estimated that approximately 130 MW of DERs were involved in the Angeles Forest disturbance and approximately 100 MW of DERs were involved in the Palmdale Roost disturbance; however, these are estimated values only.

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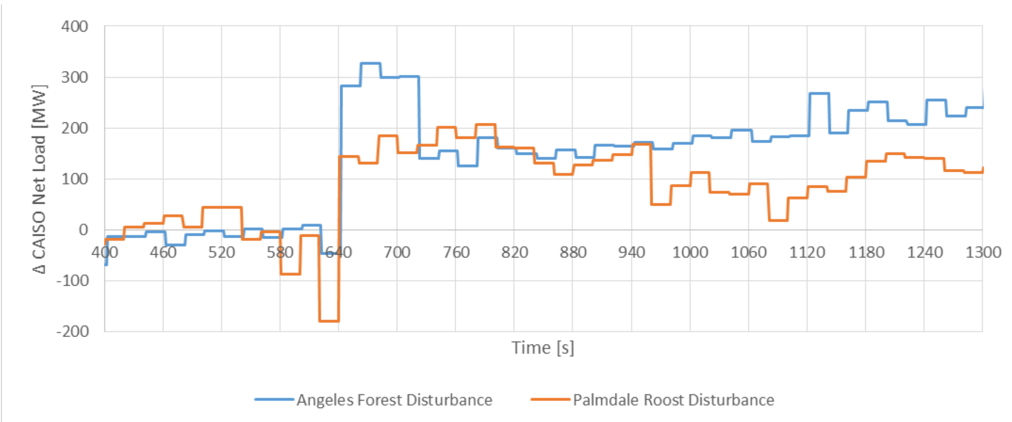

Figure C.7: CAISO Net Load during Angeles Forest and Palmdale Roost Disturbance [Source: CAISO]

SCE also gathered net load data for these disturbances (shown in **Figure C.8**). While an initial spike in net load is observed, this is attributed to using an area-wide net load SCADA point and a false interpretation of DER response during the events for the following reasons:

- The SCADA point used by SCE for area net load does not include sub-transmission generation or any metered[68] solar PV in their footprint. However, it does account for the unmetered DERs that are mostly composed of BTM solar PV.
- The SCADA point used by SCE for area net load is calculated as the sum of metered generation plus intertie imports, which includes area net load and losses.[69] Therefore, the SCADA point does not differentiate between changes in net load and changes in losses.
- As with all energy management systems (EMSs), the remote terminal units (RTUs) reporting data to the EMS are not time-synchronized. Delays in the incoming data during the disturbance can result in temporary spikes. Fast changes in metered generation (e.g., generator tripping or active power reduction) before refreshed values of intertie flow can cause the calculated load point to change rapidly around fault events. Once the refreshed values are received, the spikes balance out.

For the reasons described above, the spikes in net load were accounted for as calculation errors and variations in system losses and intertie flow changes. The temporary increase within the first tens of seconds after the fault event should not be completely attributed to DER tripping or active power reduction when using area-wide net load SCADA points. TPs and PCs, when gathering data for use in verification of DER models, should consider the bullets above when using SCADA or other EMSs when utilizing these points for verification of DER models, especially when utilizing system-wide measurements.

[68] Generally, generation greater than 1 MW is metered by SCE on the distribution, subtransmission, and transmission system.
[69] Net Load + Losses = Metered Generation + Intertie Imports

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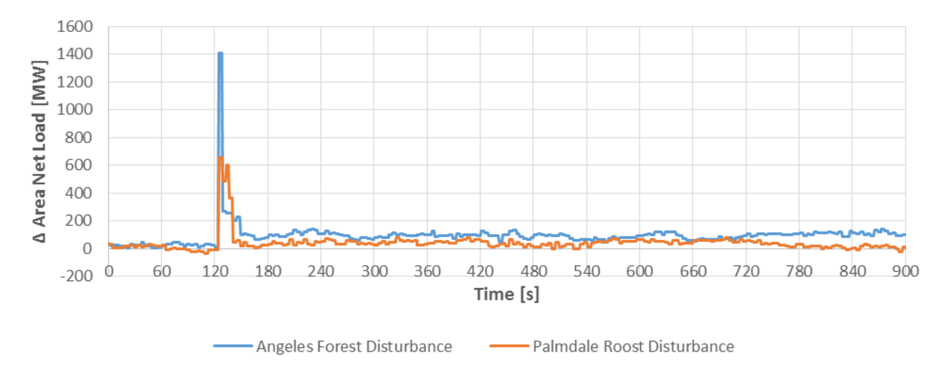

Figure C.8: SCE Area Net Load Response [Source: SCE]

It was determined that monitoring the T-D transformer bank flows using direct SCADA measurements (rather than calculated area net load values) is a more reliable method for identifying possible DER behavior during disturbances because it removes the time synchronization issues described above. Figure C.9 (left) shows direct measurements of T-D bank flows in the area around the fault. The significant upward spike does not occur in these measurements as it did in the area-wide calculation. However, it is clear that multiple T-D transformer banks did increase net loading immediately after the fault. These net load increases lasted on the order of five to seven minutes, correlating with the reset times for DER tripping as described in IEEE Std. 1547.[70] After that time, the net loading returned back to its original load level in all cases. This method of accounting for DER response is much more accurate and provides a clearer picture of how DERs respond to BPS faults. However, this method is time intensive and difficult to aggregate all individual T-D transformer banks to ascertain a total DER reduction value. TPs and PCs are encouraged to use the SCE and PG&E examples as ways to improve their data collection for DER and how to identify or attribute responses in already collected data, especially for higher impact T-D interfaces.

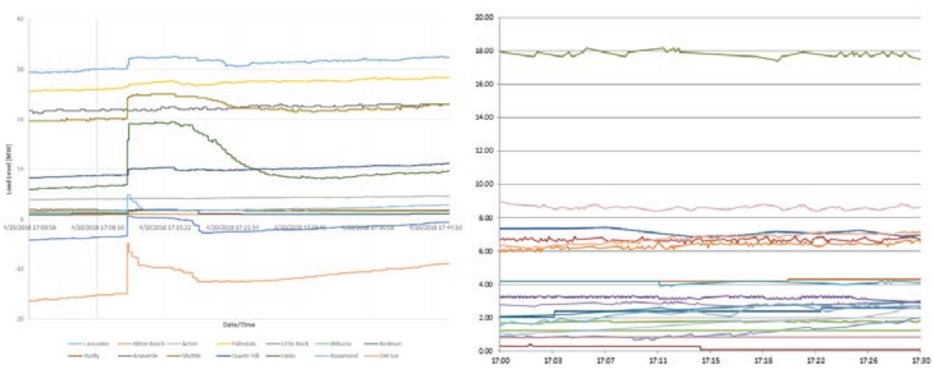

Figure C.9: SCE (left) and PG&E (right) Individual Load SCADA Points

[70] IEEE Std. 1547-2003, "IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems": https://standards.ieee.org/standard/1547-2003.html.
IEEE Std. 1547a-2014, "IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems – Amendment 1": https://standards.ieee.org/standard/1547a-2014.html.
IEEE Std. 1547-2018, "IEEE Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces": https://standards.ieee.org/standard/1547-2018.html.

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Contributors

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

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Lafayette Gatewood IV	Evergy
Irina Green	California ISO
Chester Li	Hydro One Networks, Inc.
Dan Kopin	Utility Services, Inc.
Hassan Ghoudjehbaklou	San Diego Gas and Electric
Parag Mitra	Electric Power Research Institute
Deepak Ramasubramanian	Electric Power Research Institute
Evan Paull	Western Electric Coordinating Council
Bob Micek	Tri-State Generation and Transmission Association
Raul Perez	Southern California Edison
Jay Ramamurthy	Entergy
Steven Rymsha	Sunrun
Matthew Koenig	Continental Edison
Kannan Sreenivasachar	ISO-NE
Brad Marszalkowski	ISO-NE
Gary Smullin	Smullin Engineering, Inc.
James Manning	North Carolina Electric Membership Corp.
Siby Plathottam	Argone National Labs
Derek Kou	Dominion Energy
Nicholas Jewell	Louisville Gas & Electric and Kentucky Utilities
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White Paper: Assessment of DER impacts on NERC Reliability Standard TPL-001

Action

Approve

Background

With the increasing penetration of DER, NERC System Planning Impacts of DER Working Group (SPIDERWG) undertook the task of evaluating the sufficiency and clarity of the TPL-001 standard for considering DER as part of annual Planning Assessment.

A subgroup was formed within NERC SPIDERWG in February 2019 to tackle this task. A white paper has been prepared and the final draft was submitted to the NERC PC for review in December 2019. Substantial comments on the white paper were received from PC reviewers in February 2020. This latest version reflects all the changes after addressing the comments received.

The white paper discusses the impacts of DER on the standard requirements in three distinct ways:

1. Is the requirement relevant for consideration of DER?
2. Does the existing requirement language preclude consideration of DER in any way?
3. Is the requirement language clear regarding consideration of DER?

The white paper addresses key findings and recommendations from the SPIDERWG review of TPL-001 regarding impacts of DER on the standard requirements and industry implementation of the standard. The intent of the white paper is to highlight potential gaps or areas for improvement within TPL-001 along with some potential solutions such that a SAR or an implementation guide can be developed, as needed, to address various issues by a SDT.

White Paper

Assessment of DER impacts on NERC Reliability Standard TPL-001
NERC System Planning Impacts of Distributed Energy Resources (SPIDERWG)
April 2020

Executive Summary

Many areas of the North American bulk power system (BPS) are experiencing a transition towards increasing penetrations of distributed energy resources (DERs). NERC Reliability Standard TPL-001-4[1] was developed under a paradigm of predominantly BPS-connected generation, when penetrations of DERs were anticipated to be significantly lower than current and future projections, and without much impact on the BPS. Considering the current DER trend, the NERC System Planning Impacts of DER Working Group (SPIDERWG) undertook the task of evaluating the sufficiency and clarity of the TPL-001 standard for considering DER as part of annual Planning Assessment. The use of the term DER in this whitepaper is consistent with its description in NERC DERTF's DER Connection Modeling and Reliability Considerations report (Feb 2017)[2]. The same definition was also used in the SPIDERWG Terms and Definitions Working Document (draft) and the recently crafted MOD-032-1 Standard Authorization Request (SAR) [3] also suggested Standard Drafting Team (SDT) to consider DER definition in the NERC's glossary of terms.
This white paper discusses the impacts of DER on the standard requirements in three distinct ways:

1. Is the requirement relevant for consideration of DER?
2. Does the existing requirement language preclude consideration of DER in any way?
3. Is the requirement language clear regarding consideration of DER?

Table 1 shows the key findings and recommendations from the SPIDERWG review of TPL-001 regarding impacts of DER on the standard requirements and industry implementation of the standard. The intent of this white paper is to highlight potential gaps or areas for improvement within TPL-001 along with some potential solutions such that a SAR can be developed, as needed, to address various issues by a SDT.

SPIDERWG recommends that the NERC PC review issues and that a future SDT assess the extent to which changes or implementation guidance are needed for each of these issues:

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

[2] https://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/Distributed_Energy_Resources_Report.pdf#search=distributed%20energy%20resource, where 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)."

3 The MOD-032-1 SAR was submitted by NERC SPIDERWG to NERC PC and endorsed by PC in December 2019. https://www.nerc.com/pa/Stand/Pages/Project_2020-01_Modifications_to_MOD-032-1.aspx

- Clarify Requirements R2.1 and R2.2 regarding use of phrase "System peak Load". This should be updated to "System peak net load", The SDT should consider whether terms should be added to the NERC Glossary of Terms for "Gross Load" and "Net Load".
- Clarify Requirement R2.4 regarding capturing the dynamic behavior of DER, similar to the existing language used for induction motor loads in Requirement R2.4.1. Representation of the dynamic behavior of DERs should be applicable to all stability simulations, not just System peak conditions.
- In developing Contingency list as required by the Requirement R3.4, an implementation guideline should be developed to identify that the Contingency list should include contingency of explicitly modeled U-DER as well.
- In considering tripping of generators in simulation as required by the Requirement R3.3.1.1, an Implementation guideline should be developed to identify that the "tripping of generators" should include tripping of DER as well. Current language in the Standard uses the term "generator" which is not a defined term in the NERC Glossary and typically does not include DERs. Therefore, it is unclear whether DER tripping should be considered in this assessment.
- Clarify Requirements R4.1.1 and R4.1.2 regarding representing the dynamic behavior of DERs and the performance requirements applicable to DERs during stability simulations. For example, the language referring to "pulls out of synchronism" is only relevant to synchronous generation and is not applicable to inverter-based generation (including inverter-based DER). Large amounts of DER tripping on low/high voltage/frequency conditions can adversely affect BPS performance and may pose a risk to system stability, uncontrolled separation, or cascading events if not properly studied and identified ahead of real-time operations. Studies of these risks should account for

  1. Updates to settings for existing and new inverters[4], and

  2. The extent to which DERs are less exposed to voltage disturbances due to the impedance of the transmission and distribution equipment located between the DERs and a disturbance on the BPS.
- Clarify Requirement R4.3.1.2 regarding the "generators" referenced in the language are inclusive of DER as the tripping of these facilities can potentially have an adverse impact on BPS stability performance.
- Clarify Requirement R4.3.2 regarding expected automatic operation of DER (e.g., DER tripping, dynamic voltage and frequency controls, momentary cessation, etc.) should be considered in stability analyses.

Table 1: Key Findings from SPIDERWG Review	
Requirement	**Key Findings and Recommendations**

[4] including those that have been made in response to the September 2018 Reliability Guideline "BPS-Connected Inverter-Based Resource Performance,"(https://www.nerc.com/comm/OC_Reliability_Guidelines_DL/Inverter-Based_Resource_Performance_Guideline.pdf), the September 2019 Reliability Guideline "Improvements to Interconnection Requirements for BPS-Connected Inverter-Based Resources," (https://www.nerc.com/comm/OC_Reliability_Guidelines_DL/Reliability_Guideline_IBR_Interconnection_Requirements_Improvements.pdf) revisions to PRC-024-2, revisions included in IEEE 1547-2018, and any subsequent guidelines and standards revisions

R1	• This requirement **is** relevant for consideration of DER. • The existing language **does not** preclude consideration of DER. • The existing language **is** clear for consideration of DER.
R2.1	• This requirement **is** relevant for consideration of DER. • The existing language **does not** preclude consideration of DER. • The existing language **is not** clear for consideration of DER.
R2.2	• This requirement **is** relevant for consideration of DER. • The existing language **does not** preclude consideration of DER. • The existing language **is not** clear for consideration of DER.
R2.3	• This requirement **is** relevant for consideration of DER. • The existing language **does not** preclude consideration of DER. • The existing language **is** clear for consideration of DER.
R2.4	• This requirement **is** relevant for consideration of DER. • The existing language **does not** preclude consideration of DER. • The existing language **is not** clear for consideration of DER.
R2.5	• This requirement **is** relevant for consideration of DER. • The existing language **does not** preclude consideration of DER. • The existing language **is** clear for consideration of DER.
R2.6	• This requirement **is** relevant for consideration of DER. • The existing language **does not** preclude consideration of DER. • The existing language **is** clear for consideration of DER.
R2.7	• This requirement **is** relevant for consideration of DER. • The existing language **does not** preclude consideration of DER. • The existing language **is not** clear for consideration of DER.
R2.8	• This requirement **is** relevant for consideration of DER. • The existing language **does not** preclude consideration of DER. • The existing language **is** clear for consideration of DER.
R3.1	• This requirement **is** relevant for consideration of DER. • The existing language **does not** preclude consideration of DER. • The existing language **is not** clear for consideration of DER.
R3.2	• This requirement **is** relevant for consideration of DER. • The existing language **does not** preclude consideration of DER. • The existing language **is** clear for consideration of DER.
R3.3	• This requirement **is** relevant for consideration of DER. • The existing language **does not** preclude consideration of DER. • The existing language **is not** clear for consideration of DER.

R3.4	• This requirement **is** relevant for consideration of DER. • The existing language **does not** preclude consideration of DER. • The existing language **is not** clear for consideration of DER.
R3.5	• This requirement **is** relevant for consideration of DER. • The existing language **does not** preclude consideration of DER. • The existing language **is** clear for consideration of DER.
R4.1	• This requirement **is** relevant for consideration of DER. • The existing language **does not** preclude consideration of DER. • The existing language **is not** clear for consideration of DER.
R4.2	• This requirement **is** relevant for consideration of DER. • The existing language **does not** preclude consideration of DER. • The existing language **is** clear for consideration of DER.
R4.3	• This requirement **is** relevant for consideration of DER. • The existing language **does not** preclude consideration of DER. • The existing language **is not** clear for consideration of DER.
R4.4	• This requirement **is** relevant for consideration of DER. • The existing language **does not** preclude consideration of DER. • The existing language **is** clear for consideration of DER.
R4.5	• This requirement **is** relevant for consideration of DER. • The existing language **does not** preclude consideration of DER. • The existing language **is** clear for consideration of DER.
R5	• This requirement **is** not relevant for consideration of DER.
R6	• This requirement **is** not relevant for consideration of DER.
R7	• This requirement **is** not relevant for consideration of DER.
R8	• This requirement **is** not relevant for consideration of DER.

Chapter 1 – Requirement R1

Standard Requirement R1

R1. Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use data consistent with that provided in accordance with the MOD-032 standard, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions. This establishes Category P0 as the normal System condition in Table 1.

R1.1. System models shall represent:

R1.1.1. Existing Facilities

R1.1.2. New planned Facilities and changes to existing Facilities
R1.1.3. Real and reactive Load forecasts
R1.1.4. Known commitments for Firm Transmission Service and Interchange
R1.1.5. Resources (supply or demand side) required for Load

SPIDERWG Review Finding

- This requirement is relevant for consideration of DER.
- The existing language does not preclude consideration of DER.
- The existing language is clear for consideration of DER.

Supplemental Discussion

As higher levels of DER are integrated across the Bulk Power System, DER should be part of system modeling. DER is included in R1.1.5 ("Resources (supply or demand side)"). DER data collection is consistent across the standards to reinforce the current understanding and need for inclusion of DER in BPS models used for planning assessments. While no specific threshold for DER modeling is suggested, each entity should keep track of DER to make such determinations. If the interconnecting utility is required to be notified of any newly connected DER, the data should exist for all installations of required size. If the data is available, then DER should be accounted for in the system model. Several other NERC Reliability Guidelines detail how the DER should be modeled.[5,6,7] For R-DER, it is sufficient to model the DER as a component of the composite load model, which reduces the level of effort and complexity required to incorporate while still providing valuable modeling enhancements.

It is noted that the MOD-032 SAR being proposed by SPIDERWG is seeking to include DER information as a necessary modeling component for BPS planning assessments. The SAR seeks DER information on steady-state and dynamics data, and does not seek changes to the short circuit requirement "as steady-state column should have necessary information related to positive, negative, and zero sequence data provided accordingly".

Chapter 2 – Requirement R2

Standard Requirement R2

R2. Each Transmission Planner and Planning Coordinator shall prepare an annual Planning Assessment of its portion of the BES. This Planning Assessment shall use current or qualified past studies (as indicated in Requirement R2, Part 2.6), document assumptions, and document summarized results of the steady state analyses, short circuit analyses, and Stability analyses.

Standard Requirement R2.1

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[5] https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability_Guideline_-_DER_Modeling_Parameters_-_2017-08-18_-_FINAL.pdf

[6] https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability_Guideline_-_Modeling_DER_in_Dynamic_Load_Models_-_FINAL.pdf

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

R2.1. For the Planning Assessment, the Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by current annual studies or qualified past studies as indicated in Requirement R2, Part 2.6. Qualifying studies need to include the following conditions:

R2.1.1. System peak Load for either Year One or year two, and for year five.

R2.1.2. System Off-Peak Load for one of the five years.

R2.1.3. For each of the studies described in Requirement R2, Parts 2.1.1 and 2.1.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in System response:

- Real and reactive forecasted Load.
- Expected transfers.
- Expected in service dates of new or modified Transmission Facilities.
- Reactive resource capability.
- Generation additions, retirements, or other dispatch scenarios.
- Controllable Loads and Demand Side Management.
- Duration or timing of known Transmission outages.

R2.1.4. When known outage(s) of generation or Transmission Facility(ies) are planned in the Near-Term Planning Horizon, the impact of selected known outages on System performance shall be assessed. These known outage(s) shall be selected for assessment consistent with a documented outage coordination procedure or technical rationale by the Planning Coordinator or Transmission Planner. Known outage(s) shall not be excluded solely based upon outage duration. The assessment shall be performed for the P0 and P1 categories identified in Table 1 with the System peak or Off-Peak conditions that the System is expected to experience when the known outage(s) are planned. This assessment shall include, at a minimum known outages expected to produce more severe System impacts on the Planning Coordinator or Transmission Planner's portion of the BES. Past or current studies may support the selection of known outage(s), if the study(s) has comparable post-Contingency System conditions and configuration such as those following P3 or P6 category events in Table 1.

R2.1.5. When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), the impact of this possible unavailability on System performance shall be assessed. Based upon this assessment, an analysis shall be performed for the P0, P1, and P2 categories identified in Table 1 with the conditions that the System is expected to experience during the possible unavailability of the long lead time equipment.

SPIDERWG Review Finding

- This requirement is relevant for consideration of DER.
- The existing language does not preclude consideration of DER.

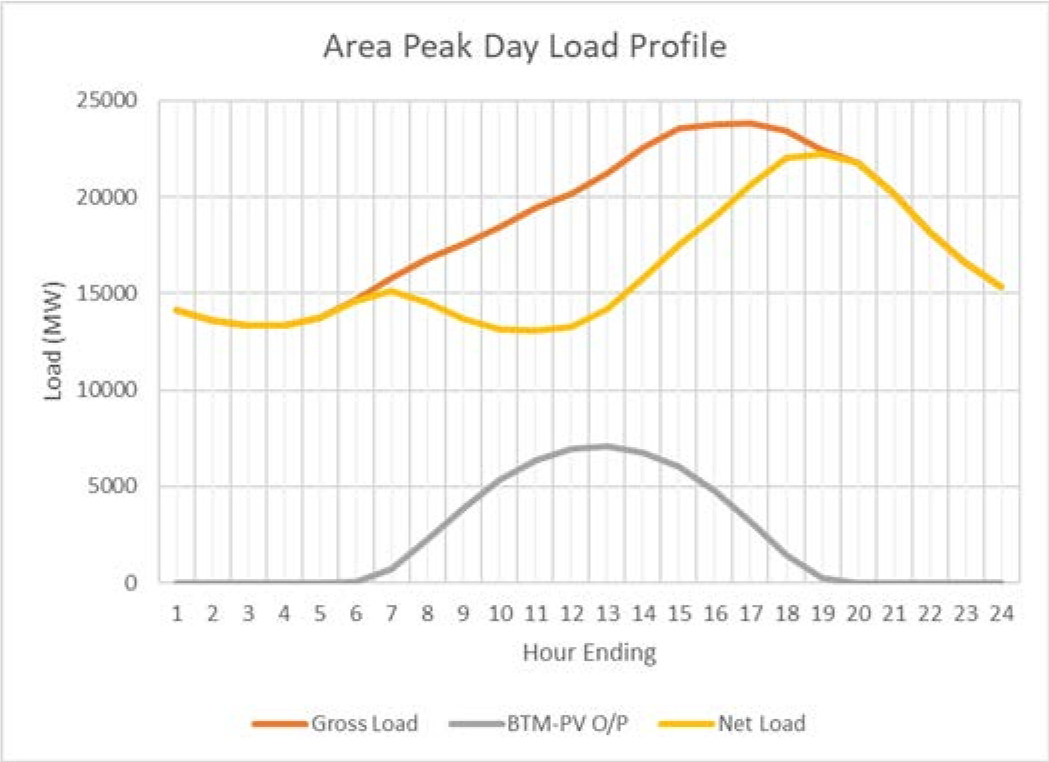
- The existing language is not clear for consideration of DER.

Supplemental Discussion

The term Load is defined in NERC Glossary of Terms as “An end-use device or customer that receives power from the electric system.” This definition is in line with the concept of “gross load” (or “gross demand”) that refers to the total amount of power consumed by end-use device or customer, without any offset by generation on the demand side. Therefore, the current language of the standard may be interpreted as requiring to study peak or off-peak gross load.

With increased penetration of DER, what the 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 gross peak load hour. Therefore, the most stressed condition of the overall transmission system should be defined by net load rather than gross load. R2.1.1 and 2.1.2 defines reference conditions to be studied. These reference conditions should be the most stressed condition which is defined by the net load. As stated above, simply referring to “System peak Load” in the TPL-001 standard, the requirement may be interpreted as System peak gross load. This interpretation would limit the flexibility for the TP and PC to determine which reference condition is more appropriate for assessing their system. In addition, a high gross load hour may be the most stressed condition for contingencies that may trip large amounts of DER. High gross load may be added as additional sensitivity scenarios under R2.1.3.

An example is provided in the diagram below of California’s hourly profiles that illustrate differences between peak gross load and peak net load. Peak gross load occurred at 4pm at around 24,000 MW, however, due to DER output, the net load of that hour was around 20,000 MW. On the other hand, at 6 pm, although gross load was slightly lower than 4pm, due to significantly lower DER output, the net load reached peak at around 22,000 MW. The SPIDERWG recommends that the peak net load of 22,000 MW should be studies because it’s the operation condition when the transmission system is under highest loading. However, the current language in TPL-001-5 can be interpreted to require TP or PC to study the peak gross load hour at 4pm, when net load was 20000 MW.



As such, the term “System peak Load” generates different interpretations and confusion regarding what snapshot the scenario should represent. This raises the risk that entities may be interpreting this to mean either, which could lead to increasingly disparate planning assumptions in the future. This issue should be addressed in a revision to the TPL-001 standard to clarify the intent and how TPs and PCs should implement the standard.

In addition to magnitude differences, the location of the load can vary between peak net load hours and peak gross load hours. In one condition the residential area could have most of the load but in another condition where the sun is up the residential load could be small. As a result, even if net load levels are similar between peak hours of gross and net system load, they can have different impacts on the BPS if DER is spread unevenly relative to load.

Consistent with the NERC Reliability Guideline for DER modeling, DER should be modeled explicitly (no load netting). DER capacity and output in peak and off-peak load conditions should be modeled consistent with the year and the snapshot hour that the scenario represents. Sensitivity scenarios could include different output levels for DER (e.g., due to cloud cover or due to different operating hour assumptions). As there’s no existing definition of term “Generation”, it’s not clear if different DER output levels are covered under the language in R 2.1.3 “Generation additions, retirements, or other dispatch scenarios. Clarification is needed or language edits is recommended to include DER output level sensitivities.

The SPIDERWG recommends the SDT to review and edit the current language in R2.1 regarding the use of term “Load”, to ensure it clearly defines most critical conditions as intended, in systems with high DER penetration. When selecting steady state reference conditions to study for Planning Assessment, the distinction between gross load and net load is quite important. The SPIDERWG recommends that the SDT should also consider whether the terms “Gross Load” and “Net Load” be added to the NERC Glossary of Terms.

Standard Requirement R2.2

R2.2. For the Planning Assessment, the Long-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current study, supplemented with qualified past studies as indicated in Requirement R2, Part 2.6:

R2.2.1. A current study assessing expected System peak Load conditions for one of the years in the Long- Term Transmission Planning Horizon and the rationale for why that year was selected

SPIDERWG Review Finding

- This requirement is relevant for consideration of DER.
- The existing language does not preclude consideration of DER.
- The existing language is not clear for consideration of DER.

Supplemental Discussion

Same comments as R2.1 on “definition of “System peak”.

Standard Requirement R2.3

R2.3. The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as qualified in Requirement R2, Part 2.6. The analysis shall be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the System short circuit model with any planned generation and Transmission Facilities in service which could impact the study area.

SPIDERWG Review Finding

- This requirement is relevant for consideration of DER.
- The existing language does not preclude consideration of DER.
- The existing language is clear for consideration of DER.

Supplemental Discussion

Make sure that inverter-based DERs are modeled appropriately in the short circuit model using the latest developed models that reflect the converter interface. Unlike synchronous generators, the short circuit current contribution from the inverter-based generation is usually limited to 100-120% of the rated load current[8].

Standard Requirement R2.4

R2.4. For the Planning Assessment, the Near-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed annually and be supported by current or past studies as qualified in Requirement R2, Part2.6. The following studies are required:

R2.4.1 System peak Load for one of the five years. System peak Load levels shall include a Load model which represents the expected dynamic behavior of Loads that could impact the study area, considering the behavior of induction motor Loads. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable.

R2.4.2. System Off-Peak Load for one of the five years.

R2.4.3. For each of the studies described in Requirement R2, Parts 2.4.1 and 2.4.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance:

- Load level, Load forecast, or dynamic Load model assumptions.
- Expected transfers.
- Expected in service dates of new or modified Transmission Facilities.
- Reactive resource capability.
- Generation additions, retirements, or other dispatch scenarios.

R2.4.4. When known outage(s) of generation or Transmission Facility(ies) are planned in the Near-Term Planning Horizon, the impact of selected known outages on System performance shall be assessed. These known outage(s) shall be selected for assessment consistent with a documented outage coordination procedure or technical rationale by the Planning Coordinator or Transmission Planner. Known outage(s) shall not be excluded solely based upon outage duration. The assessment shall be performed for the P1 categories identified in Table 1 with the System peak or Off-Peak conditions that the System is expected to experience when the known outage(s) are planned. This assessment shall include, at a minimum, those known outages expected to produce more severe System impacts on the Planning Coordinator or Transmission Planner’s portion of the BES. Past or current studies may support the selection of known outage(s), if the study(s) has comparable post-Contingency System conditions and configuration such as those following P3 or P6 category events in Table 1.

R2.4.5. When an entity’s spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), the impact of this possible unavailability on System performance shall be assessed. Based upon this assessment, an analysis shall be performed for the selected P1 and P2 category events identified in Table 1 for which the unavailability is expected to produce more severe System impacts on its

[8] See the *IEEE Joint Working Group Report, Fault Current Contributions from Wind Plants, 2013* for more details (http://www.pes-psrc.org/kb/published/reports/Fault%20Current%20Contributions%20from%20Wind%20Plants.pdf).

portion of the BES. The analysis shall simulate the conditions that the System is expected to experience during the possible unavailability of the long lead time equipment.

SPIDERWG Review Finding

- This requirement is relevant for consideration of DER.
- The existing language does not preclude consideration of DER.
- The existing language is not clear for consideration of DER.

Supplemental Discussion

Similar comment as in R2.1 and 2.2 in regards to the terms "System peak Load" and "System Off-Peak Load". Consistent with the NERC Reliability Guideline for Distributed Energy Resource Modeling[9], DERs should be modeled explicitly (no load netting). DER capacity and output in peak and Off-Peak load conditions should be modeled consistent with the year and the snapshot hour that the case represents. To evaluate the dynamic behavior of the BPS under System peak Load and Off-Peak Load, DERs should be represented appropriately as either a generator model or a DER component of the load record in stability analysis. Consistent with the NERC Reliability Guideline for modeling DER in Dynamic Load Models[10], inverter-based DER can be represented in Stability analysis using the DER_A model. The NERC Reliability Guideline for parameterization of the DER_A model[11] can be used for developing required parameters. In addition, language regarding capturing the dynamic behavior of DER should be added for clarity, similar to the language used for representing induction motor loads in the current TPL-001 version. However, representation of the dynamic behavior of DERs is critical in all stability studies, not just System peak conditions.

Standard Requirement R2.5

R2.5. For the Planning Assessment, the Long-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed to address the impact of proposed material generation additions or changes in that timeframe and be supported by current or past studies as qualified in Requirement R2, Part2.6 and shall include documentation to support the technical rationale for determining material changes.

SPIDERWG Review Finding

- This requirement is relevant for consideration of DER.
- The existing language does not preclude consideration of DER.
- The existing language is clear for consideration of DER.

Supplemental Discussion

Same comments as R2.2.

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[9] https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability_Guideline_-_DER_Modeling_Parameters_-_2017-08-18_-_FINAL.pdf

[10] https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability_Guideline_-_Modeling_DER_in_Dynamic_Load_Models_-_FINAL.pdf

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

Standard Requirement R2.6

R2.6. Past studies may be used to support the Planning Assessment if they meet the following requirements:

R2.6.1. For steady state, short circuit, or Stability analysis: the study shall be five calendar years old or less, unless a technical rationale can be provided to demonstrate that the results of an older study are still valid.

R2.6.2. For steady state, short circuit, or Stability analysis: no material changes have occurred to the System represented in the study. Documentation to support the technical rationale for determining material changes shall be included.

SPIDERWG Review Finding

- This requirement is relevant for consideration of DER.
- The existing language does not preclude consideration of DER.
- The existing language is clear for consideration of DER.

Supplemental Discussion

Consider change in DER penetration level in determining material change for evaluation of use of past studies. As DER penetration increases along with the gross load, the net load growth at the T-D interface could remain flat or even decline. This may result in similar steady-state result as in past studies, depending on how evenly the DER is spread relative to the load. However, this could result in very different dynamic performance due to the change in load composition and dynamic behavior of the DER. It is not clear whether a change in inverter technology request by resource entity qualifies as material change. As DER are included in TPL-001 studies, it is important to account for changes, in response to NERC guidelines and standards and IEEE 1547, that alter their performance.

Standard Requirement R2.7

R2.7. For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity case analyzed in accordance with Requirements R2, Parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall: [Requirements 2.7.1 – 2.7.4]

R2.7.1. List System deficiencies and the associated actions needed to achieve required System performance. Examples of such actions include:

- Installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment.
- Installation, modification, or removal of Protection Systems or Remedial Action Schemes.
- Installation or modification of automatic generation tripping as a response to a single or multiple Contingency to mitigate Stability performance violations.

- Installation or modification of manual and automatic generation runback/tripping as a response to a single or multiple Contingency to mitigate steady state performance violations.
- Use of Operating Procedures specifying how long they will be needed as part of the Corrective Action Plan.
- Use of rate applications, DSM, new technologies, or other initiatives.

R2.7.2. Include actions to resolve performance deficiencies identified in multiple sensitivity studies or provide a rationale for why actions were not necessary.

R2.7.3. If situations arise that are beyond the control of the Transmission Planner or Planning Coordinator that prevent the implementation of a Corrective Action Plan in the required timeframe, then the Transmission Planner or Planning Coordinator is permitted to utilize Non-Consequential Load Loss and curtailment of Firm Transmission Service to correct the situation that would normally not be permitted in Table 1, provided that the Transmission Planner or Planning Coordinator documents that they are taking actions to resolve the situation. The Transmission Planner or Planning Coordinator shall document the situation causing the problem, alternatives evaluated, and the use of Non-Consequential Load Loss or curtailment of Firm Transmission Service.

R2.7.4. Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures.

SPIDERWG Review Finding

- This requirement is relevant for consideration of DER.
- The existing language does not preclude consideration of DER.
- The existing language is not clear for consideration of DER.

Supplemental Discussion

DER could alleviate system deficiencies by reducing net load and reducing flows on the bulk power system, depending on how DER is spread relative to the load. As such, DER could be part of CAP and could be included within the list of actions needed to achieve required system performance. An implementation guideline should be developed to clarify that DER could part of CAP.

Standard Requirement R2.8

R2.8. For short circuit analysis, if the short circuit current interrupting duty on circuit breakers determined in Requirement R2, Part 2.3 exceeds their Equipment Rating, the Planning Assessment shall include a Corrective Action Plan to address the Equipment Rating violations. The Corrective Action Plan shall:

R2.8.1. List System deficiencies and the associated actions needed to achieve required System performance.

R2.8.2. Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures.

SPIDERWG Review Finding

- This requirement is relevant for consideration of DER.

- The existing language does not preclude consideration of DER.
- The existing language is clear for consideration of DER.

Supplemental Discussion

DERs fault contribution characteristics could be considered as part of remedial actions assessment. Similar to 2.7 above, DER could be part of CAP and could be included within the list of actions needed to address the equipment rating violations. "Use of rate applications, DSM, new technologies or other initiatives".

Chapter 3 – Requirement R3

Standard Requirement R3

R3. For the steady state portion of the Planning Assessment, each Transmission Planner and Planning Coordinator shall perform studies for the Near-Term and Long-Term Transmission Planning Horizons in Requirement R2, Parts 2.1, and 2.2. The studies shall be based on computer simulation models using data provided in Requirement R1.

Standard Requirement 3.1

R3.1. Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R3, Part 3.4.

SPIDERWG Review Finding

- This requirement is relevant for consideration of DER.
- The existing language does not preclude consideration of DER.
- The existing language is not clear for consideration of DER.

Supplemental Discussion

The current language in R3 is not clear regarding whether and how to consider DER as planning events. While the current language in the R3 doesn't preclude consideration of DER, it also doesn't explicitly require inclusion of DER contingencies. Requirement R3.4 allows PC and TP to include only contingencies that are expected to produce more severe System impacts with the rationale for those Contingencies selected for evaluation shall be available as supporting information. Without changes to the Standard or further guidelines, the assessments may neglect to evaluate the impact of DER planning events (*i.e.* loss of a generator), regardless of the penetration level. Development of Contingency list should include contingency of explicitly modeled DER when they are expected to produce a more serve System impact on the BES. The DERs categorized as U-DER in the NERC Reliability Guideline for Distributed Energy Resource Modeling[12] are typically the ones that are modeled explicitly in the power flow model. The R-DER are not expected to be included in the Contingency list. If the level of penetration or U-DER size is not significant, the assessment may be able to exclude DER contingencies with rationale.

[12] https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability_Guideline_-_DER_Modeling_Parameters_-_2017-08-18_-_FINAL.pdf

Standard Requirement R3.2

R3.2. Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R3, Part 3.5. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be conducted.

SPIDERWG Review Finding

- This requirement is relevant for consideration of DER.
- The existing language does not preclude consideration of DER.
- The existing language is clear for consideration of DER.

Supplemental Discussion

With heavy penetration of DER, extreme events could include impacts of DER. Events like wide-area cloud cover and solar eclipse could significantly reduce DER output (predominantly solar) in a relatively short time (in addition to the reduction of BPS-connected solar PV generation). Based on discussions within SPIDERWG, this should not considered extreme events due to its time frame. Rather, TPs and PCs should consider developing base case scenarios that account for the spatial aspects and any common modes that could affect DER output.

Large amounts of DER could trip following other contingencies (e.g., loss of transmission circuits), and this can amplify the impact of the triggering contingency (as was observed in the UK disturbance in summer 2019). Existing language in Table 1 on extreme events is sufficient to allow such DER considerations by 3.b “Other events based upon operating experience that may result in wide area disturbances.”

Standard Requirement R3.3

R3.3. Contingency analyses for Requirement R3, Parts 3.1 and 3.2 shall:

R3.3.1. Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent:

R3.3.1.1. Tripping of generators where simulations show generator bus voltages or high side of the generation step up (GSU) voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made.

R3.3.1.2. Tripping of Transmission elements where relay loadability limits are exceeded.

R3.3.2. Simulate the expected automatic operation of existing and planned devices designed to provide steady state control of electrical system quantities when such devices impact the study area. These devices may include equipment such as phase-shifting transformers, load tap changing transformers, and switched capacitors and inductors.

SPIDERWG Review Finding

- This requirement is relevant for consideration of DER.
- The existing language does not preclude consideration of DER.
- The existing language is not clear for consideration of DER.

Supplemental Discussion

DERs should be tripped where simulations show bus voltages that are less than known or assumed minimum DER steady-state or ride-through voltage limits. It is also recommended to include in the assessment any assumptions made in estimating DER bus voltage. The existing language does not preclude consideration of DER. R1 specifies that the "System models" for the "Planning Assessment" discussed in R3 must: "Use data consistent with that provided in accordance with the MOD-032 standard, supplemented by other sources as needed" and "System models shall represent: …1.1.5 Resources (supply or demand side) required for Load." Thus, R3 does not preclude the consideration of DER by the PC and TP. After all, (1) under MOD-032-1, the PC and TP may already request DER data "necessary for modeling purposes" and (2) DER is a "demand side" resource increasingly required for serving load. R1.1.5 uses the term "Resources" when specifying inclusion of demand side resources, but R3.3 used the term "generators" which is not a defined term in the NERC Glossary. Therefore, it is not clear whether this requirement applies to DERs that are located on the demand side offsetting the load. Terminology and consideration for DER should be addressed by language modifications to bring clarity to the requirements.

Standard Requirement R3.4

R3.4. Those planning events in Table 1, that are expected to produce more severe System impacts on its portion of the BES, shall be identified and a list of those Contingencies to be evaluated for System performance in Requirement R3, Part 3.1 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information.

R3.4.1. The Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list.

Review Finding

- This requirement is relevant for consideration of DER.
- The existing language does not preclude consideration of DER.
- The existing language is not clear for consideration of DER.

Supplemental Discussion

Same comments as R3.1.

Standard Requirement R3.5

R3.5. Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list created of those events to be evaluated in Requirement R3, Part 3.2. The rationale for those Contingencies selected for evaluation shall be available as supporting information.

SPIDERWG Review Finding

- This requirement is relevant for consideration of DER.
- The existing language does not preclude consideration of DER.
- The existing language is clear for consideration of DER.

Supplemental Discussion
Same comments as R3.2

Chapter 4 – Requirement R4

Standard Requirement R4

R4. For the Stability portion of the Planning Assessment, as described in Requirement R2, Parts 2.4 and 2.5, each Transmission Planner and Planning Coordinator shall perform the Contingency analyses listed in Table 1. The studies shall be based on computer simulation models using data provided in Requirement R1.

Standard Requirement R4.1

R4.1. Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R4, Part 4.4.

R4.1.1. For planning event P1: No generating unit shall pull out of synchronism. A generator being disconnected from the System by fault clearing action or by a Special Protection System is not considered pulling out of synchronism.

R4.1.2. For planning events P2 through P7: When a generator pulls out of synchronism in the simulations, the resulting apparent impedance swings shall not result in the tripping of any Transmission system elements other than the generating unit and its directly connected Facilities.

R4.1.3. For planning events P1 through P7: Power oscillations shall exhibit acceptable damping as established by the Planning Coordinator and Transmission Planning Engineer.

SPIDERWG Review Finding

- This requirement is relevant for consideration of DER.
- The existing language does not preclude consideration of DER.
- The existing language is not clear for consideration of DER.

Supplemental Discussion
In Requirements R4.1.1 and R4.1.2, performance criteria "pulls out of synchronism" is specific to synchronous generators and is not addressing performance requirement for asynchronous generators including DER. The language should be clarified to address performance requirements for both synchronous and non-synchronous generators.

Standard Requirement R4.2

R4.2. Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R4, Part 4.5. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the event (s) shall be conducted.

SPIDERWG Review Finding

- This requirement is relevant for consideration of DER.
- The existing language does not preclude consideration of DER.
- The existing language is clear for consideration of DER.

Supplemental Discussion

Same comments as 3.2 Dynamic contingencies should include DER tripping for voltage/frequency.

Standard Requirement R4.3

R4.3. Contingency analyses for Requirement R4, Parts 4.1 and 4.2 shall:

R4.3.1. Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent:

R4.3.1.1. Successful high speed (less than one second) reclosing and unsuccessful high-speed reclosing into a Fault where high speed reclosing is utilized.

R4.3.1.2. 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. Include in the assessment any assumptions made. Contingency analysis should include aggregated DER loss as a contingency where applicable.

R4.3.1.3. Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models.

R4.3.2. 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. These devices may include equipment such as generation exciter control and power system stabilizers, static var compensators, power flow controllers, and DC Transmission controllers.

SPIDERWG Review Finding

- This requirement is relevant for consideration of DER.
- The existing language does not preclude consideration of DER.
- The existing language is not clear for consideration of DER.

Supplemental Discussion

DERs should be tripped where simulations show load bus voltages that are less than known or assumed minimum DER ride-through voltage limits. It is also recommended to include in the assessment any assumptions made in estimating DER bus voltage. The existing language does not preclude consideration of DER. R1 specifies that the “System models” for the “Planning Assessment” discussed in R4 must: “Use data consistent with that provided in accordance with the MOD-032 standard, supplemented by other sources as needed” and “System models shall represent: …1.1.5 Resources (supply or demand side) required for Load.” Thus, R4 does not preclude the consideration of DER by the PC and TP. After all, (1) under MOD-032-1, the PC and TP may already request DER data “necessary for modeling purposes” and (2) DER is a “demand side” resource increasingly required for serving load. R1.1.5 uses the term “Resources” when specifying inclusion of demand side resources, but R4.3 used the term “generators” which is not a defined term in the NERC Glossary. Therefore, it is not clear whether it includes DERs. Terminology and consideration for DER should be addressed by language modifications to bring clarity to the requirements. Requirement R4.3.2 should include DER's dynamic controls, if any, such as DER tripping, dynamic reactive support, active power-frequency control, etc.

Standard Requirement R4.4

R4.4. Those planning events in Table 1 that are expected to produce more severe System impacts on its portion of the BES, shall be identified, and a list created of those Contingencies to be evaluated in Requirement R4, Part 4.1. The rationale for those Contingencies selected for evaluation shall be available as supporting information.

R4.4.1. Each Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list.

SPIDERWG Review Finding

- This requirement is relevant for consideration of DER.
- The existing language does not preclude consideration of DER.
- The existing language is clear for consideration of DER.

Supplemental Discussion

Same comments as R3.1.

Standard Requirement R4.5

R4.5. Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list created of those events to be evaluated in Requirement R4, Part 4.2. The rationale for those Contingencies selected for evaluation shall be available as supporting information.

SPIDERWG Review Finding

- This requirement is relevant for consideration of DER.
- The existing language does not preclude consideration of DER.
- The existing language is clear for consideration of DER.

Supplemental Discussion

Same comments as R4.2.

Chapter 5 – Requirements R5-R8

Standard Requirement R5

R5. Each Transmission Planning Engineer and Planning Coordinator shall have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System. For transient voltage response, the criteria shall at a minimum, specify a low voltage level and a maximum length of time that transient voltages may remain below that level.

Standard Requirement R6

R6. Each Transmission Planning Engineer and Planning Coordinator shall define and document, within their Planning Assessment, the criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding.

Standard Requirement R7

R7. Each Planning Coordinator, in conjunction with each of its Transmission Planning Engineers, shall determine and identify each entity's individual and joint responsibilities for performing the required studies for the Planning Assessment.

Standard Requirement R8

R8. Each Planning Coordinator and Transmission Planning Engineer shall distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planning Engineers within 90 calendar days of completing its Planning Assessment, and to any functional entity that has a reliability related need and submits a written request for the information within 30 days of such a request.

R8.1. If a recipient of the Planning Assessment results provides documented comments on the results, the respective Planning Coordinator or Transmission Planning Engineer shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

SPIDERWG Review Finding

- Requirements R5–R8 are not relevant for consideration of DER.

Participants

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

Action
Approve

Background
The goal of this Reliability Guideline is to provide clear recommendations and guidance for establishing effective modeling data requirements on collecting aggregate DER data for the purposes of reliability studies. TPs and PCs should review their requirements and consider incorporating the recommendations presented in this guideline into those requirements. DPs are encouraged to review the recommendations and reference materials to better understand the types of modeling data needed by the TP and PC, and to help facilitate this data and information transfer. In many cases, the aggregate data needed for the purposes of modeling may not require detailed information from individual DERs; rather, aggregate data related to location, type of DERs, vintage of IEEE 1547, interconnection timeline and projections, and other key data points can help develop aggregate DER models. In instances of larger U-DERs, more detailed modeling information may be needed if those DERs can have an impact on BPS performance. In either case, the TP and PC should coordinate with the DP and any other external entities on the best approaches for gathering aggregate DER data for modeling purposes.

This guideline has already been authorized for a 45-day industry commenting period and contains edits from the response to comments from that commenting period.

Summary
SPIDERWG asks the RSTC to approve this *Reliability Guideline: Model Verification of Aggregate DER Models used in Planning Studies* per the Reliability Guideline approval process.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Reliability Guideline

DER Data Collection for Modeling in Transmission Planning Studies

September 2020

RELIABILITY | RESILIENCE | SECURITY




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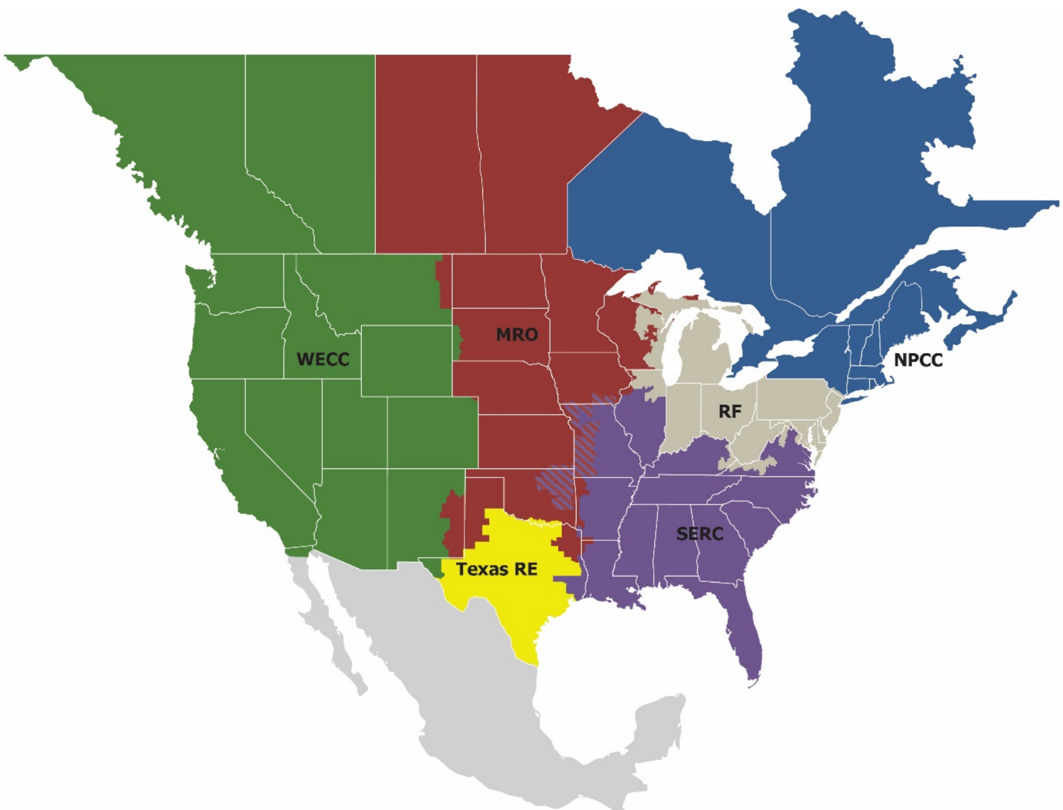
Preface

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

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

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



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

Preamble

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

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

Executive Summary

Modeling the BPS for performing BPS reliability studies hinges on the availability of data needed to represent the various elements of the grid. While many individual BPS elements are modeled explicitly,[1] some components are represented in aggregate. These aggregate representations include end-use loads[2] as well as a growing amount of distributed energy resources (DERs).[3] As the penetration of DERs continues to grow, representing DERs in planning assessments becomes increasingly important. Steady-state power flow, dynamics, short-circuit, electromagnetic transient (EMT), and other types of planning studies may need information and data that enable Transmission Planners (TPs) and Planning Coordinators (PCs) to develop models of aggregate amounts of DERs for planning purposes.

TPs and PCs establish modeling data requirements and reporting procedures per the requirements of NERC Reliability Standard MOD-032-1.[4] The data requirements should include specifications for collecting DER data for the purposes of aggregate DER modeling, particularly as DER penetration levels continue to increase. Clear and consistent requirements developed by the TPs and PCs will help facilitate the transfer of information between the Distribution Providers (DPs), Resource Planners (RPs), and any other external parties (e.g., state regulatory entities or other entities performing DER forecasting to the TP and PC for modeling purposes). The modeling data requirements established by TPs and PCs may differentiate utility-scale DERs (U-DERs) and retail-scale DERs (R-DERs) based on their size, impact, or location on the distribution system.[5] U-DERs may require detailed information regarding the facility while smaller-scale R-DER data will typically represent aggregate amounts of DERs. Both individual and aggregate information pertaining to DER levels can be useful to TPs and PCs as they develop DER models for their footprint. MOD-032 designees that develop Interconnection-wide planning cases should also ensure clear and consistent requirements for TPs and PCs to accurately account for aggregate amounts of DERs in the planning cases. TPs and PCs should also establish clear requirements and any applicable thresholds regarding DER modeling practices; however, aggregated amounts of DERs should be accounted and reported to the TP and PC for modeling purposes.[6] Any thresholds established for aggregate DER modeling should be based on engineering judgment and experience from studying DER impacts on the BPS; data regarding aggregate amounts of DERs will need to be collected by TPs and PCs to facilitate these studies.

The goal of this reliability guideline is to provide clear recommendations and guidance for establishing effective modeling data requirements on collecting aggregate DER data for the purposes of performing reliability studies. TPs and PCs should review their requirements and consider incorporating the recommendations presented in this guideline into those requirements. DPs are encouraged to review the recommendations and reference materials to better understand the types of modeling data needed by the TP and PC and to help facilitate this data and information transfer. In many cases, the aggregate data needed for the purposes of modeling may not require detailed information from individual DERs; rather, aggregate data related to location, type of DERs, vintage of IEEE 1547, interconnection time line and projections, and other key data points can help develop aggregate DER models. In instances of larger U-DERs, more detailed modeling information may be needed if those DERs can have an impact on BPS performance. In either case, the TP and PC should coordinate with the DP and any other external entities on the best approaches for gathering aggregate DER data for modeling purposes.

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[1] Such as BPS transformers, generators, circuits, and other elements

[2] Typically loads are aggregated to each distribution transformer. Therefore, all loads connected to that distribution transformer are represented as one load in the steady-state base case, and then an aggregate representation of the dynamic performance of those loads are developed using engineering judgment combined with available data.

[3] For the purpose of this guideline, SPIDERWG refers to a DER as "Any source of electric power located on the distribution system."

[4] https://www.nerc.com/_layouts/15/PrintStandard.aspx?standardnumber=MOD-032-1&title=Data%20for%20Power%20System%20Modeling%20and%20Analysis&jurisdiction=United%20States

[5] U-DER and R-DER are terms used for modeling aggregate amounts of DER. Refer to the flexible framework established in previous NERC reliability guidelines: https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability_Guideline_DER_A_Parameterization.pdf.

[6] This aligns with the guidance provided in NERC *Technical Report Distributed Energy Resource Connection Modeling and Reliability Considerations*: https://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/Distributed_Energy_Resources_Report.pdf.

Introduction

The ability to develop accurate models for BPS reliability studies hinges on the availability of data and information needed to represent the various elements of the grid. While many individual BPS elements are modeled explicitly (e.g., transformers, large BPS generators, transmission lines), some components of the grid are represented in aggregate for the purposes of BPS studies. Such models include the representation of end-use loads[7] as well as a growing focus on the representation of aggregate amounts of DERs. TPs and PCs are establishing modeling data requirements for DER data for the purposes of transmission planning assessments, and reasonable representation of DERs in the models used to execute these studies will be increasingly important. As this guideline highlights, DPs likely account for the aggregate amount of DERs connected to their system with varying degrees of detail and information available. In some instances, RPs may have information pertaining to future projections of DERs.

The primary objective of this reliability guideline is to provide recommended practices for TPs and PCs to establish effective modeling data requirements regarding aggregate DER data for the purposes of performing reliability studies. This includes TPs and PCs working with DPs, RPs, and other applicable data reporting entities to facilitate the transfer of data needed to represent aggregate DER in BPS reliability studies. The detailed guidance provided in this guideline follows the required data transfer established in NERC Reliability Standard MOD-032-1. Data collection requirements and reporting procedures established by each TP and PC are expected to vary slightly based on the types of studies being performed as well as how those studies are performed. However, there are commonalities in the type of data needed to model DERs and in how that data can be collected.

Background

The NERC *Reliability Guideline: Modeling DER in Dynamic Load Models*,[8] published December 2016, established a foundation for classifying DERs as either U-DERs or R-DERs for the purpose of modeling. That guideline also provided a flexible framework for modeling U-DERs and R-DERs in steady-state power flow base cases as well as options for modeling DER in the dynamic models. This included options for representing DERs with a stand-alone DER dynamic model or integrating DERs as part of the composite load model. The NERC *Reliability Guideline: Distributed Energy Resource Modeling*,[9] published September 2017, provided further guidance on establishing reasonable parameter values for DER dynamic models. That guideline reviewed the available dynamic models and recommended default parameter values that could be used as a starting point for modeling DERs. The NERC *Reliability Guideline: Parameterization of the DER_A Model*[10] recommended use of the DER_A dynamic model to represent either U-DERs or R-DERs in dynamic simulations. This model was in the process of being developed during the publication of the previous two guidelines. Therefore, that guideline demonstrated the benchmarking and testing of the DER_A model and also provided recommended default parameter values for the DER_A model for different scenarios of DER installations in various systems. Again, the recommendations presented in that guideline are intended to be a starting point for planning engineers to further determine representative DER dynamic model parameter values.

The NERC Distributed Energy Resources Task Force (DERTF) also published a technical report on *Distributed Energy Resources: Connection Modeling and Reliability Considerations,*[11] published December 2016, and a technical brief on *Data Collection Recommendations for Distributed Energy Resources,* published March 2018.[12] Both of these reports provided industry with a high-level overview of the information that may need to be collected and shared among

[7] Typically loads are aggregated to each distribution transformer. Therefore, all loads connected to that distribution transformer are represented as one load in the steady-state base case, and then an aggregate representation of the dynamic performance of those loads are developed using engineering judgment combined with available data.

[8] https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability_Guideline_-_Modeling_DER_in_Dynamic_Load_Models_-_FINAL.pdf

[9] https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability_Guideline_-_DER_Modeling_Parameters_-_2017-08-18_-_FINAL.pdf

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

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

[12] https://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/DER_Data_Collection_Tech_Brief_03292018_Final.pdf

entities for the purposes of modeling and studying DER impacts as well as monitoring DERs in real-time. Furthermore, these reports emphasized that netting of DERs with load should be avoided since it can mask the impacts that either may have on BPS reliability, particularly for dynamic simulations.

The NERC System Planning Impacts from Distributed Energy Resources Working Group (SPIDERWG) has developed this reliability guideline to build upon past efforts and specifically focus on gathering the data and modeling information needed to effectively execute transmission planning modeling and study activities. Effectively gathering data regarding the aggregate levels of DERs is critical for TPs and PCs to execute planning assessments and ensure reliable operation of the BPS in the long-term planning horizon.

Recommended DER Modeling Framework

The recommendations regarding DER data collection for the purposes of modeling and transmission planning studies use the recommended DER modeling framework proposed in previous NERC reliability guidelines (see **Figure I.1**).[13] For the purposes of modeling, the framework characterizes DERs as either U-DERs or R-DERs. These definitions are intended to be adapted to specific TP and PC planning practices and specific DER installations as needed. As a reference from previous DER modeling recommendations, these definitions include the following:

- **U-DER:** DERs directly connected to, or closely connected to, the distribution bus or connected to the distribution bus through a dedicated, non-load serving feeder.[14] 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,[15] commercial, and industrial customers. Typically, the residential units are single-phase while the commercial and industrial units can be single- or three-phase facilities.

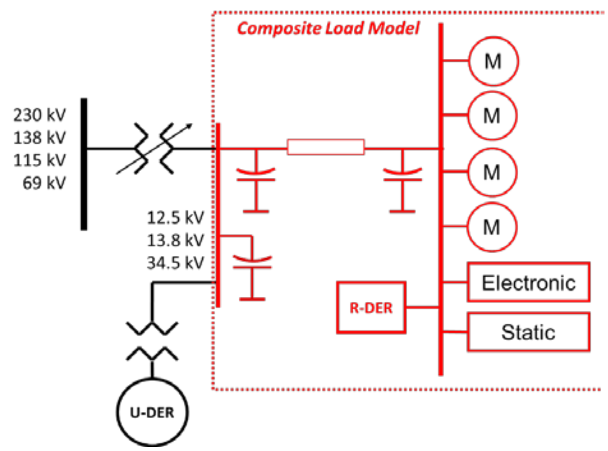

Figure I.1: DER Modeling Framework

Both U-DERs and R-DERs can be differentiated and modeled in power flow base cases and dynamic simulations. TPs and PCs have successfully adapted these general definitions for their system and often refer to U-DERs and R-DERs for the purposes of modeling aggregate DERs. Aggregate amounts of all DERs should be accounted for in either U-DER or R-DER models in the base case, and TPs and PCs may establish requirements for modeling any U-DERs as well as aggregate amounts of the remaining DERs as R-DERs. The aggregate impact of DERs, such as the sudden loss of a large amount of DERs, has been observed[16] to be a contributor to BPS performance during disturbances.

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

[14] Some entities have chosen to model larger (i.e., multi-MW) U-DERs that are connected further down on load-serving feeders as U-DERs explicitly in the base case. This has been demonstrated as an effective means of representing U-DERs and is a reasonable adaptation of the above definition. TPs and PCs should use engineering judgment to determine the most effective modeling approach.

[15] 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.

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

Types of Reliability Studies

Data of BPS elements as well as other necessary aspects[17] of the interconnected BPS are used in a wide array of reliability studies performed by TPs and PCs. In particular, studies considered by SPIDERWG include the following:

- **Steady-State Studies:[18]** Steady-state reliability studies include both power flow analysis and steady-state contingency analysis of future operating conditions.[19] In addition, steady-state stability studies typically include voltage stability[20] as well as small signal eigenvalue analysis. These studies all require information regarding the end-use load as well as the DER penetration to accurately model the behavior of these resources in future normal and abnormal operating conditions.

- **Dynamic Studies:[21]** Dynamic studies typically refer to phasor-based, time-domain simulations of the interconnected BPS. These studies include performing contingencies and identifying any potential instabilities, uncontrolled separation, or cascading events that may occur due to BPS dynamic behavior and all the elements connected to it. The data used in these simulations also represents the aggregate[22] effects of end-use loads as well as aggregate DERs. DERs, particularly in dynamic simulations, can have a relatively significant impact on BPS performance for voltage stability due to redispatched dynamic reactive devices on the BPS, rotor angle stability due to changes in BPS-connected generation dispatch, and frequency stability due to changes in rate of change of frequency and frequency response performance.[23] Furthermore, the dynamic behavior (e.g., momentary cessation, tripping, voltage and frequency support) of aggregate amounts of DERs can have a significant impact on the BPS, and the expected performance of aggregate DERs should be represented in dynamic models.[24] In many cases, the details of individual DERs are not relevant unless their individual size is deemed impactful[25] to BPS performance. A reasonable understanding of the aggregate behavior of DERs is more suitable for most dynamic simulations.[26] Regardless, TPs and PCs need access to DER data to determine potential impacts of aggregate amounts of DER on the BPS.

- **Short-Circuit Studies:** Short-circuit studies are used for a wide range of analyses, such as assessing breaker duty and setting protective relays. As DERs continue to offset BPS-connected generation, particularly during high DER output levels, short-circuit conditions may need to be assessed more regularly, or close attention may be needed in certain areas of low short-circuit strength. This is particularly a concern for systems with high penetrations of DERs as well as BPS-connected inverter-based resources. As described in **Chapter 4**, some DER data related to short-circuit performance may be needed as DER penetrations increase. It is important for TOs and TPs to establish data collection practices early to help ensure sufficient data is available for modeling purposes. TOs, TPs, and PCs will need to determine an appropriate time to begin modeling DERs for short-circuit studies; however, gathering the necessary data will help facilitate improved modeling practices in the future.

[17] Such as aggregate demand (steady-state) and the dynamic nature of end-use loads (dynamics)
[18] Fundamental-frequency, positive sequence, phasor simulations
[19] For example, high penetrations of DERs may have an impact on BPS voltage control and voltage stability due to reduced or limited dynamic reactive resources on the BPS.
[20] Active power-voltage (P-V) and reactive power-voltage (Q-V) analysis
[21] Fundamental-frequency, positive sequence, phasor simulations
[22] Or possible individual large loads or resources connected to the distribution system if they can potential have an impact to the BPS
[23] NERC SPIDERWG is working on more comprehensive reliability guidelines that will cover these topics in more detail (e.g., impacts of DERs to underfrequency load shedding (UFLS) programs).
[24] https://www.ofgem.gov.uk/publications-and-updates/ofgem-has-published-national-grid-electricity-system-operator-s-technical-report
[25] Again, this is based on TP and PC engineering judgment and experience studying DER impacts. For TPs and PCs to execute these studies, they will likely need to gather relevant data to create aggregate or large individual DER models.
[26] This is for at least most instances of R-DER. U-DER may need additional or more accurate data collection in some cases.

- **Geomagnetic Disturbance (GMD) Studies:** GMD studies are performed for applicable facilities per NERC TPL-007-3,[27] which analyzes the risk to BPS reliability that could be caused by quasi-dc geomagnetically induced currents (GICs) that result in transformer hot-spot heating or damage, loss of reactive power sources, increased reactive power demand, and misoperation of system elements due to GMD events. TPL-007-3 GIC vulnerability assessments typically do not model the distribution system for various reasons because the transmission-distribution (T-D) transformers include a delta-wye transformation with GICs not propagating through delta windings and distribution circuits being relatively short in length with high impedance. Therefore, GICs on the distribution system are minimal and are not likely to impact the distribution system. Based on this finding, DER modeling for the purposes of GMD vulnerability assessments per NERC TPL-007-3 is likely not needed at this time.[28]
- **EMT Studies:** Given the higher fidelity models, EMT analysis for DER interconnections can be useful in finding low short-circuit strength issues, such as controls instabilities, voltage control coordination issues, inability to ride through BPS disturbances, and benchmarking positive sequence fundamental-frequency phasor models. Items such as ride-through and voltage response can be better represented in EMT studies than traditional positive sequence studies. This is important when large groups of DERs (relative to the size of the system) are interconnected. Most industry experience to-date is based on studies conducted of BPS-connected inverter-based resources. However, EMT studies may be useful when large[29] amounts of aggregate DERs are connecting to areas where system strength is of concern. More industry research and experience is needed in this area; however, EMT studies are becoming increasingly used to ensure reliable operation of the BPS and should be considered in the context of increasing DER penetrations.

For all types of reliability studies, each TP and PC will need to determine the relative impact to the BPS as DER penetrations increase. To determine such impacts, information is needed to be able to model aggregate amounts of DERs. Therefore, this guideline stresses the importance of TOs, TPs, and PCs establishing data collection requirements (per the latest effective version of MOD-032) that are specifically related to collecting aggregate DER data sufficiently early such that the data is available for modeling purposes either now or in the future.

Case Assumptions

Similar to end-use load models, the assumptions used for modeling DERs will dictate how the resource(s) should be represented in planning base cases. NERC TPL-001-4 requires that planning assessments use steady-state, stability, and short-circuit studies to determine whether the BES meets performance requirements for system peak and off-peak conditions. TPs and PCs need to determine and specify these conditions to ensure clarity in data submittals from DPs and RPs in conjunction with other applicable data sources. MOD-032 designees that create the Interconnection-wide power flow and dynamics base cases should also ensure that clear and consistent modeling requirements are developed for TPs and PCs to reasonably account for and model aggregate DERs in the planning cases. For example, solar photovoltaic (PV) DERs are highly dependent on the time of day that is closely linked to the assumptions used in creating the base cases. TPs and PCs will need to consider the coincidence of DER output with demand levels to ensure cases are set up appropriately. In some areas, system peak loading may occur during late afternoon when active power output from solar PV is minimal (as illustrated in **Figure I.2** and discussed below); however, light loading conditions may occur when DER output is near its maximum. Regardless, setting up DER levels in planning studies hinges on sufficient data being collected by the TP and PC regarding the aggregate levels and behavior of DERs in their footprint.

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[27] https://www.nerc.com/_layouts/15/PrintStandard.aspx?standardnumber=TPL-007-3&title=Transmission%20System%20Planned%20Performance%20for%20Geomagnetic%20Disturbance%20Events&jurisdiction=United%20States

[28] Note that GICs on the BPS can create high levels of harmonic voltage distortion that can propagate to the distribution system. Situations where harmonic voltage distortion is identified may warrant closer investigation by affected entities.

[29] The term "large" is relative to each specific system and will need to be considered by each TP and PC. However, in order to execute these types of studies some degree of data will need to be collected by TPs and PCs.

PCs and TPs should clearly identify the assumptions used in planning cases as part of their data requirements so that DPs can effectively provide this information for the purposes of modeling aggregate DERs in planning base cases. Note that these studies are generally used to determine whether the BPS is robust enough to handle expected or impending operating conditions and credible contingencies based on the study results obtained. The following assumptions should be clearly defined for each base case in the TP and PC data requirements:

- **Year:** Each base case represents a specific year being studied. TPs are responsible for creating base cases of future, expected system conditions in the long-term planning horizon that include forecasted demand levels and should also include forecasted aggregate amount of DERs for each year being modeled. This data is based on local or regional DER growth trends and can come from multiple data sources.[30]
- **Season:** Each base case typically has a specified season (e.g., summer, spring, winter) or type of season (e.g., shoulder season), which is already defined in the planning process.
- **Time of Day:** Each TP and PC should identify the critical times of day that should be studied; this is often dependent on the time when gross demand peaks (or hits its minimum), when aggregate DER output peaks, and when net demand peaks (or hits its minimum). The assumed hour of day for each base case should be clearly defined by TPs and PCs to facilitate data collection from DPs and base case creation.
- **Load (Peak vs. Off-Peak):** The NERC TPL-001 standard uses terms such as “System peak Load” and “System Off-Peak Load”; however, it is not clear if these terms refer to gross or net load (demand) conditions. Therefore, it is recommended that TPs and PCs clearly articulate which load is being referred to in the case creation process. As the penetration of DERs continues to grow, it is likely that both peak and off-peak gross load and net load conditions should both be studied for potential reliability issues. This is particularly applicable to systems where the gross load and net load peak and off-peak conditions are significantly different. In all cases, TPs and PCs should ensure that gross load data is explicitly provided such that net loading can effectively be simulated by DER dispatch.
- **DER Dispatch Assumptions:** The TP and PC likely have established assumptions around how the DER will be dispatched in the planning base cases. While this may not directly affect the information flow from the DP to the TP and PC, these assumptions may help the DP in gathering the necessary data and information needed. These dispatch assumptions may include both active power output levels and reactive power capability. Additional planning base cases should reflect expected stressed system conditions that depend on the geospatial and temporal patterns (e.g., weather patterns) of demand and DERs, and their impact on BPS-connected generation dispatch. These conditions might include heavy transmission flows that have a very different pattern than during peak-load conditions.

[30] Such as state incentive policy forecasts or other relevant regional DER forecasting tools

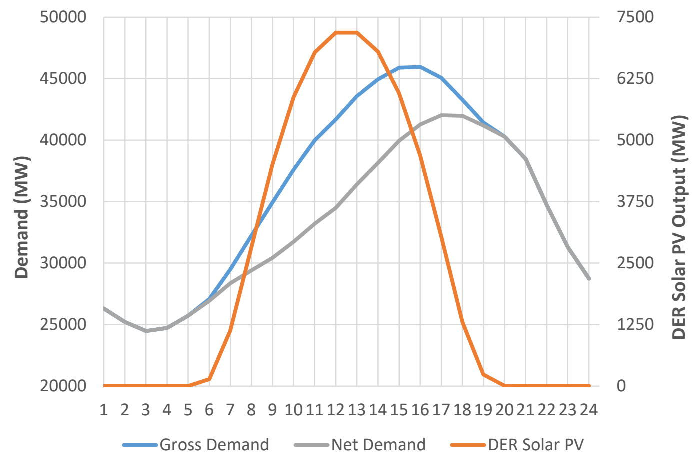

Figure I.2: DER and Demand Profiles for Summer Peak Condition [Source: CAISO]

To illustrate this concept, consider an example of the development of the Interconnection-wide "System Peak" base case. The TP in this example assumes that the "System Peak" case represents the hour of peak net demand (i.e., gross demand less DER output). Refer to Figure I.2 for a visualization of this example. Assume that this is a summer peak case, so the season has been defined. The gross demand peaks around 4:00 p.m., and net demand peaks around 5:00 p.m. local time, respectively, defining the time of day. Based on this, DER output assumptions are established, DERs in this area are predominantly distributed solar PV, and their output is assumed to be roughly 50–60% of its maximum capability at 4:00 p.m. and much closer to 0% of its maximum capability at 6:00 p.m. Assume in this example that DERs are compliant with IEEE Standard 1547-2003 based on time of installation of the DERs.[31] Furthermore, assume the DP has not required volt-var functionality by DERs, so the DERs are not expected to provide voltage support; rather, they are assumed to operate at unity power factor (defining active and reactive power output assumptions to be modeled). This concept applies to off-peak loading conditions as well as system peaking in winter as well.

By using the established case creation assumptions and DER modeling requirements specified by the TP and PC (described in the following sub-section), the DP can provide the necessary DER data needed to represent the aggregate DER in planning cases.

Time Line and Projections of DER Interconnections

The TP and PC are focused on developing planning base cases with reasonable assumptions of future BPS scenarios, including BPS generation, demand, and aggregate DERs. Accounting for the currently installed penetration of DERs helps the TP and PC understand what the existing system contains regarding DERs. This information, in most cases, should be provided by the DP to support data sharing across the transmission-distribution interface. Furthermore, the TP and PC should develop forecasts for DER growth into future years. This information may or may not be available to the DP; however, if the DP or state-level agency or regulatory body is performing DER forecasting for the purposes of distribution planning, this information may be available. In many cases, regional forecasts may be available from other data sources that could be useful for the DP, TP, and PC. If external sources (e.g., DER forecasts through state-level forecasts) are used by the DP, the DP should share that information with the TP and PC so they can incorporate those forecasts into their planning practices. Therefore, development of planning base cases uses a combination of data for existing DERs and projections of DERs.

Visualization of DER penetration, both existing and forecasted values, can be useful to the TP for the purposes of modeling DER in steady-state power flow base cases as well as dynamic simulations. Chapter 2 and Chapter 3 describe why understanding and estimating the vintage and deployed settings of DERs installed can be of significant value for the purposes of DER modeling.[32]

[31] https://standards.ieee.org/standard/1547-2003.html

[32] The Electric Power Research Institute (EPRI) is launching a public, web-based DER Performance Capability and Functional Settings Database: https://dersettings.epri.com.

Example of Applying DER Interconnection Time Lines

This section provides an illustrative example of applying DER interconnection times; it is intended solely as an example that could be adapted by TPs and PCs and is not intended to establish expected dates of standards implementation. Figure I.3 shows an example system with installed DER capacity from early 2010 to the end of 2019 as illustrated by the solid blue curve. The TP and PC are in the process of developing a five-year out 2025 base case, and they have pulled in forecasted DER growth (dotted blue curve) from either the RP, DP, or other external source (e.g., state-level agency or regulator body) that projects DER out to the end of 2025.

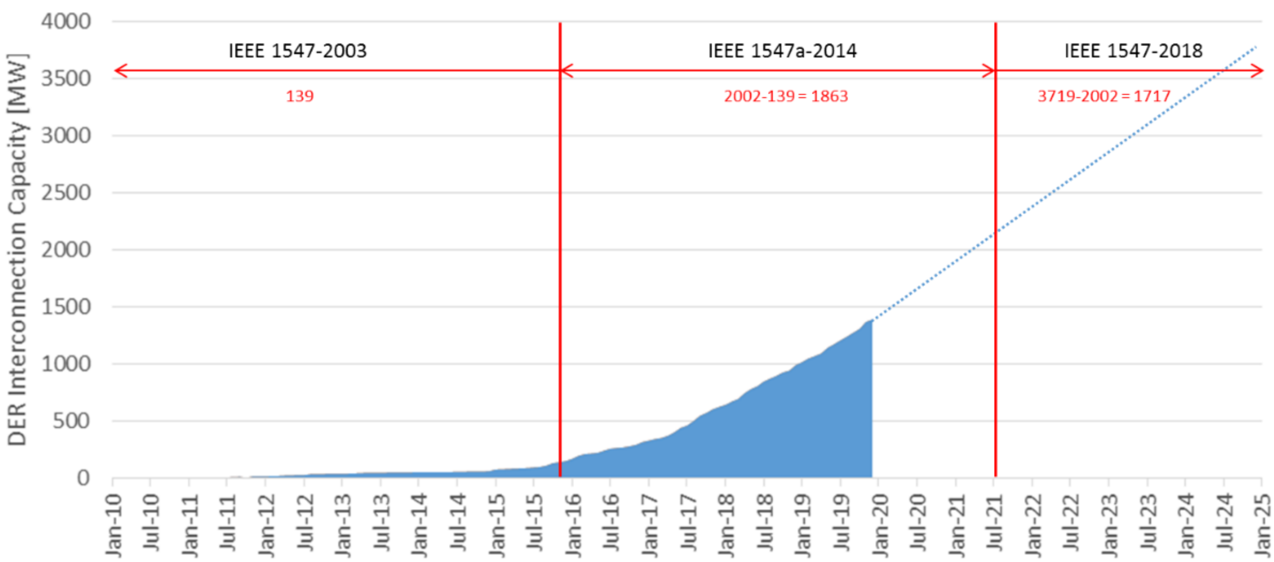

Figure I.3: Example DER Interconnection Capacity Growth

Assume all DERs connected to this example system are inverter-based and that the DERs comply with the various versions of IEEE 1547. For example, up to November 2015, due to interconnection requirements at the time, assume DERs were installed with settings compliant with IEEE 1547-2003. After November 2015 up to an assumed July 2021, assume[33] that DERs were installed with settings compliant with IEEE 1547a-2014.[34] Finally, after July 2021, assume that DERs will be installed with settings compliant with IEEE 1547-2018[35] once interconnection requirements are updated and compliant equipment becomes available. The red numbers show the amount of aggregate DER capacity that meet each standard implementation. It is clear that a small amount of resources are compliant with IEEE 1547-2003 while the remaining majority are mixed between IEEE 1547a-2014 and IEEE 1547-2018. The revised IEEE 1547-2018 includes much more robust ride-through performance and the capability for active power-frequency control on overfrequency conditions. In this example, no resources are required to maintain headroom to respond to underfrequency conditions. Interconnection requirements will presumably be updated in July 2021 to require local DER voltage control capability (volt-var capability). However, application of volt-var functionality is subject to DP practices and requirement, so wide-area implementation of this functionality should not be assumed unless confirmed as an established practice by the relevant DPs.

Based on the estimation of DER vintages as well as estimated deployed settings, the TP and PC can make reasonable assumptions regarding the following modeling considerations:

- Overall capacity of DERs connected to the system

[33] This is an assumption used here for illustrative purposes. However, while IEEE 1547a-2014 widened the ride-through settings, actual installed settings may not have been modified unless relevant interconnection requirements were adopted by DPs.
[34] https://standards.ieee.org/standard/1547a-2014.html
[35] https://standards.ieee.org/standard/1547-2018.html

- Expected locations of DER growth, if location-specific information is available
- The percentage of DERs responding to overfrequency disturbances
- The assumption that no DERs will respond to underfrequency disturbances
- The assumed DER ride-through capability, and frequency and voltage trip settings
- The assumed DER ride-through performance in terms of active and reactive current injection
- The percentage of DERs controlling voltage (steady-state)

The ability of TPs and PCs to understand when DERs were installed will greatly improve their ability to use engineering judgment to assume modeling parameters. This is particularly important for modeling aggregate amounts of R-DERs where minimal information is available.

Chapter 1: MOD-032-1 Data Collection Process

The purpose of NERC Reliability Standard MOD-032-1 is to "establish consistent modeling data requirements and reporting procedures for development of planning horizon cases necessary to support analysis of the reliability of the interconnected transmission system." MOD-032-1 serves as the foundation for the development of the Interconnection-wide planning base cases that are used as a starting point by TPs and PCs to perform their reliability assessment per the NERC Reliability Standard TPL-001. The requirements and overall flow of data is shown in **Figure 1.1**, specifically related to DER modeling information. The process is described briefly with the following requirements:

- Requirement R1 of MOD-032-1 requires that each PC and each of its TPs jointly develop data requirements and reporting procedures for steady-state, dynamics, and short circuit modeling data collection:
  - These requirements should include the data listed in Attachment 1 as well as any additional data deemed necessary for the purposes of modeling.
  - The data requirements should address data format,[36] level of detail, assumptions needed for the various types of planning cases or scenarios, a data submittal time line, and posting the data requirements and reporting procedures.
- Requirement R2 of MOD-032-1 requires each of the applicable entities[37] to provide the modeling data to the TPs and PCs according to the requirements specified.
- Requirement R3 requires each of the applicable entities to provide either updated data or an explanation with a technical basis for maintaining the current data if a written notification is provided to them by the PC or TP with technical concerns regarding the data submitted.
- Requirement R4 requires each PC to make the models for its footprint available to the ERO or its designee[38] to support the creation of Interconnection-wide base cases.

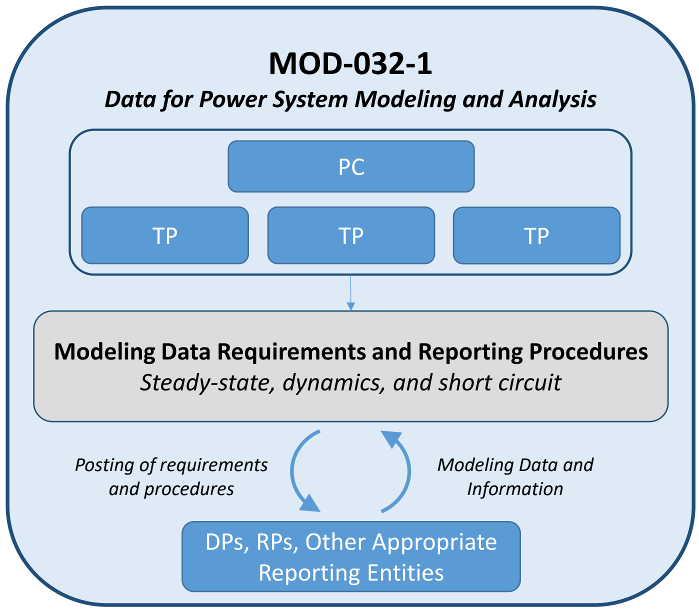

Figure 1.1: MOD-032-1 Flowchart for DER Data

MOD-032-1 Data Collection and DER

Attachment 1 of MOD-032-1 "indicates information that is required to effectively model the interconnected transmission system for the Near-Term Transmission Planning Horizon and Long-Term Transmission Planning

[36] This generally includes any model-related formats, possible software versioning, or other relevant data submittal formatting issues. Practices for collecting data differ from each TP and PC to integrate with their planning practices.

[37] Including each Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, TO, and Transmission Service Provider. Note that, at the time of writing this guideline, the Load Serving Entity has been deregistered, and SPIDERWG recommends that DPs are the best suited to provide DER information to TPs and PCs for modelling purposes. Therefore, DP is used as the applicable entity throughout this document.

[38] In each Interconnection of the NERC footprint, a "MOD-032 Designee" has been designated to create the Interconnection-wide base cases. Each designee has a signed agreement with NERC to develop base cases of sufficient data quality, fidelity, and time lines for industry to perform its planning assessments.

Horizon…A [PC] may specify additional information that includes specific information required for each item in the table below." **Figure 1.2** shows an excerpt from the MOD-032-1 Attachment 1 table.

steady-state *(Items marked with an asterisk indicate data that vary with system operating state or conditions. Those items may have different data provided for different modeling scenarios)*	**dynamics** *(If a user-written model(s) is submitted in place of a generic or library model, it must include the characteristics of the model, including block diagrams, values and names for all model parameters, and a list of all state variables)*	**short circuit**
1. Each bus [TO] a. nominal voltage b. area, zone and owner 2. Aggregate Demand[2] [LSE] a. real and reactive power* b. in-service status* 3. Generating Units[3] [GO, RP (for future planned resources only)] a. real power capabilities - gross maximum and minimum values b. reactive power capabilities - maximum and minimum values at	1. Generator [GO, RP (for future planned resources only)] 2. Excitation System [GO, RP(for future planned resources only)] 3. Governor [GO, RP(for future planned resources only)] 4. Power System Stabilizer [GO, RP(for future planned resources only)] 5. Demand [LSE]	1. Provide for all applicable elements in column "steady-state" [GO, RP, TO] a. Positive Sequence Data b. Negative Sequence Data c. Zero Sequence Data 2. Mutual Line Impedance Data [TO] 3. Other information requested by the Planning Coordinator or Transmission Planner necessary for modeling

Figure 1.2: Excerpt of MOD-032-1 Attachment 1 Table

Currently, the table in Attachment 1 does not provide a line item for aggregate DER data. Rather, the table includes a statement[39] in each of the columns that states "other information requested by the [PC] or [TP] necessary for modeling purposes" should be collected. This item should be used by the TPs and PCs as technical justification for collecting aggregate DER data necessary for modeling purposes as an interim solution until revisions to MOD-032-1 can occur. DPs should work with their respective TPs and PCs to understand expectations for gathering available DER data and making reasonable assumptions for any data that may not be available. TPs and PCs should also develop necessary processes for aggregating DER data and performing some degree of verification of the data received.[40]

Key Takeaway:
TPs and PCs should update their data reporting requirements required under Requirement R1 of MOD-032-1 to include specific requirements for aggregate DER data from the appropriate entities who have access to this data.

Regardless of the elements explicitly defined in MOD-032-1 Attachment 1, each TP and PC should jointly develop data requirements and reporting procedures for the purpose of developing the Interconnection-wide base cases used for transmission planning assessments. These requirements are often very detailed and specific to each PC and TP planning practices, tools, and study techniques. Therefore, TPs and PCs should update their data reporting requirements for Requirement R1 of MOD-032-1 to explicitly describe the requirements for aggregate DER data in a manner that is clear and consistent with their modeling practices. Coordination with their DPs in developing these requirements should result in the most effective outcome for gathering DER information for modeling.[41] **Chapter 2** provides a foundation and starting point for establishing the specific information that should be gathered for modeling purposes in coordination with the DP.

[39] Refer to items #9 and #10 in the steady-state and dynamics columns in NERC MOD-032-1, respectively.

[40] NERC SPIDERWG is working on a separate reliability guideline to support industry in performing verification of DER data and creating DER models.

[41] EPRI (2019): *Transmission and Distribution Operations and Planning Coordination*. TSO/DSO and Tx/Dx Planning Interaction, Processes, and Data Exchange. 3002016712. Electric Power Research Institute (EPRI). Palo Alto, CA: https://www.epri.com/#/pages/product/000000003002016712/.

Chapter 2: Steady-State Data Collection Requirements

This chapter describes the recommended data reporting requirements for collecting sufficient data to model aggregate DERs in Interconnection-wide power flow base cases. Each PC, in coordination with their TPs, should consider integrating these recommendations into their requirements per MOD-032-1 Requirement R1.

DER Modeling Needs for TPs and PCs

Modeling data requirements for steady-state aggregate DER data should be explicitly defined in the modeling data requirements established by each PC and TP per MOD-032-1. This section describes the recommended data necessary for representing the aggregate DERs in steady-state power flow base cases. TPs and PCs generally model gross load and aggregate DERs at specific BPS buses or at distribution buses at the low-side of the T-D transformers depending on their modeling practices. To accomplish modeling aggregate DER at the distribution bus, TPs and PCs need T-D transformer modeling data for explicit representation in the power flow model and can then assign the gross load and aggregate DERs connected to the low-side bus accordingly. The TP and PC should establish DER data collection requirements for aggregate DER data at each T-D transformer so this can be modeled correctly.[42] DPs should have some accounting of DERs at the bus-level or T-D transformer level in coordination with TP and PC data reporting needs. The DP may need to use engineering judgment to support the TP and PC in gathering the necessary data needed for suitable developing models.

DER models in the steady-state power flow base case, whether represented as a generator record (i.e., U-DERs) or as a component of the load record (i.e., R-DERs), have specific data points that must be accurately populated in order to represent aggregate DERs.[43] These data points, on a bus-level or T-D transformer level, may include the following:

- Location, both electrical and geographic
- Type of DER (or aggregate type)[44]
- Historical or expected DER output profiles[45]
- Status
- Maximum and minimum DER active power capacity (Pmax[46] and Pmin)
- Maximum and minimum DER reactive power capability (Qmax, producing vars; Qmin, consuming VARs); alternatively, a reactive power capability curve for the overall U-DER facility (this is specific to U-DERs)
- Distribution system equivalent feeder impedance (particularly for R-DERs and load modeling)

[42] Modeling on a T-D transformer basis is the most common approach for DER modeling where the T-D transformer is explicitly modeled and the aggregate load and aggregate DERs from the connected distribution feeders are represented. However, some TPs and PCs may have different modeling practices (e.g., by feeder-level basis), and therefore their requirements for data collection of DER may be slightly different.

[43] Since the BPS models use aggregate or equivalent representations of the distribution system and DERs, these models are not expected to accurately represent the steady-state reactive capability of a DER at the T-D interface. The models provide a reasonable representation of aggregate equipment capability that may have some effect on BPS performance during contingency events. Modeling of this capability is important for contingency analysis and dynamic simulations.

[44] This may be defined as part of the generator name, generator ID, or load record ID, and may be useful as the DER penetration continues to increase and different types of DER may need to be tracked.

[45] If meter-level data is available, profiles of DER output help TPs and PCs understand how the DER should be dispatched in the power flow base case. This is essential for developing reasonable base cases that represent expected operating conditions of the BPS, including the operation of aggregate DERs. If metering data is not available in the area, default profiles are helpful for TP and PC base case creation.

[46] The preferred approach for variable (inverter-based) DERs is for the DP to provide total aggregate DER capacity and the TP and PC can set active power output (Pgen) of the DER in the power flow to an output level based on assumptions specified for each case. For large synchronous DERs, similar data collection requirements for steady-state modeling data can be used as would be used for BPS-connected resources.

- (U-DER) Reactive power-voltage control operating mode[47]

If one or more DERs are represented as a U-DER with a generator record in the power flow, the TP and PC may need the following specific information to accurately represent this element (based on their specific modeling practices):

- Facility step-up transformer impedances
- Equivalent feeder or generator tie line[48] impedance (for large U-DER facilities) if applicable
- Facility or transmission-distribution transformer tap changer statuses and settings where applicable
- Shunt compensation within the facility[49]

The majority of newly interconnecting DERs across North America are either utility-scale solar PV (i.e., U-DERs) or rooftop solar PV (i.e., R-DERs) facilities. To reasonably represent these resources in the base case, the TP and PC may request that the DP provide a reasonable estimate or differentiation between U-DERs and R-DERs. This may simply be a percentage value of the estimate of U-DERs versus R-DERs and possibly the number and size of U-DERs. While individual accounting of R-DERs is very unlikely and inefficient, typically the accounting of U-DERs is much more straightforward since these resources are typically relatively large (e.g., 0.5 to 20 MW).[50]

On the other hand, DERs other than solar PV should be noted by the DP since these resources (e.g., battery energy storage, wind, small synchronous generation, combined heat and power facilities) may have different operational characteristics. For example, these resources may operate at different hours of the day, which would change the dispatch pattern when studying different hourly system conditions. DPs should have the capability to account for these different types of DERs to aid in the development of the base case models for the TP and PC; engineering judgment may be needed to estimate the expected operational characteristics and performance of the different DER technologies, particularly for forecasted DER levels.

Mapping TP and PC Modeling Needs to DER Data Collection Requests

The information described above defines the necessary information that will be needed by TPs and PCs to model aggregate DERs as either U-DERs or R-DERs. However, this information will likely not need to be provided or collected by the TP and PC for each individual DER; rather, these entities will need a reasonable understanding of the aggregate DER information. This section provides a mapping between the TP and PC needs and the information that should be requested from DPs by TPs and PCs as part of MOD-032. **Table 2.1** shows how the DER modeling needs are mapped to data requests. Also, refer to **Appendix B** for considerations for distributed energy storage systems.

Example of DER Information Mapping for Steady-State Power Flow Modeling

To apply the concepts described in **Table 2.1**, consider an example where aggregate DER data is being provided by the DP (possibly in coordination with external parties, such as a state regulatory body or other entity performing state-level DER forecasts) to the TP and PC. Following the structure of **Table 2.1**, the TP and PC would receive useful data for steady-state power flow modeling:

- 50 MW total aggregate DERs are allocated to T-D transformer (per TP and PC modeling requirements)
- 35 MW are considered U-DERs and 15 MW are considered R-DERs (based on TP and PC modeling practices)
- Of the U-DERs, 20 MW are solar PV and 15 MW are BESS (i.e., ± 15 MW)

[47] TPs and PCs should consider local DER interconnection requirements regarding power factor and reactive power-voltage control operating modes, where applicable. These modes may include operation at a set power factor (e.g., unity power factor or some of static power factor level) or operation in automatic voltage control. TPs and PCs can configure the power flow models by adjusting Qmax, Qmin, and the mode of operation to appropriately model aggregate DERs.
[48] In some cases, for generator tie line modeling, the MVA rating and length may be needed by the TP and PC.
[49] This is based on DER modeling practices established by the TP and PC.
[50] These values are used as a guideline in the DER modeling framework; however, they can be adapted based on specific modeling needs.

- Of the R-DERs, all 15 MW are solar PV
- About 75% of DER are likely IEEE 1547-2003 vintage and the remaining are most likely compliant with newer vintages of IEEE 1547 based on updated DP interconnection requirements
- All DER operates at unity power factor

Table 2.1: Steady-State Power Flow Modeling Data Collection

Aggregate DER Modeling Information Needed[51]	Information Necessary for Suitable Modeling of Aggregate DERs
Location	The DER interconnection location will need to be assigned to a specific T-D transformer or associated BPS or distribution bus based on the TP and PC modeling practices. Geographic location should also be given so that proper DER (e.g., solar) profiles and estimated impedance can be applied.
Type of DER (or aggregate type)	Specify the percentage of DERs considered U-DER and R-DER.[52] Provide an aggregate breakdown (percentage) of the types of DERs per T-D transformer. Preferably, this is specified as a percentage of aggregate DERs that are solar PV, synchronous generation, energy storage, hybrid[53] power plants, and any other types of DERs.
Historical or expected DER output profiles	For each type of aggregate DER (e.g., solar PV, combined heat and power, energy storage, etc.), specify a general historical DER output profile occurring during the studied conditions. What output are these resources dispatched to during peak and off-peak conditions? The TP and PC should define peak and off-peak conditions.
Status	Based on the DER output profile provided, TPs and PCs will know whether to set the aggregate DER model to in-service or out-of-service based on assumed normal operating conditions for the case.
Maximum DER active power capacity (Pmax)	Maximum active power capacity of aggregate DERs should be provided to the TP and PC. This, again, should be aggregated to the T-D transformer (i.e., each T-D transformer should generally have an amount of aggregated U-DER and R-DER, as necessary), depending on the TP and PC requirements.
Minimum DER active power capacity (Pmin)	Minimum active power capacity of aggregate DERs should also be provided, similar to maximum capacity. Systems with energy storage may have a Pmin value for aggregate DER modeling less than zero since the storage resources may be able to charge when generation DERs are at 0 MW output.
Reactive power-voltage control operating mode	Are the DERs controlling local voltage? Or are they set to operate at a fixed power factor? If some are operating in one mode while others are operating in a different mode, estimate the percentage in each mode using engineering judgment based on time of interconnection.

[51] The granularity of information submitted to the TP and PC by the DP should be defined in the data reporting requirements established by the TP and PC. This is most commonly on a T-D transformer basis.
[52] Consult with your TP and PC for more information on specific modeling requirements for U-DERs and R-DERs. Refer to NERC reliability guidelines: https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability_Guideline_DER_A_Parameterization.pdf.
[53] Hybrid plants combine generation and energy storage and have different operational characteristics than either individual type of DERs.

Table 2.1: Steady-State Power Flow Modeling Data Collection	
Aggregate DER Modeling Information Needed[51]	**Information Necessary for Suitable Modeling of Aggregate DERs**
Maximum DER reactive power capability (Qmax and Qmin)[54]	If DERs are controlling voltage (i.e., volt-var control), some aggregate reactive capability may need to be modeled. Otherwise, information pertaining to the expected power factor for DERs should be provided so that Qmax and Qmin can be configured in the model. For some U-DERs, a capability curve of reactive capability at different active power levels may be needed (at least at Pmax and Pmin levels).[55] Reactive devices required at the distribution bus to assist with voltage regulation and not otherwise aggregated in the DER model may also need to be represented.

[54] Qmax refers to producing vars, and Qmin refers to consuming vars.

[55] If this information is not known, the vintage of IEEE 1547-2018 standard could be useful to apply engineering judgment to develop a conservative capability curve.

Chapter 3: Dynamics Data Collection Requirements

This chapter describes the recommended data reporting requirements for collecting sufficient data to model aggregate DER in interconnection-wide dynamics cases. Each PC should consider integrating these recommendations into their requirements per MOD-032-1 Requirement R1 in coordination with their TPs.

DER Modeling Needs for TPs and PCs

Dynamics modeling data requirements for aggregate DERs should be explicitly defined in the modeling data requirements established by each PC and TP per MOD-032-1. This section describes the recommended data necessary for representing the aggregate DER in dynamic simulations performed by TPs and PCs to ensure BPS reliability. Refer to the existing NERC reliability guidelines regarding DER modeling for more information about recommended dynamic modeling approaches for DERs. While synchronous DERs exist and some new synchronous DERs are being interconnected in varying degrees,[56] inverter-based DERs (e.g., solar PV and battery energy storage) are rapidly being interconnected to the system in many areas across North America. Therefore, this section will use the DER_A dynamic model as an example for describing necessary information for the purposes of developing DER dynamic models.

The DER_A dynamic model is the recommended model for representing inverter-based DERs (i.e., wind, solar PV, and BESSs).[57] The DER_A model is appropriate for representing U-DERs and R-DERs as a standalone generator record or as a component of the load model (e.g., using the composite load model). The TP and PC will need to specify what their modeling practices are regarding U-DERs and R-DERs, including but not limited to the following:

- How are U-DER and R-DER differentiated in the planning base cases?
- Is a size threshold used to differentiate resources, or is this based on location along the distribution feeder(s)?
- Are the details of DER data different in any way between U-DERs and R-DERs?
- Are there specific interconnection requirements applicable to U-DERs, R-DERs, or both?
- Are U-DERs expected to have higher performance requirements for participating in energy markets?
- Are DERs combining generation and energy storage (i.e., hybrid plants), are these technologies ac-coupled or dc-coupled, and what are the operational characteristics of the facility (i.e., how is charging and discharging of the energy storage portion modifying total plant output)?
- What are the specific distribution-level tripping schemes or return to service requirements that would apply during the dynamics time frame for different vintages of DER installation dates?
- Are DERs generally located near the distribution substation (i.e., U-DERs) or closer to the end-use loads (i.e., R-DERs)?
- Are there any BPS protection schemes (e.g., direct transfer trip) that could result in the disconnection of DERs under certain BPS configurations?
- Are U-DERs or R-DERs expected to employ momentary cessation for large voltage excursions?

The DER_A dynamic model consists of many different parameter values that represent different control philosophies and performance capabilities for aggregate or individual inverter-based DERs; however, most of the parameter values

[56] DERs that are synchronously connected to the grid exist across North America; in some areas, these are the predominant type of DER. The DER modeling guidelines mentioned above can be referenced and adapted for gathering DER data for the purposes of modeling these resources.

[57] The New Aggregated Distributed Energy Resources (der_a) Model for Transmission Planning Studies: 2019 Update, EPRI, Palo Alto, CA: 2019, 3002015320 https://www.epri.com/#/pages/product/000000003002015320/?lang=en-US

remain fixed when representing different DER vintages or specific distribution-level interconnection requirements.[58] Therefore, it is important to focus on the control modes of operation and parameter values that change based on what types and vintages of DERs are connected to the distribution system. The following section will describe how gathering this data can be a fairly straightforward task and provide adequate information for the TP and PC to be able to use engineering judgment to model aggregate DERs in their footprint.

Mapping TP and PC Modeling Needs to DER Data Collection Requests

As mentioned, the complexity and number of parameter values of the DER_A dynamic model should not prohibit or preclude entities from developing relatively straightforward information sharing to gather the needed data for TPs and PCs to be able to model these resources. **Table 3.1** shows how parameterization of the DER_A dynamic model can be mapped to questions that should be asked by the TP and PC and to information that should be provided by the DP or other external entity to help facilitate DER model development. Note that **Table 3.1** shows default DER_A parameters to capture the general behavior of DERs compliant with IEEE 1547-2018 Category II, which is taken from NERC *Reliability Guideline: Parameterization of the DER_A Model*.[59] The table describes IEEE 1547 and its various versions; however, the concepts would also apply to other local or regional rules, such as California Rule 21 or Hawaii Rule 14H. Values listed in red are those that are likely subject to change across different vintages of the IEEE 1547 standard and would likely need to be modified to account for systems with DERS with varying vintages of IEEE 1547.[60] The questions posed in this guideline are intended to help TPs and PCs reasonably parameterize the DER_A dynamic model based on the information received. Refer to **Appendix B** for considerations for distributed energy storage systems.

Table 3.1 is intended as an example to help illustrate how the TP and PC could map questions related to DER information for the purposes of developing an aggregate DER dynamic model. The order of parameters and exact names of parameters may be slightly different across software platforms. Refer to a specific software vendor model library for exact parameter names and order of parameters. However, the concepts can be applied across software platforms.

Table 3.1: Data Collection for Parameterizing the DER_A Dynamic Model

Param	Default	Information Necessary for Suitable Modeling of Aggregate DERs
trv	0.02	Parameter values do not generally change between vintages of IEEE 1547. For the purposes of modeling, these default parameters are appropriate. Any dynamic voltage support requirements set by the DP should be communicated to the TP and PC so they can determine an appropriate modeling practice. Note that these parameters can be used to represent either dynamic voltage support or steady-state volt-var functionality; TPs and PCs will need to determine which approach is being used and specify any data collection requirements accordingly.
dbd1	-99	
dbd2	99	
kqv	0	
vref0	0	
tp	0.02	
tiq	0.02	

[58] For example, representing DERs compliant with different versions of IEEE 1547 (e.g., -2003, -2018, etc.) or DP-specific interconnection requirements.
[59] https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability_Guideline_DER_A_Parameterization.pdf
[60] https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability_Guideline_DER_A_Parameterization.pdf

Table 3.1: Data Collection for Parameterizing the DER_A Dynamic Model		
Param	**Default**	**Information Necessary for Suitable Modeling of Aggregate DERs**
ddn	20	Are DERs required to have frequency response capability enabled and operational for overfrequency conditions? As in, do DERs respond to overfrequency conditions by automatically reducing active power output based on this type of active power-frequency control system? If so, what are the required droop characteristics for these resources (e.g., 5% droop would equal a *ddn* gain of 20)?[61] What is the estimated fraction of resources installed on your system that are required to have this capability (based on interconnection date and requirements)?
dup	0	Are DERs required to have frequency response capability enabled and operational for underfrequency conditions? As in, if there is available energy, do DERs respond to underfrequency conditions by automatically increasing active power output based on this type of active power-frequency control system? Are there any requirements for DERs to have headroom to provide underfrequency response? If so, what are the required droop characteristics for these resources? What is the estimated fraction of resources installed on your system that are required to have this capability (based on interconnection date and requirements)?
fdbd1	-0.0006	If frequency response capability is enabled and operational, the deadband should be set to match any interconnection requirements governing this capability and performance. Consider the different types of interconnection requirements and what the correct assumption would be for this parameter, where applicable.
fdbd2	0.0006	If frequency response capability is enabled and operational, the deadband should be set to match any interconnection requirements governing this capability and performance. Consider the different types of interconnection requirements and what the correct assumption would be for this parameter, where applicable.
femax	99	Values vary based on what vintage of IEEE 1547 the DERs are, so a time line of interconnection capacity estimating the amount and timing of DER interconnection will support modeling.
femin	-99	Values vary based on what vintage of IEEE 1547 the DERs are; so a time line of interconnection capacity estimating the amount and timing of DER interconnection will support modeling.
pmax	1	Parameter values do not generally change between vintages of IEEE 1547. No information needed from DP for the purposes of modeling, assuming that these default parameters are appropriate. In cases where the TP or PC has determined that these default parameters are not appropriate, the TP or PC may request additional information of the DP for this purpose.
pmin	0	
dpmax	99	
dpmin	-99	
tpord[62]	5	
Imax	1.2	
vl0	0.44	
vl1	0.49	
vh0	1.2	
vh1	1.15	
tvl0	0.16	
tvl1	0.16	
tvh0	0.16	
tvh1	0.16	
Vrfrac	1.0	Values vary based on what vintage of IEEE 1547 the DERs are, so a time line of interconnection capacity estimating the amount and timing of DER interconnection will support modeling.

[61] Note that TPs and PCs will need to consider the fraction of DERs providing frequency response, if applicable. The values of *ddn* and *dup* will need to be scaled appropriate to account for this fraction. The gain value can be determined by scaling (1/droop) by the fraction of DERs contributing to frequency response. This concept applies to *dup* as well.

[62] The active power-frequency response from DERs, if utilized in studies, should be tuned to achieve and ensure a closed-loop stable control. This parameter may need to be adapted based on this tuning.

Table 3.1: Data Collection for Parameterizing the DER_A Dynamic Model

Param	Default	Information Necessary for Suitable Modeling of Aggregate DERs
fltrp	56.5	Values vary based on what vintage of IEEE 1547 the DERs are, so a time line of interconnection capacity estimating the amount and timing of DER interconnection will support modeling.
fhtrp	62.0	Values vary based on what vintage of IEEE 1547 the DERs are, so a time line of interconnection capacity estimating the amount and timing of DER interconnection will support modeling.
tfl	0.16	Parameter values do not generally change between vintages of IEEE 1547. No information needed from DP for the purposes of modeling, assuming that these default parameters are appropriate. In cases where the TP or PC has determined that these default parameters are not appropriate, the TP or PC may request additional information of the DP for this purpose.
tfh	0.16	
tg	0.02	
rrpwr	2.0	Values vary based on what vintage of IEEE 1547 the DERs are, so a time line of interconnection capacity estimating the amount and timing of DER interconnection will support modeling.
tv	0.02	Parameter values do not generally change between vintages of IEEE 1547. No information needed from DP for the purposes of modeling, assuming that these default parameters are appropriate. In cases where the TP or PC has determined that these default parameters are not appropriate, the TP or PC may request additional information of the DP for this purpose.
Kpg	0.1	Values vary based on what vintage of IEEE 1547 the DERs are, so a time line of interconnection capacity estimating the amount and timing of DER interconnection will support modeling.
Kig	10.0	Values vary based on what vintage of IEEE 1547 the DERs are, so a time line of interconnection capacity estimating the amount and timing of DER interconnection will support modeling.
xe	0.25–0.8[63]	Parameter values do not generally change between vintages of IEEE 1547. No information needed from the DP for modeling purposes, assuming that these default parameters are appropriate. In cases where the TP or PC has determined that these default parameters are not appropriate, the TP or PC may request additional information of the DP for this purpose.
vfth	0.3	TP and PC engineering judgment can be used to set this parameter value. May be subject to change across vintages of IEEE 1547 for the purposes of modeling.
iqh1	1.0	Parameter values do not generally change between vintages of IEEE 1547. No information needed from DP for the purposes of modeling, assuming that these default parameters are appropriate. In cases where the TP or PC has determined that these default parameters are not appropriate, the TP or PC may request additional information of the DP for this purpose.
iql1	-1.0	
pfflag	1	
frqflag	1	
pqflag	Q priority	Values vary based on what vintage of IEEE 1547 the DERs are, so a time line of interconnection capacity estimating the amount and timing of DER interconnection will support modeling.
typeflag	1	What penetration of energy storage resources are connected to the distribution system? What percentage of DERs are energy storage? Are these larger utility-scale energy storage DERs, or more distributed (e.g., residential) energy storage DERs? Any values or estimates as the interconnection of energy storage DERs will help determine whether to and how to separate out energy storage DERs in the models.

Table 3.1 highlights the concept that interconnection time line is critical for the purposes of creating dynamic models of aggregate DERs because the capabilities and performance of DERs is dominated by the interconnection requirements set forth on those DERs. TPs and PCs may have additional data points that provide useful information for capturing more information relevant to developing reasonable DER models, and may have other data points needed for modeling larger U-DER installations (depending on whether additional requirements or data are needed). For DER model parameter values that vary with the vintage of IEEE 1547, a time line of interconnection capacity can be shared to estimate the amount and time in which resources were interconnected. TPs and PCs will also need to consider what the expected settings of the actual installed equipment may be; this can be informed by any interconnection requirements or expected default settings used.

[63] Studies performed by EPRI have shown that *Xe* may need to be a greater value in certain systems or for certain simulated faults to aid in simulation numerical stability. These studies have shown that the increased *Xe* value does not reduce the reasonability of the DER response.

To recap the relevant information needed for aggregate DER dynamic modeling, the following data points should be considered by TPs, PCs, DPs, and other external entities in the development of requirements and when providing this information for modeling purposes:[64]

- What is the vintage of IEEE 1547 (or equivalent standard) that is applicable to the DERs and were there any applicable updates to DP interconnection requirements regarding DERs? If it is a mixed collection of vintages, based on the interconnection date, engineering judgment should be used by the DP, TP, and PC to assign percentages to different vintages, as applicable.
- Do the installed or projected future installations of DERs have the capability to provide frequency response in the upward or downward direction? If so, are there any relevant requirements or markets in which DERs may be dispatched below maximum available active power?
- Are DERs providing dynamic voltage support or any fault current contribution or are they entering momentary cessation?
- What are the expected trip settings (both voltage and frequency) associated with the vintages of IEEE 1547 or other local or regional requirements that may dictate the performance of DERs?
- Are DERs installed on feeders that are part of UFLS programs? If so, more detailed information regarding the expected penetration of DERs on these feeders may be needed. As stated previously, hybrid U-DER facilities likely need specific, more detailed modeling considerations by the TP and PC, and therefore should be differentiated accordingly.

[64] The TP and PC will need to consider these points when developing aggregate DER dynamic models, and, therefore, will need information from the DP and any other external entities that may be able to help provide information in these areas.

Chapter 4: Short-Circuit Data Collection Requirements

This chapter briefly describes considerations that should be made for gathering aggregate DER data for the purposes of short-circuit modeling and studies at the BPS level. Note that aggregate DER data collection for the purposes of distribution-level short-circuit studies is not considered.

Applications of Short-Circuit Studies

In general, short-circuit studies are used by transmission entities in two key ways: breaker duty assessment and setting protective relays. These are described below:

- **Breaker Duty Assessments:** In breaker duty assessments, all resources are on-line for the worst case assumption to ensure that BPS breakers will always be rated sufficiently to clear BPS fault events. This assumption has been used extensively in the past and will likely continue to be used in the future for these types of studies. In any system, the "significance"[65] of aggregate DER fault current will need to be considered by the engineer performing the studies. In areas where breakers are very close to their duty rating, aggregate DER contributions may be warranted (particularly of localized issues).
- **Setting Protective Relays:** Protective relay setting analyses study "all lines in-service" conditions as well as credible outage conditions that can affect the fault current characteristics of the local network. Alternate contingency events are selected and studied to ensure correct relay operation for a wide range of system configurations. In this case, the focus is not on equipment ratings; rather, it is on secure protection system operation. As the penetration of BPS-connected inverter-based resources as well as DERs continue to increase, their impact on BPS fault current impacts will become more significant and will need to be considered. This will likely be on a case-by-case basis in the near-term; however, this type of aggregate DER modeling data will likely be needed on a more regular basis in the future. Not fully modeling potential impacts to BPS fault current can have an adverse impact on setting protective relays.

In either type of study, it is important for TOs and TPs to establish data collection practices early to ensure sufficient data can be collected for performing accurate short-circuit studies. BPS equipment integrity and public safety are of utmost importance, and these studies rely on sufficient data to conduct them.

Potential Future Conditions for DER Data and Short-Circuit Studies

As the BPS continues to experience an increase in the penetration of BPS-connected inverter-based resources as well as DERs, short-circuit modeling and study practices may need to evolve. In some cases, aggregate DER data (along with possibly end-use load data) may become increasingly important for BPS short-circuit studies. In particular, each TP and PC should consider **Table 4.1**, which lays out potential future conditions where aggregate DER data may be needed for short-circuit modeling. **Table 4.1** is intended as a guide to help describe the considerations as they relate to specific system needs and therefore the need for aggregate DER short-circuit modeling data. In each scenario in **Table 4.1**, TPs, PCs, and TOs are recommended to establish short-circuit data collection requirements for existing and future DER additions to assure studies can be performed adequately.

[65] "Significance" is used loosely and generally in this discussion but becomes increasingly important under high penetration DER conditions.

Table 4.1: Potential Future Conditions for DER Data Collection for Short-Circuit Studies	
#	**Potential Future Conditions and Considerations**
1	**Condition:** BPS-connected synchronous generators dominate, and DERs are not prevalent.
	Consideration: This may be the status quo for some entities. BPS-connected synchronous generators provide significant fault current, and aggregate DERs and end-use loads are typically not modeled because the majority of fault current comes from synchronous machines.
2	**Condition:** Resource mix consists of both BPS-connected inverter-based and synchronous generators, and DERs are not prevalent.
	Consideration: This is likely the status quo for many entities with growing penetrations of BPS-connected wind and solar PV but fairly low penetrations of DERs. BPS fault currents are decreasing due to the BPS-connected inverter-based resources.[66] Aggregate DERs and end-use loads are generally not modeled in short-circuit studies because the majority of fault current still comes from the BPS (mainly synchronous generators).
3	**Condition:** BPS resource mix consists of both synchronous and inverter-based resources, and DERs are becoming increasingly prevalent.
	Consideration: Some areas are experiencing this condition today (e.g., CAISO, ISO-NE). The growth of DERs in conjunction with increasing BPS-connected inverter-based resources is leading to a high overall inverter-based system. Increased BPS-connected inverter-based resources is still affecting fault characteristics[67] on the BPS. Legacy DERs are likely not providing fault current due to the use of tripping and momentary cessation for large disturbances, and there likely has been a lack of interconnection requirements to specify behavior for DERs during fault events. Inverter-based DERs providing fault current, where applicable, may have an impact on localized breaker duty studies and may need to be considered for setting protective relays. On a broader scale, synchronous generators dominate BPS fault current; the impedance between DERs and the BPS fault is so large that DER fault current contribution to the BPS is relatively low. Therefore, TPs and PCs will need to explore this on a case-by-case basis but should ensure the ability to collect aggregate DER data.
4	**Condition:** DERs can provide the majority of energy to end-use customers during certain instances; these conditions are likely coupled with increasing BPS-connected inverter-based resources and limited on-line synchronous generators.
	Consideration: Few, if any, areas of the North American BPS experience situations like this today; however, this scenario may be more likely in the future (even within the planning horizon). Lack of on-line synchronous generators causes low fault current magnitudes. DER interconnection requirements for new-vintage DERs may allow for momentary cessation as a default setting (i.e., 1547-2018). Existing and future installations of DERs may not provide fault current unless momentary cessation is prohibited by local requirements.[68] Where DERs are providing fault current, inverter-based DERs can only provide a limited magnitude of current and their contribution will be primarily for nearby local faults; the impedance between the DERs and the BPS fault location cause their contribution to be low. BPS protective relaying could experience issues under these types of scenarios either due to very low fault current levels or unknown/unstudied fault current behavior (e.g., phase relationship).[69] Solutions may be needed to maintain acceptable levels of fault current (e.g., synchronous condensers). Some synchronous generation will likely remain on-line for the foreseeable future (i.e., hydro generators), providing a suitable amount of fault current in those areas. However, as the primary source of generation (and possibly fault current) in this scenario, aggregate DERs may need to be modeled in short-circuit studies. Aggregate representation of DERs is likely suitable so long as any significant differences in fault current contribution is differentiated. TPs and PCs will need to assess the potentiality of this scenario and determine whether they should proactively collect aggregate DER data for short-circuit modeling.

[66] The power electronics interface of inverter-based resources limits fault current contribution from these resources. Furthermore, some BPS-connected solar PV resources may employ momentary cessation, which is an operating state for inverters where no current is injected into the grid by the inverter during low or high voltage conditions outside the continuous operating range.

[67] Decreasing fault current magnitude and the uncertain phase angle relationship between voltages and currents from inverter-based resources

[68] This will need to be analyzed closely and coordinated between distribution and transmission planning and protection engineers.

[69] This would be caused both by BPS-connected inverter-based resources as well as the DERs.

Differentiating Inverter-Based DERs

It may be prudent for TPs and PCs to consider separating requirements for inverter-based and synchronous DERs due to their relatively different impacts on BPS fault characteristics. Synchronous DERs (e.g., low head hydro, run of river hydro, combined heat and power plants) likely should be modeled in short-circuit studies since they can be a significant source of fault current in that local area. However, the majority of newly interconnecting DERs in most regions are inverter-based (e.g., solar PV and BESSs). Inverter-based DERs may only provide a relatively small fault current (i.e., on the order of 1.1 pu maximum) if any. IEEE 1547-2018 allows for the use of momentary cessation during low voltages such as during fault events, and, therefore, fault current from DERs may very well be minimal or zero in the future. This type of information should be considered by the TP and PC performing short-circuit studies.

Example Impact of Aggregate DERs on BPS Fault Characteristic

Whether or not a specific DER (i.e., U-DERs) or aggregate amount of DERs (i.e., R-DERs as well as U-DERs) have a significant[70] impact on the BPS will need to be determined by the TP and PC performing such studies. During SPIDERWG discussions, Southern California Edison provided a rough rule-of-thumb for DER impacts to be the following values:[71]

- At 500 kV, 1–2 A/MW
- At 230 kV, 4–5 A/MW
- At 115 kV, 7–8 A/MW
- At 66 kV, 10–15 A/MW

These values assume a three-phase fault is applied at the transmission or sub-transmission system bus where the DERs (and end-use loads) are directly being served out of and roughly account for typical impedance between the DERs and the T-D interface. These numbers will vary by system configuration but demonstrate a relative impact as DER penetrations continue to increase across large portions of the BPS.

Considering Short-Circuit Response from DERs and Loads

Inverter-based DERs configured to provide fault current are limited to around 1.1 pu maximum fault current due to the power electronics interface of the inverter. On the other hand, direct-connected motor loads will dynamically respond during and immediately after the fault and affect overall fault current contribution along the feeder. This is particularly true for R-DERs spread throughout the feeder; however, even fault current from U-DERs located at or near the head of the feeder may provide little fault current through the T-D interface. Therefore, short-circuit characteristics of end-use loads will need to be taken into account when considering DER short-circuit contributions.

Typically, load is not modeled in short-circuit analysis because its impact and significance to overall BPS fault current levels is very low. However, in localized areas or systems dominated by DERs, fault current from DERs may play a more significant role in overall fault current contributions. In these cases, it may be deemed necessary to model DERs for short-circuit analysis. It is important to note, however, that the response from end-use loads (particularly motor load) should also be considered in cases where DER contribution to BPS fault current is deemed necessary to model. This is analogous to short-circuit studies performed at large industrial facilities where the effects of motor loads on fault current cannot be overlooked since they have a significant impact on proper relay operation. The same concept applies to the BPS in a system where the fault current contribution from DERs and loads cannot be overlooked.

[70] The term “significant” is used loosely and generally in this discussion but becomes increasingly important under higher penetrations of DERs.
[71] This assumes a mix of R-DER and U-DER along the feeder and assumes a maximum fault current from DERs of 1.1-1.2 pu based on available inverter manufacturer data.

Aggregate DER Data for Short-Circuit Studies

In cases where DER data may be necessary for short-circuit studies, the TP and PC will need to establish requirements per MOD-032-1 Requirement R1 around what types of short-circuit modeling data need to be provided by the DP. These requirements should be as clear and concise as possible to help facilitate this data transfer. It is likely that many TPs and PCs fall into either Categories 2 or 3 of Table 4.1 today. Where DER data may be needed for forward-looking short-circuit studies, the following information may be useful regarding aggregate[72] DERs:[73]

- Continuous MVA rating of aggregate DERs
- Estimated vintage of IEEE 1547-2018 and settings applicable for DER tripping and momentary cessation (i.e., would the DER trip or cease current injection for fault events)
- Assumed effective fault current contribution at a specific time frame(s)[74] during the fault
- Assumed phase angle relationship between voltages and currents

Example where DER Modeling Needed for Short-Circuit Studies

One example of where U-DER data may be needed is local breaker duty short-circuit analyses. Consider Figure 4.1, which shows a 230/69 kV network with a hypothetical yet possible situation where breaker underrating could happen. At the MK-69 bus, before the addition of DER #1 (20 MW) and DER #2 (20 MW), the breaker at MK-69 (shown in red) connecting the circuit to GY-69 is at 99.4% of interrupting duty when a fault is applied on the MK-69–GY-69 circuit (shown in Figure 4.1 as well). If the DER fault current contribution were ignored, then short-circuit studies would remain unchanged since the contribution from DERs would not be modeled. However, if the 40 MW nameplate capacity of DERs is modeled to provide 1.1 pu fault current, the breaker could be underrated as the interrupting fault duty jumps to 101.1% and exceeds the 100% rating of the BPS element. These effects may be observed locally today across many parts of the BPS but may also become more prominent as the amount of DERs continues to increase (or if the fault current contribution is much higher from a synchronous DER).

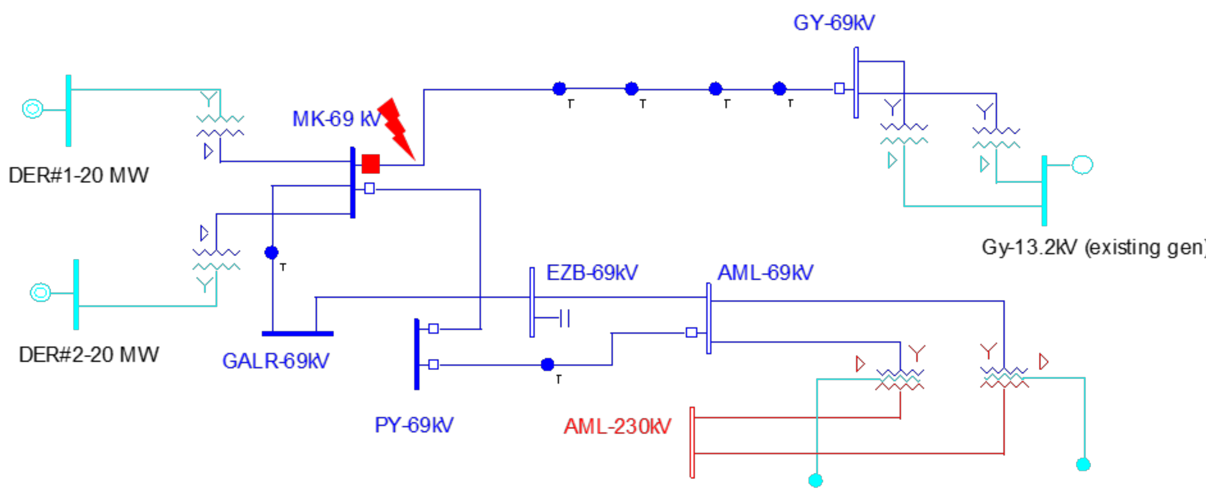

Figure 4.1: Example Network for Breaker Underrating Example

[72] Again, this is likely on a T-D transformer basis, per TP and PC data reporting requirements.
[73] Based on minimum requirements for modeling voltage-controlled current sources in short circuit programs
[74] These may include sub-transient, transient, and other applicable time frames based on TP and PC modeling and study techniques.

Chapter 5: GMD Data Collection Requirements

NERC TPL-007-3[75] requires TPs, PCs, TOs, and Generator Owners owning facilities that include power transformers with a high-side, wye-grounded winding with terminal voltage greater than 200 kV to perform GMD vulnerability analysis. The GMD vulnerability assessment is a documented evaluation of potential susceptibility to voltage collapse, cascading, and localized damage to equipment due to GMD events.[76]

During a GMD event, quasi-dc GICs flow through transmission circuits and return through the Earth by grounded-wye transformers and series windings of autotransformers that provide a dc path between different voltage levels. DC current flow through transformers produces harmonic currents that can increase transformer reactive power consumption and may cause hot-spot heating that potentially leads to premature transformer loss of life or failure. Furthermore, harmonic currents propagate through the power system can cause BPS elements to trip and may be a potential susceptibility for aggregate DER tripping.[77]

In performing GMD vulnerability assessments, TPs and PCs use a dc-equivalent system model (GIC system model) for determining GIC levels and a steady-state power flow model for assessing voltage collapse risks. Current GMD vulnerability assessment techniques, per TPL-007-3, do not call for modeling the distribution system or including DER data.[78] Typically, only higher voltage BPS elements are represented in these simulations because long transmission circuits with low impedance generally produce the highest levels of GICs. Furthermore, delta transformer windings block GICs from flowing since they do not create a return path for GICs to flow. Many T-D transformers are delta-wye (grounded on the distribution side), so GICs could only flow on the distribution side. However, distribution circuits are relatively short and have high impedance, so GIC flow at the distribution level will be insignificant with respect to BPS impacts. Hence, distribution-level circuits are not included in the dc-equivalent system model (GIC system model).

Key Takeaway:
There is currently no need to model the distribution system, end-use loads, or aggregate DERs for the purposes of vulnerability assessments in TPL-007-3.

Based on these findings, there is currently no need to model the distribution system, end-use loads, or aggregate DERs for the purposes of vulnerability assessments in TPL-007-3. However, as the penetration of DERs continues to increase to higher levels, this assumption may need to be revisited in the future. The vulnerability of DERs to GMD-caused severe voltage distortion remains an issue for industry to explore in more detail.

[75] https://www.nerc.com/_layouts/15/PrintStandard.aspx?standardnumber=TPL-007-3&title=Transmission%20System%20Planned%20Performance%20for%20Geomagnetic%20Disturbance%20Events&jurisdiction=United%20States

[76] See NERC's *Glossary of Terms* used in Reliability Standards: https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf

[77] While local distribution-related issues may arise, there is no evidence that widespread distribution issues could manifest and impact the BPS during GMD events. However, a large GMD event may cause severe harmonic distortion on the distribution system. The main concern related to DER would be potential tripping caused by harmonic distortion. However, further research is needed in this area to understand the extent to this risk. Refer to the EPRI report for more details: https://www.epri.com/#/pages/product/000000003002017707/?lang=en-US.

[78] NERC *Application Guide for Computing Geomagnetically-Induced Current in the Bulk-Power System*, December 2013: http://www.nerc.com/comm/PC/Geomagnetic%20Disturbance%20Task%20Force%20GMDTF%202013/GIC%20Application
NERC *GMD Planning Guide*, December 2013: http://www.nerc.com/comm/PC/Geomagnetic%20Disturbance%20Task%20Force%20GMDTF%202013/GMD%20Planning

Chapter 6: EMT Data Collection Requirements

As the penetration of BPS-connected inverter-based resources continues to grow, EMT modeling and simulations are becoming increasingly critical for ensuring reliable operation of the BPS. Entities are developing interconnection requirements for BPS-connected inverter-based resources to ensure that modeling information is available to perform EMT simulations when needed.[79] As the DER penetration continues to grow, there may be situations where studying reliable operation of the BPS, including networked sub-transmission systems, will require modeling DERs.[80] If industry is moving towards performing EMT simulations for BPS-connected plants (for example, on the order of 50 MW) because of known reliability issues, it warrants similar EMT simulations to be performed for pockets of high penetrations of DERs as well (for example, a small geographic area of 50–100 MW of DERs). This chapter describes the situations where representing DERs in EMT models may be needed by the TP and PC and the steps that can be taken to help facilitate development of these models in coordination with the DP.

DER Modeling Needs for TPs and PCs

EMT simulations are used to study very detailed interactions between grid elements and controls and can capture potential reliability issues that may not be detected with fundamental-frequency, positive sequence, and phasor simulation tools. As the penetration of inverter-based resources grows, EMT simulations become increasingly important in many areas. In most cases, EMT simulations are needed in pockets of the BPS where the localized penetration of these resources is high. Examples of situations where these types of studies are needed include, but are not limited to, the following:

- High penetration pockets of inverter-based resources, particularly when DERs replace or displace synchronous generation in the local area. The lack of synchronous resources presents challenges related to synchronous inertia and low short circuit strength conditions. As these pockets experience increasing penetrations of DERs, potential reliability risks may arise that require EMT simulations to identify.
- Ride-through performance for DERs (and BPS-connected inverter-based resources) becomes critical during severe voltage excursions in pockets of low short circuit strength. This often requires EMT simulations that represent the specific phase-based protection aspects and inner control loops of inverter controls.
- Analysis of voltage control performance and coordination of voltage control settings across many DERs and the BPS. Areas with high penetration of DERs may need to rely on dynamic reactive support on the BPS and may see greater variability of voltages at the distribution level. This will need to be coordinated, and EMT simulations are more effective at identifying issues than fundamental-frequency, positive sequence, phasor simulations.
- Pockets of high penetrations of inverters are prone to control interactions between neighboring facilities or with the grid. In addition, these pockets may present control stability issues for inverter-based resources that require attention for aspects of large disturbance behavior, such as active and reactive power recovery and oscillations. When DERs represent a substantial amount of generation in a localized area, these issues may arise and could impact the BPS.
- Selection of control modes, such as momentary cessation and other ride-through performance, and reliable operation of the overall area or region (including parts of the BPS) may be necessary under high DER penetration conditions.

[79] https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability_Guideline_IBR_Interconnection_Requirements_Improvements.pdf
[80] https://www.nerc.com/comm/PC/System%20Planning%20Impacts%20from%20Distributed%20Energy%20Re/Studies%20-%20SPIDERWG%20Bulk%20DG%20penetration%20study%20-%20Marszalkowski,%20Isaacs.pdf

There is no clear threshold for when EMT simulations are needed in any of the situations described above. TPs and PCs have developed various metrics to identify potential conditions, specifically for BPS-connected inverter-based resources, that warrant closer attention through EMT simulation techniques.[81]

Mapping TP and PC Modeling Needs to DER Data Collection Requests

EMT models are detailed representations of system elements used for identifying a wide range of potential issues, as mentioned above. However, representing end-use loads or aggregate DERs, in many cases, requires some assumptions and estimations be applied. While use of generic models for EMT simulations is typically discouraged for BPS-connected resources, the data for creating EMT models (or the EMT models themselves) may not be available for many types of DERs. However, for cases where the TP and PC have determined that an EMT study involving aggregate DERs may be needed to ensure reliability of the BPS, the following recommendations are made:

- **R-DER:** Small, retail-scale DERs across the distribution system (e.g., rooftop solar PV) will most likely not have DER models or information available, and this level of detail is not needed for a BPS EMT simulation. Rather, generic EMT models can be used to represent the aggregate amount of DERs at locations similar to how steady-state power flow and fundamental-frequency positive sequence simulations are performed. For the most part, the information needed to formulate an EMT model of aggregate DERs will mirror the information needed for fundamental-frequency, positive sequence dynamic models, including the following:
  - Type of DER and vintage of IEEE 1547
  - Disturbance ride-through behavior including use of momentary cessation
  - Voltage, frequency, phase angle, and ROCOF trip thresholds
  - Dynamic and steady-state voltage control performance expectations
  - Reasonably replicate, to the ability of the model, the per-phase nature of DER functions
- **U-DER:** Some entities have implemented the same modeling requirements for larger inverter-based U-DERs as for BPS-connected inverter-based resources; namely, that an EMT model may be requested from the TP or PC and will need to be supplied by the DER owner in coordination with the manufacturer, to the extent possible. This is typically applicable only for U-DER facilities greater than 1 MVA in capacity. For substations with multiple inverter manufacturers, the TP and PC may aggregate these models into distinct U-DERs for the more predominant inverter types. On the other hand, other entities may deem that generic models may be suitable for U-DERs as well, and the information described above could also apply for developing EMT models for U-DERs.
- **Load Models:** In situations where detailed DER models are being provided or created for the purposes of EMT studies, it is also important to accurately capture the expected behavior of aggregate amounts of end-use loads. The performance of the end-use loads in combination with DERs will have an impact on the distribution system and BPS performance, and these should be accounted for in some way.

Industry is still grappling with the growing need for EMT simulations in many areas, and new findings and recommendations will continually be developed. It is clear, however, that EMT simulations may be needed to appropriately identify specific reliability issues in high DER penetration pockets; therefore, the TP and PC should coordinate with the DP or other external entity to gather EMT modeling information to the extent possible, when needed.

[81] https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Item_4a._Integrating%20_Inverter-Based_Resources_into_Low_Short_Circuit_Strength_Systems_-_2017-11-08-FINAL.pdf

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Appendix B: Data Collection for DER Energy Storage

Collecting data for DER energy storage is similar to collecting data for DER generating resources. However, it is worthwhile to highlight considerations that should be made when developing data reporting requirements for collecting DER data that ensure clarity for representing energy storage for planning assessments. This appendix describes some of the considerations at a high level that should be made and also describes specific data points that are unique to energy storage from a data collection standpoint. While there are many types of energy storage technologies available today, this appendix focuses mainly on inverter-based battery energy storage since it is the most prominent form of DER expected in the foreseeable future and widely observed in DER Interconnection queues today. Existing large, synchronous DERs may need to be modeled explicitly based on TP and PC modeling practices, and the TP and PC should have these considerations listed in any modeling requirements. Note that electric vehicles today are likely modeled as part of the load since most existing electric vehicles do not provide storage capability, and demand response actions (such as reduction of heat pump loads) are also not generally modeled as energy storage in planning models. Lastly, there are different ways to model energy storage DERs—as part of the composite load model, as a standalone resource, or lumped with other forms of DERs. This guideline focuses on data collection necessary for the TP and PC to be able to make appropriate modeling decisions based on their own practices.

Considerations for Steady-State Modeling

Energy storage DERs are likely modeled similarly to other DERs in planning base cases although modeling and study practices may vary based on whether the energy storage is assumed to be charging or discharging. Energy storage DERs will need to be accounted for to ensure appropriate modeling based on TP and PC modeling practices. The following considerations should be made by the TP and PC when developing data requirements for DER information with the DP (note that these considerations build off of **Table 2.1**):

- **Location:** TPs and PCs will need to know the general location (at least mapped to a T-D transformer) of energy storage batteries such that they can be modeled appropriately in planning base cases in conjunction with other DERs and end-use loads. Separating DER generation and energy storage for collecting accurate DER data from the DP in coordination with any other state-level agency or regulatory body is a prudent step for effectively developing base cases based on TP and PC practices.
- **DER Type (or aggregate type):** As stated, differentiating out DER generators, DER energy storage, and hybrid facilities will be needed for the purposes of aggregate modeling of DERs in the future.
- **Transformer Information:** If the energy storage DER is represented as a U-DER, a generator step-up transformer may be explicitly modeled by the TP and PC based on their modeling practices.[82] In this case, transformer information may be needed by the TP and PC for modeling the energy storage DER facility. Appropriate reactive capability at the U-DER point of interconnection should be modeled regardless of modeling practice.
- **Historical or expected DER output profiles:** The output profiles for energy storage DERs are likely much different than for DER generation, such as synchronous or solar PV DERs. As such, the TP and PC will need to determine a suitable assumption for output profiles for each to create planning base cases. Therefore, some information will be needed on energy storage DER output profiles. Some questions for consideration include, but are not limited to, the following:
  - What percentage of energy storage DERs are participating in wholesale markets, and can the markets in which those DERs are participating provide any useful information in terms of how the energy storage DERs may be dispatched?

[82] These practices may include explicit modeling of the plant main power transformer and equivalent representation of individual pad-mounted transformers within the U-DER facility, or it may be simplified to an equivalent representation of transformations. The TP and PC should have modeling requirements that clarify this point.

    - What percentage of energy storage DERs are operating based on retail signals, such as time of use charges or other third-party signals that drive charging and discharging, at specific hours of the day? Most commonly, the assumption is made that energy storage DERs will charge during light load conditions and discharge during peak loading conditions; however, various entities have experienced energy storage charging patterns that do not conform to these basic assumptions. Therefore, the DP will need to coordinate with the TP, PC, and any other state-level agency or regulatory body to determine how these patterns could affect transmission planning processes and practices.

- **DER Status:** It is not likely that additional considerations will be needed for energy storage DERs related to status (on-line versus off-line). However, TPs and PCs will need to consider whether the aggregate amount of energy storage DER is charging or discharging.
- **Maximum DER active power capacity (Pmax):** As mentioned, differentiating the amount (capacity) of energy storage DERs will enable the TP and PC to model these resources, as needed. Therefore, it is not likely that additional information would be needed for energy storage DERs.
- **Minimum DER active power capacity (Pmin):** Energy storage resources have the ability to charge (unlike DER generators), so energy storage DERs will have a modeled negative Pmin value in the base case. Therefore, separating out energy storage DERs will enable reasonable representation of Pmin values in the base case.
- **Reactive power-voltage control operating mode:** Similar to DER generators, it is important to understand any interconnection requirements and operating practices for the DERs regarding their reactive power-voltage controls. Knowing this information, TPs and PCs will be able to model them accordingly.
- **Maximum DER reactive power capability (Qmax and Qmin):** If energy storage DERs are providing any voltage support, these resources will need an associated Qmax and Qmin value in the base case, and the DP will need to coordinate with the TP and PC to understand appropriate assumptions.

Considerations for Dynamics Modeling

Energy storage DERs represented in the planning base case should have some aggregate dynamic model that captures the general behavior of these resources during abnormal BPS conditions. The DER_A dynamic model is used to represent inverter-based DERs, which energy storage DERs fall under. However, the parameter values for the DER_A dynamic model that would need to be modified are fairly minimal. These include, but may not be limited to, the following (note that these considerations build off of **Table 3.1**):

- ***Typeflag*:** Explicit modeling of energy storage DER requires consideration of the *typeflag* parameter of the DER_A dynamic model. Refer to software model specifications for how to set *typeflag* to emulate an energy storage device.[83]
- ***Pmin*:** The *Pmin* will need to be modified to accommodate the capability to absorb active power (i.e., negative *Pmin*), based on the expected energy storage capacity being modeled. If the voltage-dependent current limits (absolute value, not sign) are different in charging versus discharging mode, the values of the voltage-dependent current logic (VDL) tables will need to be changed based on operating mode assumption.
- **Frequency Response Parameters:** If the energy storage DER is providing frequency response capability in either the upward or downward directions or both, these parameters will need to be configured accordingly. This could be different than the aggregate DER generation model. For example, R-DERs may not be providing underfrequency response; however, larger energy storage DERs may be providing this capability and service to a wholesale market.
- **Frequency and Voltage Ride-Through Capability:** TPs, PCs, and DPs should consider whether any different requirements are in place for DER energy storage versus DER generation; however, this is not likely in most

[83] Based on the specification for the DER_A dynamic model: https://www.wecc.org/Reliability/DER_A_Final_061919.pdf.

cases once the new IEEE 1547-2018 inverters become available. Consider whether the fractional reconnection (*vrfrac*) or active power ramp rate (*rrpwr*) may also be different for DER energy storage and generation.

- **Voltage Control Parameters:** TPs, PCs, and DPs should also consider whether any different requirements are in place for DER energy storage versus DER generation regarding voltage control. Voltage control settings that differ across DER energy storage and generation may require modeling details where additional data may be required by the TP and PC.

Considerations for Short-Circuit Modeling

As with DER generation, DER energy storage will most likely be inverter-based and therefore will only provide a small amount of fault current to BPS faults. Therefore, the TP and PC can consider whether DER energy storage would need to be differentiated in short-circuit studies based on the materials in **Chapter 4**. However, it is not likely that DER modeling for short-circuit studies is widely performed in the near-term.

Considerations for GMD Modeling

No additional considerations for DER energy storage are needed beyond the recommendations provided in **Chapter 5**.

Considerations for EMT Modeling

EMT modeling considerations for energy storage DERs are similar to those described above for dynamics modeling. If the TP or PC determine that DER data is needed for EMT simulations, differentiating DER energy storage and DER generation is recommended. Larger U-DERs (either DER generation or DER energy storage) may require more detailed models than aggregate amounts of R-DERs (again, either DER generation or DER energy storage).

Appendix C: DER Data Provision Considerations

DPs have some accounting of aggregate DER, in coordination with the TP and PC data requirements per MOD-032-1. A time line and projection of aggregate DER growth at each T-D transformer is of particular importance for steady-state, dynamics, short-circuit, and EMT modeling purposes. The transfer of aggregate DER data to the TP and PC for modeling is ultimately critical to the reliable operation of the BPS, particularly moving forward as the penetration of DERs continues to grow.

In some cases, however, the DP may not have aggregate DER information readily available to provide to the TP and PC for modeling purposes. This may be particularly true to future projections of DERs most relevant for TPs and PCs for planning purposes. External parties (e.g., state regulatory bodies like the California Energy Commission,[84] the Minnesota Public Utilities Commission,[85] and DER installers) may have more detailed information pertaining to wide-area DER projections. Thus, TPs and PCs will benefit from collaborating with DPs to determine if external parties can be engaged to help support the provision of DER data for modeling aggregate DER by the TP and PC.

TPs and PCs should consider developing an overall framework for the process of DER data collection. In particular, TPs and PCs will likely benefit by establishing data specifications that leverage the respective strengths of both DPs and DER installers for existing facilities as well as other sources for forward-looking projections. Furthermore, DPs could establish requirements that require DER installers to provide information to the DP, TP, and PC during DER interconnections. DPs may consider working with state regulators and other agencies to determine the most effective method for establishing these types of requirements. If alternative sources of DER data are readily available in higher quality forms for use by the TP and PC, these should be leveraged to the extent possible for use in planning BPS studies. Diagrammatic examples accompanying data specifications will likely reduce any confusion or misunderstanding between entities. Collaborative processes by which data specifications are determined and data collection frameworks are designed will likely result in higher quality information transferred from the DP and other applicable external entities to TPs and PCs. Higher quality information for the purposes of modeling will support reliable operation of BPS.

AEMO DER Registry Case Study

A recent example of external DER data that can be useful for modeling purposes comes from the Australian Electricity Market Operator (AEMO) DER Register.[86] Under the national electricity rules that govern Australia's major electricity market across the east and south eastern states, all network service providers (NSPs) provide or update "DER generation information," defined as "standing data in relation to a small generating unit" for any DER rated below 30 MW.[87] To facilitate the collection of DER generation information, AEMO worked with NSPs, DER installers, and other stakeholders for over a year to develop a secure online DER data submission process. AEMO requires submission of DER generation information at the national metering identifier level, simultaneously leveraging the relative strengths of NSPs and installers as DER data providers. **Figure C.1** illustrates AEMO's expectation for NSPs and installers to have different types of DER data, which AEMO determined are necessary to model and plan for the impacts of aggregate DER (options are allowed as to how the data is provided into AEMO's system).[88]

[84] https://ww2.energy.ca.gov/renewables/tracking_progress/documents/renewable.pdf

[85] https://mn.gov/puc/energy/distributed-energy/data/

[86] https://www.aemo.com.au/initiatives/major-programs/nem-distributed-energy-resources-der-program/der-register-implementation

[87] https://www.aemo.com.au/-/media/Files/Stakeholder_Consultation/Consultations/NEM-Consultations/2019/DER-register/Final/DER-Register-Final-Report.pdf

[88] https://www.aemo.com.au/-/media/Files/Electricity/NEM/DER/2019/DER-Register-Implementation/20191129---Introducing-DER-Register---NSW-Solar-Installer-Seminars_PDF.pdf

Level	Data types	Expected source of data	
		Network	Installer
Installation	Approved capacities, technologies and central control/protection (e.g. export limits)	✓	☑
	Installer licence number / ID	☑	✓
AC interface	Inverter or generator manufacturer, model, serial number and capacities, and numbers of installed units	☑	✓
	Inverter control modes and settings (e.g. volt-watt etc)	✓	☑
	Non-inverter generation control modes, settings and protection	✓	☑
	Date of commissioning	✓	☑
Device	Device (e.g. solar PV panels or battery) manufacturer, model and capacities, and numbers of installed units	☑	✓

Figure C.1: AEMO Expectations for Provision of DER Data [Source: AEMO]

The work flow for joint submission of DER generation data from the NSP and DER installers, ultimately resulting in a DER installation certificate, is shown in **Figure C.2**. The work flow diagram emphasizes the importance of a collaborative specification for attaining DER generation information. The distinction between "as-approved" and "as-installed" information is crucial; one subset of data is likely readily available to NSPs, whereas another subset of data is likely readily available to DER installers (see **Figure C.3**).

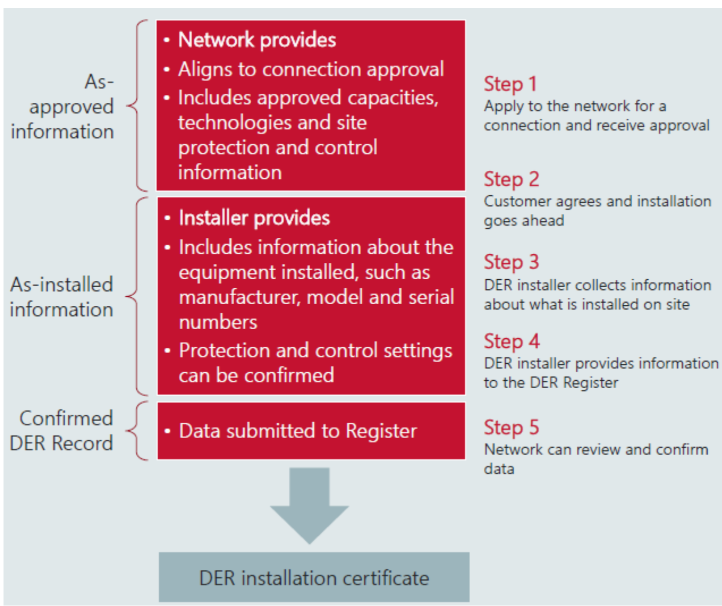

Figure C.2: Workflow of Joint Submission of DER Generation Data [Source: AEMO]

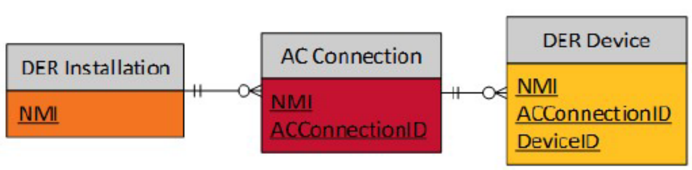

Figure C.3: Combination of DER Data as Defined by AEMO's Data Model [Source: AEMO]

To ensure quality of responses consistent with AEMO's data model structure, AEMO developed a series of scenarios to illustrate hypothetical DER configurations for NSPs and DER installers. Appendix E of AEMO's *DER Register Information Guidelines* shows the various considered scenarios.[89] The scenarios help ensure that the data requests are completed consistent with AEMO's specifications. The submission process is supported by an information collection framework that emphasizes four principals, listed below:

- Data collected should initially comprise the statically-configured physical DER system at the time of installation.
- Have regard to reasonable costs of efficient compliance compared to the likely benefits from the use of DER generation information.
- Best practice data collection should be implemented wherever possible to leverage existing data collection methods.
- Balancing information and transparency, the DER register should be accessible and easy to use while confidentiality and privacy are protected.

NSPs in the National Electricity Market have varying levels of sophistication when it comes connection approvals and data collection. As a result, AEMO's DER register system is designed with optionality to provide and validate DER data via API directly from the NSP, AEMO's web portal, or via smart-phone applications that many DER installers are already using to register an installation to access government subsidies. These options enable the minimum workflow change and cost for implementation for each NSP. The full design of the information collection framework and related implementation material is also publicly available.[90]

89 https://www.aemo.com.au/-/media/Files/Stakeholder_Consultation/Consultations/NEM-Consultations/2019/DER-register/Final/DER-Register-Final-Report.pdf

90 https://www.aemo.com.au/initiatives/major-programs/nem-distributed-energy-resources-der-program/der-register-implementation

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	SPIDERWG Discussion Complete
	Needs attention

Organization(s)	Page #	Line / Paragraph	Comment	Proposed Change	NERC Response
Wabash Valley Power Association			General Comment from WVPA Planning Engineer Tom Imel: Agree with the need for DER to be included in Models. While at MISO there were many DERs. When performing a study and equipment is close to or over 100% DERs can make a big difference.		Thank you for your comment.
ReliabilityFirst			Some Transmission Planners and Planning Coordinators utilize non-coincident load modeling when developing cases. Non-coincident load modeling utilizes peak load at an individual load delivery point, which is then scaled to match a larger areas overall forecast.	Does the drafting team have any guidance regarding DER load modeling for Transmission Planners and Planning Coordinators that utilize non-coincident load modeling? This document seems to focus mainly on coincident load modeling which is more prevalent in operational/real-time models. Should this guidance vary based on the type of planning study being performed as well (i.e., Near-Term/Long-Term with the combination of operational/planning analysis)?	Edits made in Case Assumptions section to clarify that case creation and case assumptions hinge on TPs and PCs having sufficient data about DERs and their aggregate behavior to be able to model them appropriately. Configuring base cases and considering the coincidence of loads and DERs is outside the scope of data collection, and will be considered more closely in the Reliability Guideline currently being developed by the SPIDERWG Studies sub-group.
ReliabilityFirst			Transmission Planners and Planning Coordinators use various methods to model loads from a BES perspective (i.e., equalize loads to BES buses, model the distribution transformer then equivalize loads to the low-side transformer bus, etc.). These modeling methodologies are usually not consistent across the ERO.	At the beginning of this document, it is recommended to reference other NERC or industry documents in regard to best practices of modeling load in general. Also similar to the comment above, does the drafting team have any guidance based on the type of analysis being performed or model being used to perform the analysis (i.e., operational model with node-breaker versus planning model with bus-branch configurations).	The guideline is focused on planning studies, which predominantly use bus-branch models; however, this is outside the scope of data collection for aggregate DERs. The SPIDERWG previously published a guideline on the DER_A dynamic model, which also links to previous guidelines on DER modeling developed by NERC technical groups: https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability_Guideline_DER_A_Parameterization.pdf. This is referenced in the draft guideline.
ReliabilityFirst			Transmission Planners and Planning Coordinators presently develop cases such that the sum of the load + losses in a transmission zone will align with the applicable load forecast.	Does the drafting team have any guidance regarding a method to change the way load is modified in the case to ensure that transmission load + losses will be accurate considering the proposed use or Gross load values when the DER resources are modeled explicitly?	The SPIDERWG Studies sub-group is working on a Reliability Guideline related to performing planning studies and establishing reasonably assumptions for those cases. This comment will be passed to that team for further consideration, as it relates more to base case creation and modification than to data collection.
ReliabilityFirst	ix	257	Planning Case assumptions need to be coordinated with the Interconnection Model Building Designee, and not be strictly a PC/TP function.	Add Model Building Designee as the party responsible for coordinating model assumptions.	Change made based on comment.
ReliabilityFirst	viii	221	Sentence is written as, "size is deemed impacts to BPS performance".	Change "impacts to" to "to impact"	Change made based on comment.
ReliabilityFirst	viii 11	223-229 591-612	The wording in these sections does not stress enough the importance of gathering pertinent information regarding short-circuit studies. It should be stressed to establish requirements and strive to gather the pertinent information needed to perform short-circuit studies now rather than in the future (even in areas of light DER penetration). Areas that have little DER penetration may have an increase in the future. With the guidance provided here, TPs and PCs may not have gathered the appropriate short-circuit information for earlier installations and not have as accurate representation as a result (or circle back and obtain the information at a later date, which may be cumbersome). The risk here is not just BES equipment, but utility personnel and public safety related to breaker overduty and the potential for catastrophic failures within the substation.	Remove, "significance" and the associated footnote. Instead re-write to stress the importance of establishing good data collection practices now rather than in the future (regardless of DER penetration or generation resource mix). Note the importance due to the risk of BES equipment and safety concerns. Note the importance to especially consider non-inverter based DERs. Perhaps lead this section with the, "Differentiating Inverter-Based DERs" section on line 613. Suggest to add the following verbiage prior to Table 4.1: For all items, Conditions, and Considerations in Table 4.1, it is recommended to establish data and collection requirements for existing and future DER additions in regard to short-circuit studies.	Change made based on comment.
ReliabilityFirst	ix	282-283	This section references the need for additional planning base cases that reflect expected stressed system conditions that depend on the geospatial and temporal patterns. Stressed system conditions should include weather impacts to renewable DERs. One example includes, a storm system (with higher than 50mph winds) moving through an area on the system with a high concentration of wind turbines. Due to the typical design of wind turbines, the increased wind would lock the turbine blades and quickly reduce the generating plant output to zero. Thus, creating a significant transfer into the area.	Revise the wording, add some wording, or include a footnote regarding the need to consider weather conditions in relation for renewable based DERs.	Change made based on comment.
ReliabilityFirst	4	465	There may be U-DER installations that have reactive devices installed at the distribution bus that are not automatically controlled as part of the U-DER facility to regulate voltage (i.e., manually switched via SCADA by DP operator). and therefore, are not included in the aggregate reactive capabilities of the generator modeled.	Add a bullet item that includes independently controlled reactive devices at the distribution bus, if applicable.	Change made based on comment.
ReliabilityFirst	5	500	For the 'Maximum DER reactive power capability (Qmax and Qmin) - See comment above, separately model needed reactive devices not aggregated within the generator model.	Add the following or similar, "For U-DER cases, any reactive device that is required at the distribution bus to assist with voltage regulation and that is not aggregated in the DER reactive power capability should be modeled independently using engineering judgement.	Change made based on comment.
ReliabilityFirst	v for example	for example 167	There are a lot of "should" statements in this guideline. An appendix is needed that organizes all these "should" statements by applicable entity (such as PC, TP, and DP) that "should" perform the tasks.	Add an Appendix that organizes the "should" statements by responsible entity.	These types of statements are commonly used in Reliability Guidelines, and are integrated throughout the guideline as it describes recommended practices for industry to consider. No change made.
Tom McDermott, Pacific Northwest National Laboratory (PNNL)	viii	221	improper word choice	...deemed impactful to...	Change made based on comment.
Tom McDermott, Pacific Northwest National Laboratory (PNNL)	viii	238	singular/plural	Based on this finding,...	Change made based on comment.
Tom McDermott, Pacific Northwest National Laboratory (PNNL)	ix	242-246	This assumes two extremes, traditional positive sequence RMS studies vs. EMT studies. But it's not proven that EMT studies will be better, if the RMS models can be improved and validated. The guideline doesn't seem to acknowledge that EMT models are more likely to contain proprietary design details, take more effort to validate, take more specialized training and software tools to run, and take more computing resources to run. These are all probably surmountable barriers, but it's still possible that RMS models will be made to work for most applications, including ride-through.	Strike from "Items such as..." and substitute "As larger amounts of DER are aggregated, there may be an increasing need for EMT studies to properly evaluate newer technologies and emergent control interactions, especially on weaker grids. TPs and PCs should establish methods of collecting EMT model data for DER in advance of the need arising."	Change made based on comment.

Tom McDermott, Pacific Northwest National Laboratory (PNNL)	ix	245	singular/plural	...they can be a useful tool...	Change made based on comment.
Tom McDermott, Pacific Northwest National Laboratory (PNNL)	ix	270	Time of day sounds like hour of day.	add "The sub-hourly and sub-minute variations in load and generation should also be defined."	Change made based on comment.
Tom McDermott, Pacific Northwest National Laboratory (PNNL)	x	Figure I.2 vs. line 290	At the peak of the blue curve, the orange curve seems to be around 65-70% of its peak, not 40-50% as stated in the text.	Please make them consistent, either by saying 65-70% in the text, or changing the figure if you mean to illustrate 40-50%.	Plot modified with updated plot, and text changed to match new plot.
Tom McDermott, Pacific Northwest National Laboratory (PNNL)	2	Figure 1.2	Item 1 in short-circuit column doesn't apply to IBR.	1d. Current Source Data for IBR	Figure 1.2 was pulled directly from MOD-032-1, so no modifications are made to the guideline. However, the point made is valid and should be considered for future edits to MOD-032-1 related particularly for BPS-connected IBRs.
Tom McDermott, Pacific Northwest National Laboratory (PNNL)	2	415-417	Who aggregates the DER data, and according to what metrics?	add "The TP and PC also need to establish processes by which either the TP or DP will aggregate and validate the DER data."	Change made based on comment.
Tom McDermott, Pacific Northwest National Laboratory (PNNL)	10	571	singular/plural	...dynamic voltage...	Change made based on comment.
Tom McDermott, Pacific Northwest National Laboratory (PNNL)	12	Table 4.1, row 3	Impedance may have little impact on inverter-based DER contribution to fault currents flowing on the distribution system. Maybe a different story on BPS.	...so large that DER fault current contribution to the BPS is relatively low.	Change made based on comment.
Tom McDermott, Pacific Northwest National Laboratory (PNNL)	14	673-675	Would you actually replace the breaker for a 1.7% increase in fault current?	add "This effect could become more important as the amount of aggregated DER increases."	Change made based on comment.
Tom McDermott, Pacific Northwest National Laboratory (PNNL)	15	700	word order?	"Many T-D transformers are delta-wye (grounded on the D side) and therefore GICs could only flow on the distribution side.	Change made based on comment.
Tom McDermott, Pacific Northwest National Laboratory (PNNL)	17	768	Missing bullet item	add * Replicate the per-phase nature of IEEE 1547 functions	Change made based on comment.
Tom McDermott, Pacific Northwest National Laboratory (PNNL)	17	779	Too strong for EMT. Adding to comment 22, it's not yet proven that EMT models can be aggregated.	"It is expected that EMT simulations may be needed...	Change made based on comment.
Tom McDermott, Pacific Northwest National Laboratory (PNNL)	17	779	word choice	need should be needed	Change made based on comment.
Tom McDermott, Pacific Northwest National Laboratory (PNNL)	19	Footnote 70	singular/plural	These practices	Change made based on comment.
Tom McDermott, Pacific Northwest National Laboratory (PNNL)	22	944	missing word	...process of DER data collection...	Change made based on comment.
Tom McDermott, Pacific Northwest National Laboratory (PNNL)	22	960	extra word	...all Network Service Providers (NSPs) provide...	Change made based on comment.
Tom McDermott, Pacific Northwest National Laboratory (PNNL)	24	988	extra word	...comprise the statically configured...	Change made based on comment.
Tom McDermott, Pacific Northwest National Laboratory (PNNL)	24	1000	"minimum change" to what?	...minimum workflow change and cost...	Change made based on comment.
Tom McDermott, Pacific Northwest National Laboratory (PNNL)	25	Figure C.4	Lines are blurry, labels extremely hard to read.	Re-do this in a vector graphics or other high-resolution format. The labels on the circuit diagrams are probably too small even in higher resolution, so the font size should be increased.	Figure removed. Reference to AEMO report used instead.
Rojan Bhattarai (Idaho National Laboratory)	iv	70	Bulk Electric System (BES) introduced as opposed to use of Bulk Power System (BPS) as done in preface and executive summary	I suggest we use BPS throughout.	Preamble is legal boilerplate that remains unchanged across Reliability Guidelines. The only other use of BES is in reference to the NERC TPL-001-4 standard and is the correct usage. Everywhere else uses BPS.
Rojan Bhattarai (Idaho National Laboratory)	v	95	These include representation of end-use loads4 as well as a growing focus 95 on the representation of aggregate amounts of distributed energy resources (DERs). It is difficult to follow this sentence. It can be made simpler with just use of "DERs".	These include representation of end-use loads as well as growing amount of distributed energy resources (DERs).	Change made based on comment.
Rojan Bhattarai (Idaho National Laboratory)	v	103	Is it collection of aggregate DER data or generation of aggregate data based on data from individual DERs? In the following sentence, we talk about transfer of information from DPs, they might have detailed information of individual DERs and not aggregate information.	These requirements should include specifications for collecting generating/developing aggregate DER data for the purposes of modeling, particularly as DER penetration levels continue to increase. Clear	Change made based on comment.

Rojan Bhattarai (Idaho National Laboratory)	vi	135	We probably need a reference for statement "DPs likely account for aggregate DER connected to their systems, with varying degrees of detail and information available." Also, we do not need to use aggregate DER in this sentence.	DPs likely account for DER connected to their systems, with varying degrees of detail and information available.(Reference)	Change made based on comment.
Rojan Bhattarai (Idaho National Laboratory)	vii	203	Probably better to introduce what SPIDERWG is before mentioning SPIDERWG		Change made based on comment.
Rojan Bhattarai (Idaho National Laboratory)	viii	217	Two periods (..) after "response performance"	Two periods (..) after "response performance"	Change made based on comment.
Rojan Bhattarai (Idaho National Laboratory)	viii	240	On the EMT studies section, something to consider while developing aggregated models, is the ability to capture interactions between multiple DERs. In some cases, interaction between groups of DER can propagate towards the transmission system, single aggregate model for all DERs in the distribution system may not capture such interaction between DERs.	Add: EMT studies should capture interactions between groups of multiple DERs that can propagate towards the transmission system. A single aggregate model for all DERs in the distribution system may not capture these interactions.	BPS reliability studies are typically looking at aggregate impacts of DERs on the BPS, and transmission planning practices do not get into distribution system-level interactions. The level of detail for each type of study is based on TP/PC needs, and engineering judgment is used. But detailed distribution-level interactions between individual DERs is generally outside the scope of TP/PC studies.
Rojan Bhattarai (Idaho National Laboratory)	3	439	There are some modelling practices that also include an equivalent representation of the distribution feeder one side of which is connected to low voltage side of the T-D transformer and the other side of which connects the aggregated load and DER. Such practice also requires equivalent feeder impedance data to be provided by DP.	Add: Modelling practices should be considered that include an equivalent representation of the distribution feeder - one side connected to low voltage side of the T-D transformer; the other side connected to the aggregated load and DER. Such practices would require equivalent feeder impedance data to be provided by the DP.	Change made based on comment.
Rojan Bhattarai (Idaho National Laboratory)	5	500	I have a comment on row associated with maximum DER active power capacity (Pmax) row. The state in that row suggests that the DER power capacity should be aggregated to transformer, which might in a way indicate that the upper limit of DER in the D side be at max equal to the rating of T-D transformer, which may not be the case. For system with reverse power flow overall DER capacity can be larger than the transformer rating at the T-D interface.	Please add a language acknowledging cases that have reverse power flow and possibility of DER capacity being larger than transformer rating at T-D interface, but due to the load present in the D-system, the net flow in either (T/D) side is less than rating of T-D interface transformer.	Edits made to row in table to more accurately reflect point being made. DER size relative to T-D transformer rating is not within scope of DER data collection. Data associated the DER component should be captured, which is the point of the table.
Rojan Bhattarai (Idaho National Laboratory)	6	530	Probably mention "direct transfer trip" usage by some utilities following any disturbances on the upstream of substation, as an example.	Add: ... for example "direct transfer trip" following disturbances upstream of substations.	Change made based on comment.
Rojan Bhattarai (Idaho National Laboratory)	6	535	Even though the NERC guideline for parameterization of DER_A shows that most of parameter values of DER_A can remain fixed across various DER vintages, no studies have been performed testing the sensitivity of these parameters to the response of DER and how accurately it represents various DER vintages. So, if there are any parameters (other than control and ride through parameters) that can change between different vintage of DERs those parameters should be identified as well.	Add language: Studies need to be performed to test the sensitivity of the parameters of DER_A to the response of DER and their accuracy in representing various DER vintages. Any parameters (other than control and ride through parameters) that can change between different vintages of DERs should be identified as well.	This topic is more suited for the DER model verification guideline, rather that DER data collection guideline.
Rojan Bhattarai (Idaho National Laboratory)	14	665	It might be better or easier to understand if we change "assumed phase relationship between voltages and currents" to priority mode selected.	Add language: DERs can operate in either active or reactive power priority mode, and response of DER can be different based on priority mode selected.	The bullet under consideration is not describing active versus reactive current priority; it is highlighting the need for inverter-based resources to conform to expected angular relationships between voltages and currents. With respect to short-circuit assessments, this aspect is critical for setting protective relays.
NRECA			In collaboration, NRECA and ACES staff submit the following comments on behalf of our Cooperative members: We find the draft Reliability Guideline: DER Data Collection for Modeling in Transmission Planning Studies guideline to be reasonable and straightforward. It is our hope that this data facilitation guideline will also forestall the creation of a NERC Reliability Standard on this topic. Subsequently, we have commented as such on the posted Project 2020-01 Modifications to MOD-032-1 SAR. Given the numerous and somewhat unique arrangements cooperatives have for power supply and transmission services, we believe that coordinated data requirements, across all entities, is best for maintaining an efficient system. The guideline provides enough flexibility to manage local circumstances. Sharing of that data, along with notification of potential affected systems impacts, needs to be part of these study requirements.		Thank you for your comment.
Thomas Foltz on behalf of American Electric Power			AEP has recently expressed strong concern regarding revising MOD-032 in this regard as part of Project 2020-01. While we have chosen to not "repeat" that feedback in its entirety in our comments regarding this draft Reliability Guideline, the RG drafters may wish to reference our formally submitted comments for further insight, as AEP does not agree with the SAR as proposed. https://sbs.nerc.net/CommentResults/Index/192 Historically, draft Reliability Guidelines having strong subject matter ties to NERC obligations have been posted for industry comment after those obligations have been under enforcement for some time. As a result, experience with the obligations has been gained by that point providing both RG authors and industry the necessary insight to recommend or comment on perceived recommended practices regarding the obligation(s). This Reliability Guideline however has been posted for industry comment simultaneously with the draft SAR to revise MOD-032, before the standard has been revised, and as a result, well before any practical experience has been gained with those obligations. While authoring this draft Reliability Guideline is obviously well intentioned by its drafters, consideration should be given to perhaps temporally withdraw this RG for consideration until a revised MOD-032 has been under enforcement for some time.		This Reliability Guideline provides recommended practices for entities to develop DER data requirements as part of their modeling data requirements (i.e., MOD-032). The current standard permits such requirements to be developed, and this guideline supports industry in their implementation of the current standard. Revisions to MOD-032-1 are outside the scope of this guideline.
Thomas Foltz on behalf of American Electric Power			As is the case with the draft SAR currently proposed for Project 2020-01, there appears to be a misunderstanding that the Functional Entity "Distribution Provider" encompasses all the entities who need to provide the necessary data. That is not the case however, as not all municipalities and cooperatives are themselves registered as Distribution Providers. As a result, many of them are under no obligation to provide this data to those tasked with obtaining it. Consideration should be given in further refining the entities that are applicable as U-DER. Once again, AEP's previously-submitted comments regarding the draft SAR for Project 2020-01 provides further detail about our concerns (link provided above).		The guideline in a number of places reference Distribution Providers as well as other applicable entities that may have information regarding existing or future DER installations. The applicability of NERC Registration and any issues being address by a Standard Drafting Team are outside the scope of this Reliability Guideline.
Thomas Foltz on behalf of American Electric Power	v	102-104	Revise to provide clarity that the "requirements should include specifications" refers to the data requirements and not the requirements within MOD-032-1.	Perhaps consider instead, using "The data requirements should include..."	Change made based on comment.

Walling Energy Systems Consulting, LLC	viii	237	It is agreed that there will be no significant flow of GIC on distribution systems. However, one of the major impacts of GMD at the transmission level is the creation of potentially high levels of harmonic voltage distortion. Distortion at the transmission level will propagate into the distribution system, and can potentially be amplified at this system level due to resonances established by distribution capacitor banks. DER is not tested for ride-through of high-distortion conditions, nor is such performance specified in IEEE 1547. How can the blanket statement of "non likely to impact" be made?	Change this sentence to "Therefore, GICs at this level are minimal and are not likely to directly impact the distribution system. However, GIC at the transmission level can potentially create extreme levels of harmonic voltage distortion that will propagate to the distribution level. The response of DER to this distortion is largely undefined." Delete the last sentence of this paragraph.	Change made based on comment.
Walling Energy Systems Consulting, LLC	ix	242	From the context of this sentence, it can be implied that "positive-sequence RMS models" refers to fundamental frequency phasor-domain models such as typically used for dynamic analysis. The use of "RMS" in this context is in error. The RMS magnitude is the root-sum-square of all frequency components, which during many types of disturbances contain substantial non-fundamental-frequency components. The RMS magnitude of the system response can only be determined by an EMT-type analysis. The wide usage of "RMS" as a descriptor for fundamental-frequency phasor analysis is a misnomer, although recognized to be widely used in Europe, that should not be perpetuated in this document.	Replace "RMS" with "fundamental-frequency phasor"	Change made based on comment.
Walling Energy Systems Consulting, LLC	x	291	This sentence implies that DER installed subsequent to IEEE 1547a in 2014 or the new IEEE 1547-2018 will have voltage support available and activated. IEEE 1547a-2014 only allowed voltage regulation but did not mandate its availability. IEEE 1547-2018 mandates that the voltage-reactive power (volt-var or voltage regulation) function be available, but its implementation is at the discretion of the distribution provider. Very few DPs, at this time, implement volt-var on a widespread basis. Most DPs implement it on very limited basis, if at all. Thus this statement is highly misleading as it leads to an assumption that is not consistent with actual practice with most utilities.	Add following this sentence (on line 296), a new footnote that states: "It should not be automatically assumed that post-2014 DER have voltage regulation capabilities activated. Implementation of voltage regulation functionality is at the discretion of the distribution provider, and currently this function is infrequently applied out of concern regarding its potential adverse impacts on distribution system operations and voltage management."	Change made based on comment.
Walling Energy Systems Consulting, LLC	xi	339	This sentence incorrectly implies that IEEE 1547 only applies to inverter-based DER. This standard applies to all DER equally. It is intentionally technology-agnostic.	Delete "and therefore comply with the various versions of IEEE 1547"	Change made based on comment.
Walling Energy Systems Consulting, LLC	xi	341	This sentence inaccurately implies that DER installed after 2016 will have different settings than those installed prior to this date. IEEE 1547a made no changes to mandatory requirements for settings; this amendment only allowed a wider choice for those settings, with some slightly different default values. The trip setting ranges are inclusive of the former IEEE 1547-2003 settings, and most DPs did not change their setting specifications until recently in many cases, and not even today in many other cases.	Replace the sentence starting on Line 341 and the sentence starting on Linee 342 with "After November 2016, standards allowed greater flexibility in settings, with actual settings at the discretion of the DP. DP policies regarding these settings vary widely, and are continuing to evolve. The historical DER trip and reactive control setting policies of the DP must be mapped to the DER interconnection growth over the same periods to determine the expected behavior of the DER." Preface the sentence starting on Line 344 with "In this example, the red numbers..."	Change made based on comment.
Walling Energy Systems Consulting, LLC	xi	349	This sentence incorrectly makes the assumption that DER interconnection requirements will require activation of the volt-var capability that is required to be available in post-2021 DER. Most DPs neither require, nor allow, volt-var activation on a widescale basis. Some DPs implement this functionality on a limited basis for specific applications, and many others prohibit its activation at all. This whole paragraph seems remote from the current reality.	Revise this sentence to "Interconnection requirements for DER installed subsequent to July 2021 may require local DER voltage control (volt-var), subject to DP practices and policies. Widescale implementation of this functionality should not be assumed unless confirmed as an established policy by the relevant DPs."	Change made based on comment.
Walling Energy Systems Consulting, LLC	3	446	Information regarding DER reactive capability and regulation mode is functionally irrelevant to BES/BPS loadflow studies as the reactive power output is largely a function of distribution system details that are not modeled, including line voltage regulators, switched cap banks and the detailed complexities of the distribution system topology. Furthermore, T-D transformer tap changers effectively decouple distribution system voltages magnitudes from transmission voltage magnitudes in the steady-state. Inclusion of this in the base case is only meaningful in establishing very approximate initial conditions for dynamic analysis. The DER models cannot be expected to provide the absolute DER reactive power; they are only useful for providing the differential reactive power in response to short-term transmission voltage variations.	Add a footnote at the end of this sentence stating "Collection of reactive capability and voltage regulation mode data is primarily to establish initial conditions for dynamic simulation. Due to distribution system details (e.g., line regulators, switched cap banks) that are not possible to model on an aggregate basis, DER models cannot be assumed to provide accurate rendition of steady-state DER reactive power, but do provide a reasonable rendition of the change in reactive power with short-term changes in the transmission voltage during dynamic simulations."	Change made based on comment.
Walling Energy Systems Consulting, LLC	4	458	IEEE 1547-2018 requires U-DER to provide the required reactive capability and the voltage regulation at the POI, not at the DER unit level. Also, trip settings are based on the POI voltage. Almost always, this POI is at the MV (distribution primary voltage) level. Thus, the U-DER step-up transformer characteristics are irrelevant to both steady-state and dynamic performance.	Replace with: "If the DER facility is represented as a U-DER having its POI at the distribution primary voltage level (the usual case for U-DER), then the DER model should directly connect to the distribution bus or feeder, without representation of the DER generator step-up (GSU) transformer. If the DER has a POI at the low-voltage level (e.g., 480V), i.e., the GSU is utility-provided with metering on the LV side, then the GSU should be explicitly modeled."	Change made based on comment.
Walling Energy Systems Consulting, LLC	4	496	This line perpetuates the ill-advised assumption that DER installed after this change in standards will indeed have different settings. This is totally at the discretion of the DP	Change to "...vintage and the remaining have settings specified in the utility's revised interconnection policies in 2017 (for example"	Change made based on comment.
Walling Energy Systems Consulting, LLC	6	512	The statement "While synchronous DERs exist.." makes the strong implication that synchronous DER are a very rare exception. In some areas (Ontario, southeast Texas, San Joaquin Valley of California) synchronous generator DER are either dominant or form a large portion of the installed DER base as well as new DER additions	Replace "exist across North America" with "are present in varying degrees of penetration across North America"	Change made based on comment.
Walling Energy Systems Consulting, LLC	6	527	Energy storage, combined with storage, is presently being promoted for residential behind-the-meter applications. This hybridization is not limited to U-DER	Change "U-DER" to "DER"	Change made based on comment.
Walling Energy Systems Consulting, LLC	6	531	This line implies that IEEE 1547-2018 imposes fixed requirements for tripping and return to service. In fact, this standard provides wide ranges of settings from which DPs can specify specific settings.	Change to "What are the specific distribution-level tripping schemes or return-to-service requirements that would apply during the dynamics timeframe for different vintages of DER installation date?"	Change made based on comment.
Walling Energy Systems Consulting, LLC	6	Footnote 49	This footnote incorrectly indicates that the applicable versions of IEEE 1547 are the prevailing factor dictating different settings. It is the applicable DP interconnection practice, which typically lag far behind the standards, and make use of wide ranges of settings even where the current standard is applied, dictate.	Delete footnote 49	Footnote kept, but change made to clarify this point.
Walling Energy Systems Consulting, LLC	7	Table 3.1	The default IEEE 1547-2018 parameters for volt-var are null; the mode is not implemented except as specified by the DP and the parameters are at the discretion of the DP. The vintage of 1547 is only partly relevant as the DP discretion is the prevailing factor. It is absolutely incorrect to state that "no information is needed from the DP"	Revise information necessary such that the total amount of DER capacity with volt-var implemented is determined as well as the parameters that are specified by the DP.	Change made based on comment.

Walling Energy Systems Consulting, LLC	9	Table 3.1	IEEE 1547-2018 does not specify the inverter current regulator time constant (tg). The default parameter here is at least an order of magnitude longer than realistic. However, this time constant is probably necessary for the numeric stability of the simulation platform and is probably short enough to not materially affect dynamic study accuracy.	Remove the heading that indicates recommended simulation parameters, that are not specified by IEEE 1547-2018, are defined in that standard. The heading for these parameters should be "recommended default parameters"	Change made based on comment.
Walling Energy Systems Consulting, LLC	10	565	Incorrect statement that the vintage of IEEE 1547 is the prevailing factor.	Replace "vintage of IEEE1547" with "vintage of applicable DP interconnection requirements"	Change made based on comment.
Walling Energy Systems Consulting, LLC	13	617	The statement that synchronous generator DER are "rare" is quite generally false. These DER are actually dominant in some regions.	Revise the sentence to "However, the majority of newly interconnecting DERs in most regions are inverter based (e.g., solar PV and BESSs).	Change made based on comment.
Walling Energy Systems Consulting, LLC	13	641	The statement that synchronous motor loads consume substantially more current during the fault" is completely false. Synchronous motors act identically as synchronous generators with regard to fault contribution, adding to fault current. This does not offset the DER contribution..	Delete this entire section; there is no interaction worthy of special consideration regarding the short-circuit response of loads and DER together. Each have impacts that are accurately considered independently.	Change made based on comment.
Walling Energy Systems Consulting, LLC	15	700	This statement is unjustifiably absolute, considering the unknowns regardin	Modify this sentence to "...and have high impedance; therefore GIC flow at the distribution level will be insignificant."	Change made based on comment.
Walling Energy Systems Consulting, LLC	17	764	"RMS" is inappropriate here, as stated in a previous comment.	Delete "RMS"	Change made based on comment.
Walling Energy Systems Consulting, LLC	19	846	IEEE 1547-2018 requires U-DER to provide the required reactive capability and the voltage regulation at the POI, not at the DER unit level. Also, trip settings are based on the POI voltage. Almost always, this POI is at the MV (distribution primary voltage) level. Thus, the U-DER step-up transformer characteristics are irrelevant to both steady-state and dynamic performance.	Replace with: "If the DER facility is represented as a U-DER having its POI at the distribution primary voltage level (the usual case for U-DER), then the DER model should directly connect to the distribution bus or feeder, without representation of the DER generator step-up (GSU) transformer. If the DER has a POI at the low-voltage level (e.g., 480V), i.e., the GSU is utility-provided with metering on the LV side, then the GSU should be explicitly modeled."	Change made based on comment.
Southern California Edison	24	Footnote 60	This utility has a mix of R_DER and U-DER along the feeder, and assumes a 1.1-1.2 pu maximum fault current	This utility has a mix of R_DER and U-DER along the feeder, and assumes 1.2 pu maximum fault current for R_DER and uses manufacturer provided maximum fault current for U-DER.	Change made based on comment.
ERCOT	vii	178-181	"For reference…" and "provided here as a reference:" are redundant.		Change made based on comment.
ERCOT	vii	199		Remove "and"	Change made based on comment.
ERCOT	viii	217		Remove extra period.	Change made based on comment.
ERCOT	viii	221		Change "impacts" to "impactful"	Change made based on comment.
ERCOT	ix/x	262-264/311-322	Is this suggesting forecasting for U-DER as well? Depending on the market type, U-DER might be more difficult to predict (quantity, size, type).		It is understood that forecasting may be a challenge for both R-DERs and U-DERs based on various factors. However, TPs and PCs should gather suitable data to be able to apply engineering judgment in the development of their long-term planning base cases. SPIDERWG is developing a guideline on DER forecasting practices.
ERCOT	x	290	The example should note that this is a solar PV DER.		Change made based on comment.
ERCOT	5	500, Table 2.1	There should be a reference to Appendix B.		Change made based on comment.
ERCOT	7	552, Table 3.1	There should be a reference to Appendix B.		Change made based on comment.
ERCOT	10	571		Change "voltages" to "voltage"	Change made based on comment.
ERCOT	12	611, Table 4.1	Are there any short circuit studies that can be provided as a reference for these conditions?		There are no explicit short-circuit studies to reference; however, this section has been discussed with NERC SPCS to get their general BPS protection-related feedback.
ERCOT	12	611, Table 4.1	It may be intentional, but the guidance for short circuit studies is not very clear. Even in the last condition (DER providing majority of energy to end-use customers during certain instances), it isn't stated if DERs should be modeled in SC studies. I understand that everyone's system is different, but it would be beneficial to have clearer direction.		This was intentional. There is currently not enough experience in this area to provide strong industry guidance with significant detail. However, SPIDERWG (and other NERC groups) felt it important to cover the importance of having data available to facilitate these studies, if needed. More guidance is likely to come in the future.
ERCOT	13	627	Pleasee reference the utility that is providing the SC contribution assumptions. Have any other entities provided input?		Change made based on comment.
ERCOT	16		Are there any such EMT studies available to reference?		Footnote added with reference to prior presentation in SPIDERWG.
ERCOT	16	730	The need to perform EMT studies is well before 100%, though it would be difficult to quantify.	"As these pockets experience increasing penetrations of DER…"	Change made based on comment.
ERCOT	17	779		Change "need" to "needed"	Change made based on comment.
Long Island Power Authority - Transmission Planning	vii	182 - 192	U-DER is defined here as "directly connected to, or closely connected to, the distribution bus or connected to the distribution bus through a dedicated, non load-serving feeder. R-DER is defined as behind-the-meter DER offsetting load. This leaves a large gap into which the majority of DER capacity falls, which is large exporting DER facilities (e.g., PV farms) that are on load-serving feeders and often quite distant from the distribution bus. Footnote 15 is noted, but does little to alleviate the confusion.	Provide explicit guidance as to how large (multi-MW) exporting DER generation facilities that are interconnected to ordinary load-serving feeders, at a substantial distance from the distribution bus, should be designated.	Modifications have been made to a footnote related to this subject. Explicit modeling guidance is outside the scope of this guideline.
Long Island Power Authority - Transmission Planning	3	446-457	Information regarding DER reactive capability and regulation mode is functionally irrelevant to BES/BPS loadflow studies as the reactive power output is largely a function of distribution system details that are not modeled, including line voltage regulators, switched cap banks and the detailed complexities of the distribution system topology. Furthermore, T-D transformer tap changers effectively decouple distribution system voltages magnitudes from transmission voltage magnitudes in the steady-state. Inclusion of this in the base case is only meaningful in establishing very approximate initial conditions for dynamic analysis. The DER models cannot be expected to provide the absolute DER reactive power; they are only useful for providing the differential reactive power in response to short-term transmission voltage variations.	Add a footnote at the end of this sentence stating "Collection of reactive capability and voltage regulation mode data is primarily to establish initial conditions for dynamic simulation. Due to distribution system details (e.g., line regulators, switched cap banks) that are not possible to model on an aggregate basis, DER models cannot be assumed to provide accurate rendition of steady-state DER reactive power, but do provide a reasonable rendition of the change in reactive power with short-term changes in the transmission voltage during dynamic simulations."	Change made based on comment.
Long Island Power Authority - Transmission Planning	3	Footnote 39	The sentence inaccurately equates renewable with inverter-based with variable generation. Not all renewable DER are inverter based (e.g., small hydro), not all inverter-based is renewable (e.g., batteries and fuel cells), and not all renewable generation has the uncontrollable characteristics of PV and wind.	Replace "renewable, inverter based DERs" with "inherently variable DERs (e.g., wind and solar)"	Change made based on comment.
Long Island Power Authority - Transmission Planning	3	455 - 457	Only the reactive power capability of DER units providing voltage regulation (vol-var function) are relevant. Reporting should be limited to this aggregate reactive capability. With this, it is not necessary to report reactive power-voltage control operating mode. Constant power factor, constant reactive power, etc. non-regulating modes are not relevant. While DER in constant pf mode will change reactive power with active power output changes, these changes are more than likely offset by compensating changes in distribution capacitor banks that are not modeled.	Change to "Maximum DER reactive power capability for DER operating in the volt-var mode", and likewise "Minimum DER reactive power capability for DER operating in the volt-var mode". Delete the bullet line on Line 457.	Updates have been made to guideline to account for this. No change to bullet list needed.

Long Island Power Authority - Transmission Planning	4	464	Distribution transformers (i.e., MV to LV) are not available with load tap changers. Inclusion of this will cause wasted effort and confusion chasing data that do not exist.	Delete the bullet on Line 464	Revisions made to clarify bullet.
Long Island Power Authority - Transmission Planning	5	Table 2.1	DER reactive power capacity reported should be limited to only DER having volt-var implemented. All other reactive capacity is irrelevant.	Change box to "Maximum DER reactive power capability of DER with volt-var function activated (Qmax and Qmin)	This is explained in the box accompanying this heading. No change needed.
Long Island Power Authority - Transmission Planning	6	518	Most U-DER is located on load-serving distribution feeders remote from the substation. Therefore, U-DER may often need to be implemented in the composite load model in order to adequately represent the impact of loads (e.g., motor stalling) on DER dynamic performance.	Change "R-DER" to "R-DER and U-DER"	Change made based on comment.
Long Island Power Authority - Transmission Planning	6	522	A key consideration that needs to be added is where U-DER are located on distribution feeders.	Add an additional bullet "Where are U-DER typically located on the distribution system relative to the aggregation of the load. E.g., near the substation, near the centroid of the load, or at the remote fringes of the feeder."	Change made based on comment.
Long Island Power Authority - Transmission Planning	13	641	The statement that "synchronous motor loads may consume substantially more current during the fault" is completely false. Synchronous motors act identically as synchronous generators with regard to fault contribution, adding to fault current. This does not offset the DER contribution..	Please review this entire section; there is no interaction worth of special consideration regarding the short-circuit response of loads and DER together.	Change made based on comment.
Long Island Power Authority - Transmission Planning	15	705	The unknowns of DER behavior during GMD is not sufficiently indicated.	Add at the end of this sentence a new sentence "The vulnerability of DER to GMD-caused severe voltage distortion remains as an unknown, and an issue that may be worthy for further investigation by the industry."	Change made based on comment.
Long Island Power Authority - Transmission Planning	17	779	Likely topographical error: sentence mentions "that EMT simulations are need for appropriately…".	Change underlined word to "needed".	Change made based on comment.
Long Island Power Authority - Transmission Planning	xi	340-341	Possible typographical error. The applicable time period for IEEE 1547-2003 mentioned in the text does not match Figure I.3	The date "November 2016" should be written "November 2015" to be compatible with the Figure I.3, or the Figure I.3 should be modified to reflect the text.	Change made based on comment.
Long Island Power Authority - Transmission Planning	6	527	Energy storage, combined with generation, is presently being promoted for residential behind-the-meter applications. This hybridization is not limited to U-DER	Change "U-DER" to "DER"	Change made based on comment.
Central Lincoln People's Utility District	viii	188	Central Lincoln is not a NERC registered entity, but does respond to MOD-032 data requests from Bonneville Power Administration (BPA). As an electric utility in the state of Oregon, Central Lincoln follows applicable state law. https://www.oregonlaws.org/ors/757.300 states that Central Lincoln must meter and bill on the net energy used by the customers this NERC guideline is calling R-DERs. The cost of any additional metering cannot be charged to the customer. Other states likely have similar laws due to the lobbying efforts of photovoltaic promotors. Since Central Lincoln saw no reason to burden other customers with these costs, only a single net registering meter is installed at these locations. Central Lincoln and other similar distribution utilities have no method of providing any reasonable aggregate generation estimates. The good news is that the net usage is already included in the existing MOD-032 data. Please note that the Federal Power Act excludes local distribution, so these distributed energy resources are excluded from standards by definition.	Remove definition plus all other references to "R-DER"	Thank you for your comment. The term R-DER is used specifically for modeling-related discussions of how to model aggregate amounts of DERs. It is widely agreed that explicitly representing DERs due to their different dynamic response and impact to net loading on the BPS is important for TP and PC planning assessments. Entities are encouraged to coordinate across the transmission-distribution interface, and apply engineering judgment to gather available data for the purposes of developing planning models. Similar to aggregate demand information, this includes sharing of DER-related information.
Manitoba Hydro	vii	196-198	It's noted that the PC/TP may establish modelling requirements. Where should this be documented?	Will MOD-032 be modified to require the establishment of modelling requirements or possibly in FAC-001?	NERC MOD-032 Requirement R1 states that "Each [PC and TP] shall jointly develop steady-state, dynamics, and short circuit modeling data requirements and reporting procedures…". This is already the requirement of each TP and PC to develop per the existing MOD-032-1. This is detailed in the Introduction section of this guideline.
Manitoba Hydro	vii	Fig 1.1	The figure implies a single aggregate model for R-DER. If there are multiple types of DER in a		The figure is referenced in more detailed guidance materials created by NERC SPIDERWG. A sentence in the guideline states hat "these definitions are intended to be adapted to specific TP and PC planning practices and specific DER installations, as needed." This is intended to capture, for example, situations where different DER types may exist. Again, this is covered in more detail in other guidelines developed.
Manitoba Hydro	viii	223	Traditional short circuit studies focus on high short circuit levels so that equipment vulnerability (eg. breaker duty) can be checked as short circuit levels increase. This section has indicated a potential risk of low short circuit levels (eg. protection relays).	Will TPL-001 be modified to include the requirement of determining minimum short levels and potential consequences including adverse control interactions? On page 25, line 650, it is recommended to also consider motor load.	NERC Reliability Standards revisions are outside the scope of this Reliability Guideline. However, SPIDERWG is currently working on a comprehensive review of NERC Reliability Standards and how DER may affect implementation of those standards.
Manitoba Hydro	viii	230	TPL-007-3 currently only requires consideration of 200 kV and above networks. This section highlights T-D transformers as a likely location of decoupling GMD effects due to the presence of a delta connection. If the primary is grounded-wye, it is vulnerable to GIC.	Will TPL-007 be modified to include modelling up to the T-D interface, assuming the primary winding is grounded wye? On page 15, line 691 there are implications of aggregate DER tripping due to elevated harmonics. Will this be included to TPL-007? This report raises issues but then says there's no need to model the distribution/DER for TPL-007 studies.	NERC Reliability Standards revisions are outside the scope of this Reliability Guideline. However, SPIDERWG is currently working on a comprehensive review of NERC Reliability Standards and how DER may affect implementation of those standards.
Manitoba Hydro	ix	245	It's noted that EMT studies are useful when large amounts of DER are connected.	Can this be quantified in terms of a metric like short circuit ratio or percent of load, for example? On page 16, line 748-750 says there is no clear threshold but some PC/TPs have developed metrics. Why not compare and contrast the available metrics and provide industry guidance?	More research and experience is needed to develop any quantifiable metrics; however, the concepts can be discussed qualitatively. Industry is encouraged to identify areas where the penetration of DERs may be relatively high and consider exploring EMT studies to determine if any reliability issues may exist under high DER penetration conditions.
Manitoba Hydro	ix	262-264	It's noted that TPs forecast demand levels and aggregate amount of DERs for each year being modeled. According to the functional model, the TP is not responsible for forecasts. The Distribution Provider may know where DER is located today but may not be able provide a forecast of future DER amounts and locations over the 10-year planning horizon. The Resource Planner may be in a better position to provide this forecast and data for MOD-032.	The Functional Entities should be expanded to include Resource Planner in addition to Distribution Provider.	Change made based on comment.

Manitoba Hydro	x	315-316	It is expected that the TP/PC should develop forecasts for DER growth in future years. They may be able to determine some sensitivity cases but the base forecast should come from other responsible entities like Resource Planners. It's not just the total amount but the specific location that is important. Assuming a uniform distribution of DER across a TP/PC area may not be reasonable.	The Functional Entities should be expanded to include Resource Planner. The Resource Planner should forecast expected amounts (eg. 50:50 probability) as well as locations. Will TPL-001 be expanded to clarify expectations regarding DER growth forecasts?	Avoid portraying that BPS connected EMT experience is 1:1 related to DERs.
Manitoba Hydro	1	Fig 1.1	The flowchart is reasonable for acquiring modelling information for DER that are currently installed. Forecast information will require a different process. The base models developed through MOD-32 tend to reflect firm development plans. Additional cases are developed through the TPL process to cover sensitivity cases.	Some thought is required on what the minimum requires are for MOD-032.	NERC SPIDERWG is working on a Reliability Guideline specifically focused on forecasting DERs for planning models, and will explore this concept in much more detail.
Manitoba Hydro	3	439-440	Currently the T-D transformer is not considered a BES facility and some entities aggregate the load to the BES bus rather than model the transformer explicitly and represent the load on the low voltage bus. Manitoba Hydro agrees that the proposed model in this guideline is more accurate.	Will MOD-032 be modified to require representation of all T-D transformers or only those with DER?	SPIDERWG submitted a SAR to include aggregate DERs in MOD-032 data collection requirements; however, determination of which T-D interfaces to model for each specific case dependent on individual TP and PC modeling practices.
Manitoba Hydro	6	525	The TP/PC are supposed to identify special interconnection requirements.	Will FAC-001 be modified to add this requirement?	NERC Reliability Standards revisions are outside the scope of this Reliability Guideline. However, SPIDERWG is currently working on a comprehensive review of NERC Reliability Standards and how DER may affect implementation of those standards.
Manitoba Hydro	16	712	It's noted that some entities have interconnection requirements for EMT data. So far NERC has stayed out of the EMT arena.	Where is NERC in terms of EMT studies? Will this be mandated in TPL-001 at some point?	NERC Reliability Standards revisions are outside the scope of this Reliability Guideline. However, SPIDERWG is currently working on a comprehensive review of NERC Reliability Standards and how DER may affect implementation of those standards.
Manitoba Hydro	17	778-781	Unless NERC gets into EMT modelling requirements, EMT data should not be linked to MOD-032. Instead, FAC-001 should be modified to encourage development of EMT modelling requirements as part of the interconnection process.	Will FAC-001 be modified to add this requirement?	NERC Reliability Standards revisions are outside the scope of this Reliability Guideline. However, SPIDERWG is currently working on a comprehensive review of NERC Reliability Standards and how DER may affect implementation of those standards. Regardless, this Reliability Guideline is highlighting the need for EMT data if and where reasonably appropriate as a form of dynamics data that should be collected.
Manitoba Hydro	20-21	Appendix B	Appendix B should focus on the minimum requirements for MOD-032. EMT modelling should be removed.	Simplify Appendix B to focus on MOD-032 changes.	Appendix B provides recommended considerations for collecting suitable data to be able to model distributed energy storage systems. It is not linked directly to MOD-032. No change made.
Edison Electric Institute (submitted by Mark Gray, Manager Transmission Operation EEI)	General Comment	N/A	EEI supports the draft Reliability Guideline titled DER Data Collection for Modeling in Transmission Planning Studies dated March 2020. The information and guidance supports modeling data requirements/specifications and the development of associated reporting procedures per MOD-032-1, considering the increased amounts of renewable resources. EEI supports efforts, such as this guideline, that ensure Reliability Standards such as MOD-032-1 can remain effective as grid resources change over time. In addition to the proposed Reliability Guideline to support DER data collection, we request this group to also development Implementation Guidance for Reliability Standard MOD-032-1 so that the industry will have useful examples of how they can more effectively implement MOD-032-1 through the useful information provided in this Reliability Guideline.	N/A	Thank you for your comment.
CAISO	x	307	Figure I.2 should graphically illustrate the impact of DER on peak and off-peak hours, which is a net load profile similar to the Duck Curve that demonstrates minimal and peak load shiftings, steep ramping need, and overgeneration risk	it is recommended to add a net load profile in Figure I.2 (CAISO source)	Change made based on comment.
CAISO	x	287-291	The Guideline should include language saying that the "System Peak" base case should represent the hour of net peak and the DER output should be consistent with the hour. This will be consistent with recommendation in the SPIDERWG whitepaper on Assessment of DER Impacts on the TPL-001. The proposed change in Colum F is recommended based on assumptions that the proposed change on row 13 is accepted and the net load peaks at 7 PM in the modified Figure I.2	To illustrate this concept, consider the development of the interconnection-wide "System Peak" base case. The "System Peak" base case should represent the hour of net peak and the DER output should be consistent with the hour. Refer to Figure I.2 for a visualization of this example. Let us assume that this is a summer peak case, so the season has been defined. Then it is determined that the gross and net load peak around 6 PM and 7 PM local time respectively, which defines the time of day. Based on this time, the DER output assumptions are established – DER outputs are assumed to be roughly 40-50% of its maximum capability at 6 PM and 0% of its maximum capability at 7 PM~~this time~~.	Change made based on comment.
Georgia Transmission Corporation	General Comment		The draft Reliability Guideline: DER Data Collection for Modeling in Transmission Planning Studies provides a starting point towards DER data collection to be used in transmission planning models. There are many references within the guideline that identify DER penetration as a primary factor that impacts BPS reliability, however, there is no guidance on DER penetration levels for when these impacts occur, which would be a valuable addition to the guideline and highly recommended by GTC.		SPIDERWG does not believe establishing blanket thresholds for DER impacts or modeling is appropriate; this is system dependent and will change for different systems. In order to determine "DER impacts to the BPS", sufficient modeling data is needed to perform reliability studies in the planning horizon such that any corrective action plans can be developed and implemented in a timely manner. This guideline specifically focuses on data collection aspects needed to execute those studies. Having data collection processes in place for TPs and PCs will help facilitate this information transfer to enable those studies to be performed.
Georgia Transmission Corporation	General Comment		GTC recognizes the challenges with determining DER penetration levels that impact BPS reliability as each system has different characteristics that would influence these thresholds. However, the position that DER data be collected on ALL DER systems is a very costly proposal with little to no benefit to systems with low levels of DER penetration. Establishing resources to create and maintain DER databases and model data will impact DPs and TPs across the board, therefore, the cost versus benefit needs to support the added cost.		Establishing data collection requirements is the first step in enabling data transfer such that aggregate impacts of DERs can be modeled in reliability studies. This guideline stresses that this data is needed to facilitate those studies for reliable operation of the BPS. Aggregate DER information, similar to aggregate demand/load data, is important in BPS planning studies. Establishing data requirements after in-service operation has proved very costly for certain entities.
Georgia Transmission Corporation	General Comment		This data collection guideline has the potential to be very useful to industry provided that DER penetration thresholds are added that will substantiate the cost of implementing.		This is a common question, and TPs/PCs should ensure data collection practices are in place to enable reliability studies to help determine impacts of DERs on the BPS.
Georgia Transmission Corporation	vii	198-199	The referenced report is not representative of the impact of aggregate DER loss on BPS (System) reliability. It appears that the unexpected loss of 1,131 MW of wind and steam turbine generation was the main culprit.	Either find a relevant example where loss of aggregated DER was the sole culprit impacting BPS reliability, or delete the comment altogether.	Change made based on comment.
Georgia Transmission Corporation	viii	220-221	More clarity is needed on the size of DER where impacts are seen.	Please include an example where DER penetration has wide area impacts to System stability.	The penetration can impact all aspects of the BPS (stability of all kinds, overloads, etc.) so it's hard to provide clear hard guidance on any one threshold because of the local and regional impacts.
Georgia Transmission Corporation	viii	227-229	More clarity is needed related to DER penetration and its impacts to the System. If the impact of adding the DER is less than 10% increase in fault current, then modeling may not be necessary.		SPIDERWG does not believe establishing blanket thresholds is an appropriate technique. Guideline updated to stress importance of data collection to facilitate determination of impacts.
Georgia Transmission Corporation	ix	245	Provide more clarity and/or description to the phrase "large amounts of aggregate DER"?		Add these points to the response, and also add some points in the Intro on this.

Georgia Transmission Corporation	2	411-416	This statement alone is sufficient for the TP & PC to establish data requirements for DER. This contradicts the need statement of the MOD-032 SAR.		The catch-all statement in MOD-032 has been highlighted as insufficient in justifying the collection of DER data; hence, the SPIDERWG MOD-032 SAR to address this issue. However, it can be used as an interim solution until improvements are made. Change made based on comment.
Georgia Transmission Corporation	5	Table 2.1 Row 5	The following statement is incomplete: "Systems with energy storage may have a Pmin value for aggregate DER modeling less than since the storage resources may be able to charge when generation DERs are at 0 MW output."	Correct the statement as follows: "Systems with energy storage may have a Pmin value for aggregate DER modeling less than zero since the storage resources may be able to charge when generation DERs are at 0 MW output."	Change made based on comment.
Georgia Transmission Corporation	14	652-653	Provide more clarity and/or description to the phrase "a system dominated by DERs"?		Sentence modified to add clarity.
Georgia Transmission Corporation	14	667	The provided example is unrealistic and should be modified to represent a more common scenario of concern. Seldom do utilities allow a breaker to be operated at 99.4% of interrupting duty without justifying it to be replaced.	Modify the example so the breaker is operated at a more common interrupting duty of 80-85% prior to addition of the DER and represent a more dramatic increase in fault contribution from a synchronous machine DER such as 3-4 pu fault current.	Sentence added to the example to clarify regarding synchronous DER as well as the example presented.
Georgia Transmission Corporation	17	779	The sentence contains a grammatical error.	Replace the word "need" with "needed".	Change made based on comment.
Arizona Public Service Company	ix	262-264	Year: the expected demand levels are dependent on the method of modeling UDER and RDER. Specifically the DER that are explicitly represented require load representation of "Gross demand" before DER impacts. However, if both "Net demand" and installed aggregate DER are provided, this represents an unrealistic representation effectively double-counting the DER online. This should be specifically indicated.	Include in the language discussion of the net and gross loads and treatment with explicit versus netted representation of individual and aggregate DER.	SPIDERWG believes that it is important for expected DER levels to be explicitly modeled in planning cases such that the dynamics of end-use loads can be differentiated from DER performance. Past disturbances analyzed by NERC have identified DER impacts to BPS performance; specifically DER tripping affecting net loading following the normally-cleared contingency event on the BPS.
Arizona Public Service Company	ix	271-277	Load: The reader is left to infer "provide gross load and explicit models of both individual and aggregate DER" as is represented in Figure I.1. However, the provision of explicit DER models necessitates a representation of gross load (as if DER were not present). This is important, because of DER is present and net load values are provide in addition to assumed aggregate DER, the DER output is being double counted.	Specify "gross load is to be provided" and net load effectively simulated by a specified DER dispatch.	Change made based on comment.
Arizona Public Service Company	x	326	In concept, understanding the vintage of DER installed is very important. DPs in practice may need to understand the vintage, and also the actual settings employed to aggregate DER systems. For example, the capability of IEEE 1547a-2014 may exist in the inverters, but the actual settings may mirror the IEEE 1547-2003 devices.	Clarify that "capabilities" and also "actual deployed settings" are to be estimated based on vintage.	Change made based on comment.
Arizona Public Service Company	xi	352-354	In concept, understanding the vintage of DER installed is very important. DPs in practice may need to understand the vintage, and also the actual settings employed to aggregate DER systems. For example, the capability of IEEE 1547a-2014 may exist in the inverters, but the actual settings may mirror the IEEE 1547-2003 devices.	Clarify that "capabilities" and also "actual deployed settings" are to be estimated based on vintage.	Change made based on comment.
Arizona Public Service Company	2	411-417, 420	TP and PC entities may develop data requirements, however, no specific requirement exists for DPs to obtain this information in many cases. UDER may be available. RDER is generally 3rd party and vary in sophistication and data availability, outside of individual DP efforts to track interconnections on their systems. For example, DPs may have installed capacity, but not actual operating output (many RDER have limited metering or production information), or access to grid support function settings which may have been changed since inverter commissioning unbeknownst to the DP.	Specify if options exist for DPs that may not have the data readily available, or whether assumptions suffice for TP and PC modeling purposes.	Change made based on comment.
Arizona Public Service Company	4	473-477	This may constitute an impractical ask of DPs. Many 3rd party DER vendors are now combining technologies (PV + ES) and providing aggregate control. Generally for larger scale UDER (as indicated on 470) this is well known with metering and monitoring of operational conditions. However for RDER, dispatch decisions may be made by a homeowner, or 3rd party aggregator unaffiliated with a DP program or product. While installed aggregate capacity is easily determined, dispatch patterns can vary widely. Determining an hourly dispatch pattern may present an untenable challenge.	Add a sentence specifying what is needed and what is not. Are DPs expected to provide hourly dispatch "scenarios" for customer owned RDER?	Change made based on comment.
Arizona Public Service Company	10	559-560	Although vintage can be insightful in determining market availability of capabilities, the actual settings of devices (if known) are most impactful on assessing BPS impact. Quite often, devices are capable of performing certain functions, but are not actually configured to do so as field deployed.	Recommend inserting language referencing the difference between device capability and actual device setting (i.e. understanding what is known and what is not).	Change made based on comment.
Arizona Public Service Company	14	662-663	Similarly, capabilities for UDER are generally known and verified with commissioning and testing. However, capabilities for RDER are generally not known. For DPs who do not know what the DER response to fault looks like, how do they provide data to the TP or PC for modeling?	Recommend inserting language referencing what DPs who do not have this data provide to the TP or PC.	Sections describe making estimates of this information using engineering judgment. Covered in multiple places throughout guideline.
Southern Company Services	3	Paragraph 3	There may be DERs that are modeled on the same low-side bus that behave very differently or have very different profiles etc. In this paragraph is makes it seem like the DP will only provide aggregate information, but in this case the modeling may be broken up in to separate aggregate blocks based on behavior.	The language in this section should match other sections in the document that talk about the PC/TP defining the assumptions and requirements for the DP to provide the data.	Change made based on comment.
Southern Company Services	3	Paragraph 3	The second bullet "Historical DER output profiles" could be be overly burdensome.	Maybe change to historical or expected DER output at system conditions specified by the TP/PC	Change made based on comment.
Southern Company Services	7	Table 3.1	Footnote 41 gets somewhat lost or overlooked in the table since its just a reference in the paragraph above.	Recommend making footnote 41 a "Note 1" attached to the bottom of Table 3.1.	Change made based on comment.
MISO			The order of R-DER and U-DER discussions is inconsistent throughout the document	Please work to standardize for ease of use and readability	All uses or R-DER and U-DER reviewed and modified to ensure clarity.
MISO	viii	205-206	The future operating conditions should apply to both types of analyses.	Modify language to reflect. "Steady-state reliability studies include both power flow analysis and contingency analysis of future operating conditions"	Change made based on comment.
MISO	5	Table 2.1	Incomplete wording under the Minimum DER active power capacity (Pmin) item.	"... may have a Pmin value for aggregate DER modeling less than zero since the storage resources..."	Change made based on comment.
MISO	17	779-780	Grammatical correction	"... that EMT simulation are needed to appropriately identify specific reliability issues:..."	Change made based on comment.
MISO	v	96	Suggest adding in to the Executive Summary the SPIDERWG definition of Distributed Energy Resource (DER) to ensure clarity regarding applicability of this recommendation (electricity producing resources).		Change made based on comment.
MISO	19	827	Suggest adding a note to guide readers to the location and/or body working on Demand Response (DR).		This topic is outside the scope of DER data collection for the purposes of this guideline.
MISO	16	711, 724	Suggest adding in the meaning of EMT and RMS acronyms.		EMT is previously defined; change made to define RMS.

MISO			Commends the working group on recognizing the need to differentiate between IEEE-1547 version and to change the assumptions depending on implementation year.		Thank you for your comment.
Ameren	Page 5	Table 2.1, Row 2	Table 2.1, Row 2 recommends "Specify the percentage of DERs considered R-DER and U-DER. Provide an aggregate breakdown (percentage) of the types of DERs per T-D transformer. Preferably, this is specified as a percentage of aggregate DERs that are solar PV, synchronous generation, energy storage, hybrid power plants, and any other types of DERs."	To better accommodate the collection of R-DER, we recommend that the load record in PSS/e is expanded to track the different types of R-DER (Solar, Wind, Battery, etc.). Currently, PSSE aggregates all types of DER into a single load record.	This information will be passed along to SPIDERWG sub-group tackling modeling improvements needed in presently used commercial simulation programs. Thank you for the comment.
Ameren	Page 5	Table 2.1, Row 3	Table 2.1, Row 3 recommends that for each type of aggregate DER (e.g., solar PV, combined heat and power, energy storage, etc.), specify a general historical DER output profile occurring during the studied conditions. What output are these resources dispatched to during peak and off-peak conditions? The TP and PC should define what peak and off-peak conditions are (e.g., season, time of day, etc.).	Metering is not available on roof top solar installations. We recommend that generic geographic DER output profiles are developed for solar roof top installations for locations across the country.	Change made based on comment.
Ameren	Page 7	Table 3.1	The DER_A Parameterization document contains in Table 2.1 starting on page 8, complete sets of dynamic model parameters for several different vintages of DER equipment. While Table 3.1 in the most recent draft DER Data Collection document, starting on page 7, doesn't contain all of the different sets of parameters, there is some discussion questions included on all the parameter values which are subject to variation based on DER vintage. Either both of these documents need to be considered together, or it might be beneficial to include the different parameter sets in the latest document in addition to questions to address the DER owners.	Consider including different DER_A parameter sets from the earlier DER_A Parameterization document, Table 2.1 as part of the information in Table 3.1 of the DER Data Collection guideline document.	Table 3.1 in the guideline under review includes all of the parameter values from the previous guideline; however, it does not include all the variations of parameter values as this is not the intent of this guideline. Rather, Table 3.1 describes the questions that at TP and PC could ask of applicable data submitters (e.g., the DP) to help facilitate determination of those parameter values shown in the DER_A parameterization guideline. This is described at the front of Chapter 3, prior to Table 3.1.
Missouri Basin Municipal Power Agency d/b/a Missouri River Energy Services (MRES)	1-37 (All)	All	Missouri River Energy Services (MRES) has a general comment with regard to the compliance responsibilities being laid out in the Reliability Guideline document. For some vertically integrated utilities, compliance responsibilities may be more uniform for the modeling of distributed energy resources (DERs) connected to its electrical system. That vertically integrated utility usually has a breadth of compliance responsibilities including: Distribution Provider, Transmission Owner / Operator / Planner, Generation Owner / Operator, Resource Planner, and often time Balancing Authority. However, some non-vertically integrated utilities have more complex compliance responsibilities and arrangements. Some NERC entities have only Transmission Owner (TO) compliance responsibilities, some have only Distribution Provider (DP) compliance responsibilities, and some have a combination of the two (or more). MRES and many of our members do not have DP compliance responsibilities, which makes it difficult to require this data be submitted for much of our connected load/demand. According to the initial policy coming out of the Planning Coordinators, that doesn't preclude MRES from responsibilities to collect and administer that information. Although MRES does not content that this is unjust, we do believe that there is a compliance gap between the expectation of the Planning Coordinators and the DP compliance responsibilities. Since the Load-Serving Entity compliance role is no longer in effect, the DP compliance responsibilities being laid out in the Reliability Guideline seem ill equipped for the initial policy coming from Planning Coordinators. Furthermore, DPs only participate in modeling from a MOD-031 perspective (Total Internal Demand, Net Energy for Load, and Demand Side Management). This does not pertain to the DER information directly, but MRES recognizes the intent of the Reliability Guideline.	Investigate Compliance Role Applicability	As stated in the Preamble of all NERC Reliability Guidelines: "It is in the public interest for NERC to develop guidelines that are useful for maintaining or enhancing the reliability of the [BES]...These guidelines establish a voluntary code of practice on a particular topic for consideration and use by BES users, owners, and operators...The objective of this reliability guideline is to distribute key practices and information on specific issues critical to maintaining the highest levels of BES reliability. Reliability guidelines are not to be used to provide binding norms or create parameters by which compliance to standards is monitored or enforced. While the incorporation of guideline practices is strictly voluntary, reviewing, revising, or developing a program using these practices is highly encouraged to promote and achieve the highest levels of reliability for the BES..."
PPL NERC Registered Affiliates			PPL NERC Registered Affiliates are concerned that the Guideline does not provide recommendations as to how TPs and PCs will obtain the aggregated DER information needed to accurately model the BES from non-FERC regulated entities who operate distribution systems with interconnected DER within the TP/PCs footprint (ex. municipal electric systems). A NERC registered entity is not the appropriate entity to collect this information and state laws and regulations may prohibit the collection of this information by a NERC registered entity.	It is suggested that the guideline clearly acknowledge this issue and also encourage TPs and PCs to work with state regulators to determine how aggregated DER information from non-FERC jurisdictional entities may be provided to a TP/PC.	NERC Reliability Guidelines do not provide recommendations related to NERC Registration. Rather, they provide recommended practices for NERC Registered Entities to consider. Data transfer from relevant entities with necessary information will need to occur to facilitate reliability studies. As with demand data, information pertaining to DERs within the footprint of relevant distribution entities will need to be provided in some way for developing interconnection-wide base cases and performing planning assessments.
PPL NERC Registered	v, vii, viii, ix	106-107 119-121 188-189 197-198 215-222 251-258	In the several referenced locations noted, it is unclear what entity is responsible for preparing the aggregated DER model information that will be provided to the TP/PC for inclusion in the BES planning model. We are concerned that this ambiguity could lead to TP/PCs requiring the provision of DER information of an inappropriate level of granularity for their needs.	We recommend that NERC consider adding language to the Guideline recognizing that an entity or entities, other than a TP/PC may have more direct access to DER data sources and more familiarity with the sub-transmission systems to which distribution is connected than a TP/PC, allowing them to more easily accommodate the process required to create aggregated DER models. These more appropriate entities should be responsible for preparing the aggregated DER model and providing it to the TP/PC for inclusion in BES models for planning purposes.	In multiple places throughout the guideline, "other external entities" that may have useful DER data are mentioned that may support TPs and PCs in their data collection activities. Further, the Resource Planner was also included specifically for forecasted DER levels, where applicable.
PPL NERC Registere	v, 2	116-117 423-424 "Key Takeaway"	PPL NERC Registered Affiliates are concerned that the use of the word "ensure" in several places in this Guideline could be reasonably interpreted as creating a requirement as opposed to a recommended best practice. Using line 563 as an example, we appreciate the use of "considered" over the use of "ensure" as it is elsewhere in the guideline as it strikes the tone of providing a recommended best practice rather than a requirement.	For example, it is suggested that the sentence on lines 116-117 be revised to state: "TPs and PCs ~~should review~~ are encouraged to review their requirements ~~to ensure they encompass~~ and consider incorporating, as appropriate, the considerations presented in this guideline."	Change made based on comment.
PPL NERC Registered Affiliates	v	122-123	Remove reference to "DP" as discussed in our comments to other sections.	In either case, the ~~DP,~~ TP~~,~~ and PC should coordinate with the appropriate entities on the best approach…	Change made based on comment.
PPL NERC Registered Affiliates	vii	197-198		Remove "individual large" before U-DER. (to "……modeling either U-DERs as well as aggregate amounts of the remaining DERs as R-DERs.")	change made based on comment.
PPL NERC Registere	viii	208	In the discussion of steady-state studies, line 208 contains the phrase "possible DER penetration." It is unclear what this phrase is intended to mean.	We suggest removing the word "possible" to be consistent with the way the term "load" is used in the sentence and provide additional clarity.	Change made based on comment.

PPL NERC Registered Affiliates	xi	354-359	We recommend that the DER assumptions section consider the locations of DER growth as well.	Add the location of DER growth as one of the listed modeling considerations.	Change made based on comment.
PPL NERC Registered Affiliates	1	387 / Footnote 32	PPL NERC Registered Affiliates strongly oppose the inclusion of compliance applicability information and references to submitted SARs in this draft Reliability Guideline. As explicitly stated in the Preamble of the document, "*Reliability guidelines **are not to be used [emphasis added]** to provide binding norms or create parameters by which compliance to standards is monitored or enforced. While the incorporation of guideline practices are strictly voluntary; reviewing, revising, or developing a program using these practices is highly encouraged to promote and achieve the highest levels of reliability for the BES.*" It appears the SPIDERWG is attempting "to provide binding norms or create paraments" for Distribution Providers and has come to a conclusion the "DP is the appropriate entity". It is inappropriate to include this language in a Reliability Guideline.	In footnote 32, delete the last three sentences which state "~~*Note that at the time of writing this guideline, a Standard Authorization Request (SAR) was submitted by the NERC DERTF to replace LSE with DP since the registration of LSE was removed. SPIDERWG also submitted a SAR further emphasizing that the DP is the appropriate entity to support collection of DER data. Therefore, DP is used as the applicable entity throughout this document.*~~ "	The reference to the SAR submitted by SPIDERWG was removed.
PPL NERC Registered Affiliates	1	Figure 1.1	We strongly oppose specifying the Distribution Providers are the only entity that may have the data needed by TPs and PCs for their modeling. As noted in our comments below to page 2 lines 411-417, TSPs already have FERC jurisdictional means in place to obtain information.	Replace "DPs" with "Data reporting entities" or with "appropriate entities who have access to this data" as described in the "Key Takeaway" box on page 2.	Change made based on comment.
PPL NERC Registered Affiliates	2	Line 406-409 / Figure 1.2	The figure seems to display Attachment 1 to MOD-032-1, however, the table is drastically truncated.		Change made based on comment.
PPL NERC Registered Affiliates	2	411 - 417 / footnote 35	PPL NERC Registered Affiliates disagree with inclusion of footnote 35, but agree with the statement in these lines otherwise. We suggest there are other entities that may fall outside of the explicit Reliability Standard framework that can provide DER data. Any additional details that may be needed by PCs and TPs is already explicitly described in Attachment 1 by the third sentence in the attachment which states "A Planning Coordinator may specify additional information that includes specific information required for each item in the table below." Additionally, the "steady-state" column (item 9) and the dynamics column (item 10) of Attachment 1 already have a requirement for "Other information requested by the Planning Coordinator or Transmission Planner necessary for modeling purposes. [BA, GO, LSE, TO, TSP]" [emphasis added]. Therefore, PCs can request any other needed information through their Transmission Service Providers (TSP) or other registered entities. TSPs can obtain the information through mechanisms in their FERC jurisdictional OATTs. Because of this, footnote 35 is not needed. Furthermore, as noted in our comments to footnote 32, it is inappropriate to include binding norms or create parameters in a Reliability Guideline. Therefore, footnote 35 should be removed.	Delete footnote 35.	Change made based on comment.
PPL NERC Registered Affiliates	3	449-457	PPL NERC Registered Affiliates recommend adding these data points to the list of specified points that contribute to the aggregate DER.	Add reactive power capability curves of DER and reactive power compensation devices, e.g. SVC, shunts.	Change made based on comment.
PPL NERC Registered Affiliates	6	521-531		Add a question regarding momentary cessation characteristics for large disturbances.	Change made based on comment.
PPL NERC Registere	10	568	PPL NERC Registered Affiliates are concerned with the phrase "future projected installations of DER" as a data point as this phrase is ambiguous and raises questions regarding who is preparing/providing the future projections, how far those projections look out and the level of granularity to be included in a future projection.	This concern would be somewhat mitigated by the inclusion of language clearly specifying that more appropriate entities than the TP/PC may exist and such entities should be responsible for preparing DER aggregation models and providing the same to TP/PCs for inclusion in the planning models, as suggested on line 15 of these comments. This will enable entities with more familiarity with DER data and sub-transmission system topology to manage future DER projection responsibilities and then provide aggregated DER data to TP/PCs.	TPs and PCs are responsible for creating planning cases that project expected operating conditions into the long-term planning horizon (e.g., 5-10 years out). Projections of future demand and DER levels may come from various data sources that aggregate up to the TP and PC based on the data requirements they have established. While it is a challenge to accurately forecast future demand and DER levels, TPs and PCs will need to use engineering judgment based on available data from applicable entities and can perform sensitivity studies to determine any potential reliability issues should the forecasts be inaccurate. NERC SPIDERWG is working on a separate guideline related to forecasting DER in planning models, and will consider these points in the development of that guideline.
PPL NERC Registered Affiliates	16	728-731		Clarify the recommended penetration level (%) of DER when the EMT study is required.	This is based on specific system needs, and will vary across different areas or parts of the BPS. A bright line criteria for % level of DER when EMT studies are required or needed is not recommended. This is described in the guideline.
PPL NERC Registere	19	815	PPL NERC Registered Affiliates disagrees with the inclusion of Energy Storage as an Appendix. Energy storage has a broad range of definitions (pumped hydro, flywheel, batteries etc.)and the unique characteristics of each are not fully fleshed out. Additionally, it is unclear why if data collection for energy storage is intended to be addressed, that conversation does not occur in the main body of the guideline.	PPL NERC Registered Affiliates suggest that Energy Storage either be clearly defined and incorporated into the body of the guideline or removed from the guideline and become the subject of a separate guideline, as appropriate.	The introductory paragraph of Appendix B explains that DER energy storage encompasses many types of DERs, stating: "While there are many types of energy storage technologies available today, this section focuses mainly on inverter-based battery energy storage since it is the most prominent form of DER expected in the foreseeable future and widely observed in DER interconnection queues today." SPIDERWG believes this is an important topic to cover, with only a some unique characteristics of energy storage that should be accounted for from a data collection standpoint.
Public Utility District No. 1 of Cowlitz County	5	112	Cowlitz PUD agrees with this and already collects the majority of the data as outlined in the Guideline and has reported it to Columbia Grid for use in the composite load model for area 40. Cowlitz PUD could similarly report the data to WECC through BPA (Cowlitz's PC) using the MOD-032 process. Cowlitz feels this data collection should be done regardless of the amount of DER installed.	None	Thank you for your comment.
Public Utility District No. 1 of Cowlitz County	5	119-121	Cowlitz PUD agrees that the detailed information will not always be available and assumptions must be made.	None	Thank you for your comment.

Public Utility District No. 1 of Cowlitz County	8 & 9	205-246	At this time there are some areas that have a reliability need to study the penetration of DER there are other areas that do not have this need. Western Washington State is one of the areas that does not have a high penetration of DER. Solar DER in particular required a significant subsidy from the State government to become even remotely cost effective. Incentives for solar peaked at $1.08 per kwh generated in Washington State! Performing all of the studies as detailed in this Guideline would be onerous and of little value at this time, especially for a smaller utility such as Cowlitz PUD. The total DER penetration at Cowlitz PUD is about 2.4 MVA of RDER – this amounts to about 0.35% of our peak summer load when the solar is expected to be at its generating peak (increases to 0.40% for Spring or Autumn cases). Cowlitz PUD feels that there needs to be some limit placed before studies are required. Whether those limits are a hard MVA threshold or a percentage of system load or a combination of the two. A tiered approach could also be used phasing in the types of studies for DER.	Cowlitz PUD strongly recommends that a minimum threshold of 75 MVA of installed DER be met before requiring any of the proposed studies in the Guideline. In addition, Cowlitz PUD recommends that the level of DER to system load should also be greater than 10% before requiring any of the studies. The studies being deferred until these proposed thresholds are met are any and all: Steady-State Studies involving DER, Dynamic Studies involving DER, Short Circuit Studies involving DER and EMT studies involving DER. It might even make sense to set separate levels and/or criteria for different studies – such as: • Set the Steady-State Studies at a 10% DER to load percentage (or higher) • Dynamic studies might be avoided entirely if the droop settings are set within WECC guidelines (PRC-001-WECC-CRT-1.2) • Short Circuit studies set at 25% DER to load percentage (or higher) • Set the EMT studies at 50% DER to load percentage (or higher)	SPIDERWG does not believe that establishing a blanket threshold for DER modeling is a recommended practice across North America. DER impacts may occur on a localized basis. Further, ensuring data collection requirements and practices are established ahead of DER installations helps facilitate suitable information exchange for TPs and PCs to adequately execute reliability studies of the BPS. Each TP and PC should understand the impacts of aggregate levels of DERs, which requires suitable and reasonable data to execute these studies. Thresholds could be determined by TPs and PCs assuming studies show negligible impacts to BPS performance by using simplified modeling assumptions; however, this should be on a case-by-case basis.
Electric Power Research Institute (EPRI)	viii-ix	240-246	The section on EMT studies and its mention of low short circuit and weak grid seems more suitable to an IRPTF document. Especially the content related to benchmarking of RMS models and fault ride through. DER today is modeled in aggregated (unless it is a U-DER) and even then, model benchmarking of U-DER models to my knowledge does not fall under the same requirements as model benchmarking for BPS connected IBRs. In relation to SPIDERWG, is there an expectation of high risk with regard to low short circuit and DER?	Either the entire section can be removed from this document, or it has to be clearly mentioned that this is more of a BPS connected IBR topic rather than a DER topic. The way it is mentioned right now can lead to significant confusion when conducting planning studies related to DER	Change made based on comment.
Electric Power Research Institute (EPRI)	x	291	Although the IEEE 1547-2018 standards requires the availability of Volt-Var, its use is completely at the guidance of the DP.	Add a lines which says that use of Volt-Var is at the discretion of the DP and its wide spread use is not yet common out of concern of potential impacts within the distribution system which have not yet been fully studied.	Change made based on comment.
Electric Power Research Institute (EPRI)	xi	341	Although IEEE 1547a-2014 widened the ride-through settings, it is possible that inverters in the field did not have their settings change, and nor did the DP's guidance change. Due to this, even though the standard had widened the range, it is possible the settings were still conservative.	Include a statement to the effect that although the IEEE standard incorporated a wide ride through setting, the actual setting would be consistent with relevant DP practice and has to be taken into account	Change made based on comment.
Electric Power Research Institute (EPRI)	4	464	It is possible that some of the transformers may not have tap changers.	Add a line to state that if tap changer is absent, it should be noted, and the power flow model should freeze the tap movement.	Change made based on comment.
Electric Power Research Institute (EPRI)	4	494-495	Regarding the split of U-DER and R-DER, would suggest to add a split to also include synchronous DER such as diesel gensets or small hydro	Amend the split to include synchronous DER	Adding synchronous DER to this example is not necessary to get the key points across.
Electric Power Research Institute (EPRI)	6	517	The notation DER_A is a WECC notation.	For uniform application, reference this public document which provides notations across software platforms - The New Aggregated Distributed Energy Resources (der_a) Model for Transmission Planning Studies: 2019 Update, EPRI, Palo Alto, CA: 2019, 3002015320 https://www.epri.com/#/pages/product/000000003002015320/?lang=en-US	Change made based on comment.
Electric Power Research Institute (EPRI)	7	Table 3.1	The values of ddn and dup should be coordinated with the fraction of DERs that are providing frequency response. For example, if there is a total aggregate of 20MVA of DER, but only 5 MVA of it are DERs that provide frequency response at 5% droop, then if a single DER_A model is used to represent the entire 20 MVA of DER, the values of ddn and/or dup should be scaled appropriately. In this scenario, the appropriate values would be (1/0.05)*5/20.	Add a footnote or explanation as provided in the previous column	Change made based on comment.
Electric Power Research Institute (EPRI)	9	Table 3.1	Some recent studies have shown that the value of Xe may need to be higher for certain systems/faults to allow for numerical stability of the simulation. A higher value does not reduce the accuracy of the response and thus a range of values between 0.25-0.8 can be used	Change the value to indicate a range between 0.25-0.8 and a footnote to say an appropriate value to be used based on numerical stability	Change made based on comment.
Electric Power Research Institute (EPRI)	13	641	During a fault, both induction motors and synchronous motors would provide reactive current and not consume reactive current. However after fault clearing, an induction motor can only consume Vars but a synchronous motor can either provide vars or consume vars. Synchronous motors have an excitation system just like a synchronous generator.	Rather than specifically calling out any type of load, just add a statement that short circuit characteristics of loads will have to be taken into account when considering DER short circuit contributions	Change made based on comment.
Electric Power Research Institute (EPRI)	15	700	A bit more modification is required	Add a sentence "...insignificant. Because of this, the distribution level circuits are not included in the dc-equivalent system model (GIC system model)."	Change made based on comment.
Electric Power Research Institute (EPRI)	16	749-750, footnote 69	The reference in the footnote is directed towards BPS connected IBRs and not DERs. Lines 748-749 provide a possible erroneous impression that the reference is for DER	modify lines 749-750 to indicate that the reference in footnote 69 is for BPS connected IBR and not necessarily DER	Change made based on comment.
Electric Power Research Institute (EPRI)	17	778	Another section on load models is very important here. Performance of DERs at the detailed level which is described for EMT simulations will be meaningless if appropriate models are not used to represent the load in that area. No conclusion can be made from the study if load are modeled as static loads.	Add another bullet point after U-DER to highlight the need and importance of load models and their relation to DER simulations in EMT simulations	Change made based on comment.
Electric Power Research Institute (EPRI)	N/A	N/A	Could be useful to reference EPRI's Transmission and Distribution Operations and Planning Coordination report (DOE funded)	EPRI (2019): Transmission and Distribution Operations and Planning Coordination. TSO/DSO and Tx/Dx Planning Interaction, Processes, and Data Exchange. 3002016712. Electric Power Research Institute (EPRI). Palo Alto, CA. Available online at https://www.epri.com/#/pages/product/000000003002016712/.	Change made based on comment.
Electric Power Research Institute (EPRI)	N/A	N/A	Keeping a database which has an overview of DER trip settings as per DP guidelines or change in standard will become increasingly challenging.	Could be useful to reference EPRI's DER settings database (https://dersettings.epri.com/). There's also a paragraph or two in the NERC IEEE 1547-2018 reliability guideline that could be used	Change made based on comment.
Electric Power Research Institute (EPRI)	N/A	N/A	Detailed DER unit or facility data may not be needed	Further stress that DER data collection be limited to aggregate data at the T&D interface (substation)	This is highlighted in multiple places throughout the guideline.

Electric Power Research Institute (EPRI)	N/A	N/A	The industry (both utilities and software vendors) are in need of more specific guidance on data sharing solutions in order to be able to meet NERC expectations as cost-effectively and quickly as possible. Especially when its guidelines impact on the distribution domain, where the contributions of so many, so much smaller, entities are required, NERC is in a position to benefit everyone (itself, its members and society at large) by providing more concrete guidance in terms of data exchange approaches. A common, well-articulated, industry-level definition of the data to be provided and the organizational format in which it is to be provided is needed. This is true whether the data is distribution detail to support aggregation on the transmission side, or aggregated data created on the distribution side. Either option requires distribution network model data management at a level and scale that is currently out of reach for a large proportion of distribution utilities today. Lacking a concrete definition of the data distribution is to provide, the tool vendors serving the distribution community will be faced with implementing multiple, locally mandated data exchange interfaces. This approach will cost distribution utilities (and their customers) more, will compound the data management challenges faced by distribution utilities, and will impede the ability of distribution utilities to adapt to future changes in requirements.	Acknowledgement of distribution utilities challenges in collecting and providing this data – this is likely to be an evolution over the next decade or so. An option would be to add a section on the CIM and how the CIM may be informed – and enable – the DER data collection & exchange across the T&D interface in this guideline. Alternatively, there are two other courses of action that could be pursued that would significantly help utilities achieve the results NERC, as a whole, is calling for: - consider the transmission / distribution data exchange requirements holistically across both planning and operations - support the development of a uniform, standards-based approach for transmission / distribution data sharing. There is joint work going on within the IEC Common Information Model (CIM) and 61850 Working Groups addressing the data modeling of aggregate DER information. There is significant work underway to refine the CIM to better support distribution network model data exchange. Few examples are the GridAPPS-D work out of PNNL, EPRI's Grid Model Data Management work (http://integratedgrid.com/distribution-gis-and-grid-model-data-management/), and work from European Union (http://publica.fraunhofer.de/eprints/urn_nbn_de_0011-n-5488574.pdf). NERC could leverage the foundation being built by these sorts of data exchange standardization efforts in its guidelines.	Thank you for the comments. SPIDERWG will review this material and would benefit from EPRI presentation on this topic at a future meeting.
Electric Power Research Institute (EPRI)	N/A	N/A	There could be improvements in the document's formatting.	Fix some formatting issues, like inclusion of a bookmarks in the PDF to facilitate easier navigation through the documents.	NERC Publications department will address any formatting issues.
Oncor Electric Delivery	vii	198-199	Grammatical Error - "The aggregate impact of DERs, such as the 198 sudden loss of a large amount of DERs, and has been observed17 to have an impact on BPS reliability."	"The aggregate impact of DERs, such as the 198 sudden loss of a large amount of DERs, has been observed17 to have an impact on BPS reliability."	Change made based on comment.
Oncor Electric Delivery	xi	349-350	Not all locations will require local voltage controls due to a variety of reasons, but will probably require local voltage control capability to be enabled at a later time.	"Interconnection requirements will presumably be updated in July 2021 to require local DER voltage control capability."	Change made based on comment.
Oncor Electric Delivery	6	512	Texas has seen a number of distributed synchronous generator interconnections and would like to reflect that not all synchronous are existing installations, but we agree that there is a greater number of new inverter based connections.	"While synchronous DER exist and new synchronous are being interconnected across North America, inverter-based DERs..."	Change made based on comment.
Oncor Electric Delivery	12	Table 4.1 #3	Technical Error - Inverters with certification previous to UL 1741SA were not capable of momentary cessation.	"Legacy DERs are likely not providing fault current due to the use of tripping and momentary cessation for large disturbances, and there..."	Change made based on comment.

PRC-019-2 Compliance Implementation Guidance

Action

Endorse for submittal to the ERO.

Background

The SPCS was requested to develop compliance implementation guidance for PRC-019-2 based on questions from the industry. The SPCS developed a guidance document and requested a Planning Committee review in September, 2019. The document was revised based on the PC comments.

This document provides guidance related to NERC Standard PRC-019-2. Included is an engineering background to help entities understand the coordination of control systems, protective functions, and equipment capabilities. It is also intended to establish reasonable assumptions that may be used in the calculations to meet the intent of this standard.

The document provides examples showing coordination of voltage control systems, Protection Systems and equipment capabilities for Synchronous Generation, Synchronous Condenser, and Dispersed Power Producing Resources.

NERC Planning Committee Compliance Implementation Guidance PRC-019-2

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2 Overview

2.1 Preamble

Implementation Guidance provides a means for registered entities to develop examples or approaches to illustrate how registered entities could comply with a standard that are vetted by industry and endorsed by the Electric Reliability Organization (ERO) Enterprise. The examples provided in this Implementation Guidance are not exhaustive, as there are likely other methods for implementing a standard. The ERO Enterprise's endorsement of an example means the ERO Enterprise Compliance Monitoring and Enforcement Program (CMEP) staff will give these examples deference when conducting compliance monitoring activities. Registered entities can rely upon the example and be reasonably assured that compliance requirements will be met with the understanding that compliance determinations depend on facts, circumstances, and system configurations. [1] Per the NERC Compliance Guidance Policy, Principles for Compliance Guidance;

- Guidance documents cannot change the scope or purpose of the requirements of a standard.
- The contents of this guidance document are not the only way to comply with a standard.
- Forms of guidance should not conflict.
- Guidance should be developed collaboratively and posted on the NERC website for transparency.

2.2 Purpose

This document provides guidance related to NERC Standard PRC-019-2. Included is engineering background to help entities understand the coordination of control systems, protective functions, and equipment capabilities. It is also intended to establish reasonable assumptions that may be used in the calculations to meet the intent of this standard. Example calculations utilizing these engineering concepts are included to demonstrate compliance. These examples DO NOT represent the only method for showing compliance. They are simply an example of the engineering principles and philosophies an entity may consider for compliance with the standard.

This document identifies the different variables and system conditions associated with generation control and protection coordination. Generation resources have inherent differences that can be analyzed through the methodologies outlined in this document. The diversity of the systems throughout the industry may require analysis from a different vantage point.

[1] Source : http://www.nerc.com/pa/comp/Resources/ResourcesDL/Compliance_Guidance_Policy_FINAL_Board_Accepted_Nov_5_2015.pdf

2.3 Scope

This Implementation Guidance applies to Generator Owners (GO) and Transmission Owners (TO) who are seeking to demonstrate compliance with PRC-019-2 Requirements R1 and R2. The standard requirements are copied below, for the readers convenience.

R1. At a maximum of every five calendar years, each Generator Owner and Transmission Owner with applicable Facilities shall coordinate the voltage regulating system controls, (including in-service1 limiters and protection functions) with the applicable equipment capabilities and settings of the applicable Protection System devices and functions.

1.1. Assuming the normal automatic voltage regulator control loop and steady-state system operating conditions, verify the following coordination items for each applicable Facility:

1.1.1. The in-service limiters are set to operate before the Protection System of the applicable Facility in order to avoid disconnecting the generator unnecessarily.

1.1.2. The applicable in-service Protection System devices are set to operate to isolate or de-energize equipment in order to limit the extent of damage when operating conditions exceed equipment capabilities or stability limits.

R2. Within 90 calendar days following the identification or implementation of systems, equipment or setting changes that will affect the coordination described in Requirement R1, each Generator Owner and Transmission Owner with applicable Facilities shall perform the coordination as described in Requirement R1. These possible systems, equipment or settings changes include, but are not limited to the following:

- Voltage regulating settings or equipment changes;
- Protection System settings or component changes;
- Generating or synchronous condenser equipment capability changes; or
- Generator or synchronous condenser step-up transformer changes.

The document provides examples showing coordination of voltage control systems, Protection Systems and equipment capabilities for the following types of resources:

- Traditional Synchronous Generation
- Type 1 & Type 2 Wind Turbine
- Inverter Based Resources:
  - Type 3 Doubly Fed Induction Generator (DFIG) or Doubly Fed Asynchronous Generator (DFAG) Wind Turbine

- Type 4 Full Conversion Wind Turbine
- Photovoltaic (Solar) System
- Battery Energy Storage Systems (BESS)

3 Engineering Background

This section provides in-depth discussion of protection systems and generator performance that are under the purview of PRC-019 standard. Key concepts and reasonable assumptions will be presented to establish a baseline level of knowledge for coordination. It also explains the theory behind various protection systems, control systems, and different types of generation resources. It is critical that an entity understand these concepts for protection and control system coordination.

3.1 Traditional Synchronous Generation Capability Curve

The capability curve characteristic for a synchronous generator is typically plotted on a 1.0 per unit terminal voltage basis. This standard does not specify a per unit voltage for evaluation of generator capability curves (GCC). Per IEEE C37.102, a capability curve based on 0.95 per unit voltage may be used for coordination since it is the minimum voltage the GCC is valid for. This voltage condition will provide a conservative scenario for coordination with the loss-of-field curve characteristic.

The GCC is developed from three distinct limitations of the machine: the rotor winding limit, the stator winding limit, and the stator end-iron limit. The rotor winding limit (RWL) defines the internal field current capability and is governed by the following equations:

$$center_{RWL} = -\left(\frac{V_{gen}^2}{X_{d\_G}}\right)$$

$$radius_{RWL} = V_{gen} \times \left(\frac{E_G}{X_{d\_G}}\right)$$

The stator winding limit (SWL) defines the current capability of the stator winding and is governed by the following equations:

$$center_{SWL} = 0$$

$$radius_{SWL} = MVV_{gen}$$

The stator end-iron limitation (SEIL) defines the magnitude of VARs the generator is capable of absorbing from the system. This limitation is highly dependent on the thermal capability of the stator end-core. Thus, this capability is typically defined by the OEM.

3.2 Control Systems

Excitation Systems that employ protection functions (i.e. V/Hz tripping, etc.) may be evaluated for coordination like protection systems. The excitation control system and relays associated with a generating unit tend to receive their reference voltage and currents from the same source, the terminals of a generator. These systems typically react in the same manner during abnormal system or generator conditions that may damage the unit. Generator control systems with protection functions programmed to trip using operating quantities aligned with PRC-019, should be evaluated for coordination just like Protection Systems. These functions typically react to abnormal system or generator conditions to prevent a generator from exceeding its limitation. Thus, these systems can adhere to the requirements outlined in the standard for protection functions. An entity may disable protection functions within a control system and only enable them within a relay to simplify coordination. They may provide documentation of control system programming as evidence that the functions are disabled.

3.3 Field Winding Overexcitation

Overexcitation occurs when the excitation system applies an excess amount of dc current to the field winding. The field winding has a thermal limit that is typically defined by an inverse-time curve characteristic. During an overexcitation condition, primary protection is provided through control functions (e.g. limiters), within the excitation system, to prevent encroaching on this thermal capability. Protection functions act as a backup protection system, if the control functions fail, to prevent the field winding from exceeding the thermal capability.

Per IEEE Std 421.5, there are several OEL types "but all operate through the same sequence of events: Detect the overexcitation condition, allow it to persist for a defined time-overload period, and then reduce the excitation to a safe level." The limiter may use field current, field voltage, exciter field current, or exciter field voltage as an operating quantity. This control function may operate based on an instantaneous or an inverse-time curve characteristic.

Overexcitation protection may be provided through a protection function in an excitation system and/or an external protection system (e.g. relay, etc.). These functions may use field current or field voltage as an operating quantity. Protective functions may operate based on an instantaneous or an inverse-time curve characteristic.

3.4 Stator Over Flux (Overexcitation)

The core flux of the stator winding is directly proportional to stator voltage and inversely proportional to the frequency/speed of the turbine. Overfluxing of the stator core may occur when an excitation system boosts the stator output voltage beyond the rated voltage or when the stator is at rated voltage with reduced turbine speed. These conditions can cause the stator flux to exceed the magnetic flux density capability of its core and saturate. This can lead to thermal damage due to flux spilling out and inducing eddy currents into components not designed to withstand these conditions. A V/Hz control function (e.g. limiter) provides primary protection to prevent the stator core from encroaching on its thermal capability. A protection function will provide backup protection in the event that the control function fails to prevent the stator core from encroaching upon its thermal capability.

There are different types of V/Hz limiters, but they all use the ratio of generator terminal voltage to generator frequency (rotor speed) as an operating quantity. This function operates similar to an OEL in that it will detect an excessive magnetic flux condition, allow it to persist for a defined time period, and then reduce the excitation current to bring the generator terminal voltage to an acceptable level (relative to the turbine frequency/speed). The limiter may use an instantaneous, definite-time, or inverse-time characteristic.

Protection for stator overflux may be provided via an excitation system protection function and/or an external protection system (e.g. relay, etc.). This function will typically use either volts per hertz or phase overvoltage as an operating quantity. The protective functions may utilize an instantaneous, definite-time, or inverse-time curve characteristic.

All equipment overexcitation (V/Hz) capabilities should be plotted on the same base voltage if coordination is verified on a single graph. It is recommended an entity use the generator voltage as the base for reference and transpose all other curves (GSU, UAT) to this base. The generator overexcitation capability is typically the most limiting curve and generator protection systems typically obtain their voltage input from the terminals of the generator. Hence, using the generator voltage as the base voltage will simplify the calculations. An entity may refer to IEEE C37.106: Guide for Abnormal Frequency Protection for Power Generating Plants for further information on stator overexcitation.

3.5 Field Winding Underexcitation (limiter etc.)

Underexcitation may occur when the field current is reduced too low or when the generator experiences a complete loss of field excitation. This condition may cause thermal damage to the generator and mechanical damage to the turbine. Excitation system control functions (e.g. Underexcitation Limiters) provide primary protection for an underexcitation condition. If the control function fails to prevent further excitation reduction, then a protection function will act as a backup protection system to prevent generator damage.

An excitation system control function will attempt to stop further reduction of field excitation in response to an excessive underexcitation condition. Per IEEE Std 421.5, an underexcitation limiter (UEL) may use a combination of generator voltage and current or active and reactive power as an operating quantity.

The conversion of the operating characteristic from the R-X to the P-Q plane requires an entity to consider a voltage magnitude. The UEL may vary its characteristic in the P-Q plane through the use of a voltage magnitude V, V^2, or not at all. If the UEL voltage dependency is V^2 then it will remain stationary in the R-X plane for coordination purposes with the loss of field (40) scheme. In this case, an entity may use 1.0 per unit to perform the conversion and verify coordination. If there is no voltage dependency or the voltage dependency is proportional to V, then an entity may use 0.95 per unit voltage to perform the conversion and verify coordination. The use of the lowest valid terminal voltage produces the closest boundary of the UEL, relative to the loss of field, in the R-X plane. If an entity does not know the voltage dependency of the UEL, using the lowest valid operating voltage, 0.95 per unit, is the most conservative approach for verifying coordination.

A loss of field scheme may provide protection for a complete loss of field excitation. This scheme may be located within the excitation system and/or an external protection system.

3.6 Loss of Field Protection Schemes

The negative offset Mho scheme (method #1[2]) is the most commonly used scheme in the industry for detecting a loss of field condition. This scheme may appear to lack coordination with the stator core end iron limitation section of the GCC; however, during an actual loss of field condition the electrical parameters of a machine are drastically different than nominal conditions. When a synchronous machine loses the field excitation, the internal generator voltage (rotor voltage) will begin to decay; causing the generator to eventually lose synchronism and operate as an induction machine and absorb VARs from the system to re-excite the rotor. The machine will establish a new power equilibrium and operate asynchronously. The generator may produce less than 40% average real power while absorbing greater than 50% reactive power from the system for excitation. The apparent power plot will consist of a smaller real power output with a larger negative reactive power component. Thus, the area of coordination with the generator capability curve will be smaller compared to normal operating conditions.

A loss of field event can cause stator winding overloads, rotor damage, torque pulsations (due to loss of synchronization with the power system), and stator end-core damage. The reactive power transient, following a loss of field event, is highly dependent on the machine load levels prior to the contingency. This is because the slip between the generator and the system is directly correlated with initial generator loading; while the apparent impedance measured by the protection system is inversely correlated with slip. If heavily loaded (large magnitude of mechanical input power), the slip will be high, and the machine will absorb VARs in excess of the machines nominal rating. This condition is categorized as a severe loss of field event and employing an instantaneous trip or minimal time delay is the industry standard. If a machine is producing a lower magnitude of real power (lightly loaded), a loss of field will result in a lower slip and cause the apparent impedance measured by the protection system to be larger. This scenario exposes this Mho element to stable power swings. Therefore, it is industry standard to use a time delay to avoid element misoperations while still providing adequate protection to the machine.

An entity may refer to IEEE C37.102: Guide for AC Generator Protection for further information on loss of field protection schemes.

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[2] See IEEE Std C37.102 Guide for AC Generator Protection

3.7 Protection Coordination Philosophy

Coordination of protective relays is an art that varies between individual organizations based on their inherent philosophies. There is one faction that prefers their protective function lie just beyond, on the ragged edge, of equipment capability to allow the unit to operate up to its full potential. There is another faction that prefers their protective relays trip just before a machine reaches its capability. Both approaches are reasonable for meeting the requirements of PRC-019; as long as the protection scheme is within reasonable margin from the machine's capability (i.e. measurement errors, etc.) or follows protection philosophies based on objective reasoning (i.e. loss of field methodologies, etc.) from IEEE C37.102.

3.8 Inverter Based Resource Generating Facility

A typical Inverter Based Resource (IBR) Generating Facility generation plant consists of multiple Inverter Based Resources (IBR) branching off medium voltage (MV) feeders (e.g. 34.5kV). These resources are connected to MV collection feeders using step up transformers. Each IBR typically has local control with a control function that regulates the output of that individual unit. The individual IBR will also have protection algorithms within the control system to ensure the resource does not exceed its capabilities. Each IBR Generating Facility may have limiters implemented at the point of interconnection (POI) through its plant level control system. In addition, the collector bus and GSU may have protection systems that correlate with the plant output capability. For this case, the limiters and protection systems must be coordinated all the way up to the POI to ensure reliable operation and comply with the requirements of PRC-019.

An entity should not use artificial capability limitations at the POI, such as TO/ISO contractual obligations, for PRC-019. An inverter's maximum output capability (MVA) should be used as a reference point for coordination purposes.

If an Inverter Based Resource (IBR) Generating Facility regulates voltage at the POI, via a plant controller, then the coordination should occur at the point of origin for voltage regulating control down to the individual IBR. This will consist of the in-service control functions (e.g. limiters, etc.) and protection functions of the plant controller at the POI down to the individual inverters. The in-service control functions mentioned include voltage, Q_{min}, Q_{max}, P_{max}, P_{min}, frequency, etc. The capability of the plant at an aggregate level may be considered within this coordination study. During Fault Ride-Through (FRT), the plant controller will transfer control to the individual inverters. Hence, it is important that an entity understand how the individual inverters will operate and coordinate.

Some entities may regulate voltage solely at the inverter level and have reactive compensating devices connected to the collector bus. Note 1 from PRC-019 clarifies the voltage regulating system controls and states the following:

> 1 Limiters or protection functions that are installed and activated on the generator or synchronous condenser.

These reactive compensating devices are not integrated into the inverter control system; they are in place to support the system voltage but have no direct effect on the output power of an individual inverter. Hence, these reactive compensating devices are excluded from the requirements of PRC-019 since they are external to the generator control system.

If the voltage is regulated through a plant controller with reactive compensating devices connected to the collector bus, then these devices are integrated into the control system of the plant. The reactive power output of the reactive compensating device is a voltage source behind the point of voltage regulation and inherent to the voltage control system. The terminals of the IBR generating facility will now have a voltage source and current sources contributing to grid level voltage support. The plant controller will use the system voltage, which is now a function of this reactive power input, to send reference commands to individual inverters within the collector system. Therefore, an entity must ensure that the reactive compensating device protection scheme coordinates with the capabilities of the plant.

If control functions and protection functions are performed within the same device, then they may have identical set-points. The reasoning behind this is that both functions will experience the same potential errors since they are within the same controller and are receiving the same source inputs. However, the protection function must have a time delay to allow the control function margin to operate. This time delay margin should be long enough to allow the control action to reduce the parameter (i.e. voltage, current, etc.) before tripping occurs. The manufacturer may be consulted for control time delays and good engineering judgment should be applied.

For the purposes of power system protection and control evaluations, inverter-based resources have three operational statuses: On-line, Offline (tripped), and Momentary Cessation. This third operational status, momentary cessation, deviates from the traditional norms for utility scale power generation. From the vantage point of power system reliability, tripping an inverter and turning off an inverter's output can have the same detrimental impacts to reliability. Fundamentally, tripping an inverter and turning off an inverter output are the same concept, particularly from the vantage point of power system reliability. Therefore, it is recommended for entities to treat momentary cessation and tripping an inverter as the same action for PRC-019. This recommendation is consistent with guidance provided in NERC ERO Enterprise CMEP Practice Guide: Information to be Considered by CMEP Staff Regarding Inverter-Based Resources[3].

An entity may remove (disable) the momentary cessation function from the inverter programming to comply with the requirements of the standard. For inverters that are not capable of removing the functionality, an entity may program their momentary cessation functionality to the lowest voltage magnitude (for undervoltage conditions) and the highest voltage magnitude (for overvoltage conditions) the inverter is capable of withstanding to ensure the coordination required in PRC-019.

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[3] Reference CMEP Practice Guide https://www.nerc.com/pa/comp/guidance/CMEPPracticeGuidesDL/CMEP%20Practice%20Guide%20Information%20to%20be%20Considered%20by%20CMEP%20Staff%20Regarding%20Inverter-Based%20Resources_V1.1.pdf

This will allow the resource to provide as much support as possible for system abnormalities and achieve coordination with equipment capability.

Inverter Based Resource forms of generation are evolving and have great potential for further advancements. With that, these sources experience periodic firmware upgrades, similar to firmware upgrades required for microprocessor relays. When a plant controller or IBR unit control system firmware is upgraded, an entity should verify that the coordination requirements in R1 are intact to determine if a coordination analysis is required per R2 of the standard.

Both the plant controller and the individual inverters have built-in control systems that can operate in different modes. The plant controller can operate in the following modes:

- **Voltage Control Mode:** The plant controller regulates the voltage at the POI to a voltage setpoint, by increasing or decreasing plant reactive power output.

- **Power Factor Control Mode:** The plant controller maintains power factor at the POI to a power factor setpoint, by increasing or decreasing plant reactive power output.

The IBR may receive a power limit, an active power reference, reactive power reference, power factor reference from the plant controller, or voltage reference that meets the objective as defined at POI level. Each inverter can operate in the following modes:

- **Voltage Control:** In this mode, the IBR regulates to a voltage setpoint, measured at its terminals, by increasing or decreasing reactive power output.

- **Reactive Power (Var) Control**: In this mode the resource receives a Var reference from the plant controller and provides the commanded Vars.

- **Power Factor Control:** In this mode the resource receives a power factor reference from the plant controller and provides power based on the commanded power factor.

In addition to the above operational control modes, during FRT mode the resources can be set to operate in reactive power priority (Q-priority) or in active power priority (P-priority). In the Q-priority mode, the resource prioritizes reactive power production over real power. It provides the Vars and uses the balance of the resource’s KVA capability and real power availability to provide real power (or limits real power if in the power factor mode). In the P-priority mode, the resource prioritizes active power over reactive power. It outputs the maximum amount of real power available and can provide the balance of KVA capability (if any) to satisfy the Var commanded from the plant controller.

3.9 Synchronous Condensers

A synchronous condenser is a synchronous machine that contains an excitation system but does not have a mechanical input power system (i.e. prime mover, boiler, etc.). This machine is typically used to boost system voltage via the output of Vars or lower system voltage via the absorption of Vars. The synchronous condenser cannot produce real power since it does not have a prime mover. To the contrary, the machine will absorb a small amount of real power from the system due to windage losses, transients, etc. This drastically reduces the operating region in a typical GCC. However, the synchronous condenser operates in the same manner as a traditional synchronous generator in terms of voltage regulation and the associated control systems. Therefore, a synchronous condenser may use an implementation methodology similar to a synchronous generator for the purposes of PRC-019.

To illustrate coordination, an entity may mimic a very small amount of real power absorption, creating lines that depict the characteristics of each system component. This provides a visual for both engineering implementation and compliance evidence. Some OEM's provide capability curves for synchronous condensers that are similar to synchronous generation capability curves (D-curves, etc.). Therefore, an entity may display the entire generator capability curve and associated coordination curves in the positive real power quadrant. This approach is essentially identical to the methodology of a synchronous generator. Either one of these methodologies are sufficient evidence for evaluation of compliance with the standard.

3.10 Blackstart Generators

Blackstart units are any generation resources an entity uses to bring a unit on-line or support plant station service during start-up. For the purposes of PRC-019, a blackstart generator is any unit that is material to and designated as part of a Transmission Operator's restoration plant. During normal generator operation, station service is typically fed from the generator terminal via auxiliary transformers. However, during a full plant outage, an external source (either the transmission grid or a smaller generator) is required to provide the auxiliary power necessary to bring a unit on-line. A black start unit may be either a synchronous source or a dispersed power producing resource, depending on the design of the plant[4]. The type of unit determines the methodology an entity may use to demonstrate compliance with PRC-019. An entity may refer to the sections of this guideline that align with the type of unit.

3.11 Steady-State Stability Limit (SSSL)

The classical SSSL methodology portrayed in PRC-019 assumes the generator is supplied with a fixed excitation (the internal voltage behind the generator impedance) based on the nameplate rating of the machine. This methodology represents the manual SSSL, or the expected machine reaction given the voltage regulator is in the manual operation mode. Calculating the dynamic SSSL, with the voltage regulator in automatic mode, requires determining the relationship between a specific power output and power transfer angle (δ). This angle is defined as the angle between the generator internal voltage and the system voltage. Determining this relationship requires nonlinear equations and is a complicated task. Furthermore, use of the manual SSSL is the most conservative condition for

[4] If it is designated as part of a Transmission Owner's restoration plant, per 4.2.4.

coordination purposes. Therefore, even though the standard specifically instructs an entity to assume the voltage regulator is in automatic mode, it also allows the use of the manual SSSL for coordination purposes.

Per “Protective Relaying for Power Generation Systems” (see references in PRC-019), excitation limiters are typically set to coordinate with the manual SSSL. This approach normally provides the most restrictive operational scenario for coordination since the dynamic SSSL (voltage regulator is in automatic mode) typically provides the operator with more margin to absorb reactive power. Therefore, the Under-Excitation Limiter (UEL) is typically responsible for preventing an entity from operating in a region defined by the manual SSSL; this is not the protection schemes responsibility.

The industry norm has been to set protection systems based on the characteristics of the machine. An entity typically uses a loss of field (40) protection scheme to prevent thermal damage associated with absorbing an excessive amount of reactive power. The setting philosophy for this scheme has been solely based on the internal impedance of the generator. By using the generator impedance setting philosophy, the loss of field impedance characteristic will end up plotting just outside the GCC. This is especially true when plotting a negative-offset dual mho scheme in the P-Q plane. This is because the apparent impedance swing from the relays perspective will vary depending on the pre-contingency system load and will exceed the leading Var boundary of the GCC. Hence, the characteristic plot of this protection system will coordinate with the generator capability for a complete loss of excitation (as long as acceptable time delays are applied) but may not coordinate with the manual SSSL. The coordination between the loss of field scheme and SSSL is ultimately up to the desire of the entity and may or may not be adjusted to include the SSSL.

Modifying the system impedance will alter the resultant manual SSSL curve characteristic of a synchronous generator. An entity may conservatively determine this limit by utilizing a weak system configuration in their analysis. A weak system may be established by increasing the transfer impedance of the generator; the larger the system impedance the weaker the system will be able to respond to reactive power transients. The removal of adjacent generation will also reduce the strength of the system. It is good industry practice to remove an adjacent generator and implement the most critical transmission contingency scenario to create a “weak system” condition. An entity may then use a power flow/short circuit software to create a Thevenin equivalent (boundary equivalent) at the high-voltage side of the generator step-up transformer. This equivalent impedance may be used as a portion of X_S to provide an accurate representation of a weak system in the SSSL calculation; the GSU impedance will provide the remaining portion of X_S.

Historically, steady state stability has been a topic centered on synchronous machines. The stability limit identified in requirement 1.1.2 is defined as an angular stability limit. IBR units do not fit the traditional derivation of steady state stability. Therefore, the methodology for establishing the manual SSSL does not apply to IBR units.

3.12 Equipment or Protection System Changes

For equipment or protection system changes that have an impact on coordination, the entity should perform the new coordination analysis before putting a generating unit back into service. For example, the replacement of an excitation system or generator relay requires an entity to ensure proper coordination with limiters and equipment capabilities before putting the machine back on-line. Without this verification, a generation unit can be tied back into the grid and become susceptible to damage, misoperations, and system stability issues.

4 Compliance Implementation and Evidence

This guidance document demonstrates example methodologies an entity may use to validate coordination between generator control and protection systems. The first example method demonstrates coordination for a synchronous generation unit. This method identifies protection and limiter characteristic curves for the voltage control system and the generator protection system. These plots include stator overexcitation (V/Hz), field winding overexcitation, and generator underexcitation. The second example method demonstrates coordination for a synchronous condenser. This methodology closely resembles the methodology outlined for a synchronous generator. The third example method demonstrates coordination from an IBR generating facility point of interconnection down to the IBR level.

5 Example Calculations

5.1 Synchronous Generation Example

Properly documented, the following calculations may be used to demonstrate compliance for this specific example. Different generator designs and protection schemes may require modifications to the calculations. An entity should not blindly copy the methodology outlined below; but should have an in-depth understanding of its holistic generation system before making specific coordination decisions. The one-line diagram for the synchronous generator example calculation is shown in Figure 1 and the system parameters are shown below in Table 1.

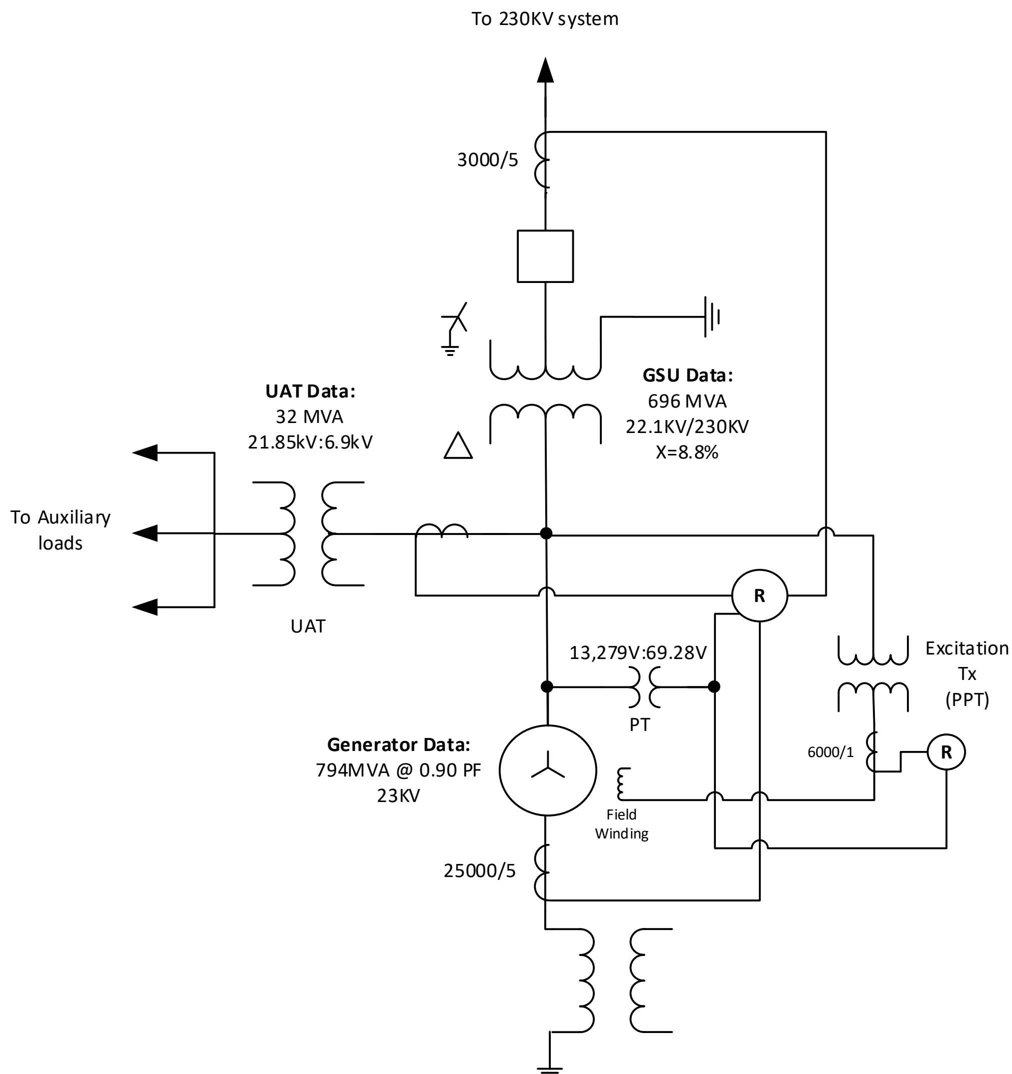

Figure 1: Synchronous Generator Sample System

Example Calculations	
Generator Input Descriptions	**Input Values**
Synchronous Generator nameplate (MVA @ rated pf):	$MVA_{GEN} = 794\ MVA$
	$PF_{GEN} = 0.90$
Generator rated voltage (Line-to-Line):	$V_{Gen} = 23\ kV$
Direct Axis Subtransient Reactance, per unit:	$X''_{d} = 18.4\%$
Direct Axis Unsaturated Transient Reactance, per unit:	$X'_{di} = 30\%$
Direct Axis Synchronous Reactance, per unit:	$X_{d} = 181\%$
Generator Base Impedance:	$Z_{G\_Base} = \frac{V_{gen}^2}{MVA_{GEN}} = 0.666\Omega$
Generator Current transformer (CT) ratio:	$CTR_{Gen} = \frac{25000}{5} = 5000$
Generator Potential transformer (PT) ratio:	$PTR_{Gen} = \frac{13279}{69.28} = 191.67$
Primary to Secondary Impedance Ratio:	$ZTR = \frac{CTR_{Gen}}{PTR_{Gen}} = 26.086$
Nominal relay (secondary) voltage:	$V_{Gen\_nom} = \frac{V_{Gen}}{PTR_{Gen}} = 120$
Nominal relay (secondary) current:	$I_{Gen\_nom} = \frac{MVA_{GEN}}{(\sqrt{3} \times V_{Gen} \times CTR_{Gen})}$
Generator Step-Up (GSU) Transformer Input Descriptions	**Input Values**
Generator step-up (GSU) transformer rating:	$MVA_{GSU} = 696\ MVA$
GSU transformer reactance (696 MVA base):	$X_{GSU\_TBASE} = 8.8\%$
GSU transformer MVA base:	$MVA_{GSU\_Base} = 696\ MVA$
GSU Transformer High-side Nameplate Voltage	$V_{GSU\_HS} = 230kV$
GSU Transformer Low-side Nameplate Voltage	$V_{GSU\_LS} = 22.1kV$
GSU transformer high-side no-load tap Voltage	$V_{GSU\_HS\_TAP} = 235kV$
GSU transformer turns ratio:	$GSU_{ratio} = \frac{V_{GSU\_HS}}{V_{GSU\_LS}}$
High-side nominal system voltage (Line-to-Line):	$V_{Sys\_nom} = 230\ kV$

Example Calculations	
GSU Current transformer (CT) ratio:	$CTR_{GSU} = \frac{3000}{5}$
Unit Auxiliary Transformer (UAT) Input Descriptions	**Input Values**
UAT nameplate MVA Base:	$MVA_{UAT\_Base} = 32\ MVA$
UAT high-side nameplate voltage:	$V_{UAT\_HS} = 21.85\ kV$
UAT low-side nameplate voltage:	$V_{UAT\_LS} = 6.9\ kV$
Bulk Electric System Descriptions	**Input Values**
System Base MVA:	$MVA_S = 100\ MVA$
System Base Voltage:	$V_S = 230\ kV$

Table 1

Analysis of System

5.1.1 Manual Steady State Stability Limit (SSSL):

To calculate the manual SSSL, an entity must determine the system impedance (transfer impedance) from the vantage point of the generator. In order to identify this impedance, define a configuration that will create a minimum generation/weak system condition. For this example, we removed the largest transmission line in the switchyard and the largest adjacent generator within the facility. The resultant equivalent impedance will represent a portion of the total system impedance to use in the SSSL calculations.

The system impedance at minimum generation/weak system (per short circuit program):

Eq. (1) $$Z_{Weak\_pu} = 0.00094 + j0.01086$$

Convert the weak system impedance to the transformer base:

Eq. (2) $$Z_{W\_TxBase\_pu} = \left(\frac{MVA_{GSU\_Base}}{MVA_S}\right) \times \left(\frac{V_S^2}{V_{GSU\_HS\_TAP}{}^2}\right) \times Z_{Weak\_pu}$$

$$Z_{W\_TxBase\_pu} = \left(\frac{696MVA}{100MVA}\right) \times \left(\frac{230kV^2}{235kV^2}\right) \times (0.00094 + j0.01086)$$

$$Z_{W\_TxBase\_pu} = 0.006 + j0.072$$

Convert the transformer base weak system impedance to the generator base:

Eq. (3) $$Z_{W\_Gbase\_pu} = \left(\frac{MVA_{Gen}}{MVA_{GSU\_Base}}\right) \times \left(\frac{V_{GSU\_LS}^2}{V_{Gen}^2}\right) \times Z_{W\_TxBase\_pu}$$

$$Z_{W\_Gbase\_pu} = \left(\frac{794MVA}{696MVA}\right) \times \left(\frac{22.1kV^2}{23kV^2}\right) \times (0.006 + j0.072)$$

$$Z_{W\_Gbase\_pu} = 0.007 + j0.076$$

Eq. (4) $$Z_W = Z_{W\_pu} \times Z_{G\_Base}$$

$$Z_W = (0.007 + j0.076) \times 0.666\Omega$$

$$Z_W = (0.004+j0.051)\ \Omega$$

The total system impedance will consist of the equivalent minimum generation/weak system impedance and the transformer impedance. The transformer impedance may be defined on the transformer nameplate or OEM test reports.

Convert the GSU transformer impedance to the generator base:

Eq. (5) $$X_{GSU\_Gbase\_pu} = \left(\frac{MVA_{Gen}}{MVA_{GSU\_Base}}\right) \times \left(\frac{V_{GSU\_LS}^2}{V_{Gen}^2}\right) \times X_{GSU\_TBASE}$$

$$X_{GSU\_Gbase\_pu} = \left(\frac{794MVA}{696MVA}\right) \times \left(\frac{22.1kV^2}{23kV^2}\right) \times (j0.088)$$

$$X_{GSU\_Gbase\_pu} = j0.093$$

Eq. (6) $$X_{GSU\_Gbase} = X_{GSU\_Gbase\_pu} \times Z_{G\_Base}$$

$$X_{GSU\_Gbase} = j0.093 \times 0.666\Omega$$

$$X_{GSU\_Gbase} = j0.062\Omega$$

Total System Impedance for Weak System Conditions (Per IEEE C37.102):

Eq. (7) $$Z_{S\_pu} = X_{GSU\_GBase\_pu} + Z_{W\_Gbase\_pu}$$

$$Z_{S\_pu} = j0.093 + (0.007 + j0.076)$$

$$Z_{S\_pu} = 0.007 + j0.169$$

Eq. (8) $$Z_S = Z_{S\_pu} \times Z_{G\_Base}$$

$$Z_S = (0.007 + j0.169) \times 0.666\Omega$$

$$Z_S = (0.004 + j0.113)\ \Omega$$

Eq. (9) $$X_S = Im(Z_S)$$

$$X_S = j0.113\Omega$$

Convert Total System Impedance for Weak System Conditions to secondary (relay) ohms:

Eq. (10) $$Z_{S\_sec} = Z_S \times \frac{CTR_{Gen}}{PTR_{Gen}}$$

$$Z_{S\_sec} = (0.004 + j0.113)\ \Omega \times \frac{5000}{191.67}$$

$$Z_{S\_sec} = (0.115 + j2.936)\ \Omega$$

Eq. (11) $X_{S\_sec} = Im(Z_{S\_sec})$

$$X_{S\_sec} = j2.936\Omega$$

Convert the generator steady state (Synchronous) Impedance to secondary ohms:

Eq. (12) $X_{d\_G} = X_d \times Z_{G\_Base}$

$$X_{d\_G} = j1.81 \times 0.666\Omega$$

$$X_{d\_G} = j1.206\,\Omega$$

Eq. (13) $X_{d\_G\_sec} = X_{d\_G} \times \frac{CTR_{Gen}}{PTR_{Gen}}$

$$X_{d\_G\_sec} = j1.206 \times \frac{5000}{191.67}$$

$$X_{d\_G\_sec} = j31.458\,\Omega$$

Steady State Stability Limit (SSSL) Characteristic Plot in R-X Plane:

The Center Offset in the R-X plane is defined by:

Eq. (14)[5] $c_{RX} = -\left(\frac{1}{2}\right) \times \left|X_{d\_G\_sec} - X_{S\_sec}\right|$

$$c_{RX} = -\left(\frac{1}{2}\right) \times |j31.458\,\Omega - j2.936\Omega|$$

$$c_{RX} = -14.261\,\Omega$$

[5] See IEEE Std C37.102 Guide for AC Generator Protection

The radius in the R-X plane is defined by:

Eq. (15) $$r_{RX} = \left(\frac{1}{2}\right) \times \left|X_{d\_G\_sec} + X_{S\_sec}\right|$$

$$r_{RX} = \left(\frac{1}{2}\right) \times |j31.458\,\Omega + j2.936\Omega|$$

$$r_{RX} = 17.197\,\Omega$$

Use the following equations to create the characteristic curve of the SSSL in the R-X plane:

Eq. (16) $$R_{SSSL} = r_{RX}\cos\theta$$

Eq. (17) $$X_{SSSL} = r_{RX}\sin\theta + c_{RX}$$

Steady State Stability Limit (SSSL) Characteristic Plot in P-Q Plane:

Using a 0.95 per unit voltage magnitude will define the most limiting SSSL curve for coordination purposes.

The Center Offset in the P-Q plane is defined by:

Eq. (18)[6] $$c_{PQ} = -\left(\frac{1}{2}\right) \times (0.95V_{Gen})^2 \times \left(\frac{1}{\left|X_{d\_G}\right|} - \frac{1}{|X_S|}\right)$$

$$c_{PQ} = -\left(\frac{1}{2}\right) \times (0.95 \times 23kV)^2 \times \left(\frac{1}{|j1.206\Omega|} - \frac{1}{|j0.113\Omega|}\right)$$

$$c_{PQ} == \ 1922.772\,MVAR$$

The Radius in the P-Q plane is defined by:

[6] See IEEE Std C37.102 Guide for AC Generator Protection

Eq. (19)[6] $r_{PQ} = \left(\frac{1}{2}\right) \times (0.95V_{Gen})^2 \times \left(\frac{1}{|X_{d\_G}|} + \frac{1}{|X_S|}\right)$

$$r_{PQ} = \left(\frac{1}{2}\right) \times (0.95 \times 23kV)^2 \times \left(\frac{1}{|j1.206\Omega|} + \frac{1}{|j0.113\Omega|}\right)$$

$$r_{PQ} = 2318.675\ MVA$$

Use the following equations to create the characteristic curve of the SSSL in the P-Q plane:

Eq. (20) $P_{SSSL} = r_{PQ} \cos\theta$

Eq. (21) $Q_{SSSL} = r_{PQ} \sin\theta + c_{PQ}$

Table 2 contains the plot points on the R-X and P-Q planes for the manual steady state stability limit.

Table 2

θ	R_{SSSL} (Ω)	X_{SSSL} (Ω)	P_{SSSL_min} (MW)	Q_{SSSL_min} (MVAR)
90°	0	2.9	0	4241.4
80°	2.986	2.7	402.634	4206.2
70°	5.882	1.9	793.034	4101.6
60°	8.598	0.6	1159.337	3930.8
50°	11.054	-1.1	1490.415	3699.0
40°	13.174	-3.2	1776.208	3413.2
30°	14.893	-5.7	2008.031	3082.1
20°	16.16	-8.4	2178.842	2715.8
10°	16.936	-11.3	2283.449	2325.4
0°	17.197	-14.3	2318.675	1922.8
-10°	16.936	-17.2	2283.449	1520.1
-20°	16.16	-20.1	2178.842	1129.7
-30°	14.893	-22.9	2008.031	763.4
-40°	13.174	-25.3	1776.208	432.4
-50°	11.054	-27.4	1490.415	146.6
-60°	8.598	-29.2	1159.337	-85.3
-70°	5.882	-30.4	793.034	-256.1
-80°	2.986	-31.2	402.634	-360.7
-90°	0	-31.5	0	-395.9

Analysis of Generator Capability

The Generator Capability Curve (GCC) is typically provided by the manufacturer. The GCC may be represented in either the P-Q plane or the R-X plane or both.

5.1.2 Generator Capability Curve:

The Generator Capability Curve (GCC) may be obtained from the generator manufacturer. The plot is typically provided on a P-Q axis. An entity can use the equation below to convert this curve to the R-X plane.

Convert P-Q to nominal R-X:

Eq. (22) $$Z_{pf\_Nom\_Mag} = \left(\frac{V_S^2}{MVA_{pf}}\right) \times \left(\frac{CTR_{Gen}}{PTR_{Gen}}\right)$$

Eq. (23) $$Z_{pf\_Nom} = Z_{pf\_Nom\_Mag} \times \cos(\Theta_{pf}) + j[Z_{pf\_Nom\_Mag} \times \sin(\Theta_{pf})]$$

The Generator Capability Curve is typically not valid (not accurate) for voltage levels below 0.95 per unit. Therefore, a minimum GCC curve can be established as the worst-case condition for coordination purposes.

Convert P-Q to minimum R-X:

Eq. (24) $$Z_{pf\_Min\_Mag} = \left(\frac{(0.95V_S)^2}{MVA_{pf}}\right) \times \left(\frac{CTR_{Gen}}{PTR_{Gen}}\right)$$

Eq. (25) $$Z_{pf\_Min} = Z_{pf\_Min\_Mag} \times \cos(\Theta_{pf}) + j[Z_{pf\_Min\_Mag} \times \sin(\Theta_{pf})]$$

Table 3 contains the plot points on the P-Q and R-X planes for the generator capability curve. These points will be used to display generator underexcitation coordination. Therefore, only the underexcited (leading power factor) portion of the GCC will be shown.

Table 3

P_{Gen} (MW)	Q_{Gen} (MVAR)	R_{Nom} (Ω)	X_{Nom} (Ω)	R_{Min} (Ω)	X_{Min} (Ω)
786.06	-95.28	17.301408	-2.09714	15.614520	-1.892669
778.12	-150.86	17.092272	-3.313808	15.425776	-2.990712
754.3	-246.14	16.534196	-5.395369	14.922112	-4.869321
698.72	-381.12	15.221382	-8.302572	13.737297	-7.493071
698.72	-381.12	15.221382	-8.302572	13.737297	-7.493071
635.2	-385.09	15.886247	-9.631037	14.337338	-8.692011
595.5	-389.06	16.241014	-10.6108	14.657515	-9.576243
555.8	-391.442	16.596483	-11.68867	14.978326	-10.54902
516.1	-393.03	16.92376	-12.88809	15.273693	-11.63150
476.4	-396.206	17.123174	-14.24077	15.453665	-12.85230
436.7	-400.97	17.145469	-15.74266	15.473786	-14.20775
397	-404.94	17.035925	-17.37664	15.374922	-15.68242
357.3	-406.528	16.83229	-19.15141	15.191142	-17.28414
317.6	-410.498	16.270066	-21.02906	14.683734	-18.97873
277.9	-412.88	15.482356	-23.00236	13.972826	-20.75963
238.2	-416.85	14.260554	-24.95597	12.870150	-22.52276
198.5	-420.82	12.65292	-26.82419	11.419260	-24.20883
158.8	-422.408	10.760842	-28.62384	9.711659	-25.83301
119.1	-425.584	8.4152396	-30.07046	7.594754	-27.13859

79.4	-428.76	5.7626162	-31.11813	5.200761	-28.08411
47.64	-432.73	3.4687834	-31.50812	3.130577	-28.43607
43.67	-428.76	3.2444727	-31.85482	2.928137	-28.74898
35.73	-412.88	2.8708902	-33.17473	2.590978	-29.94020
31.76	-408.91	2.6054606	-33.5453	2.351428	-30.27464
23.82	-400.97	2.0373215	-34.29491	1.838683	-30.95116
19.85	-399.382	1.7131034	-34.46764	1.546076	-31.10704
15.88	-397	1.3881829	-34.70457	1.252835	-31.32088
7.94	-394.618	0.7033354	-34.95577	0.634760	-31.54758
0	-393.824	2.146E-15	-35.04042	0.000000	-31.62398

5.1.3 Generator Over Flux Capability Curve:

This curve represents the amount of V/Hz the stator winding can withstand; any level above this curve leaves the generator susceptible to damage via flux overspill onto non-laminated portions of the stator. The overexcitation capability curve for the generator may be represented in per-unit quantities from the base voltage at the generator terminal. This curve may be obtained from the generator OEM.

Table 4 contains the plot points for the generator over flux capability curve.

Table 4

Gen_24 (pu)	Gen_24$_t$ (sec.)
1.06	10000
1.06	3775
1.07	767
1.08	265
1.09	143
1.10	89
1.12	45

1.14	26
1.16	18.1
1.18	13
1.20	10
1.22	7.94
1.24	6.42
1.26	5.52
1.28	4.75
1.29	4.35
1.30	4.12

5.1.4 Generator Step-Up (GSU) Transformer Over Flux Capability Curve:

The overexcitation capability curve for the GSU may be obtained from the transformer OEM or test reports. This curve represents the V/Hz magnitudes the transformer core may be exposed to. If the GSU low voltage winding has a different base voltage than the generator terminal, then the curve should be converted to the generator base.

Eq. (26) $$GSU\_24_{Gen\_base} = GSU\_24_{GSU\_base} \times \left(\frac{V_{GSU\_LS}}{V_{Gen}}\right)$$

Table 5 contains the plot points for the GSU overexcitation capability curve on the generator base.

Table 5

$GSU\_24_{GSU\_base}$ (pu)	$GSU\_24_{Gen\_base}$ (pu)	GSU_24_{t} (sec.)
1.25	1.201	60000
1.27	1.22	6000
1.30	1.249	300
1.32	1.268	60
1.56	1.499	6
1.65	1.585	0.6

5.1.5 Unit Auxiliary Transformer (UAT) Over Flux Capability Curve:

The overexcitation capability curve for the UAT may be obtained from the transformer OEM or test reports. This curve represents the V/Hz magnitudes the transformer core may be exposed to. If the UAT high-voltage winding has a different base voltage than the generator terminal, then the curve should be converted to the generator base.

Eq. (27) $$UAT\_24_{Gen\_base} = UAT\_24_{UAT\_base} \times \left(\frac{V_{UAT\_HS}}{V_{Gen}}\right)$$

Table 6 contains the plot points for the UAT overexcitation capability curve on the generator base.

Table 6

$UAT\_24_{UAT\_base}$ (pu)	$UAT\_24_{Gen\_base}$ (pu)	UAT_24_t (sec.)
1.125	1.069	1500
1.15	1.092	390
1.20	1.14	66
1.25	1.188	27
1.30	1.235	17.40
1.35	1.282	12.60
1.40	1.33	9.6

5.1.6 Generator Field Winding Overexcitation Capability Curve:

The field winding capability represents the thermal overload rating (I^2t) of the field winding. This curve defines the magnitude of current the excitation system may inject into the field winding. Per IEEE C50.13 "Standard for Cylindrical-Rotor Synchronous Generators", the permissible rotor currents for overexcitation are derived from the following equation:

Eq. (28) $$T_{Field} = \frac{33.75}{(I_{Field})^2 - 1}$$

Table 7 contains the plot points for the field winding thermal capability curve.

Table 7

I_{Field} (pu)	T_{Field} (sec)
1.13	121.885
1.25	60
1.46	29.825
2.09	10.02

Analysis of Generator Voltage Control System

The excitation system limiter and/or trip element set points may be obtained from the excitation system OEM documentation. An entity may request these values in MW/MVAR units and R/X impedance units.

5.1.7 Excitation System Underexcitation Limiter (UEL):

The UEL should prevent the excitation control system from reducing the internal generator voltage beyond a level that would exceed the generators VAR absorption capability and the manual SSSL. The excitation system UEL may be obtained from the excitation system OEM or from field service/test reports. The UEL will coordinate with the protective functions within the excitation system and the Loss of Field relay element. It will also coordinate with the stator core-end capabilities. Therefore, the protection engineer and the excitation system engineer/technician must coordinate their set-points and schemes before the unit can be put in-service and serve grid load. The following example includes both P-Q and R-X values. For a given voltage control system, use the manufacturer provided information (either P-Q, R-X, or both).

Table 8 contains the plot points for the excitation system UEL in the P-Q and R-X plane.

Table 8

P_{AVR_UEL} (MW)	Q_{AVR_UEL} (MVAR)	R_{AVR_UEL} (Ω)	X_{AVR_UEL} (Ω)
0	-285		
20	-285	3.37	-48.19
103	-282	15.7	-43.14
230	-274	24.81	-29.57
316	-265	25.61	-21.49
406	-234	25.51	-14.73
529	-193	23.02	-8.28
684	-145	19.31	-4.1
762	-107	17.75	-2.49

5.1.8 Excitation System Field Winding Overexcitation Limiter (OEL):

The OEL should prevent the excitation system from exceeding field current beyond a magnitude that would exceed the field current thermal capability. The excitation system OEL may be obtained from the excitation system OEM or from field service/test reports. The OEL will coordinate with the protective functions within the excitation system and the relay protection scheme (50, 51, 49, etc.). It will also coordinate with the Generator Field Winding Capability curve. Therefore, the protection engineer and the excitation system engineer/technician must coordinate their set-points and schemes before the unit can be put in-service and serve grid load.

For this example, an inverse-time OEL was implemented using field current as an operating quantity.

Table 9 contains the plot points for the excitation system OEL.

Table 9

I_{41_OEL} (pu)	$T\_I_{41\_OEL}$ (sec.)
1.0573	633.0
1.0676	315.0
1.0777	208.0
1.0850	140
1.1147	50.0
1.2477	24.0
1.3450	16.0
1.4447	13.0
1.5454	11.0
1.6958	9.0
1.7936	8
1.8941	7.0
1.9899	6.0
200.0	4.0
200.0	0.0

5.1.9 Excitation System Field Winding Overexcitation Protection (OEP):

The purpose of an OEP scheme is to initiate a generator trip, through the excitation system, for a condition in which the excitation system OEL fails to stop an increase in field current beyond its characteristic curve. The protection functions within an excitation system operate like a relay; therefore, one must treat it as a protection system for coordination purposes. The excitation system time overcurrent element will be set to coordinate with the thermal capability curve of the field winding, per IEEE C50.13 or OEM ratings. This scheme should also coordinate with the excitation system OEL by allowing the OEL the opportunity to initiate action first. This thermal limit may be verified with the OEM to ensure an accurate curve is plotted.

This example used an inverse-time protective function with the nominal field current as an operating quantity. The nominal field current is based on the power potential transformer (PPT) and the load current the excitation system draws. This value may be acquired from the excitation system OEM or field service/test reports.

Nominal field current (I_{41_Nom}):

Eq. (29) $I_{41\_Nom} = 0.864$

Time Overcurrent Pickup:

Eq. (30) $OEP\_P = 0.92\ A$

$$OEP\_P_{pu} = \frac{OEP\_P}{I_{41\_Nom}}$$

$$OEP\_P_{pu} = \frac{0.92}{0.864}$$

$$OEP\_P_{pu} = 1.065$$

Time Overcurrent Time Dial:

$$OEP\_TD = 2.3$$

Time Overcurrent Curve:

$$OEP_{Curve} = Moderately\ Inverse$$

Table 10 contains the plot points for the excitation system OEP.

Table 10

I_{41_OEP} (pu)	$T\_I_{41\_OEP}$ (sec)
1.109	145.9
1.11	142.7
1.112	136.8
1.123	111.5
1.130	99.9
1.135	93
1.158	70.8
1.216	44.8
1.274	33.2
1.332	26.7
1.39	22.4
1.505	17.3
1.621	14.3

1.737	12.3
1.969	9.8
2.316	7.8
2.895	6.1

5.1.10 Excitation System Stator Volts per Hertz Limiter:

The purpose of this limiter is to prevent the excitation system from producing high magnitudes of terminal voltage when the prime mover is not operating at appropriate speeds. The intent is to prevent exposing the generator stator core and connected transformers from excessive magnetic flux. The excitation system V/Hz limiter will coordinate with the protective functions within the excitation system, and the relay protection scheme (24,59P). The limiter will also coordinate with the generator overexcitation capability curve. The set-point and curve characteristic may be obtained from the excitation system OEM or field service/test reports. This curve is on the generator base voltage since its voltage source comes from PT’s at the terminal of the generator.

For this example, an inverse-time limiter function was implemented utilizing a V/Hz operating quantity.

Table 11 contains the plot points for the Excitation System Stator Overexcitation Limiter.

Table 11

AVR_{24_Lim} (pu)	$T\_AVR_{24\_Lim}$ (sec.)
1.30	0.70
1.25	1.0
1.20	1.50
1.15	2.20
1.12	3.40
1.10	4.20
1.09	5.20
1.08	7.10
1.07	9.80
1.06	16.90
1.0537	62.0

Analysis of Protection Schemes

Protection schemes may be located within a protection system or the generator control system.

5.1.11 V/Hz Overexcitation Protection Scheme:

The generator V/Hz scheme should initiate a generator trip for a condition in which the excitation system V/Hz limiter fails to stop an increase in stator voltage, relative to frequency, beyond its characteristic curve. The V/Hz scheme will coordinate with the generator stator overexcitation capability curve. The scheme will also coordinate with the excitation system V/Hz limiter by allowing the limiter the opportunity to initiate action first. The V/Hz schemes associated with the excitation transformer or the GSU should align with the generator V/Hz scheme for the design provided in the example.

The Level 1 element will be used as a definite time element to initiate an alarm and identify an overexcitation condition. This will give the generator operator the opportunity to manually correct the abnormal overexcitation conditions.

Definite Time Level 1 Element:

$$24D1P = 105\ \%$$

$$24D1D = 60\ cycles$$

The Level 2 element will be used as a definite time element to initiate a generate trip during high levels of V/Hz to prevent overexcitation damage. This set-point and time delay will coordinate with the overexcitation capabilities of the generator to prevent damage. This element will also allow enough margin for the excitation control system to correct the abnormal operating conditions before the relay initiates a trip.

Definite Time Level 2 Element:

$$24D2P2 = 128\ \%$$

$$24D2D = 66\ cycles = 1.10\ sec.$$

The inverse time element will be used to initiate a generator trip for low to moderate overexcitation conditions. This curve characteristic will coordinate with the overexcitation capability of the generator to prevent damage. It will also allow enough margin for the excitation control system to correct the abnormal operating condition before the relay initiates a trip.

Inverse Time Pickup:

$$24IP = 106\,\%$$

Inverse Time Dial:

$$24ITD = 1.5$$

Inverse Time Curve:

$$24IT\_Curve = 1.0$$

Volts/Hz (24) Inverse Time Element Curve Characteristics:

Eq. (31) $$T_{24\_IT} = \frac{(0.003 * 24ITD)}{\left(V_{24\_IT} - 1\right)^2} minutes$$

Table 12 contains the calculations of the time delays for the inverse time curve characteristic.

Table 12

V_{24IT} (pu)	M_{24IT}	T_{24IT} (sec)
1.06	1	75
1.07	1.009	55.1
1.08	1.019	42.2
1.09	1.028	33.3
1.10	1.038	27
1.11	1.047	22.3
1.12	1.057	18.7
1.15	1.085	12
1.18	1.113	8.3
1.20	1.132	6.8
1.25	1.179	4.3
1.28	1.208	3.4

Table 13 contains the calculations of the time delays for the definite time element plot.

Table 13

V_{24DT} (pu)	T_{24IT} (sec)
$24D2P2$	1.10
$24D2P2$	3.4

5.1.12 Field Winding Overcurrent (50/51) Overload Protection Scheme:

The winding overcurrent scheme should initiate a generator trip for a condition in which the excitation system OEL fails to stop an increase in field current beyond its characteristic curve. The overcurrent element monitoring the excitation current will coordinate with the thermal capability of the field winding, per IEEE C50.13 or OEM ratings. The scheme will also coordinate with the excitation system OEL by allowing the limiter the opportunity to initiate action first.

Nominal field current (I_{41_Nom}):

$$I_{41\_Nom} = 0.864$$

Time Overcurrent Pickup:

Eq. (32) $$51P = 0.92\ A$$

$$51P_{pu} = \frac{51P}{I_{41\_Nom}}$$

$$51P_{pu} = 1.065$$

Time Overcurrent Time Dial:

$$51TD = 12.3$$

Time Overcurrent Curve:

$$51P_{Curve} = U1$$

Time Overcurrent Curve Characteristics:

Eq. (33) $$T_{51} = 51TD \times \left[0.0226 + \frac{0.0104}{\left({M_{51}}^{0.02} - 1\right)}\right]$$

Table 14 contains the calculations of the curve characteristic for the time overcurrent element.

Table 14

I_{51} (pu)	M_{51}	T_{51} (sec)
1.109	1.041	157.5
1.11	1.042	154.1
1.112	1.044	147.7
1.123	1.055	120.4
1.130	1.061	107.9
1.135	1.066	100.4
1.158	1.088	76.5
1.216	1.142	48.4
1.274	1.196	35.9
1.332	1.251	28.8
1.39	1.305	24.2
1.505	1.413	18.7
1.621	1.522	15.4
1.737	1.631	13.3
1.969	1.849	10.6
2.316	2.175	8.4
2.895	2.719	6.6

5.1.13 Generator Loss of Field (40) Protection Scheme:

This example will use IEEE C37.102 method 1 for the loss of field (LOF) protection scheme. The level 1 element will detect loss of field conditions during heavier load conditions. This element may be plotted in either the P-Q plane or the R-X plane or both. This element does not have to coordinate with the curves identified within PRC-019 because it protects against severe slip frequency (pole slippage), in which the apparent impedance/power swing loci will overshoot the capability curve of the generator and has a very short time delay.

Zone 1 Diameter:

Eq. (34) $Z_{G\_base\_sec} = Z_{G\_Base} \times ZTR$

$$Z_{G\_base\_sec} = 0.666\Omega \times 26.086$$

$$Z_{G\_base\_sec} = 17.38$$

Eq. (35) $40Z1P = \frac{V_{Gen\_nom}}{\left(I_{Gen\_nom} \times \sqrt{3}\right)} j$

$$40Z1P = \frac{119.997}{\left(3.986 \times \sqrt{3}\right)} j$$

$$40Z1P = 17.38\ \Omega$$

Zone 1 Offset:

Eq. (36) $X'_{d\_act} = X'_{di} \times Z_{G\_Base}$

$$X'_{d\_act} = j0.3 \times 0.666\Omega$$

$$X'_{d\_act} = j0.2\ \Omega$$

Eq. (37) $X'_{d\_sec} = X'_{d\_act} \times ZTR$

$$X'_{d\_sec} = j0.2\Omega \times 26.086$$

$$X'_{d\_sec} = j5.214\ \Omega$$

Eq. (38) $40XD1 = -\frac{X'_{d\_sec}}{2}$

$$40XD1 = -\frac{j5.214\Omega}{2}$$

$$40XD1 = -j2.607\ \Omega$$

Loss of Field Zone 1 (40) Plot in R-X Plane:

The Zone 1 Mho element center offset is equal to the radius of the element plus the offset of the element from the origin.

Center Offset:

Eq. (39) $$c_{40\_1\_RX} = -\left|-\left(\frac{40Z1P}{2}\right) + 40XD1\right|$$

$$c_{40\_1\_RX} = -\left|-\left(\frac{j17.38\Omega}{2}\right) + -j2.607\Omega\right|$$

$$c_{40\_1\_RX} = -11.297\ \Omega$$

Center Radius:

Eq. (40) $$r_{40\_1\_RX} = \frac{|40Z1P|}{2}$$

$$r_{40\_1\_RX} = \frac{|j17.38\Omega|}{2}$$

$$r_{40\_1\_RX} = 8.69\ \Omega$$

An entity can use the equation below to plot this curve to the R-X plane.

Eq. (41) $$R_{40\_1} = r_{40\_1\_RX} \times \cos(\theta)$$

Eq. (42) $X_{40\_1} = r_{40\_1\_RX} \times \sin(\theta) + c_{40\_1\_RX}$

Loss of Field Zone 1 (40) Translation to P-Q Plane:

Zone 1 Offset (primary Ohms):

Eq. (43) $$40XD1_{pri} = \frac{40XD1}{ZTR}$$

$$40XD1_{pri} = \frac{-j2.607\Omega}{26.086}$$

$$40XD1_{pri} = -j0.1\ \Omega$$

Maximum Mho reactance distance from origin:

Eq. (44) $$40MAX_{X\_sec} = -(|40XD1| + |40Z1P|)$$

$$40MAX_{X\_sec} = -(|-j2.607\Omega| + |j17.38\Omega|)$$

$$40MAX_{X\_sec} = -19.987\ \Omega$$

Eq. (45) $$40MAX_X = \frac{-19.987\Omega}{ZTR}$$

$$40MAX_X = \frac{40MAX_{X\_sec}}{26.086}$$

$$40MAX_X = -0.766\ \Omega$$

MVA of Offset Setting:

Eq. (46) $$MVA_{40XD1} = \frac{\left(V_{Gen}{}^{2}\right)}{40XD1_{pri}}$$

$$MVA_{40XD1} = \frac{(23kV^{2})}{-j0.1\Omega}$$

$$MVA_{40XD1} = j5293.333\ MVA$$

MVA of Maximum Reactance Distance from Origin:

Eq. (47) $$MVA_{40Max} = \frac{\left(V_{Gen}{}^{2}\right)}{40MAX_{X}}$$

$$MVA_{40Max} = \frac{(23kV^{2})}{-0.766\Omega}$$

$$MVA_{40Max} = -690.435\ MVA$$

In the P-Q plane the offset of the Mho circle will be represented by the MVA of the maximum Mho reactance from the origin, since this will produce a small MVA magnitude. The maximum distance of the Mho circle on the reactance axis, from the origin, will be equivalent to the MVA magnitude from the impedance offset setting.

Therefore, the diameter of the Mho Circle in the P-Q plane will equal:

Eq. (48) $$40Z1_{PQ} = |MVA_{40XD1}| - |MVA_{40Max}|$$

$$40Z1_{PQ} = |j5293.333MVA| - |-690.435\ MVA|$$

$$40Z1_{PQ} = 4602.899\ MVA$$

The radius of the Mho Circle in the P-Q plane will equal:

Eq. (49) $r_{40\_1\_PQ} = -\frac{40Z1_{PQ}}{2}$

$$r_{40\_1\_PQ} = -\frac{4602.899\ MVA}{2}$$

$$r_{40\_1\_PQ} = 2301.499\ MVA$$

The center offset of the Mho Circle in the P-Q plane will equal:

Eq. (50) $c_{40\_1\_PQ} = MVA_{40Max} - r_{40\_1\_PQ}$

$$c_{40\_1\_PQ} = -690.435\ MVA - 2301.499\ MVA$$

$$c_{40\_1\_PQ} = -2991.884\ MVAR$$

Use the following equations to create the characteristic curve for the loss of field element (40) in the P-Q plane:

Eq. (51) $P_{40\_1} = r_{40\_1\_PQ} \times \cos(\theta)$

Eq. (52) $Q_{40\_1} = r_{40\_1\_PQ} \times \sin(\theta) + c_{40\_1\_PQ}$

Table 15 contains the plot points on the R-X and P-Q planes for the Loss of Field #1 element.

Table 15

θ	R_{40_1} (Ω)	X_{40_1} (Ω)	P_{40_1} (MW)	Q_{40_1} (MVAR)
90°	0	-2.6	0	-690.4
80°	1.509	-2.7	399.642	-725.4
70°	2.972	-3.1	787.142	-829.2
60°	4.345	-3.8	1150.725	-998.8
50°	5.586	-4.6	1479.343	-1228.9
40°	6.657	-5.7	1763.012	-1512.5

30°	7.526	-7.0	1993.114	-1841.2
20°	8.166	-8.3	2162.655	-2204.7
10°	8.558	-9.8	2266.485	-2692.2
0°	8.69	-11.3	2301.499	-2991.9
-10°	8.558	-12.8	2266.485	-3391.5
-20°	8.166	-14.3	2162.655	-3779
-30°	7.526	-15.6	1993.114	-4142.6
-40°	6.657	-16.9	1763.012	-4471.2
-50°	5.586	-18.0	1479.343	-4754.9
-60°	4.345	-18.8	1150.725	-4985
-70°	2.972	-19.5	787.142	-5154.5
-80°	1.509	-19.9	399.642	-5258.4
-90°	0	-20	0	-5293.3
-100°	-1.509	-19.9	-399.642	-5258.4
-110°	-2.972	-19.5	-787.142	-5154.5
-120°	-4.345	-18.8	-1150.725	-4985
-130°	-5.586	-18	-1479.343	-4754.9
-140°	-6.657	-16.9	-1763.012	-4471.2
-150°	-7.526	-15.6	-1993.114	-4142.6
-160°	-8.166	-14.3	-2162.655	-3779
-170°	-8.558	-12.8	-2266.485	-3391.5
-180°	-8.69	-11.3	-2301.449	-2991.9
-190°	-9.558	-9.8	-2266.485	-2592.2
-200°	-8.166	-8.3	-2162.655	-2204.7
-210°	-7.526	-7.0	-1993.114	-1841.2
-220°	-6.657	-5.7	-1763.012	-1512.5
-230°	-5.586	-4.6	-1479.343	-1228.9
-240°	-4.345	-3.8	-1150.725	-998.8
-250°	-2.972	-3.1	-787.142	-829.2
-260°	-1.509	-2.7	-399.642	-725.4
-270°	0	-2.6	0	-690.4

The level 2 element will protect against loss of field during lighter load conditions, where the lower slip frequency will cause higher characteristic impedances and lower asynchronous current magnitudes. This element may be plotted in either the P-Q plane or the R-X plane or both. For this example, this element will coordinate with the varying generator impedance characteristic during a complete loss of field scenario.

Zone 2 Diameter:

Eq. (53) $$40Z2P = X_d \times Z_{G\_Base} \times\ ZTR$$

$$40Z2P =\ j1.81 \times 0.666\Omega \times\ 26.086$$

$$40Z2P = j31.458\ \Omega$$

Zone 2 Offset:

Eq. (54) $$40XD2 = 40XD1$$

$$40XD2 =\ -j2.607\ \Omega$$

Loss of Field Zone 2 (40) Plot in R-X Plane:

The Zone 2 Mho element center offset is equal to the radius of the element plus the offset of the element from the origin.

Center Offset:

Eq. (55) $$c_{40\_2\_RX} = -\left|-\left(\frac{40Z2P}{2}\right) + 40XD2\right|$$

$$c_{40\_2\_RX} =\ -\left|-\left(\frac{j31.458\ \Omega}{2}\right) + -j2.607\ \Omega\right|$$

$$c_{40\_2\_RX} =\ -18.336\ \Omega$$

Center Radius:

Eq. (56) $$r_{40\_2\_RX} = \frac{|40Z2P|}{2}$$

$$r_{40\_2\_RX} = \frac{|j31.458\,\Omega|}{2}$$

$$r_{40\_2\_RX} = 15.729\,\Omega$$

Use the following equations to create the characteristic curve for the loss of field element (40) in the P-Q plane:

Eq. (57) $R_{40\_2} = r_{40\_2\_RX} \times \cos(\theta)$

Eq. (58) $X_{40\_2} = r_{40\_2\_RX} \times \sin(\theta) + c_{40\_2\_RX}$

Loss of Field Zone 2 (40) Translation to P-Q Plane:

Zone 2 Offset (primary Ohms):

Eq. (59) $40XD2_{pri} = \frac{40XD2}{ZTR}$

$$40XD2_{pri} = \frac{-j2.607\,\Omega}{26.086}$$

$$40XD2_{pri} = -j0.1\,\Omega$$

Maximum Mho reactance distance from origin:

Eq. (60) $40MAX_{X2\_sec} = -(|40XD2| + |40Z2P|)$

$$40MAX_{X2\_sec} = -(|-j2.607\,\Omega| + |j31.458\,\Omega|)$$

$$40MAX_{X2\_sec} = -34.065\,\Omega$$

Eq. (61) $$40MAX_{X2} = \frac{40MAX_{X2\_sec}}{ZTR}$$

$$40MAX_{X2} = \frac{-34.065\,\Omega}{26.086}$$

$$40MAX_{X2} = -1.306\,\Omega$$

MVA of Offset Setting:

Eq. (62) $$MVA_{40XD2} = \frac{\left(V_{Gen}{}^{2}\right)}{40XD2_{pri}}$$

$$MVA_{40XD2} = \frac{(23kV^{2})}{-j0.1\,\Omega}$$

$$MVA_{40XD2} = j5293.333\,MVA$$

MVA of Maximum Reactance Distance from Origin:

Eq. (63) $$MVA_{40Max\_2} = \frac{\left(V_{Gen}{}^{2}\right)}{40MAX_{X2}}$$

$$MVA_{40Max\_2} = \frac{(23kV^{2})}{-1.306\,\Omega}$$

$$MVA_{40Max\_2} = -405.102\,MVA$$

In the P-Q plane the offset of the Mho circle will be represented by the MVA of the maximum Mho reactance from the origin, since this will produce a small MVA magnitude. The maximum distance of the Mho circle on the reactance axis, from the origin, will be equivalent to the MVA magnitude from the impedance offset setting.

Therefore, the diameter of the Mho Circle in the P-Q plane will equal:

Eq. (64) $40Z2_{PQ} = |MVA_{40XD2}| - |MVA_{40Max\_2}|$

$$40Z2_{PQ} = |j5293.333\ MVA| - |-405.102\ MVA|$$

$$40Z2_{PQ} = 4888.231\ MVA$$

The radius of the Mho Circle in the P-Q plane will equal:

Eq. (65) $r_{40\_2\_PQ} = \dfrac{40Z2_{PQ}}{2}$

$$r_{40\_2\_PQ} = \frac{4888.231\ MVA}{2}$$

$$r_{40\_2\_PQ} = 2444.116\ MVA$$

The center offset of the Mho Circle in the P-Q plane will equal:

Eq. (66) $c_{40\_2\_PQ} = MVA_{40Max\_2} - r_{40\_2\_PQ}$

$$c_{40\_2\_PQ} = -405.102\ MVA - 2444.116\ MVA$$

$$c_{40\_2\_PQ} = -2849.218\ MVAR$$

Use the following equations to create the characteristic curve for the loss of field element (40) in the P-Q plane:

Eq. (67) $P_{40\_2} = r_{40\_2\_PQ} \times \cos(\theta)$

Eq. (68) $Q_{40\_2} = r_{40\_2\_PQ} \times \sin(\theta) + c_{40\_2\_PQ}$

Table 16 contains the plot points on the R-X and P-Q planes for the Loss of Field #2 element.

Table 16

θ	R_{40_2} (Ω)	X_{40_2} (Ω)	P_{40_2} (MW)	Q_{40_2} (MVAR)
90°	0	-2.6	0	-405.1
80°	2.731	-2.8	424.416	-442.2
70°	5.38	-3.6	835.937	-552.5
60°	7.864	-4.7	1222.058	-732.6
50°	10.11	-6.3	1571.047	-976.9
40°	12.049	-8.2	1872.301	-1278.2
30°	13.622	-10.5	2116.666	-1627.2
20°	14.78	-13	2296.717	-2013.3
10°	15.49	-15.6	2406.984	-2424.8
0°	15.729	-18.3	2444.116	-2849.2
-10°	15.49	-21.1	2406.984	-3273.6
-20°	14.78	-23.7	2296.717	-3685.2
-30°	13.622	-26.2	2116.666	-4071.3
-40°	12.049	-28.4	1872.301	-4420.3
-50°	10.11	-30.4	1571.047	-4721.5
-60°	7.864	-32	1222.058	-4965.9
-70°	5.38	-33.1	835.937	-5145.9
-80°	2.731	-33.8	424.416	-5256.2
-90°	0	-34.1	0	-5293.3
-100°	-2.731	-33.8	-424.416	-5256.2
-110°	-5.38	-33.1	-835.937	-5145.9
-120°	-7.864	-32	-1222.058	-4965.9
-130°	-10.11	-30.4	-1571.047	-4721.5
-140°	-12.049	-28.4	-1872.301	-4420.3
-150°	-13.622	-26.2	-2116.666	-4071.3
-160°	-14.78	-23.7	-2296.717	-3685.2
-170°	-15.49	-21.1	-2406.984	-3273.6
-180°	-15.729	-18.3	-2444.116	-2849.2
-190°	-15.49	-15.6	-2406.984	-2424.8
-200°	-14.78	-13	-2296.717	-2013.3
-210°	-13.622	-10.5	-2116.666	-1627.2
-220°	-12.049	-8.2	-1872.301	-1278.2
-230°	-10.11	-6.3	-1571.047	-976.9
-240°	-7.864	-4.7	-1222.058	-732.6
-250°	-5.38	-3.6	-835.937	-552.5
-260°	-2.731	-2.8	-424.416	-442.2
-270°	0	-2.6	0	-405.1

Coordination Plots/Diagrams for Compliance Evidence

The following graphs may be used as evidence to demonstrate compliance with the requirements of PRC-019. An entity may compile the information derived in the previous sections of this example to develop these coordination plots.

The stator overexcitation scheme (Figure 2) consists of excitation system V/Hz limiter coordination with relay and excitation system V/Hz protection. In addition, the illustration shows the coordination between the relay and excitation system V/Hz protection with the generator, GSU, and UAT overexcitation capability.

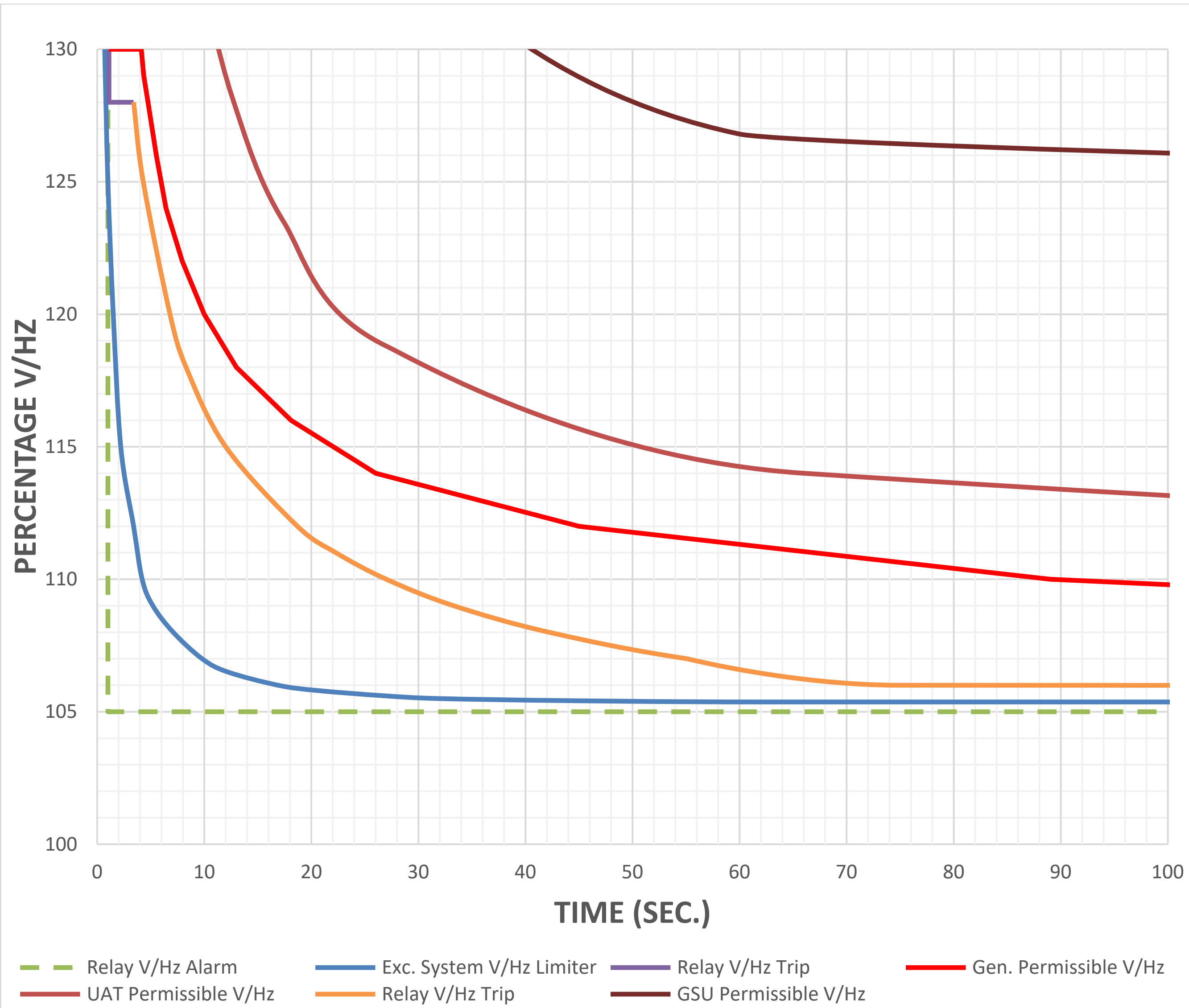

Figure 2: Synchronous Generator Stator Overflux Coordination

The generator field winding overexcitation scheme (Figure 3) consists of the excitation system limiter coordination with relay and excitation system protection. In addition, the illustration shows the coordination between the relay and excitation system OEP protection with the field winding thermal capability.

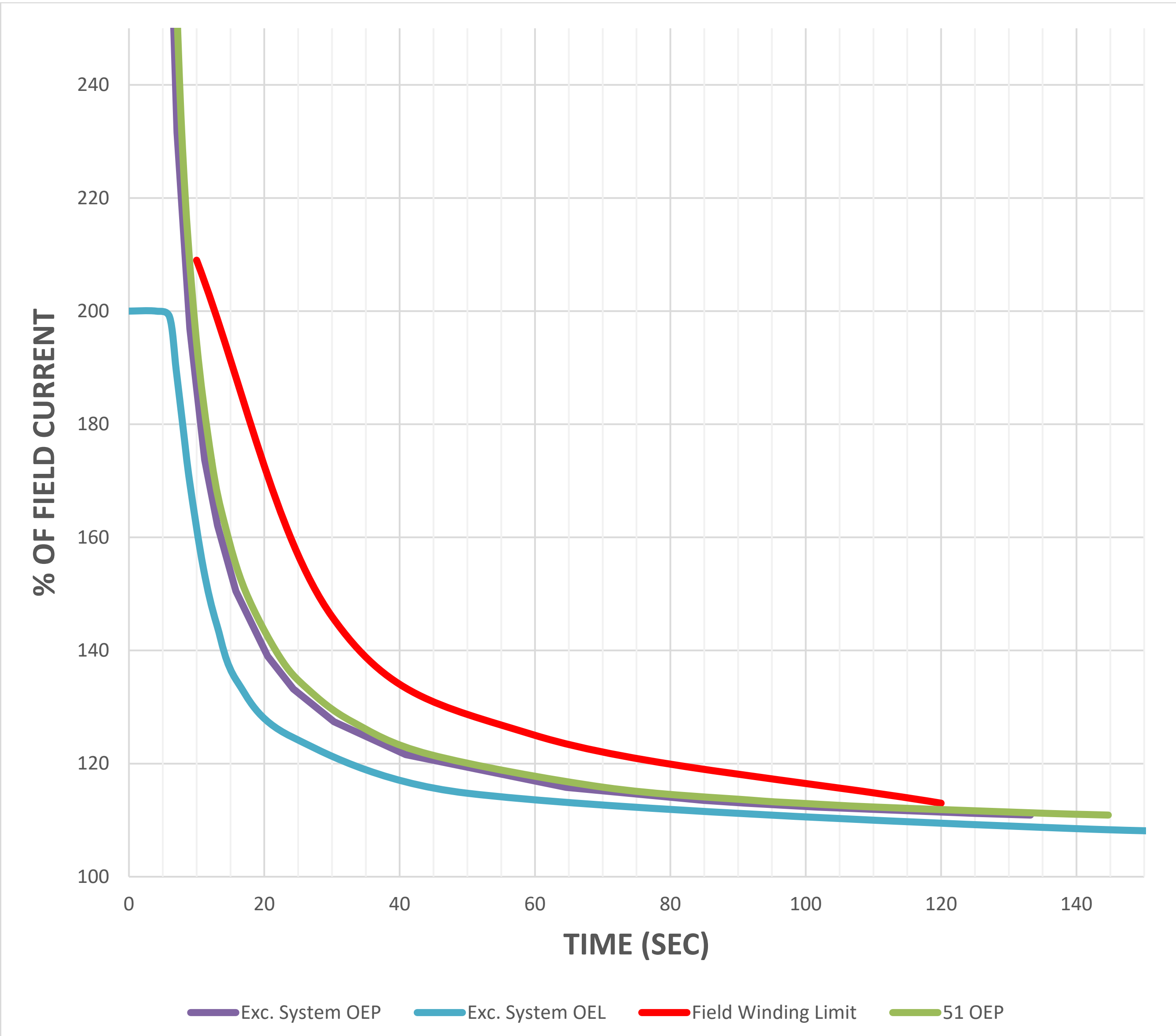

Figure 3: Synchronous Generator Overexcitation Coordination

The generator underexcitation scheme (Figure 4 & 5) consists of excitation system UEL coordination with loss of field protection. In addition, the illustration shows the coordination between the loss of field protection scheme with the stator end-winding thermal capability.

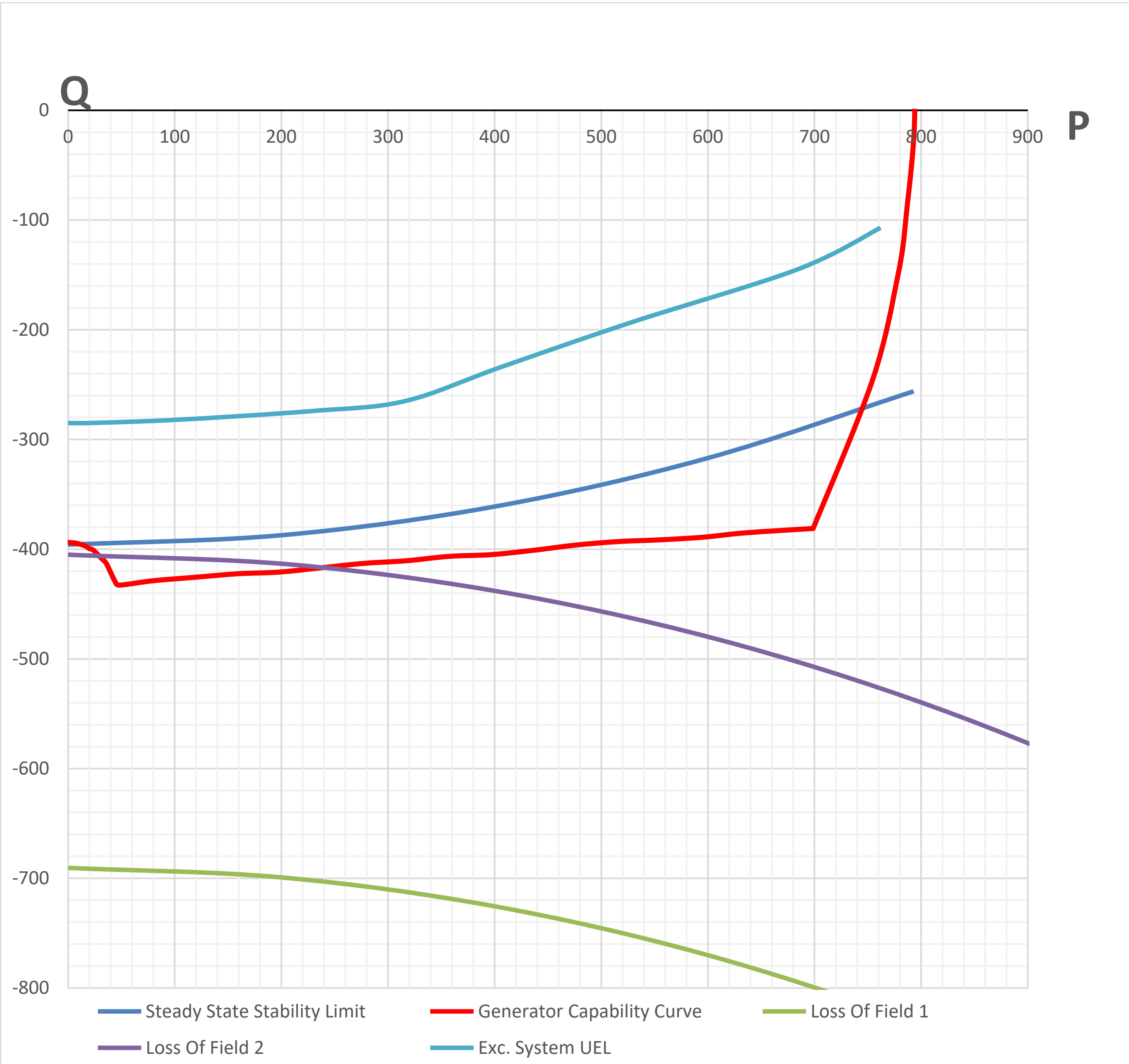

Figure 4: Synchronous Generator Underexcitation P-Q Coordination

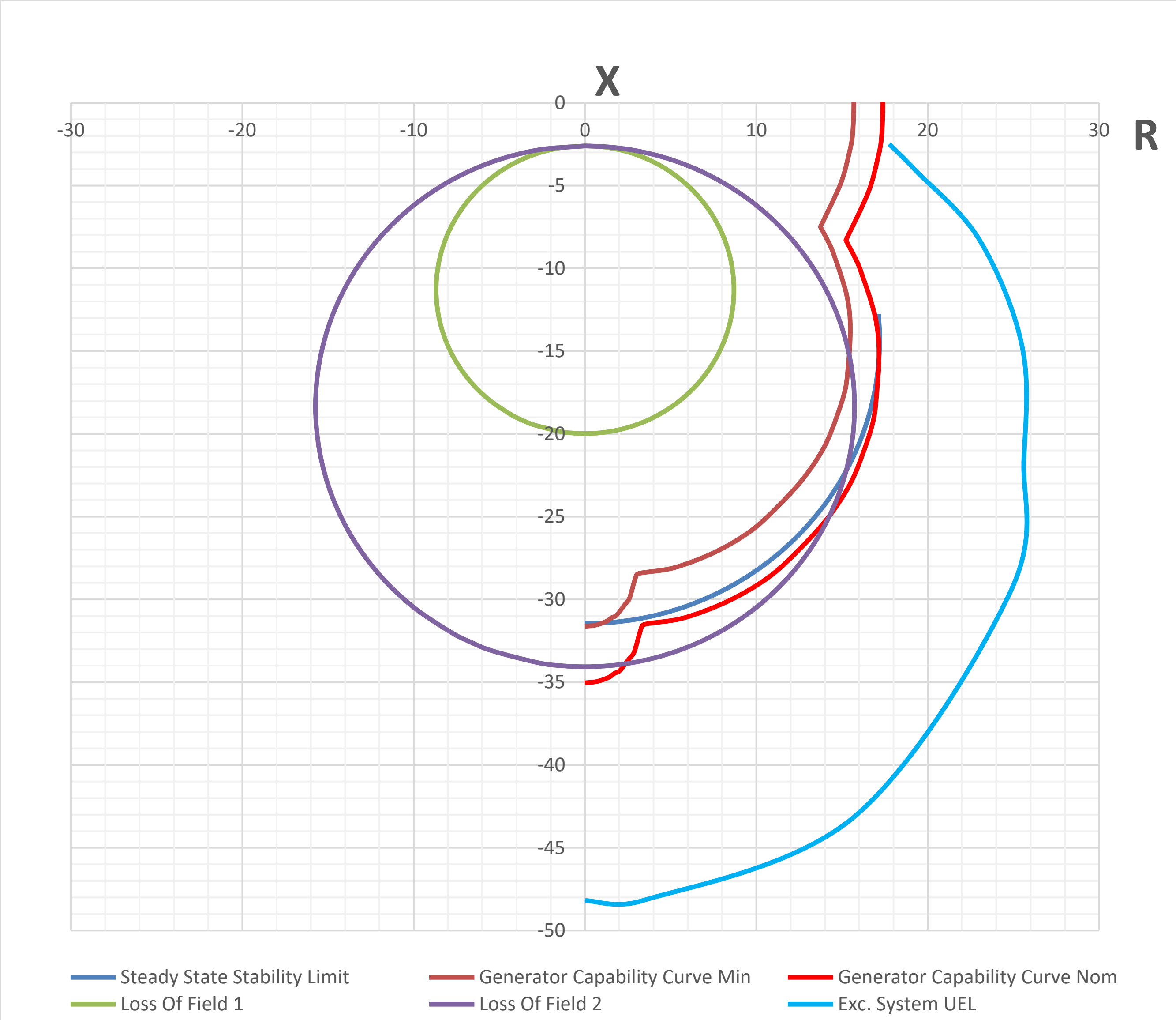

Figure 5: Synchronous Generator Underexcitation R-X Coordination

5.2 Synchronous Condenser Example

Properly documented, the following calculations may be used to demonstrate compliance for this specific example. Different generator designs and protection schemes may require modifications to the calculations. An entity should not blindly copy the methodology outlined below; but should have an in-depth understanding of its holistic generation system before making specific coordination decisions. The one-line diagram for the synchronous condenser example calculation is shown in Figure 1 and the system parameters are shown below in Table 17. This example assumes an entity removed the prime mover of the synchronous generator from Example 3.1 to convert the machine to a synchronous condenser.

Example Calculations	
Synchronous Condenser Input Descriptions	**Input Values**
Synchronous Condenser nameplate (MVA @ rated pf):	$MVA_{GEN} = 794\ MVA$
	$PF_{GEN} = 0.90$
Generator rated voltage (Line-to-Line):	$V_{Gen} = 23\ kV$
Direct Axis Subtransient Reactance, per unit:	$X"_{d} = 18.4\%$
Direct Axis Unsaturated Transient Reactance, per unit:	$X'_{di} = 30\%$
Direct Axis Synchronous Reactance, per unit:	$X_{d} = 181\%$
Generator Base Impedance:	$Z_{G\_Base} = \frac{V_{gen}^2}{MVA_{GEN}} = 0.666\Omega$
Generator Current transformer (CT) ratio:	$CTR_{Gen} = \frac{25000}{5} = 5000$
Generator Potential transformer (PT) ratio:	$PTR_{Gen} = \frac{13279}{69.28} = 191.67$
Primary to Secondary Impedance Ratio:	$ZTR = \frac{CTR_{Gen}}{PTR_{Gen}} = 28.086$
Nominal relay (secondary) voltage:	$V_{Gen\_nom} = \frac{V_{Gen}}{PTR_{Gen}} = 120$
Nominal relay (secondary) current:	$I_{Gen\_nom} = \frac{MVA_{GEN}}{\left(\sqrt{3} \times V_{Gen} \times CTR_{Gen}\right)}$
Generator Step-Up (GSU) Transformer Input Descriptions	**Input Values**
Generator step-up (GSU) transformer rating:	$MVA_{GSU} = 696\ MVA$
GSU transformer reactance (696 MVA base):	$X_{GSU\_TBASE} = 8.8\%$
GSU transformer MVA base:	$MVA_{GSU\_Base} = 696\ MVA$

Example Calculations	
GSU Transformer High-side Nameplate Voltage	$V_{GSU\_HS} = 230kV$
GSU Transformer Low-side Nameplate Voltage	$V_{GSU\_LS} = 22.1kV$
GSU transformer high-side no-load tap Voltage	$V_{GSU\_HS\_TAP} = 235kV$
GSU transformer turns ratio:	$GSU_{ratio} = \frac{V_{GSU\_HS}}{V_{GSU\_LS}}$
High-side nominal system voltage (Line-to-Line):	$V_{Sys\_nom} = 230\ kV$
GSU Current transformer (CT) ratio:	$CTR_{GSU} = \frac{3000}{5}$
Unit Auxiliary Transformer (UAT) Input Descriptions	**Input Values**
UAT nameplate MVA Base:	$MVA_{UAT\_Base} = 32\ MVA$
UAT high-side nameplate voltage:	$V_{UAT\_HS} = 21.85\ kV$
UAT low-side nameplate voltage:	$V_{UAT\_LS} = 6.9\ kV$
Bulk Electric System Descriptions	**Input Values**
System Base MVA:	$MVA_S = 100\ MVA$
System Base Voltage:	$V_S = 230\ kV$

Table 17

Analysis of System

5.2.1 Manual Steady State Stability Limit (SSSL):

To calculate the manual SSSL, an entity must determine the system impedance (transfer impedance) from the vantage point of the generator. In order to identify this impedance, one should identify a configuration that will create a minimum generation/weak system condition. For this example, we removed the largest transmission line in the switchyard and the largest adjacent generator within the facility. The resultant equivalent impedance will represent a portion of the total system impedance to use in the SSSL calculations.

The SSSL is the same as Example 3.1 since the system data and generator impedance are identical.

Steady State Stability Limit (SSSL) Characteristic Plot in P-Q Plane:

Using a 0.95 per unit voltage magnitude will define the most limiting SSSL curve for coordination purposes.

The Center Offset in the P-Q plane is:

$$c_{PQ} = 1922.772\ MVAR$$

The Radius in the P-Q plane is defined by:

$$r_{PQ} = 2318.675\ MVA$$

Use the following equations to create the characteristic curve of the SSSL in the P-Q plane:

$$P_{SSSL} = r_{PQ} \cos\theta$$

$$Q_{SSSL} = r_{PQ} \sin\theta + c_{PQ}$$

Table 18 contains the plot points on the P-Q plane for the manual steady state stability limit.

Table 18

θ	P_{SSSL_min} (MW)	Q_{SSSL_min} (MVAR)
-89°	40.47	-395.55
-89.25°	30.35	-395.70
-89.5°	20.23	-395.81
-89.75°	10.12	-395.88
-90°	0	-395.90

Analysis of Generator Capability

The Generator Capability Curve (GCC) is provided by the manufacturer. The GCC may be represented in either the P-Q plane or the R-X plane or both.

5.2.2 Generator Capability Curve:

The Generator Capability Curve may be acquired from the machine OEM. The plot is typically provided on a P-Q axis.

Table 19 contains the plot points on the P-Q plane for the generator capability curve.

Table 19

pf	P_{Gen} (MW)	Q_{Gen} (MVAR)
0.0	47.64	-436.7
-0.01	7.94	-404.94
-0.05	23.82	-428.76
-0.10	47.64	-436.7

5.2.3 Generator Over Flux Capability Curve:

This curve represents the amount of V/Hz the stator winding can withstand; any level above this curve leaves the generator susceptible to damage via flux overspill onto non-laminated portions of the stator. The overexcitation capability curve for the generator may be represented in per-unit quantities from the base voltage at the synchronous condenser terminal. This curve may be acquired from the machine OEM.

Table 20 contains the plot points for the synchronous condenser overexcitation capability curve.

Table 20

Gen_24 (pu)	Gen_24_t (sec.)
1.06	10000
1.06	3775
1.07	767
1.08	265
1.09	143
1.10	89
1.12	45
1.14	26
1.16	18.1
1.18	13
1.20	10
1.22	7.94
1.24	6.42
1.26	5.52
1.28	4.75
1.29	4.35
1.30	4.12

5.2.4 Generator Step-Up (GSU) Transformer Over Flux Capability Curve:

The overexcitation capability curve for the GSU may be acquired from the transformer OEM or test reports. This curve represents the V/Hz magnitudes the transformer core may be exposed to. If the

GSU low-voltage winding has a different base voltage than the generator terminal, the curve should be converted to the generator base.

Eq. (26) $$GSU\_24_{Gen\_base} = GSU\_24_{GSU\_base} \times \left(\frac{V_{GSU\_LS}}{V_{Gen}}\right)$$

Table 21 contains the plot points for the GSU overexcitation capability curve on the generator base.

Table 21

$GSU\_24_{GSU\_base}$ (pu)	**$GSU\_24_{Gen\_base}$ (pu)**	**GSU_24_t (sec.)**
1.25	1.201	60000
1.27	1.22	6000
1.30	1.249	300
1.32	1.268	60
1.56	1.499	6
1.65	1.585	0.6

5.2.5 Unit Auxiliary Transformer (UAT) Over Flux Capability Curve:

The overexcitation capability curve for the UAT may be acquired from the transformer OEM or test reports. This curve represents the V/Hz magnitudes the transformer core may be exposed to. If the UAT high-voltage winding has a different base voltage than the generator terminal, the curve should be converted to the generator base.

Eq. (27) $$UAT\_24_{Gen\_base} = UAT\_24_{UAT\_base} \times \left(\frac{V_{UAT\_HS}}{V_{Gen}}\right)$$

Table 22 contains the plot points for the UAT overexcitation capability curve on the generator base.

Table 22

$UAT\_24_{UAT\_base}$ (pu)	**$UAT\_24_{Gen\_base}$ (pu)**	**UAT_24_t (sec.)**
1.125	1.069	1500
1.15	1.092	390
1.20	1.14	66
1.25	1.188	27
1.30	1.235	17.40
1.35	1.282	12.60
1.40	1.33	9.6

5.2.6 Generator Field Winding Overexcitation Capability Curve:

The field winding capability represents the thermal overload rating (I^2t) of the field winding. This curve defines the magnitude of current the excitation system may inject into the field winding. Per IEEE C50.13 "Standard for Cylindrical-Rotor Synchronous Generators", the permissible rotor currents for overexcitation are derived from the following equation:

Eq. (28) $$T_{Field} = \frac{33.75}{(I_{Field})^2 - 1}$$

Table 23 contains the plot points for the field winding thermal capability curve.

Table 23

I_{Field} (pu)	T_{Field} (sec)
1.13	121.885
1.25	60
1.46	29.825
2.09	10.02

Analysis of Generator Voltage Control System

The excitation system limiter and/or trip element set points may be obtained from the excitation system OEM. An entity may request these values in MW/MVAR units and R/X impedance units.

5.2.7 Excitation System Underexcitation Limiter (UEL):

The UEL will prevent the voltage regulator from reducing the internal generator voltage beyond a level that would exceed the generators VAR absorption capability and the manual SSSL. The excitation system UEL set points and curve characteristic may be obtained from the excitation system OEM or from field service/test reports. The UEL will coordinate with the protective functions within the excitation system and the Loss of Field relay element. It will also coordinate with the stator core-end capabilities. Therefore, the protection engineer and the excitation system engineer/technician must coordinate their set-points and schemes before the unit can be put in-service and serve grid load. The following example includes both P-Q and R-X values. For a given voltage control system, use the manufacturer provided information (either P-Q, R-X, or both).

Table 24 contains the plot points for the excitation system UEL in the P-Q plane.

Table 24

P_{AVR_UEL} (MW)	Q_{AVR_UEL} (MVAR)
0	-285
20	-285
47	-284

5.2.8 Excitation System Field Winding Overexcitation Limiter (OEL):

The OEL should prevent the excitation system from exceeding field current beyond a magnitude that would exceed the field current thermal capability. The excitation system OEL set points and curve characteristic may be obtained from the excitation system OEM or from field service/test reports. The OEL will coordinate with the protective functions within the excitation system and the relay protection scheme (50, 51, 49, etc.). It will also coordinate with the Generator Field Winding Capability curve. Therefore, the protection engineer and the excitation system engineer/technician must coordinate their set-points and schemes before the unit can be put in-service and serve grid load.

For this example, an inverse-time OEL was implemented using field current as an operating quantity.

Table 25 contains the plot points for the excitation system OEL.

Table 25

I_{41_OEL} (pu)	$T\_I_{41\_OEL}$ (sec.)
1.0573	633.0
1.0676	315.0
1.0777	208.0
1.0850	140
1.1147	50.0
1.2477	24.0
1.3450	16.0
1.4447	13.0
1.5454	11.0
1.6958	9.0
1.7936	8
1.8941	7.0
1.9899	6.0
200.0	4.0

200.0	0.0

5.2.9 Excitation System Field Winding Overexcitation Protection (OEP):

The purpose of an OEP scheme is to initiate a generator trip, through the excitation system, for a condition in which the excitation system OEL fails to stop an increase in field current beyond its characteristic curve. The excitation system protection element functions like a relay; therefore, one must treat it as a relay for coordination purposes. The excitation system time overcurrent element will be set to coordinate with the thermal capability curve of the field winding, per IEEE C50.13 or OEM ratings. This scheme should also coordinate with the excitation system OEL by allowing the OEL the opportunity to initiate action first. This thermal limit may be verified with the OEM to ensure an accurate curve is plotted.

This scheme typically uses the nominal field current as an operating quantity. The nominal field current is based on the power potential transformer (PPT) and the load current the excitation system draws. This value may be acquired from the excitation system OEM or field service/test reports.

Nominal field current (I_{41_Nom}):

$$I_{41\_Nom} = 0.864$$

Time Overcurrent Pickup:

$$OEP\_P_{pu} = 1.065$$

Time Overcurrent Time Dial:

$$OEP\_TD = 2.3$$

Time Overcurrent Curve:

$$OEP_{Curve} = Moderately\ Inverse$$

Table 26 contains the plot points for the excitation system OEP.

Table 26

I_{41_OEP} (pu)	$T\_I_{41\_OEP}$ (sec)
1.109	145.9
1.11	142.7
1.112	136.8
1.123	111.5
1.130	99.9
1.135	93
1.158	70.8
1.216	44.8
1.274	33.2
1.332	26.7
1.39	22.4
1.505	17.3
1.621	14.3
1.737	12.3
1.969	9.8
2.316	7.8
2.895	6.1

5.2.10 Excitation System Stator Volts per Hertz Limiter:

The purpose of this limiter is to prevent the excitation system from producing high magnitudes of terminal voltage when the prime mover is not operating at appropriate speeds. The excitation system V/Hz limiter will coordinate with the protective functions within the excitation system and the relay protection scheme (24,59). The limiter will also coordinate with the generator overexcitation capability curve. The set-point and curve characteristic may be obtained from the excitation system OEM or field service/test reports. This curve is on the generator base voltage since its voltage source comes from PT's at the terminal of the generator.

For this example, a dual function V/Hz protective function was implemented utilizing a definite-time and inverse time operating characteristic.

Table 27 contains the plot points for the excitation system Stator Overexcitation Limiter.

Table 27

AVR_{24_Lim} (pu)	$T\_AVR_{24\_Lim}$ (sec.)
1.30	0.70
1.25	1.0
1.20	1.50

1.15	2.20
1.12	3.40
1.10	4.20
1.09	5.20
1.08	7.10
1.07	9.80
1.06	16.90
1.0537	62.0

Analysis of Protection Schemes

Protection functions may be located within a protection system or the generator control system.

5.2.11 V/Hz Overexcitation Protection Scheme:

The generator V/Hz scheme should initiate a generator trip for a condition in which the excitation system V/Hz limiter fails to stop an increase in stator voltage, relative to frequency, beyond its characteristic curve. The V/Hz scheme will coordinate with the generator stator overexcitation capability curve. The scheme will also coordinate with the excitation system V/Hz limiter by allowing the limiter the opportunity to initiate action first. The V/Hz schemes associated with the excitation transformer or the GSU should align with the generator V/Hz scheme for the design provided in the example.

The Level 1 element will be used as a definite-time element to initiate an alarm and identify an overexcitation condition. This will give the generator operator the opportunity to manually correct the abnormal overexcitation conditions.

Definite-Time Level 1 Element:

$$24D1P = 105\ \%$$

$$24D1D = 60\ cycles$$

The Level 2 element will be used as a definite-time element to initiate a generate trip during high levels of V/Hz to prevent overexcitation damage. This set-point and time delay will coordinate with the overexcitation capabilities of the generator to prevent damage. This element will allow enough margin for the excitation control system to correct the abnormal operating conditions before the relay initiates a trip.

Definite-Time Level 2 Element:

$$24D2P2 = 128\ \%$$

$$24D2D = 66\ cycles = 1.10\ sec.$$

The inverse time element will be used to initiate a generate trip for low to moderate overexcitation conditions. This curve characteristic will coordinate with the overexcitation capability of the generator to prevent damage. It will allow enough margin for the excitation control system to correct the abnormal operating condition before the relay initiates a trip.

Inverse Time Pickup:

$$24IP = 106\ \%$$

Inverse Time Dial:

$$24ITD = 1.5$$

Inverse Time Curve:

$$24IT\_Curve = 1.0$$

Volts/Hz (24) Inverse Time Element Curve Characteristics:

Eq. (31) $$T_{24\_IT} = \frac{(0.003 * 24ITD)}{\left(V_{24\_IT} - 1\right)^2} minutes$$

Table 28 contains the calculations of the time delays for the inverse time curve characteristic.

Table 28

V_{24IT} (pu)	M_{24IT}	T_{24IT} (sec)
1.06	1	75
1.07	1.009	55.1
1.08	1.019	42.2

1.09	1.028	33.3
1.10	1.038	27
1.11	1.047	22.3
1.12	1.057	18.7
1.15	1.085	12
1.18	1.113	8.3
1.20	1.132	6.8
1.25	1.179	4.3
1.28	1.208	3.4

Table 29 contains the calculations of the time delays for the definite-time element plot.

Table 29

V_{24DT} (pu)	T_{24IT} (sec)
$24D2P2$	1.10
$24D2P2$	3.4

5.2.12 Field Winding Overcurrent (50/51) Overload Protection Scheme:

The winding overcurrent scheme should initiate a generator trip for a condition in which the excitation system OEL fails to stop an increase in field current beyond its characteristic curve. The overcurrent element monitoring the excitation current will coordinate with the thermal capability of the field winding, per IEEE C50.13 or OEM ratings. The scheme will also coordinate with the excitation system OEL by allowing the limiter the opportunity to initiate action first.

Nominal field current (I_{41_Nom}):

$$I_{41\_Nom} = 0.864$$

Time Overcurrent Pickup:

$$51P_{pu} = 1.065$$

Time Overcurrent Time Dial:

$$51TD = 12.3$$

Time Overcurrent Curve:

$$51P_{Curve} = U1$$

Time Overcurrent Curve Characteristics:

Eq. (33) $$T_{51} = 51TD \times \left[0.0226 + \frac{0.0104}{\left({M_{51}}^{0.02} - 1\right)}\right]$$

Table 30 contains the calculations of the curve characteristic for the time overcurrent element.

Table 30

I_{51} (pu)	M_{51}	T_{51} (sec)
1.109	1.041	157.5
1.11	1.042	154.1
1.112	1.044	147.7
1.123	1.055	120.4
1.130	1.061	107.9
1.135	1.066	100.4
1.158	1.088	76.5
1.216	1.142	48.4
1.274	1.196	35.9
1.332	1.251	28.8
1.39	1.305	24.2
1.505	1.413	18.7
1.621	1.522	15.4
1.737	1.631	13.3
1.969	1.849	10.6
2.316	2.175	8.4
2.895	2.719	6.6

5.2.13 Generator Loss of Field (40) Protection Scheme:

This example will employ IEEE C37.102 method 1 for the loss of field (LOF) protection scheme. The level 1 element will detect loss of field conditions during heavier load conditions. This element may be plotted in either the P-Q plane or the R-X plane or both. This element does not have to coordinate with the curves identified within PRC-019 because it protects against severe slip frequency (pole slippage), in which the apparent impedance/power swing loci will overshoot the capability curve of the generator and has a very short time delay. Since the electrical parameters match the synchronous generator in Example 1, this example will use the same loss of field scheme.

Zone 1 Diameter:

$$40Z1P = 17.38\ \Omega$$

Zone 1 Offset:

$$40XD1 = -j2.607\ \Omega$$

Loss of Field Zone 1 (40) Plot in R-X Plane:

The Zone 1 Mho element center offset is equal to the radius of the element plus the offset of the element from the origin.

Center Offset:

$$c_{40\_1\_RX} = -11.297\ \Omega$$

Center Radius:

$$r_{40\_1\_RX} = 8.69\ \Omega$$

Loss of Field Zone 1 (40) Translation to P-Q Plane:

Zone 1 Offset (primary Ohms):

$$40XD1_{pri} = -j0.1\ \Omega$$

Maximum Mho reactance distance from origin:

$$40MAX_{X\_sec} = -19.987\ \Omega$$

$$40MAX_{X} = -0.766\ \Omega$$

MVA of Offset Setting:

$$MVA_{40XD1} = j5293.333\ MVA$$

MVA of Maximum Reactance Distance from Origin:

$$MVA_{40Max} = -690.435\ MVA$$

In the P-Q plane the offset of the Mho circle will be represented by the MVA of the maximum Mho reactance from the origin, since this will produce a small MVA magnitude. The maximum distance of the Mho circle on the reactance axis, from the origin, will be equivalent to the MVA magnitude from the impedance offset setting.

Therefore, the diameter of the Mho Circle in the P-Q plane will equal:

$$40Z1_{PQ} = 4602.899\ MVA$$

The radius of the Mho Circle in the P-Q plane will equal:

$$r_{40\_1\_PQ} = 2301.499\ MVA$$

The center offset of the Mho Circle in the P-Q plane will equal:

$$c_{40\_1\_PQ} = -2991.884\,MVAR$$

Table 31 contains the plot points on the R-X and P-Q planes for the Loss of Field #1 element.

Table 31

θ	P_{40_1} (MW)	Q_{40_1} (MVAR)
90°	0	-690.4
89.75°	10.04	-690.456
89.50°	20.08	-690.522
89.25°	30.12	-690.632
89°	40.16	-690.785

The level 2 element will protect against loss of field during lighter load conditions, where the lower slip frequency will cause higher characteristic impedances and lower asynchronous current magnitudes. This element may be plotted in either the P-Q plane or the R-X plane or both. For this example, this element will coordinate with the varying generator impedance characteristics during a complete loss of field scenario.

Zone 2 Diameter:

Eq. (53) $$40Z2P = X_d \times Z_{G\_Base} \times ZTR$$

$$40Z2P = j1.81 \times 0.666\Omega \times 26.086$$

$$40Z2P = j31.458\,\Omega$$

Zone 2 Offset:

Eq. (54) $$40XD2 = 40XD1$$

$$40XD2 = -j2.607\,\Omega$$

Loss of Field Zone 2 (40) Plot in R-X Plane:

The Zone 2 Mho element center offset is equal to the radius of the element plus the offset of the element from the origin.

Center Offset:

$$c_{40\_2\_RX} = -18.336\,\Omega$$

Center Radius:

$$r_{40\_2\_RX} = 15.729\,\Omega$$

Loss of Field Zone 2 (40) Translation to P-Q Plane:

Zone 2 Offset (primary Ohms):

$$40XD2_{pri} = -j0.1\,\Omega$$

Maximum Mho reactance distance from origin:

$$40MAX_{X2\_sec} = -34.065\,\Omega$$

$$40MAX_{X2} = -1.306\,\Omega$$

MVA of Offset Setting:

$$MVA_{40XD2} = j5293.333\,MVA$$

MVA of Maximum Reactance Distance from Origin:

$$MVA_{40Max\_2} = -405.102\,MVA$$

In the P-Q plane the offset of the Mho circle will be represented by the MVA of the maximum Mho reactance from the origin, since this will produce a small MVA magnitude. The maximum distance of the Mho circle on the reactance axis, from the origin, will be equivalent to the MVA magnitude from the impedance offset setting.

Therefore, the diameter of the Mho Circle in the P-Q plane will equal:

$$40Z2_{PQ} = 4888.231\ MVA$$

The radius of the Mho Circle in the P-Q plane will equal:

$$r_{40\_2\_PQ} = 2444.116\ MVA$$

The center offset of the Mho Circle in the P-Q plane will equal:

$$c_{40\_2\_PQ} = -2849.218\ MVAR$$

Table 32 contains the plot points on P-Q planes for the Loss of Field #2 element.

Table 32

θ	P_{40_2} (MW)	Q_{40_2} (MVAR)
90°	0	-405.1
89.75°	10.66	-405.02
89.50°	21.32	-405.09
89.25°	31.99	-405.20
89°	42.65	-405.37

Coordination Plots/Diagrams for Compliance Evidence

The following graphs may be used as evidence to demonstrate compliance with the requirements of PRC-019.

The stator overexcitation scheme (Figure 6) consists of excitation system V/Hz limiter coordination with relay and excitation system V/Hz protection. In addition, the illustration shows the coordination between the relay and excitation system V/Hz protection with the generator, GSU, and UAT overexcitation capability.

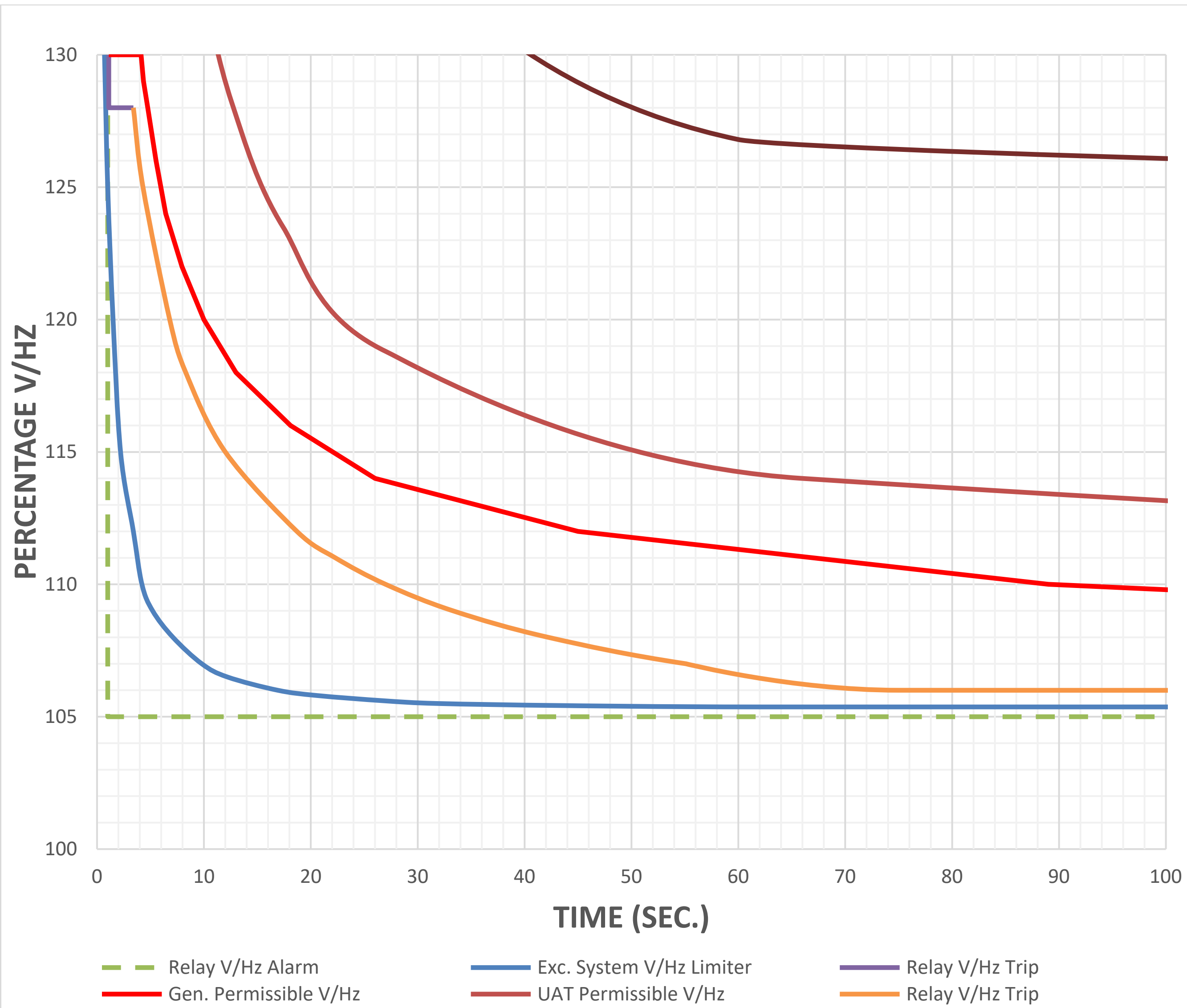

Figure 6: Synchronous Condenser Over Flux Coordination

The generator field winding overexcitation scheme (Figure 7) consists of excitation system limiter coordination with relay and excitation system protection. In addition, the illustration shows the coordination between the relay and excitation system V/Hz protection with the field winding thermal capability.

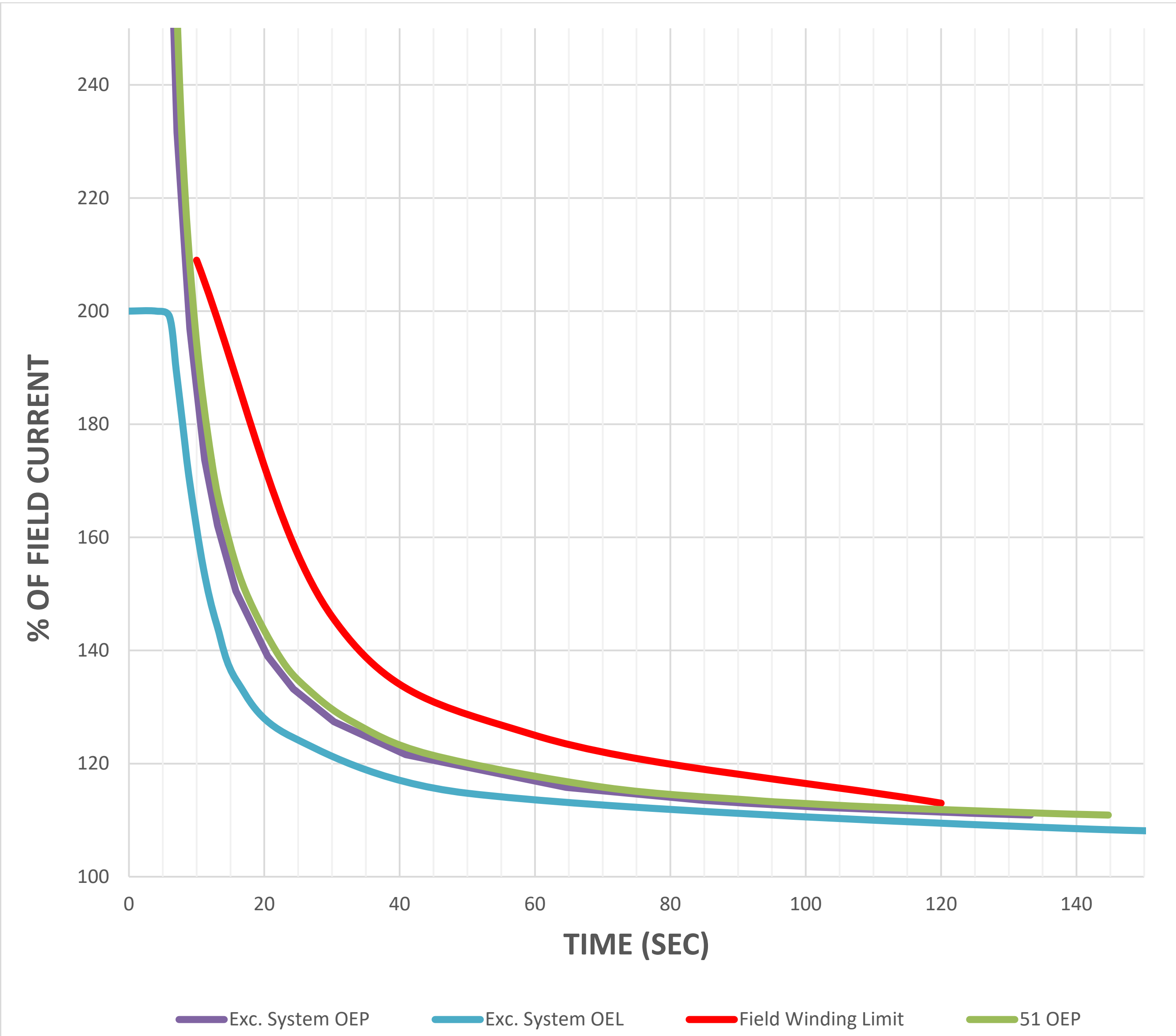

Figure 8

Figure 7: Synchronous Condenser Overexcitation Coordination

The generator underexcitation scheme (Figure 8) consists of excitation system UEL coordination with loss of field protection, with the synchronous condenser absorbing a small amount of real power from the grid to operate. In addition, the illustration shows the coordination between the loss of field protection scheme with the stator end-winding thermal capability.

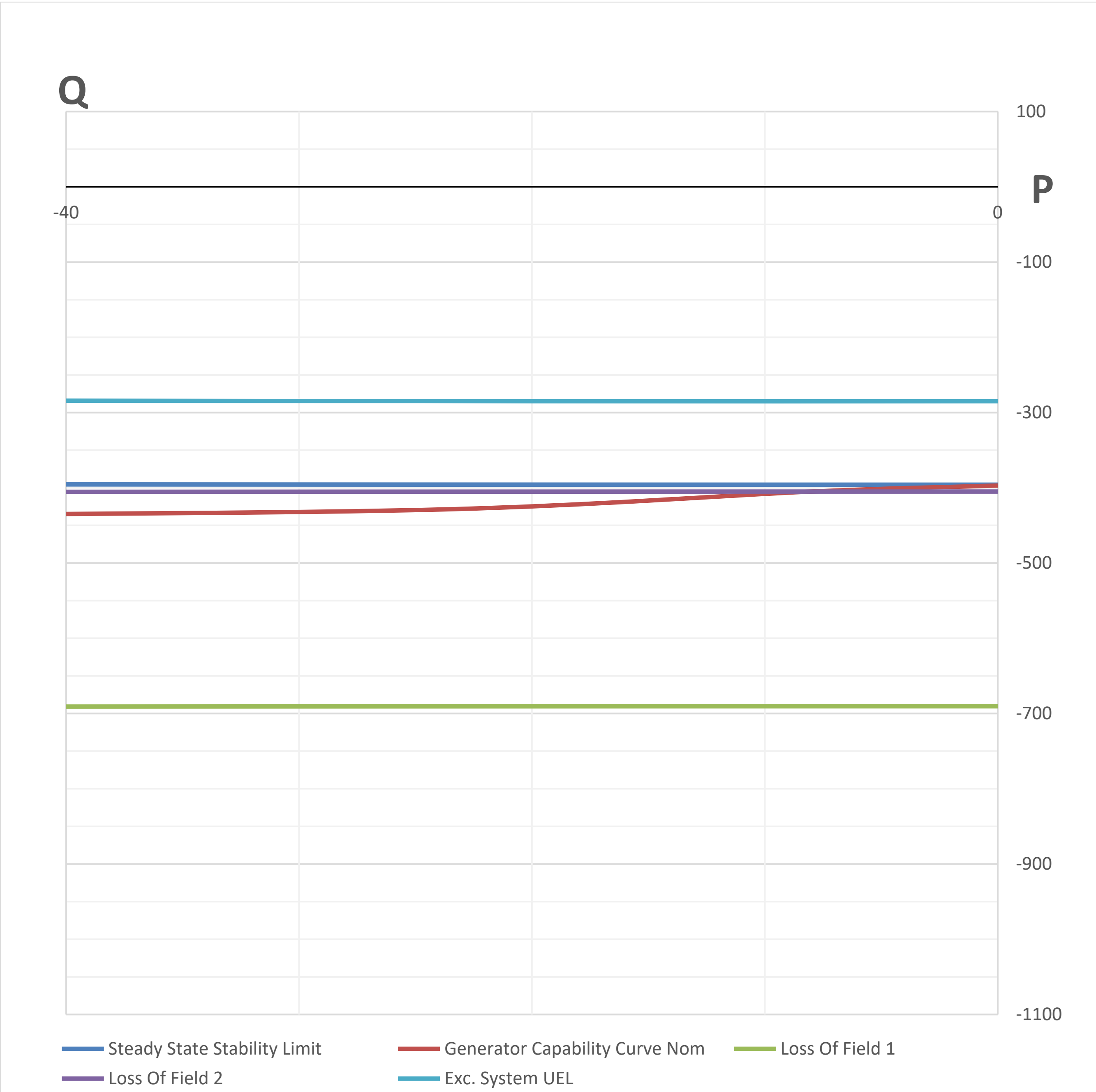

Figure 8: Synchronous Condenser Underexcitation Coordination

Figure 9 is an illustration of the alternative plot for the generator underexcitation scheme. This figure consists of excitation system UEL, loss of field protection, and generator capability coordination over the entire range of the D-curve. The data input for this figure mimics the data points from example 1. You may refer to the data tables in example 1 for a detailed breakdown of this figure. Even though this is not an accurate representation of the real power out of the machine, this depiction is suitable for proving PRC-019 coordination.

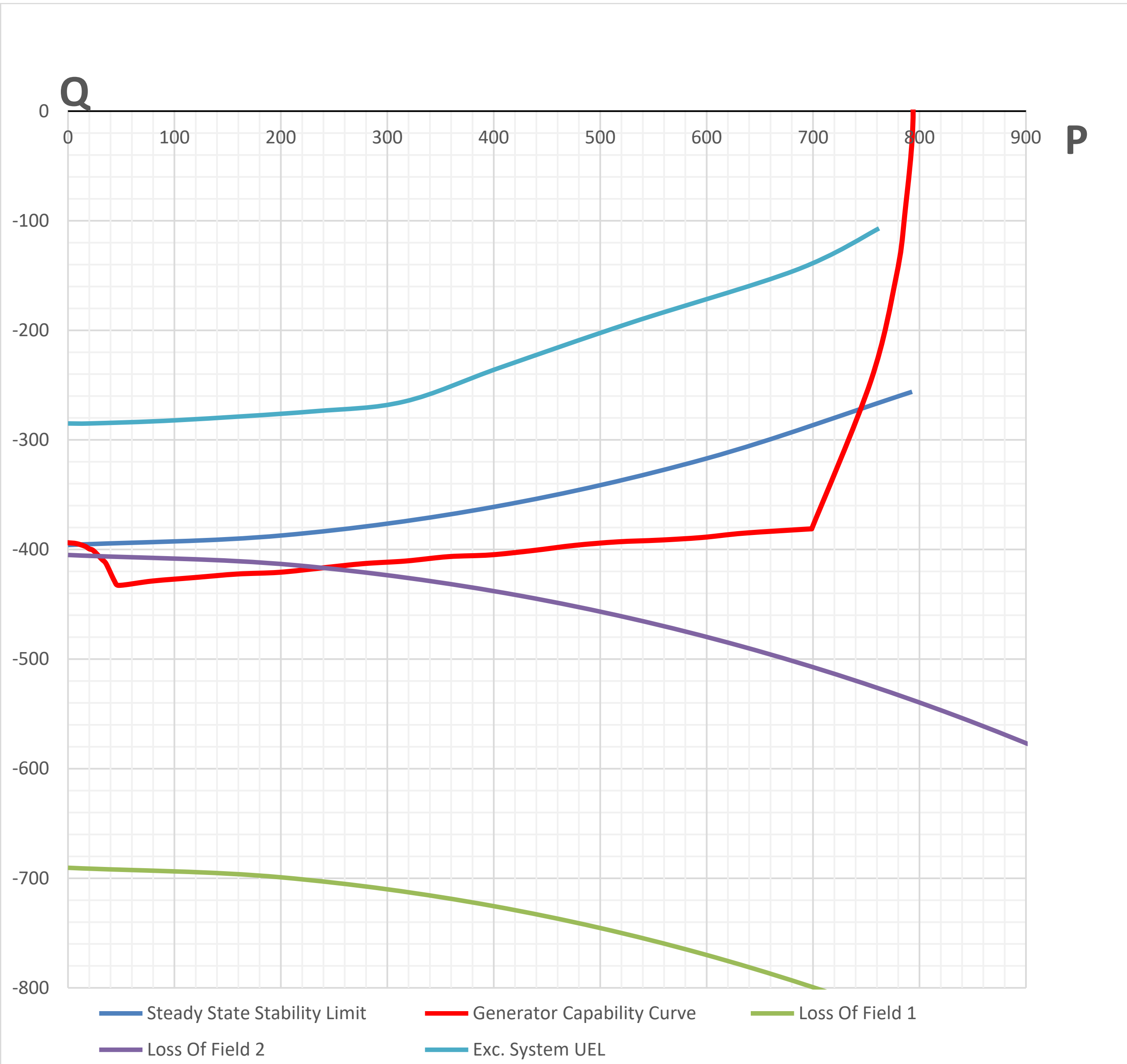

Figure 9: Synchronous Condenser Alternate Underexcitation Coordination

5.3 Dispersed Power Producing Resources Example

Properly documented, the following calculations may be used to demonstrate compliance for this specific example. It is an entity's responsibility to determine the design and configuration of their control and protection schemes. Different generator designs and protection schemes may require modifications to the calculations. An entity should not blindly copy the methodology outlined below; but should have an in-depth understanding of its holistic generation system before making specific coordination decisions.

The one-line diagram for example calculations is shown in Figure 6 and the system parameters are shown below in Table 33. Connections for external relays are identified throughout the IBR generating facility. These protection systems are multi-function microprocessor relays that are capable of implementing the protective function identified in this section.

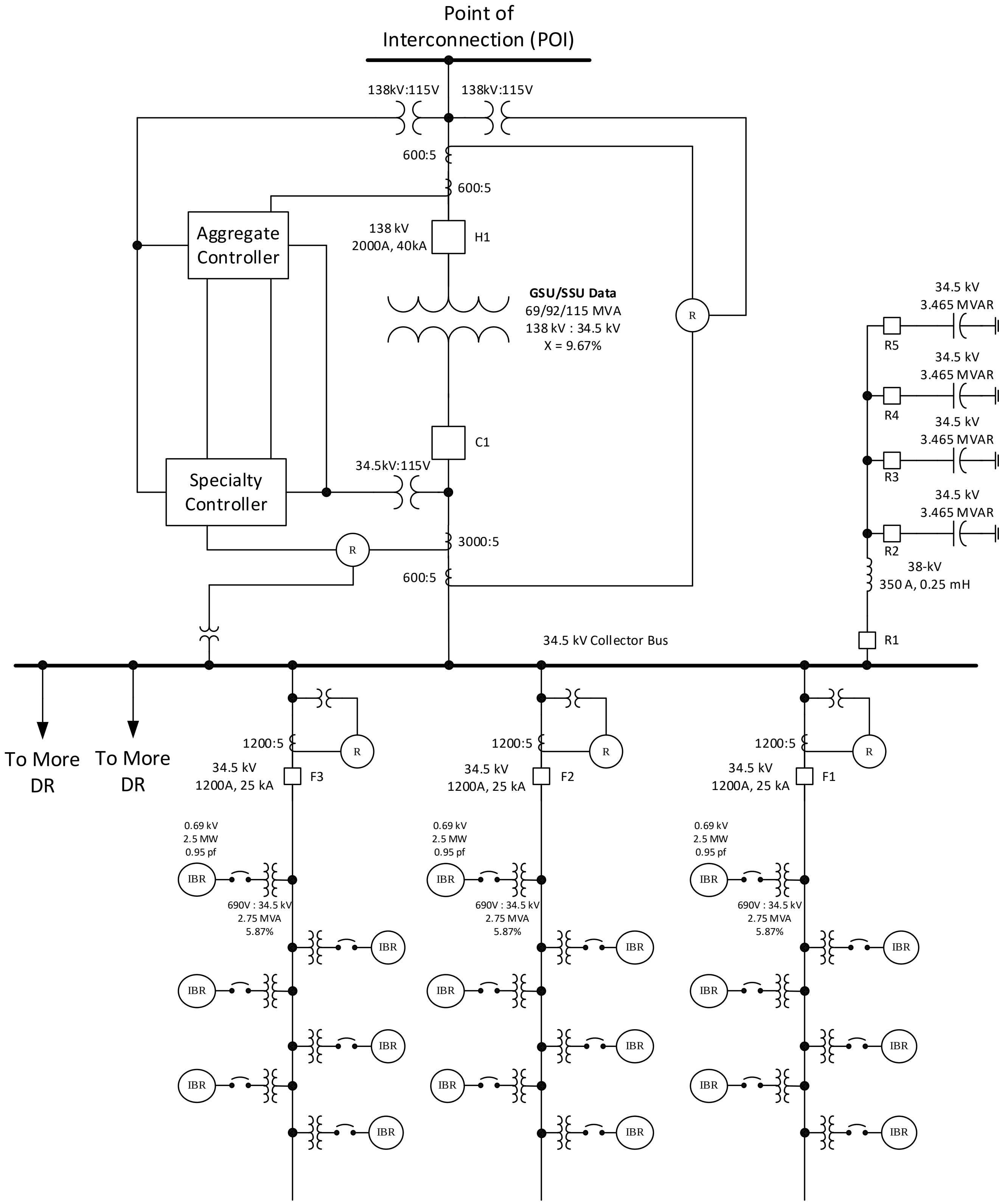

Figure 10: Dispersed Power Producing Resource Sample System

Example Calculations	
Inverter Based Resource Input Descriptions	**Input Values**
IBR Generator nameplate (MW @ rated pf and voltage):	$MW_{A\_GEN} = 2.5\ MW$
	$PF_{A\_GEN} = 0.95$
IBR Generator rated voltage (Line-to-Line):	$V_{A\_Gen} = 0.69\ kV$
Total Number of Inverters	$Gen_{Total} = 40$
Pad-mount Transformer Input Descriptions	**Input Values**
Pad-mount transformer rating:	$MVA_{Pad} = 2.75\ MVA$
Pad-mount transformer reactance:	$X_{Pad} = 5.87\%$
Pad-mount Transformer Nameplate High-side Voltage	$V_{Pad\_HS} = 34.5kV$
Pad-mount Transformer Nameplate Low-side Voltage	$V_{Pad\_LS} = 0.69kV$
Generator Step-Up (GSU) Transformer Input Descriptions	**Input Values**
Generator step-up (GSU) transformer rating:	$MVA_{GSU} = 115\ MVA$
GSU transformer reactance (69 MVA base):	$X_{GSU\_TBASE} = 9.67\%$
GSU transformer MVA base:	$MVA_{GSU\_Base} = 69\ MVA$
GSU Transformer Nameplate High-side Voltage	$V_{GSU\_HS} = 138kV$
GSU Transformer Nameplate High-side Tap Voltage	$V_{GSU\_HS\_Tap} = 138kV$
GSU Transformer Nameplate Low-side Voltage	$V_{GSU\_LS} = 34.5kV$
GSU Low-Side Current Transformer (CT) ratio:	$CTR_{GSU\_LS} = \frac{3000}{5}$
GSU Low-Side Potential Transformer (PT) ratio:	$PTR_{GSU\_LS} = \frac{34500}{115}$
GSU High-Side Current Transformer (CT) ratio:	$CTR_{GSU\_HS} = \frac{600}{5}$

Example Calculations	
GSU High-Side Potential Transformer (PT) ratio:	$PTR_{GSU\_HS} = \frac{138000}{115}$
High-side nominal GSU voltage (Line-to-Ground):	$V_{GSU\_HS\_nom} = \frac{V_{GSU\_HS}}{PTR_{GSU\_HS} \times \sqrt{3}} = 66.4$
Low-side nominal GSU voltage (Line-to-Ground):	$V_{GSU\_LS\_nom} = \frac{V_{GSU\_LS}}{PTR_{GSU\_LS} \times \sqrt{3}} = 66.4$
Collector Bus Input Descriptions	**Input Values**
Collector Bus Base Voltage:	$V_{Collector} = 34.5\ kV$
Capacitor Bank Input Descriptions	**Input Values**
Cap Bank MVAR:	$MVAR_{Cap} = 4 \times 3.465\ MVAR = 13.86\ MVAR$
Cap Bank Base Voltage:	$V_{Cap} = 34.5\ kV$
Cap Bank Current Transformer (CT) ratio:	$CTR_{CAP} = \frac{1200}{5}$
Cap Bank Potential Transformer (PT) ratio:	$PTR_{CAP} = \frac{34500}{115}$
Point of Interconnection Descriptions	**Input Values**
Line Current Transformer (CT) ratio:	$CTR_{Line} = \frac{1200}{5}$
Line Voltage Transformer (VT) ratio:	$VTR_{Line} = \frac{138000}{115}$
System Base MVA:	$MVA_S = 100\ MVA$
System Base Voltage:	$V_S = 138\ kV$

Table 33

For this example, voltage control occurs at the Point of Interconnection (POI) via the plant controller (aggregate controller). The plant controller will operate in Voltage Control Mode, monitoring the grid level voltage magnitude and phase angle. It will use these measurements as a reference to send signals to the individual inverters within the IBR generating facility. This will allow the inverters to track the grid voltage and operate in a “grid following” manner.

Analysis of Dispersed Power Producing Resource Capability

The inverter capability is typically provided by the inverter OEM. These capabilities may vary widely since there are different types of inverters and various manufacturers. Therefore, an entity must obtain accurate data from the OEM.

5.3.1 Dispersed Power Producing Resource Data:

Each inverter within the IBR generating facility has the same nameplate ratings. The MVA rating will provide the maximum amount of power the inverter can output.

IBR Generator rated MVA:

Eq. (69) $$MVA_{A\_GEN} = \frac{MW_{A\_GEN}}{PF_{A\_GEN}}$$

$$MVA_{A\_GEN} = \frac{2.5\ MW}{0.95}$$

$$MVA_{A\_GEN} = 2.632\ MVA$$

IBR Generator rated MVAR:

Eq. (70) $$MVAR_{A\_GEN} = MVA_{A\_GEN} \times \sin\left(\cos^{-1} PF_{A\_GEN}\right)$$

$$MVAR_{A\_GEN} = \ 2.632\ MVA \times \sin(\cos^{-1} 0.95)$$

$$MVAR_{A\_GEN} = 0.822\ MVAR$$

Total IBR generating facility Generator MW:

Eq. (71) $$MW_{A\_GEN\_T} = MW_{A\_GEN} \times\ Gen_{Total}$$

$$MW_{A\_GEN\_T} = 2.5\ MW \times 40$$

$$MW_{A\_GEN\_T} = 100\ MW$$

Total IBR generating facility Generator MVA:

Eq. (72) $$MVA_{A\_GEN\_T} = MVA_{A\_GEN} \times Gen_{Total}$$

$$MVA_{A\_GEN} = 2.632\ MVA \times 40$$

$$MVA_{A\_GEN} = 105.28\ MVA$$

Total IBR Generating Facility Generator MVAR:

Eq. (73) $$MVAR_{A\_GEN\_T} = MVAR_{A\_GEN} \times Gen_{Total}$$

$$MVAR_{A\_GEN\_T} = 0.822\ MVAR \times 40$$

$$MVAR_{A\_GEN\_T} = 32.88\ MVAR$$

5.3.2 IBR Voltage Analysis:

The inverters are capable of riding-through voltage excursions at their respective AC terminals. The inverter low-voltage ride-through (LVRT) and high-voltage ride-through (HVRT) curves define the unit's capability to withstand voltage deviations. These curves also define the voltage protection set points and curve characteristic within the inverter control system. If an inverter experiences a voltage excursion beyond this characteristic, then the inverter control system will initiate a trip. Since voltage is being regulated at the POI, any transformer no-load tap changer (NLTC) settings between the IBR unit terminal and the POI should be taken into consideration. The inverter HVRT and LVRT capability/protection curves may be acquired from the inverter OEM.

Table 34 contains the plot points for the inverter voltage ride-through capabilities (steady state capabilities).

Table 34

$V_{Inverter\_HVRT}$ (pu)	T_{HVRT} (sec)	$V_{Inverter\_LVRT}$ (pu)	T_{LVRT} (sec)

1.10	5	0.90	5
1.20	5	0.10	5
1.20	0.5	0	5
1.30	0.5		
1.30	0.0016		

Analysis of Collector System

An entity may evaluate capabilities/limitations associated with the collector bus of the IBR generating facility.

5.3.3 Bus Continuous Voltage Capability:

For this example, the engineering of the collector system used ANSI C84.1 as one of the design criteria for voltage capability. Per ANSI C84.1, the maximum continuous operating voltage for a 34.5 kV system is 1.05 per unit of nominal voltage. For this example, the continuous voltage capability of the 34.5 kV collector bus was designed to be within +/- 5% of nominal voltage.

Collector Bus Continuous Upper Voltage Limit:

$$V_{Collector\_\max\_pu} = 105\%$$

$$V_{Collector\_\max} = 105\% \times V_{Collector}$$

$$V_{Collector\_\max} = 36.2\ kV$$

Collector Bus Continuous Lower Voltage Limit:

$$V_{Collector\_\mathrm{min}\_pu} = 95\%$$

$$V_{Collector\_\mathrm{min}} = 95\% \times V_{Collector}$$

$$V_{Collector\_\mathrm{min}} = 32.8\ kV$$

Analysis of Collector Bus VAR Support (Cap Bank, Synchronous Condenser, etc.)

An entity may consider reactive compensating devices into the total power output capability of their plant. If the IBR generating facility has these devices, then this output capability should be used as a reference point for protection coordination purposes.

5.3.4 Short Time Overvoltage Capability:

Per IEEE C37.99, the maximum continuous overvoltage capability of a capacitor unit is 110% of the rated voltage. IEEE 1036 defines the characteristic curve for prohibited operation above 100% of rated voltage. This curve was used as a basis for the capacitor bank equipment capability.

Table 35 contains the plot points for the Cap Bank overexcitation capability curve on the collector bus base voltage.

Table 35

V_{Cap_Lim} (pu)	T_{Cap} (sec)
2.20	0.1
2.0	0.25
1.70	1
1.40	15
1.30	60

Analysis of Point of Interconnection (POI)

The POI for a dispersed power resource is typically the high-voltage side of the GSU transformer or Station Step-up Transformer (SSU) transformer.

5.3.5 POI Voltage Limits:

The voltage capabilities at the terminal of the inverters will coordinate with the voltage limitations of the collector system and the interconnecting transmission system (POI). The interconnecting transmission system voltage limitations are typically outside of the inverter steady state voltage limitations. An inverter typically has a steady state voltage range of +/- 10% AC terminal voltage before they go into FRT mode. The voltage limit for this example interconnecting transmission system is defined as +14/-16 kV from a 138-kV reference point. In this example, the limit was defined by the Transmission Owner engineering design.

POI Upper Voltage Limit:

$$V_{POI\_\max\_pu} = \frac{(138kV + 14kV)}{V_S}$$

$$V_{POI\_\max\_pu} = \frac{(138kV + 14kV)}{138kV}$$

$$V_{POI\_\max\_pu} = 1.10$$

POI Lower Voltage Limit:

$$V_{POI\_\min\_pu} = \frac{(138kV - 16kV)}{V_S}$$

$$V_{POI\_\min\_pu} = \frac{(138kV - 16kV)}{138kV}$$

$$V_{POI\_\min\_pu} = 0.884$$

Analysis of Protection Schemes

Protection schemes may be located within protection systems or control systems throughout the IBR generating facility. Figure 9 identifies

5.3.6 Feeder Undervoltage (27) Protection Settings:

Each feeder has a designated relay to provide protection for the feeder circuit. Each relay has undervoltage settings that are programmed to trip the feeder off-line.

Level 1 Definite-Time Phase Undervoltage Element:

$$27P1P_{Fdr\_sec} = 10\ V_{sec}$$

$$27P1P_{Fdr\_pu} = \frac{27P1P_{Fdr\_sec}}{V_{GSU\_LS\_nom}}$$

$$27P1P_{Fdr\_pu} = \frac{10\ V_{sec}}{66.4\ V_{sec}}$$

$$27P1P_{Fdr\_pu} = 0.151$$

$$T_{27P1P\_Fdr} = 330\ cycles = 5.5\ sec$$

5.3.7 Collector Bus Overvoltage (59) Protection Settings:

This voltage scheme will coordinate with the collector bus and associated equipment voltage limitations.

Level 1 Definite-Time Phase Overvoltage Element:

$$59P1P_{CollectorBus\_pu} = 1.10$$

$$59P1P_{CollectorBus\_sec} = 59P1P_{LS\_pu} \times V_{GSU\_LS\_nom}$$

$$59P1P_{CollectorBus\_sec} = 1.10 \times 66.4\ V_{sec}$$

$$59P1P_{CollectorBus\_sec} = 73.04\ V_{sec}$$

$$T_{59P1P\_CollectorBus} = 1800\ cycles = 30\ sec$$

Level 2 Definite-Time Phase Overvoltage Element:

$$59P2P_{CollectorBus\_pu} = 1.30$$

$$59P2P_{CollectorBus\_sec} = 59P2P_{LS\_pu} \times V_{GSU\_LS\_nom}$$

$$59P2P_{CollectorBus\_sec} = 1.30 \times 66.4$$

$$59P2P_{CollectorBus\_sec} = 86.32\ V_{sec}$$

$$T_{59P2P\_CollectorBus} = 15\ cycles = 0.25\ sec$$

5.3.8 POI (27) Protection Settings:

The voltage protection scheme will coordinate with the voltage limitations of the interconnecting system

Level 1 Definite-Time Phase Undervoltage Element:

$$27P1P_{POI\_sec} = 39.84\ V_{sec}$$

$$27P1P_{POI\_pu} = \frac{27P1P_{HS\_sec}}{V_{GSU\_LS\_nom}}$$

$$27P1P_{POI\_pu} = \frac{39.84\ V_{sec}}{66.4\ V_{sec}}$$

$$27P1P_{POI\_pu} = 0.6$$

$$T_{27P1P\_POI} = 420\ cycles = 7.0\ sec$$

Level 2 Definite-Time Phase Undervoltage Element:

$$27P2P_{POI\_sec} = 57.77\ V_{sec}$$

$$27P2P_{POI\_pu} = \frac{27P2P_{HS\_sec}}{V_{GSU\_LS\_nom}}$$

$$27P2P_{POI\_pu} = \frac{57.77\ V_{sec}}{66.4\ V_{sec}}$$

$$27P2P_{POI\_pu} = 0.87$$

$$T_{27P2P\_POI} = 600\ cycles = 10\ sec$$

5.3.9 POI Overvoltage (59) Protection Settings:

The voltage protection scheme will coordinate with the voltage limitations of the interconnecting system.

Level 1 Definite-Time Phase Overvoltage Element:

$$59P1P_{POI\_sec} = 73.79\ V_{sec}$$

$$59P1P_{POI\_pu} = \frac{59P1P_{HS\_sec}}{V_{GSU\_HS\_nom}}$$

$$59P1P_{POI\_pu} = \frac{73.79\ V_{sec}}{66.4\ V_{sec}}$$

$$59P1P_{POI\_pu} = 1.11$$

$$T_{59P1P\_POI} = 300\ cycles = 5\ sec$$

The level 2 element will provide faster tripping for more severe levels of overvoltage. This element will also provide coordination with the capacitor bank voltage limitations.

Level 2 Definite-Time Phase Overvoltage Element:

$$59P2P_{POI\_sec} = 78.82\ V_{sec}$$

$$59P2P_{POI\_pu} = \frac{59P2P_{HS\_sec}}{V_{GSU\_HS\_nom}}$$

$$59P2P_{POI\_pu} = \frac{78.82\ V_{sec}}{66.4\ V_{sec}}$$

$$59P2P_{POI\_pu} = 1.19$$

$$T_{59P2P\_POI} = 12\ cycles = 0.2\ sec$$

Coordination Plots/Diagrams for Compliance Evidence

The following graphs may be used as evidence to demonstrate compliance with the requirements of PRC-019.

The inverter voltage ride through scheme (Figure 11) consists of inverter LVRT and HVRT coordination with feeder protection.

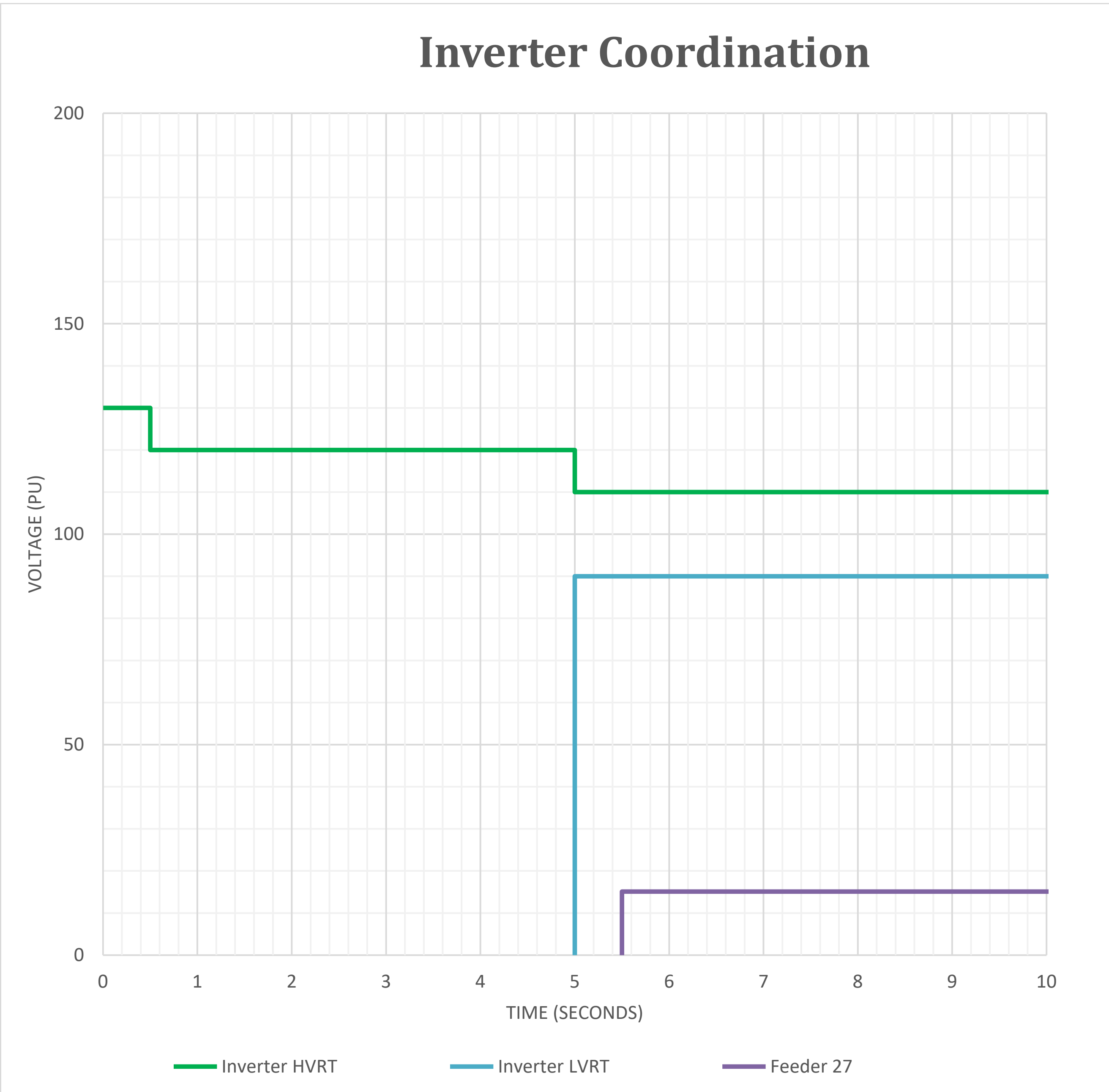

Figure 11: Inverter Voltage Coordination

The collector bus scheme (Figure 12) consists of voltage protection, associated with the collection bus, coordination with capacitor bank.

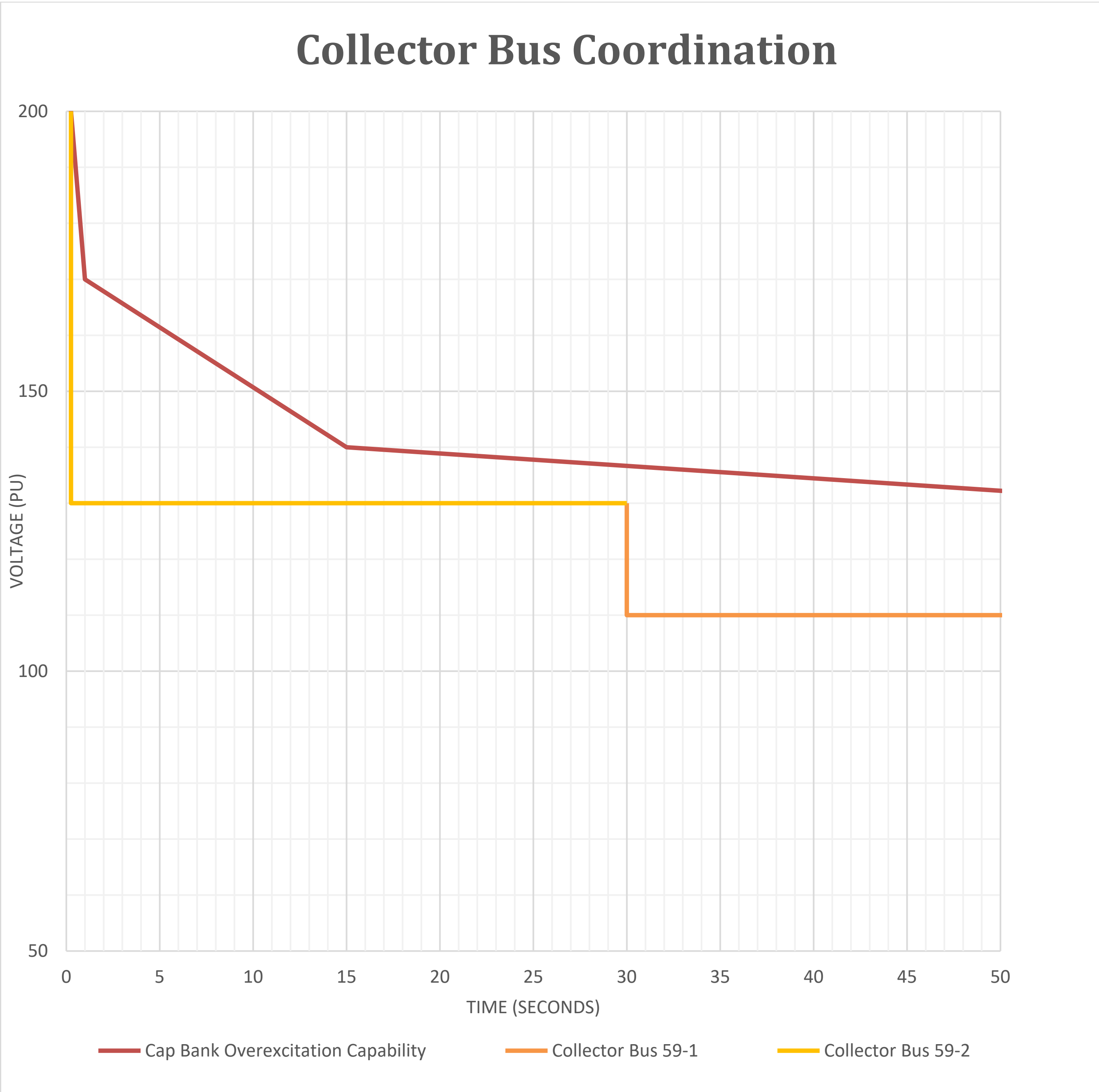

Figure 12: Collector Bus Voltage Coordination

The point-of-interconnection scheme (Figure 13) consists of voltage protection, associated with the high-side of the main power transformer, coordination with the interconnecting system capabilities.

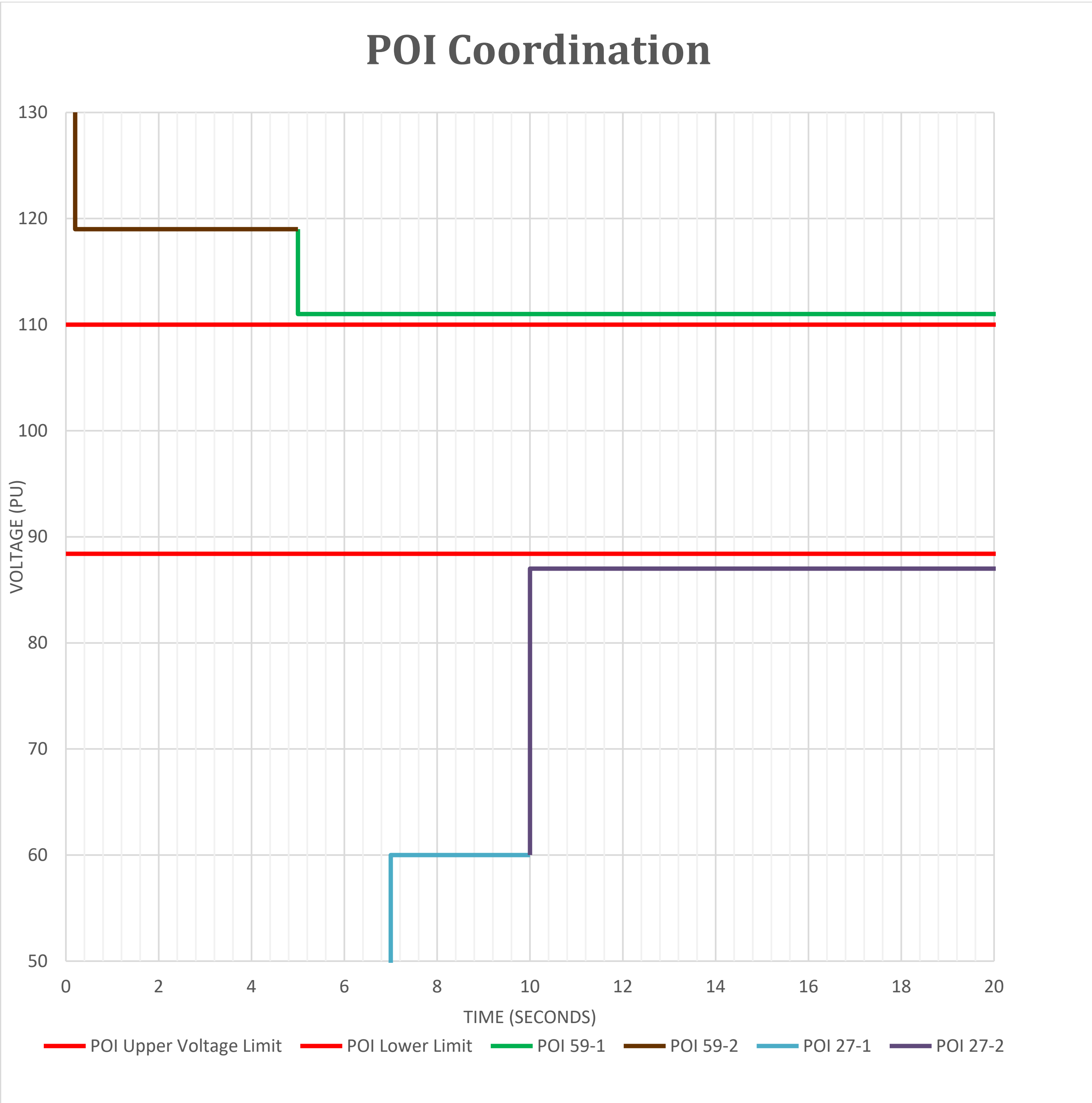

Figure 13: Dispersed Power Producing Resource POI Voltage Coordination

6 References (Associated Documents)

- "Protective Relaying for Power Generation Systems", Boca Raton, FL, Taylor & Francis, 2006, Reimert, Donald
- "IEEE C37.102, IEEE Guide for AC Generator Protection"
- "IEEE C50.13, IEEE Standard for Cylindrical-Rotor 50 Hz and 60 Hz Synchronous Generators Rated 10 MVA and Above"
- "IEEE C37.106, IEEE Guide for Abnormal Frequency Protection for Power Generating Plants"
- "ANSI C84.1, American National Standard for Electric Power Systems and Equipment-Voltage Ratings (60 Hz)"
- "IEEE Std C37.99, IEEE Guide for the Protection of Shunt Capacitor Banks"
- "IEEE Std 1036, IEEE Guide for the Application of Shunt Power Capacitors"
- "NERC BPS-Connected Inverter-Based Resource Performance Guideline"
- "IEEE Std 421.5, IEEE Recommended Practice for Excitation System Models for Power System Stability Studies"
- "Power System Stability and Control", McGraw-Hill 1994, Prahba Kundur
- Alla, M.,Guzman, A., Finney, D., Fischer, N., "Capability Curve-Based Generator Protection Minimizes Generator Stress and Maintains Power System Stability" in 45th Annual Wester Protective Relay Conference, October 2018.

Compliance Input Working Group Report

Action
Information

Background
Compliance Input Working Group (CIWG) report to the Reliability and Security Technical Committee (RSTC).

Summary
- The CIWG Cloud Encryption Team submitted their draft Compliance Implementation Guidance to the ERO on June 29, 2020. It is still in review as of August 28, 2020. The team had also had their Security Guideline for BCSI Cloud Encryption posted on the NERC website. This completes the deliverables assigned to the team. All deadlines were met for submissions to the Electric Reliability Organization (ERO).
- The CIP to Cyber Security Framework (CSF) mapping team is working on the final posting for their first effort for the 2014 CSSWG CSF to CIP mapping document update. That document is still under review. The recommendation is currently to post the document under the RSTC "Reliability and Security Guidelines" section. The team is also working on a new version of the tool which has expanded functionality by mapping CIP to the CSF, and includes a companion document showing how to effectively use the mapping tool. Currently, the team has recruited 5 volunteers to validate the tool meets expectations for clarity, ease-of-use, and value.
- The Bulk Electric System Cyber System Information (BCSI) in the Cloud Tabletop team completed the tabletop in May 2020, and is working on lessons learned documentation. Currently, Western Area Power Administration (WAPA) is working with Microsoft to answer the last questions on the second request for information from the ERO team.
- The Evidence Request Tool (ERT) team, working with the NERC ERT team, reworked the communication process for feedback in order to have more effective feedback and increase the overall interaction between the two groups. Working with Stephanie Lawrence at NERC, the team put together a survey which helped prioritize feedback from the CIWG. This prioritized list was then sent to the NERC ERT team so they could work on the highest prioritized items. This will continue until the current feedback list is worked through. Both groups consider this a successful approach.
- The team for review of the "Joint Staff White Paper on Supply Chain Vendor Identification - Noninvasive Network Interface Controller" successfully completed their review May 22, 2020. The paper was successfully reviewed and posted on the NERC website on July 31, 2020.
- The CIWG is continuing to make administrative changes to optimize the group, including using Office 365 Forms for fast delivery of surveys to collect information from the teams, a more detailed email template for recruiting volunteers, disbanding teams that complete their deliverables or tasks, and writing thank you letters for individuals who

participated in the groups. The CIWG continues use of the extranet site to track tasks and exchange information.

- Discussions have occurred to look at changing the scope and name of the CIWG to the Security Working Group (SWG), which would expand the scope of the CIWG in certain areas. No decisions have been finalized, but a meeting is scheduled to go over the details and ensure the scope of the group is appropriate.

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GMD Task Force Update

Written Update to the RSTC – No Presentation

September 15, 2020

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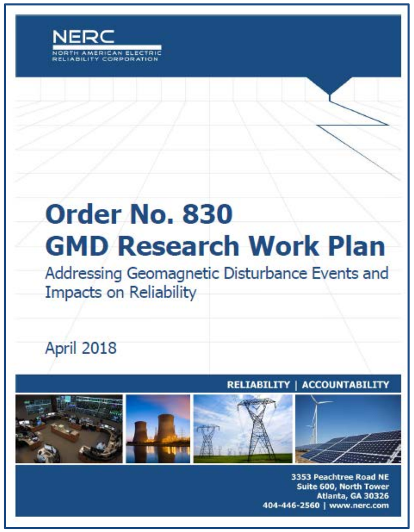
GMD Research Plan Update

- Two-year research effort with Electric Power Research Institute (EPRI) concluded Q1 2020
  - Promotes further knowledge of severe GMD event impacts and addresses FERC directives for research
  - Final EPRI white paper published in August 2020

    Research Findings for GMD Research Work Plan (EPRI Report 3002019720)



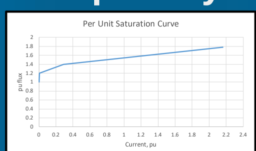
Work Plan is Posted on the GMDTF site

- GMDTF will review final deliverables to develop recommendations to the ERO
- All EPRI reports and tools in this project are available to the public at no charge

NERC GMD Research Plan Objectives

Improved Earth Conductivity Models

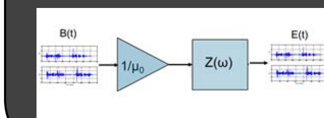
Improved Harmonic Analysis Capability



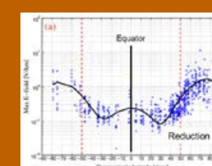
<u>Delivered Products:</u>

- GIC Harmonics Tool
- 84 Transformer Thermal Models
- Updated Earth Models
- Technical reports that further the basis for accurate TPL-007 GMD Assessments

Geoelectric Field Evaluation

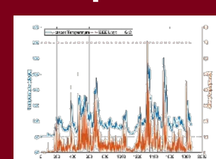


Latitude Scaling Factor



Harmonic Impacts

Transformer Thermal Impacts



Spatial Averaging

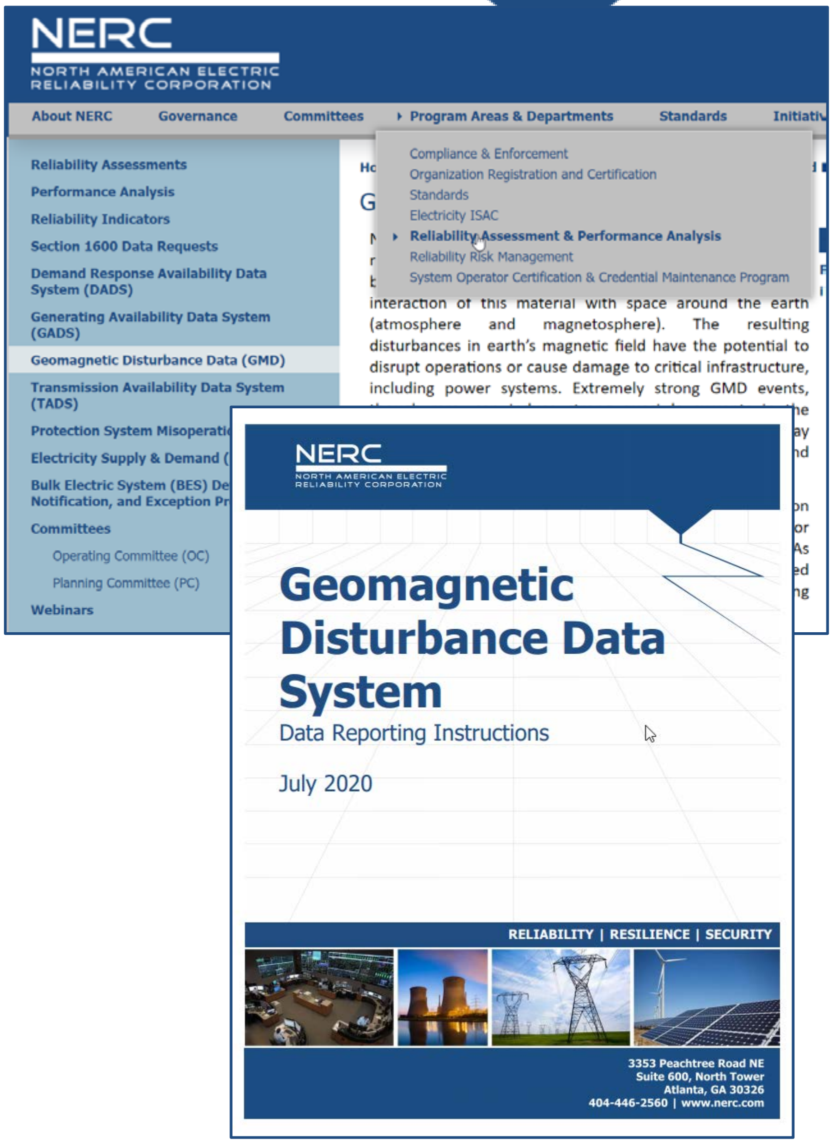
$$E_{peak} = 8 \times \alpha \times \beta \ (\mathrm{V/km})$$

α= Geomagnetic Latitude Scaling Factors

β= Conductivity Scaling Factor

Data Reporting Information

- GMDTF is supporting NERC implementation of approved Section 1600 Data Request addressing FERC Order No. 830
  - GMDTF is providing ongoing technical feedback to NERC on the data application and industry rollout plans
- RSTC will receive an update from NERC Staff during the Sept 15 meeting
- NERC's GMD Data web page has reporting instructions and links
- On average, ~200 GMD events could meet reporting criteria per 11 year solar cycle



For more information...

Chair: Emanuel Bernabeu (PJM)
Vice Chair: Ian Grant (TVA)
NERC Staff Coordinator: Mark Olson

Group	Subgroup	Task No	Task Name	Task Description	Strategic Focus Area	Target Completion	Requested RSTC Action	Status	Comment	2019 RISC Report Risk Profile(s)	2018 RISC Report Risk Profile(s)	ERO LTS	ERO 2020 Workplan Priorities	Assessment/Report Rec
GMDTF		1	Final Report on NERC GMD Research Work Plan tasks (FERC Order No. 851)	Final Report on NERC GMD Research Work Plan tasks; Upon completion of research deliverables, the task force will review, comment, and provide an assessment of the research results and outcome. Research required by Order 851.	RP2A	Q42020	Information	EPRI Reports were published addressing all research plan tasks. NERC Staff and GMDTF reviewing.	Disband upon completon of work in 2020. ORS activities support ongoing monitoring and reduction of GMD risk.	2 - Extreme Natural Events	3, 7	FA2		
GMDTF		2	Develop a Data Reporting Instruction for entities to collect and report GIC and magnetometer data as specified in the ROP Section 1600 Data Request	Develop a Data Reporting Instruction for entities to collect and report GIC and magnetometer data as specified in the ROP Section 1600 Data Request	RP2A	Q2-2020	Information	DRI is complete. PC Reviewed January 14 – February 14, 2020. NERC IT staff is developing the data reporting application for implementation before year-end 2020. Update to RSTC is on Sept agenda.	Disband upon completon of work in 2020. ORS activities support ongoing monitoring and reduction of GMD risk.		3, 7			Board approved Section 1600 Data Request, meeting FERC Order 830
GMDTF		5	Analyze data from GMD events collected under the GMD Data Request and other necessary information to further understand GIC effects on BES facilities. Summarize observations, including observations on GIC modeling.	Analyze data from GMD events collected under the GMD Data Request and other necessary information to further understand GIC effects on BES facilities. Summarize observations, including observations on GIC modeling.	RP2A	Q4-2020	Information	Activity is from 2018 RISC Report. The required reviews are enabled through the implementation of the Sect 1600 data request occurring in 2020.	Disband upon completon of work in 2020. ORS activities support ongoing monitoring and reduction of GMD risk. Transfer this task to the ERO (through Event Analysis program, PA activities, regional technical committees, and support from EPRI as needed.)	2 - Extreme Natural Events	7			

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Inverter-Based Resource Performance Task Force (IRPTF) Update

Jeff Billo, IRPTF Vice Chair

RSTC Meeting

September 15, 2020

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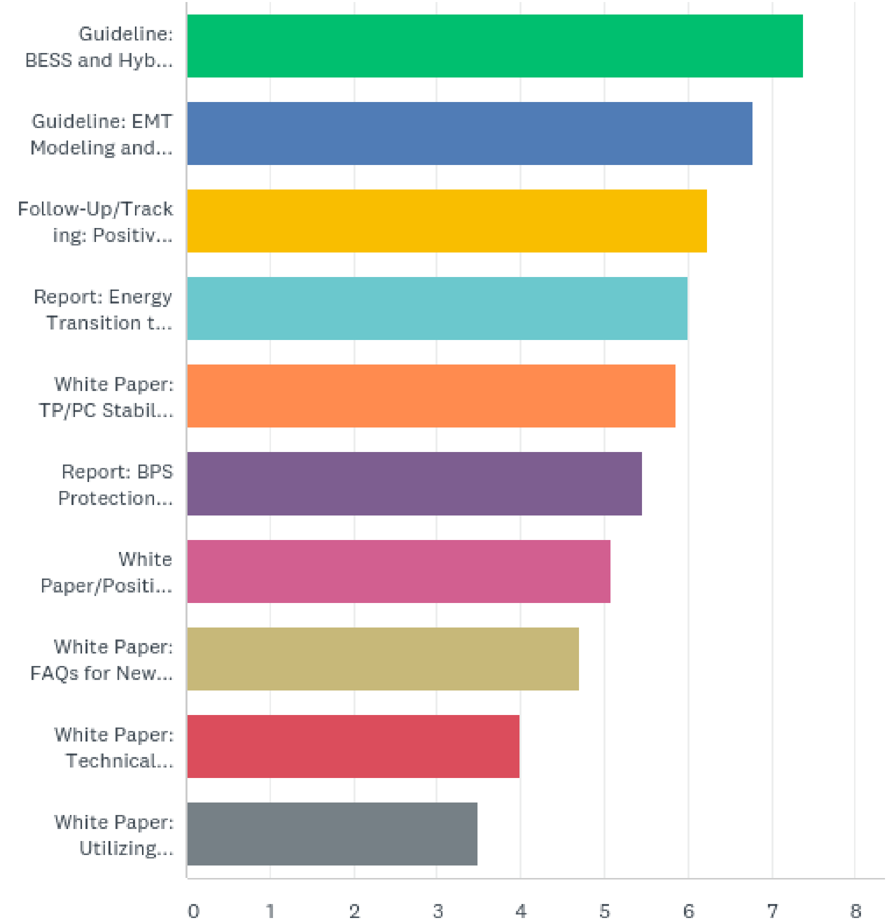
IRPTF Priorities

- IRPTF currently has a full plate of work plan items; additionally, several potential new topics were discussed at the June meeting
- An IRPTF survey was conducted in June to get member feedback on task priorities
- 75 members responded:

https://www.nerc.com/comm/PC/InverterBased%20Resource%20Performance%20Task%20Force%20IRPT/IRPTF_Priorities_June_2020.pdf

- Top 2 items:
  1. BESS and Hybrid Plant Performance, Modeling, and Studies Reliability Guideline
  2. EMT Modeling and Studies Reliability Guideline



Reliability Guideline

BESS and Hybrid Plant Performance, Modeling, Studies

- *Goal: Provide industry with clear guidance and recommendations for battery energy storage and hybrid plant performance, modeling, and studies*
- Status:
  - Initial rough draft completed in August
  - Meeting fairly often to continue work on report
- Next Steps:
  - IRPTF developments into Fall 2020
  - Goal to have final draft ready in late Fall 2020
  - Seek approval in Q4 2020/Q1 2021

Reliability Guideline EMT Modeling and Simulations

- *Goal: Provide industry with clear guidance and recommendations for use of EMT models and performing EMT simulations*
- Status:
  - Work kicked off; sub-group formed
  - Meeting regularly to continue work on report
  - Scope recently updated to scale down report
- Next Steps:
  - IRPTF developments into Fall 2020
  - Goal to have final draft ready in winter 2020/2021
  - Seek approval in Q1 2021

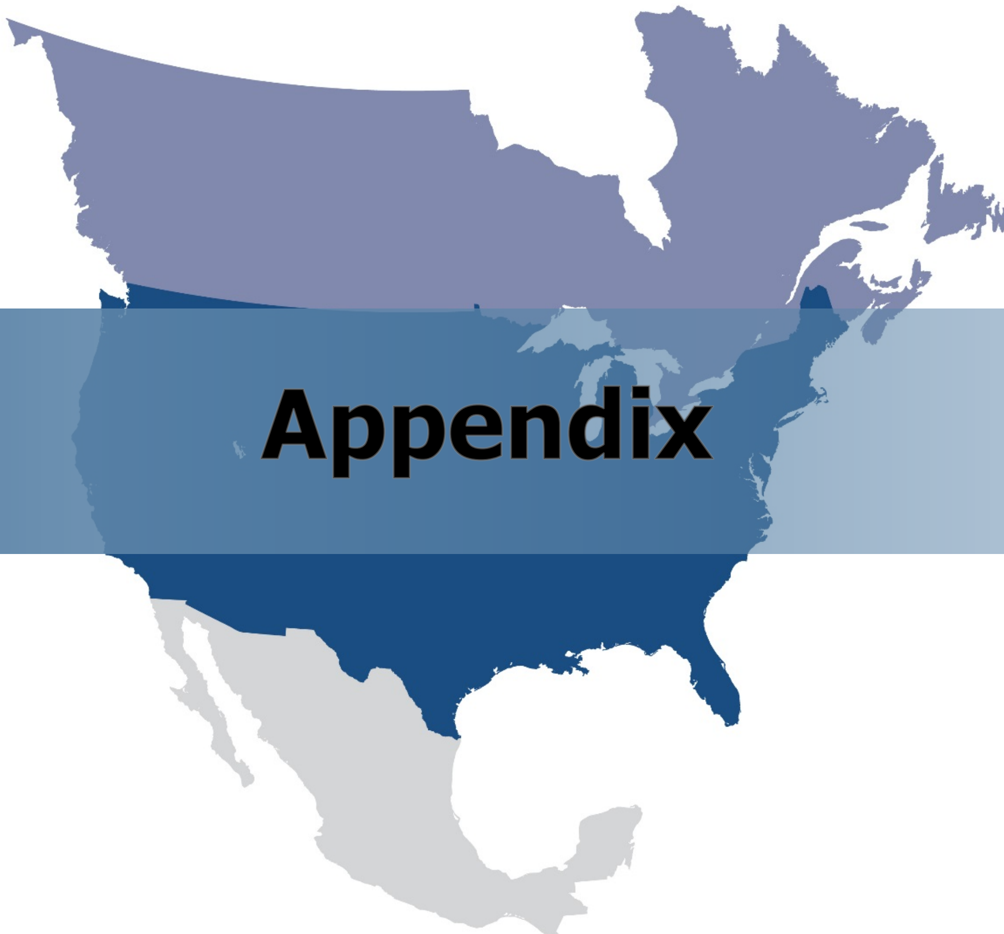
NERC-WECC Joint Report on IBR Modeling

- The NERC Alert following the Canyon 2 Fire Event highlighted a number of IBR modeling issues, which were predominantly observed in the Western Interconnection
- NERC and WECC subsequently reviewed a WECC base case and WECC processes and issued a report with certain findings and recommendations (see Appendix in this presentation for summary):
  - https://www.nerc.com/comm/PC/InverterBased%20Resource%20Performance%20Task%20Force%20IRPT/NERC-WECC_2020_IBR_Modeling_Report.pdf
- The results of this effort are consistent with findings from IRPTF's May 2020 Modeling and Studies Technical Report:
  - https://www.nerc.com/comm/PC/InverterBased%20Resource%20Performance%20Task%20Force%20IRPT/IRPTF_IBR_Modeling_and_Studies_Report.pdf

Upcoming Meetings

- IRPTF is meeting via WebEx September 22-23
- IRPTF is tentatively planning on meeting via WebEx in December

Questions and Answers



Appendix

- Key Findings and Recommendations

#	Modeling Issue	Recommendations
1	Type 3 and Type 4 wind plants and solar PV plants are represented using the first-generation dynamic models (i.e., wt3g, wt4g).	Generator Owners (GOs) should update their first-generation generic wind and solar PV models to the second-generation models at the earliest possible time due to modeling limitations and simplifications within the first-generation renewable energy models. This may require additional verification testing to ensure accurate parameterization of the dynamic models.
2	Wind and solar PV plants above the modeling threshold established in the WECC *Data Preparation Manual* (i.e., 20 MVA) are represented with either no dynamic model or an incorrect dynamic model (e.g., synchronous generator model).	GOs should develop appropriate dynamic models for their wind facilities that meet the specifications set in the WECC *Data Preparation Manual* and should use the latest recommended dynamic models (i.e., the second-generation renewable energy models). These models should be provided to the respective TP and PC at the earliest possible time.
3	Wind and solar PV plant models are likely parameterized by using generic values that do not reflect as-built settings of equipment installed in the field. TPs and PCs performing verification of dynamic models for wind and solar PV plants are not capturing modeling errors.	GOs should ensure that the dynamic models for their respective facilities are parameterized to reflect the actual installed equipment at each specific site and should not include generic parameter values. GOs should coordinate with their TPs and PCs if they have any questions regarding how to parameterize their dynamic models. TPs and PCs should verify[3] the dynamic model parameters provided by GOs to ensure that they match the as-built controls, settings, and configuration of the equipment installed in the field. This verification should occur for all generator models provided and should occur prior to TPs and PCs providing these models to WECC for inclusion in the Interconnection-wide base case.
4	Several modeling errors were identified during the review of case quality.	GOs should ensure that all data fields are reported correctly per the WECC *Data Preparation Manual*. TPs and PCs should verify that the data fields are submitted correctly. WECC should ensure that data quality checks are being performed on all incoming data from TPs and PCs for their areas. WECC should place additional scrutiny during case review processes to ensure errors are being corrected. Change management processes should be implemented to ensure updates are reflected in the current release of WECC base cases in a timely manner: in particular, generator turbine type, dynamics models for resources above the modeling size thresholds, distributed energy resource (DER) modeling practices, handling retired units, matching power flow and dynamics data, modeling battery energy storage systems (BESSs), interoperability between software vendors, and modeling dynamic reactive devices all should be a primary modeling improvement for WECC and its stakeholder groups.

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Reliability Assessment Subcommittee

Status Report

Written Update – No Presentation

September 15, 2020

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Summary

- 2020 Long Term Reliability Assessment and Probabilistic Assessment
  - Review of Schedule
- 2020 Winter Assessment Schedule
- ERS Measure 6 Pilot

2020 Long-Term Reliability Assessment Development

Date	Milestone
June 22	Assessment Areas provide preliminary data and narratives
June 26 – July 8	RAS Peer Review
July 14 – 16	RAS Meeting
July 31	Final data and narrative inputs due
July – August	Report Drafting
Mid-September	RSTC review draft report
October	RSTC Endorsement Vote
November	NERC staff provides LTRA to the NERC Board

Table Shading		
Complete	*Future RSTC Action*	*Future Other Action*

2020-2021 Winter Reliability Assessment Development

Date	Milestone
September 2	Assessment Areas submit Preliminary Data and Narratives
September 2 – 24	Report Development and RAS Review
Early October	RSTC review draft report
October	RSTC Endorsement Vote
November	Report release

Table Shading		
Complete	*Future RSTC Action*	*Future Other Action*

2020 Probabilistic Assessment

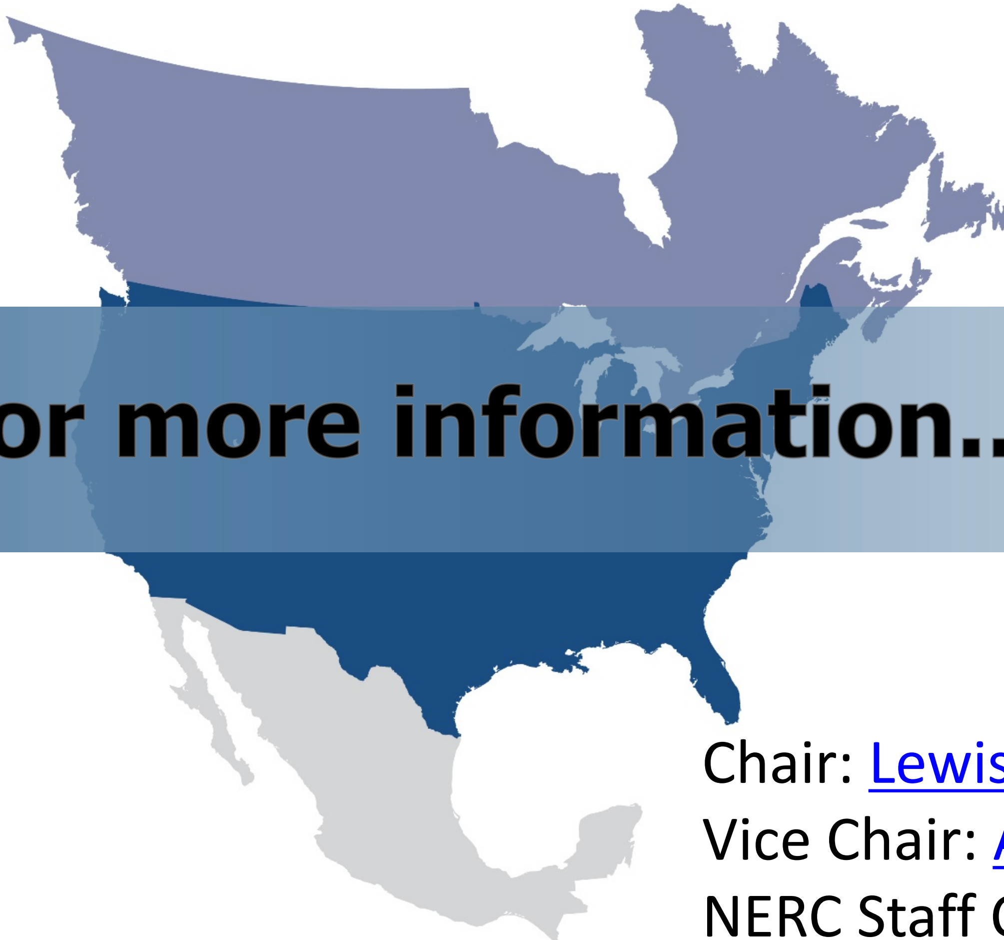
- RAS and Probabilistic Assessment Working Group (PAWG) are conducting the biennial Probabilistic Assessment (ProbA)
- ProbA complements the LTRA by providing additional probabilistic resource adequacy statistics
  - Loss of Load Hours (LOLH)
  - Expected Unserved Energy (EUE)
- Base case and regionally-derived risk scenarios are examined
- Results will be included in the 2020 LTRA
  - Detailed scenario analysis results will be reported separately in early 2021
- ProbA and LTRA analysis supports ERO objectives for assessing energy adequacy (ERO Enterprise Priorities Focus Area 2)

ERS Measure 6 White Paper

- RAS approved white paper documenting results of pilot study:

Measure 6: Forward-Looking Net Demand Ramping Assessment

- RAS pilot study was initiated based on Essential Reliability Services Working Group (ERSWG) 2015 report
  - Measure 6 is aimed at tracking and projecting levels of ramping variability for trending and assessment of resource needs
  - Pilot study objective was to evaluate feasibility of a screening approach for assessment areas to use to monitor future ramping concerns
- RAS found the screening approach was feasible and supports monitoring potential flexibility concerns.
  - Some areas already employ ramping assessments that go beyond screening
- RAS will include a request for information on ramping screening and studies in the 2021 LTRA Request for each assessment area



For more information…

Chair: Lewis De La Rosa (PJM)
Vice Chair: Anna Lafoyiannis (TVA)
NERC Staff Coordinator: Bill Lamanna

Group	Subgroup	Task No	Task Name	Task Description	Strategic Focus Area	Target Completion	Requested RSTC Action	Status	Comment	2019 RISC Report Risk Profile(s)	2018 RISC Report Risk Profile(s)	ERO LTS	ERO 2020 Workplan Priorities	Assessment/Report Rec
RAS		1	Summer Reliability Assessment	Seasonal Reliability Assessment Required by NERC RoP Sect 800. Include seasonal scenarios to evaluate resource/energy adequcy risks in assessment areas.	RP1B	2Q 2020	Information	Complete. Published in May 2020.			1, 2, 3			LTRA 2019 Rec 1
RAS		2	Long-Term Reliability Assessment	Annual Reliability Assessment Required by NERC RoP Sect 800. Includes probabilistic assessment (ProbA) to assess energy adequacy risk (LTRA Rec 1). Analysis is also underway to assess storage impacts on BPS (LTRA Rec 6)and transmission development trends/reliability risk (LTRA rec 7).	RP1A, RP1F	4Q 2020	Endorse	Data received from NERC Regions. NERC staff and RAS are developing report. Anticipate RSTC review in September 2020.			1, 2, 3	FA2	FA2-3	LTRA 2019 Rec 1, 6, and 7
RAS		3	Winter Reliability Assessment	Seasonal Reliability Assessment Required by NERC RoP Sect 800. Include seasonal scenarios to evaluate resource/energy adequcy risks in assessment areas.	RP1B	4Q-2020	Endorse	Data requested from regions in July 2020. Anticipate RSTC review in October 2020.			1, 2, 3			LTRA 2019 Rec 1
RAS		4	Composite Study (Review)	Review and provide input to NERC Staff (Advanced System Analytics and Modeling) on NERC Study of Resource Adequacy and Transmission Deliverability		4Q-2020	Information	NERC Staff is studying this issue and working with RAS for industry technical input. RAS and PAWG have provided feedback to NERC on study scope. NERC staff and study participants are reviewing results.			1,3			
RAS		5	Ramping Resource Analysis	Measure 6 Analysis White Paper documenting the results of screening analysis to identify areas with changes in their load patterns or their resource mix that could impact ramping and flexibility needs over time		Q2-2020	Information	Complete. RAS approved white paper documenting results of pilot assessment and posted it on the RAS website. Methods such as the screening approach described in the white paper will be used to evaluate ramping concerns in future assessments.		1 - Grid Transformation	1,3			LTRA 2019 Rec 4
RAS	PAWG	1	Data collection approaches and recommendations techincal report	Develop a technical report that describes industry approaches and best practices for probabilistic assessment	RP1B	Q1 - 2021	Approve	Draft prepared for RAS Review Aug 2020, Moved 1 quarter to account for RAS/RSTC review periods and response to comments.		1 - Grid Transformation	2, 3			
RAS	PAWG	2	Long-Term Reliability Assessment Enhancement	Develop screening approaches or other probabilistic studies to supplement LTRA in off ProbA years.	RP1B	Q4 2020	Information	RAS will consider options at Sept meeting.		1 - Grid Transformation	3			LTRA 2019 Rec 1
RAS	PAWG	3	Probabilistic Assessment - Base Case	Perform biennial ProbA, sensitivity/scenario studies, for the 2020 LTRA	RP1B	Q4-2020	Endorse	Preliminary results are in review. Base ProbA to be in conjunction with 2020 LTRA.		1 - Grid Transformation	3	FA2	FA2-3	LTRA 2019 Rec 1
RAS	PAWG	4	Probabilistic Assessment - Scenario Case	Develop and present findings in a Scenario report that expands upon the Base Case	RP1B	Q1-2021	Approve	Regional risk scenarios approved by RAS. Sensitivity scenarios to be complete in Q1 2021.		1 - Grid Transformation	3	FA2	FA2-3	LTRA 2019 Rec 1
RAS	PAWG	5	Scope Review	Perform periodic scope review		Q2 2020	Approve	RAS approved the revised scope April 2020. It contains minor updates from previous scope. Submitted to NERC staff for RSTC approval during transition.						

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System Protection & Control Subcommittee Update

Jeff Iler, System Protection & Control Subcommittee Chair
RSTC Meeting
September 15, 2020

RELIABILITY | RESILIENCE | SECURITY




Activity Update

- Last Webex Meeting: September 2, 2020
- Next Webex Meeting: TBD
- Current Initiatives:
  - PRC-019 Compliance Implementation Guidance
    - Requesting RSTC Endorse for Submittal to the ERO
  - PRC-023 SAR
    - Requesting RSTC Endorse
  - Protection System Commissioning Lesson-Learned
    - LL20200702_Commisioning_Testing published
    - Developing outreach plan

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Activity Update

- Current Initiatives:
  - Technical Paper on Impact of BPS-Connected Inverter-Based Resources on BPS Protection Systems
    - Work in Progress
  - PRC-024-3 Implementation Guidance
    - Work in Progress

Questions and Answers

Questions and Answers

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

Website: SPIDERWG
Hierarchy: Reports to RSTC
Chair: Kun Zhu (September 2019)
Vice-Chair: Bill Quaintance (July 2018)
NERC Lead: Ryan Quint, JP Skeath
Scope Approved: December 2018

#	Task Description	Risk Profile(s)	Strategic Focus Area(s)	Target Completion	Requested Action	Status
Modeling Subgroup *(Co-Leads: Irina Green, CAISO; Mohab Elnashar, IESO)*						
M1	**DER Modeling Survey** *Perform industry survey of SPIDERWG members regarding use of DER planning models in BPS studies, dynamic load models and DER modeling guidelines.*	1, 2	2, 3	Q4-2020	No	Survey results complete; white paper being created to capture key takeaways from survey. To be presented to RSTC at appropriate time.
M2	**Reliability Guideline: DER Data Collection for Modeling** *Guideline providing recommendations and industry practices for the mandatory and optional DER data to be collected by the Reliability Coordinator as well as on how, where, and when to gather such data.* • *Review the documentation of existing data collection techniques and processes that has been developed by the industry.* • *Recommendations for DER data collection technique suitable for various study types.* *Recommendations for the DER data complexity requirements based on DER penetration levels*	1, 2	2, 3	Q3 2020	Yes	Currently developing responses to industry comments. Expected completion in June 2020. *(High priority task for SPIDERWG)*
M6	**Modeling Distributed Energy Storage and Multiple Types of DERs** *SPIDERWG will dig into technical considerations of modeling distributed energy storage, specifically distributed battery energy storage (D-BESS). The group will also consider how to model multiple types of DERs, including D-BESS and distributed solar PV (D-PV). Lastly, the group will focus on forecasting and dispatch assumptions for D-BESS. SPIDERWG will determine the level of guidance or reference materials needed once discussions begin. Task to be coordinated with Studies sub-group.*	1, 2	2, 3	Q2 2021	Yes	New work task; starting May 2020. *(High priority task for SPIDERWG)*
Verification Subgroup *(Co-Leads: Michael Lombardi, NPCC; Mike Tabrizi, DNV-GL)*						
V1	**Reliability Guideline: DER Performance and Model Verification** *Reliability Guideline covering aggregate DER model verification, including recommended measurement practices, executing model verification activities, model benchmarking, relation to MOD-033 activities, and conversion of data sources for verification.*	1, 2	2, 3	Q4-2020	Yes	Near completion of initial draft; planned to go to RSTC in September for posting for industry comment. *(High priority task for SPIDERWG)*
V2	**Reliability Guideline: DER Forecasting Practices and Relationship to DER Modeling for Reliability Studies** *Guidance providing how forecasting practices are linked to DER modeling for reliability studies. DER forecasting practices are important for accurately representing the correct amount and type of DER, particularly at an aggregate level representation for BPS studies.*	1, 2	2, 3	Q2-2021	Yes	On track; early stages of development.
Studies Subgroup *(Co-Leads: Peng Wang, IESO; Mohab Elnashar, IESO)*						

S1	**Reliability Guideline: Bulk Power System Planning under Increasing Penetration of Distributed Energy Resources** *Reliability Guideline providing recommended practices for performing planning studies considering the impacts of aggregate DER behavior – study approaches, analyzing BPS performance criteria incorporating DER models into studies, developing study assumptions, etc.*	1, 2	2, 3	Q4-2020	Yes	On track; nearing completion of initial draft, completing some final sections. Seeking RSTC authorization to post after December 2020 meeting. *(High priority task for SPIDERWG)*
S2	**White Paper: Review of TPL-001 Standards for Incorporation of DER** *White paper discussing technical review of NERC TPL-001-5, and development of any recommendations pertaining to consideration and study of DER impacts to the BPS.*	1, 2	2, 3, 4	Q2-2020	Yes	Reviewing feedback from PCEC before PC disbandment; making additional edits to the white paper. Planning to bring to RSTC in September 2020. *(High priority task for SPIDERWG)*
S3	**Recommended Simulation Improvements and Techniques** *Guidance (white paper) to software vendors on tools enhancements for improved accounting and study of aggregate DER.*	1, 2	2, 3	Q3-2020	Infor-mation	On track; nearing completion of white paper providing vendor guidance.
S4a	**Reliability Guideline: Recommended Approaches for Developing Underfrequency Load Shedding Programs with Increasing DER Penetration** *Guidance on how to study UFLS programs and ensure their effectiveness with increasing penetration of DER represented.*	1, 2	2, 3	Q1-2021	Yes	On track. Nearly complete in sub-group team; needs Studies sub-group review, then to SPIDERWG. Planning for December 2020 RSTC.
S4b	**White Paper: DER Impacts to UVLS Programs** *Short white paper on potential impacts of DERs on UVLS program design; leverage work of PRC-010 standards review (C6 task).*	1, 2	2, 3	Q2-2021	Yes	On track.
S5	**White Paper: Beyond Positive Sequence RMS Simulations for High DER Penetration Conditions** *Considerations for high penetration DER systems and the need for more advanced tools (e.g., co-simulation tools) for studying DER impacts on the BPS.*	1, 2	2, 3	Q2-2021	Yes	On track.
Coordination Subgroup *(Co-Leads: Clayton Stice, ERCOT; Jimmy Zhang, AESO)*						
C2	**Reliability Guideline: Communication and Coordination Strategies for Transmission Entities and Distribution Entities regarding Distributed Energy Resources** *Develop recommended strategies to encourage coordination between Transmission and Distribution entities on issues related to DER such as information sharing, performance requirements, DER settings, etc.*	1, 2	2, 3	Q2-2021	Yes	Tabled to align with standards review (C6 activity) activity; will start later 2020.
C5	**SPIDERWG Terminology: Working Definitions Document** *Review of existing definitions and terminology and development and coordination of new terms, for consistent reference across sub-groups.*	1, 2	2, 3	Q3-2020	Infor-mation	Initial draft complete, shared with Coordination sub-group; to be shared with overall SPIDERWG shortly. Report to SPIDERWG in September.

C6	**NERC Reliability Standards Review** *White Paper reviewing NERC Reliability Standards and impacts of DER.*	1, 2	2, 3, 4	Q4-2020	Yes	On track; initial reviews complete, consolidating responses into draft white paper; white paper to be reviewed by SPIDERWG; plan to have white paper ready for RSTC by December. *(High priority task for SPIDERWG)*
C7	**Tracking and Reporting DER Growth** *Coordinated review of information regarding DER growth, including types of DER, size of DER, etc. Consideration for useful tracking techniques for modeling and reliability studies.*	1, 2	2, 3	Ongoing	No	In monitoring and data collection stage.

Completed and Cancelled Tasks (for Tracking Purposes Only)

#	Task Description	Risk Profile(s)	Strategic Focus Area(s)	Target Completion	Requested Action	Status
Completed Tasks						
M3	**Reliability Guideline: DER_A Model Parameterization** *Guideline providing recommendation for DER modeling practices.*	1, 2	2, 3	Q3-2019 (Complete)	Yes	Complete. *(High priority task for SPIDERWG)*
M4	**Review of MOD-032-1 for DER Data Collection** *(In coordination with activity C4) Proposing MOD-032-1 SAR to address modifications to the standard to facilitate data collection for DERs for interconnection-wide modeling.*	1, 2	2, 3, 4	Q4-2019	Yes	Complete. PC endorsed at December 2019 PC meeting. Provided to NERC Standards staff December 2019.
M5	**Modeling Notification: Dispatching DER off Pmax in Case Creation** *Modeling notification on recommended practices and considerations for DER modeling when dispatching DER at output levels other than Pmax in the powerflow and dynamics data. Practices to ensure expected response from DER in these modeled conditions.*	1, 2	2, 3	Q3-2019 (Complete)	Infor-mation	Complete; approved by SAMS and posted to SAMS webpage.
C1	**Reliability Guideline: BPS Reliability Perspectives on the Adoption of IEEE Std. 1547-2018** *Reliability Guideline of BPS perspectives for adopting and implementing IEEE 1547-2018.*	1, 2	2, 3	Q1-2020	Yes	Complete. Approved March 2020, and posted. (High priority task for SPIDERWG)
C4	**Review of MOD-032-1 for DER Data Collection see M4 activity.**	1, 2	2, 3, 4	Q4-2019 (Complete)	Yes	Complete.
Cancelled Tasks						
C3	**Educational Material to Support Information Sharing between Industry Stakeholders** *Develop material to educate industry stakeholders on practices, recommendations and technical work developed by other industry organizations.*	1, 2	2, 3	Ongoing	No	Task cancelled; references to industry materials and SPIDERWG materials will be provided in other work products. Ongoing industry outreach and engagement by SPIDERWG members.

Possible Misunderstandings of the Term “Load Loss” White Paper

Action
Review

Background
Engineers and other staff working for Transmission Planners, Planning Coordinators, Transmission Operators, and other industry entities, as well as some NERC documents and other industry documents, may in some instances use the term "load loss" in ways that may be inconsistent or even misleading to some industry stakeholders. For example, state and federal regulators may interpret "load loss" to be customers that were subjected to an outage (a loss of electric service) due to unplanned outages of, damage to, or misoperation of elements in the bulk power system (BPS). However, when discussing the system response to transmission faults or other system disturbances, planning engineers, operating personnel, and staff for other industry entities may refer to customer load that is temporarily shut down or transferred to an emergency standby power source (battery and/or generator) by customer-owned controls or end user equipment as "load loss". The differences in the assumed meaning of “load loss” has the potential to cause significant misunderstandings between various industry stakeholders regarding the severity of actual or potential future events, reporting requirements for events, and the need to provide network improvements based on projected system performance.

NERC SAMS prepared this whitepaper per request from the NERC Planning Committee (PC) to describe the relevant concerns and to provide recommendations.

Summary
SAMS requests that the RSTC review the *Possible Misunderstandings of the Term “Load Loss”* white paper and provide feedback to NERC SAMS.

Possible Misunderstandings of the Term "Load Loss"

July 2020

Problem Statement

Engineers and other staff working for Transmission Planners, Planning Coordinators, Transmission Operators, and other industry entities, as well as some NERC documents and other industry documents, may in some instances use the term "load loss" in ways that may be inconsistent or even misleading to some industry stakeholders. For example, state and federal regulators may interpret "load loss" to be customers that were subjected to an outage (a loss of electric service) due to unplanned outages of Bulk Power System elements, damage to Bulk Power System elements, or miss-operation of elements in the Bulk Power System. However, when discussing the system response to transmission faults or other system disturbances, planning engineers, operating personnel, and staff for other industry entities may refer to customer load that is temporarily shut down or transferred to an emergency stand-by power source (battery and/or generator) by customer-owned controls or end-user equipment as "load loss". The differences in the assumed meaning of "load loss" has the potential to cause significant misunderstandings between various industry stakeholders regarding the severity of actual or potential future events, reporting requirements for events, and the need to provide network improvements based on projected system performance.

Background

Historically, the term "load loss" or the alternative term "load dropped" was used to communicate the amount of customer load which had no electric service (a.k.a., loss-of-service) due to an event on the electric power system. For example, a summer thunderstorm with high winds causes outages of distribution and transmission facilities for a specific utility's system. The utility estimates the number of customers that had no electric service and the amount of load which had been "lost" or "dropped" and considers that as "load loss". In this example, if the number of customers with no electric service was 200,000, the utility would estimate the corresponding "load dropped" to be about 1000 MW. The utility would report to the state utility commission(s) that about 200,000 customers experienced an outage and the load dropped was about 1000 MW. "Load loss" was equivalent to "load dropped" or "customer outage" in this example. This seems to have been a fairly well-established terminology in the electric utility industry as this example is indicative of common reporting.

In the 1970's some utility systems began observing that the load in a control area (balancing area) immediately after a transmission system fault occurred would be less than the pre-fault level. The load in the control area would gradually return to the pre-fault level, typically recovering in 15-20 minutes. This was observed even though no customers experienced a loss-of-service due to the transmission fault. Subsequent investigations discovered that the temporary reduction in system load was due mainly to residential air conditioners shutting down due to the action taken by controls in each air conditioner. Those controls could cause the air conditioner to shut down and then restart 10-20 minutes later. This phenomenon was observed to cause the load in a control area to temporarily reduce by 10% or more for these events. The exposure to this phenomenon has continued to the present.

End-users are installing an increasing level of equipment with controls that respond to disturbances on the Bulk Power System. For instance, adjustable speed drives used in many industrial processes as well as chillers and air handlers for large commercial buildings will typically respond to a transmission system fault by shutting down, even though the fault is very remote from the customer's location and does not cause a loss-of-service to the customer. Depending on the control system, they may restart automatically after a time delay, or may restart only after a human operator takes some action. Another example is an energy management system used in an industrial facility or commercial property. Many of those energy management systems respond to a fault on the Bulk Power System by shutting down processes, even though the fault is very remote from the customer's location and does not cause a loss-of-service to the customer. Depending on the control system, they may restart automatically after a time delay, or may restart only after a human operator takes some action.

Some large customers have a stand-by power source (perhaps batteries augmented with a generator) and have controls that switch over to the stand-by source automatically. Many of these facilities will switch over to the stand-by source for faults or disturbances on the Bulk Power System, even if those faults are very remote from the facility and do not result in a loss-of-service to the facility. Reconnecting that customer's load to the power system may occur automatically after a time delay or may occur only after a human operator takes some action.

In summary, a significant percentage of end-users have controls that respond to faults or other disturbances on the Bulk Power System, even if the fault or disturbance does not cause a loss-of-service to the customer. Because of the presence of these customer-owned controls, a fault or disturbance on the Bulk Power System may prompt a significant amount of customer-initiated load reduction. However, these customers do not experience a loss-of-service. This customer-initiated load reduction is not "load loss" in the historic use of the term.

Present Opportunities for Misunderstandings

There are three main areas of potential misunderstandings around the use of the term "load loss". These are Regulatory entities' interpretation of information on actual or possible future Bulk Power System (BPS) events; Transmission Operator's and industry agencies' understanding of and reporting on actual BPS events; and Transmission Planner's and Planning Coordinator's interpretation of projected system performance as determined by modeling and simulations. Each of these three perspectives are described in greater detail below.

Regulatory Entities' Interpretation of BPS Events – Actual and Projected

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

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

Transmission Operator and Industry Agencies – Reporting Requirements

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

The lack of clarity or definition of what is meant by “load” “loss” may result in miscommunication. For example, consider the following scenario. A summer-peaking electric utility serves a fairly dense metropolitan area that has 10,000 MW of load in the summer. A three-phase fault occurs on a transmission line near the metro area on a hot summer day. The fault is cleared in 7 cycles by breakers that remove the faulted line from service. Zero customers experience a loss-of-service. Due to the response of customer control equipment, the utility sees a temporary reduction in load of 1000 MW. The load for the utility begins recovering after 10 minutes, but the full 1000 MW is not “back” until about 20 minutes after the incident. The customer-initiated load reduction was 1000 MW but zero customers experienced a loss of service. The presumed intent behind the EOP and DOE reporting requirements would indicate that the utility does not need to report the incident. However, the staff at the Transmission Operator may not consider the intent behind the reference to “loss” of load, and may simply consider the temporary change in load for the company and believe the incident needs to be reported. The need to report the incident might also be misunderstood by staff at DOE or some other entity. It is possible that someone at an agency may hear an informal report that 1000 MW of load loss occurred, and form the opinion that reporting the event is required.

Transmission Planners and Planning Coordinators – Evaluation of Future System Performance
Transmission Planners and Planning Coordinators use the metrics in the NERC TPL Standards to evaluate the future performance of the BPS. Those standards use the definitions of Consequential Load Loss and Non-Consequential Load Loss. Those definitions are:

> **Consequential Load Loss** – "All Load that is no longer served by the Transmission system as a result of Transmission Facilities being removed from service by a Protection System operation designed to isolate the fault."
>
> **Non-Consequential Load Loss** - "Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive Load, or (3) Load that is disconnected from the System by enduser equipment."

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

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

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

Recommended Actions

Industry stakeholders should use the term/phrase "load loss" only to refer to customers that experienced (or might experience, if the scenario is predictive) a loss-of-service. When reporting information on system disturbances (actual or predicted) to industry stakeholders, it is recommended that information on customers that have or might experience a loss of service be based on the *number* of customers without electric service. If it is necessary to communicate the amount of load represented by the customers without electric service, the amount of load should be clarified by stating that it represents the load for customers that have or would experience a loss-of-service (e.g., 500 MW of customers are without electric service).

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

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

In summary, NERC SAMS proposes the following recommended actions:

- NERC SAMS recommends changes to the NERC EOP-004 standard to clarify the meaning of "loss of firm load" to explicitly exclude changes in balancing area load due to customer-initiated load reduction.
- NERC SAMS recommends modifying TPL standards and the NERC Glossary to include Customer-Initiated Load Reduction (or something similar) as a defined term. Creating a defined term to cover load reduction due to end-user equipment (as in exclusions 2 and 3 of the Non-Consequential Load Loss definition) would significantly reduce the potential for misunderstandings.
- Transmission Planners and Planning Coordinators should discuss this issue with their respective Transmission Operators to assure that the Transmission Operators are aware of the potential for significant levels of customer-initiated load reductions in association with a BPS disturbance.
- The RSTC, or one of its subcommittees, should initiate a dialogue with state commissions with regulatory responsibilities for electric utilities to assure that those commissions have an awareness of the potential for significant levels of customer-initiated load reductions in association with a BPS disturbance.
- The RSTC, or one of its subcommittees, should initiate a dialogue with DOE to recommend changes to language in relevant documents that refer to loss of load.

RSTC Transition Plan

Action

- Reliability and Security Technical Committee (RSTC) Subgroup Organization Proposal – **Approve**
- Security Integration and Technology Enablement Subcommittee (SITES) Scope - **Approve**
- RSTC Notional Work Flow Process document – **Approve**
- Integrating Security Topics into RSTC Technical Groups – **Endorse**

Background

The RSTC Transition Team (RSTCTT) developed a proposed subgroup organization to improve the efficiency and effectiveness of the RSTC. The draft proposal was presented to the full RSTC on July 28, 2020. After discussion, the consensus of the group was to have the RSTCTT continue to develop the proposal for further discussion at the September 15, 2020 RSTC meeting. The proposal also includes assigning RSTC members as Sponsors for specific subgroups within program areas. The program areas are supported by RSTC sponsors and NERC staff. Security is expected to be a consideration for each subgroup where appropriate.

As part of the proposal, the RSTCTT has proposed the development of a new Security Integration and Technology Enablement Subcommittee (SITES). The activities of SITES is intended to help industry adopt emerging technologies in a secure, reliable, and resilient manner. Thus, it will focus on work products that assist in integrating these technologies in a manner that complements grid planning, design, operations, and restoration practices.

The RSTCTT also developed a RSTC Notional Work Flow Process document that shows how new risks to reliability, resilience and security are integrated into the work plan of the RSTC and its subgroups. The work flow also includes touch points with the Reliability Issues Steering Committee (RISC). This includes inclusion of risks identified in the RISC Report as well as coordination on measuring success for risk mitigations and residual risk over time.

Security, both cyber and physical, plays a vital role in ensuring the reliability of the bulk power system. It is envisioned that each RSTC subgroup will consider security in its work plan and work products as a normal course of action. The RSTCTT developed the *Integrating Security Topics into RSTC Technical Groups* document as an introductory means to use as a framework by sponsors, NERC staff, and subgroup leadership to integrate security into their respective work plans and products. This document is intended to support efforts of the RSTC to incorporate cyber and physical security considerations within the scope of every RSTC subgroup.

Summary

The RSTCTT is seeking to obtain RSTC approval for the *RSTC Subgroup Organization Proposal, the proposed SITES Scope and the proposed RSTC Notional Work Flow Process*. The RSTCTT is also seeking to obtain RSTC endorsement of the *Integrating Security Topics into RSTC Technical*

Groups for use as a framework by sponsors, NERC staff and subgroup leadership to integrate security into their respective work plans and products.

Security Integration and Technology Enablement Subcommittee

Scope Document
September 2020

Purpose

The 2019 NERC Reliability Issues Steering Committee (RISC) Report has highlighted “grid transformation” and “security risks” as two of the highest priority risk issues for the ERO Enterprise and electric industry.[1] To proactively support industry efforts to mitigate these risks and assess the state of industry efforts in this area, the NERC Security Integration and Technology Enablement Subcommittee (SITES) will focus specifically on recommended practices for incorporating cyber and physical security aspects into conventional planning, operations, design, and restoration activities across North America. The SITES will also identify, assess, and recommend technologies that may not be fully utilized in bulk power system (BPS) operational technology systems, and support the enablement of these technologies on the BPS in a secure, reliable, and effective manner. The goal of the subcommittee is to pave the way for industry to adopt emerging technologies by removing barriers (e.g., regulatory, technological, complexity) while ensuring reliability and security of the BPS.

Activities

The activities of the SITES are intended to help industry adopt emerging technologies in a secure, reliable, and resilient manner. Thus, it will focus on work products that assist in integrating these technologies in a manner that complements grid planning, design, operations, and restoration practices. Key activities and work products of the SITES include, but are not limited to, the following:

1. Provide strategic guidance and industry recommendations for state-of-the-art security practices and emerging technology solutions (e.g., cloud computing, virtualization) that can be used to inform electric industry approaches to operational technology.
    a. Enhance the effective use of emerging technologies such as inverter-based resources, new digital communications strategies, and advanced BPS hardware and software systems
    b. Identify solutions that eliminate or mitigate potential reliability, security, and resilience risks to the BPS that could result from an increased cyber-attack surface or improperly implemented technologies.
2. Develop recommendations to ensure that cybersecurity is an integral component of BPS planning, design, operations, and restoration:
    a. How to effectively *plan* a future BPS by considering existing and emerging security vulnerabilities, equipping planners with knowledge necessary to reduce those vulnerabilities

[1] https://www.nerc.com/comm/RISC/Related%20Files%20DL/RISC%20ERO%20Priorities%20Report_Board_Accpeted_November_5_2019.pdf

including the need to consider balancing economies of scale against the risk of a centralized attack surface; develop methods, models, and tools that simulate potential security risks to BPS reliability; establish industry agreed-upon levels of cyber-resilience.

b. How to effectively *operate* the existing and future BPS by using new technologies in an effective way that does not pose unforeseen cyber-attack vulnerabilities. Empower grid operators by providing solutions that integrate cyber and physical security intelligence into the real-time operating picture.

c. How to effectively *design* the existing and future BPS to minimize potential cyber-attack threats while leveraging state-of-the-art capabilities and equipment in a manner that is suitable for secure and reliable operation of the BPS.

d. How to effectively *restore* the BPS if a cyber-attack were to affect a geographically diverse area comprised of various types of operating entities, addressing system restoration coordination activities under severe cyber-attack or coordinated physical attack risk conditions.

3. Provide strategic direction to assess the transformation of the BPS operational and technological environments across North America; define recommended practices related to the convergence of information and operational technology (IT/OT) and its growing reliance on emerging technologies, and assess the risks that these changes present to the BPS now and into the future.

4. Develop a framework[2] for a baseline cybersecurity posture for all cyber systems on the BPS, that further protects the North American BPS during its rapid transformation (e.g., increased penetrations of inverter-based resources, distributed energy resources, microgrids, cloud computing).

5. Identify potential security threats across all sectors of the BPS and define the effects that these threats could have on BPS planning, operations, design, and restoration activities both from an overall system perspective as well as individual elements.

   a. Consider the impacts that electrically and geographically diverse attacks could have on reliable operation of the BPS.

   b. Identify risks to the BPS that could arise as emerging technologies are adopted such as: cyber threats from distributed energy resource management systems, diverse data locations in cloud environments, supply chain, contingency events from electromagnetic pulse (EMP) and high-altitude EMP (HEMP), and other geographically diverse threats.

   c. Identify existing cyber risks (e.g., in coordination with E-ISAC), recommend mitigation strategies, and deliver them in an appropriate fashion to industry for implementation.

6. Coordinate with the NERC Electricity Information Sharing and Analysis Center (E-ISAC) to gather information about statistically likely attack vectors, using this information to develop recommended practices for planning, designing, and operating a secure and resilient BPS.

[2] Leveraging the NIST Cybersecurity Framework: https://www.nist.gov/cyberframework

7. Develop planning, operating, design, or restoration metrics that could be used to measure adequate levels of reliability of the BPS in the context of cyber and physical security.
8. Develop collaborative partnerships with industry, governmental partners, national laboratories, research and development institutes, academia, and other organization to determine the current state-of-the-art in cyber and physical security designs, cutting-edge tools, and expertise.
    a. Provide a forum for open discussion about new research, tools, and initiatives across North America.
    b. Encourage develop of partnerships between NERC, research partners, and asset owners that help streamline the piloting and eventual adoption of new solutions.
9. Support development of the annual NERC Long Term Reliability Assessment and other assessments pertaining to emerging technologies and the transforming grid.
10. Develop and promote educational materials that describe emerging technologies and their impacts to BPS reliability and resilience, to enhance industry practices regarding planning, designing, and operating a cyber-secure and cyber-resilient BPS.
11. Consult with the Electricity Subsector Coordinating Council (ESCC), the Institute of Electrical and Electronics Engineers (IEEE), and other industry technical groups, as needed.
12. Coordinate with the NERC Security Working Group and other NERC technical stakeholder groups to ensure alignment is assignments and responsibilities.
13. Any other activities or assignments defined by the NERC Reliability and Security Technical Committee (RSTC).

Deliverables

The SITES will develop any of the following deliverables (based on specific topic need) to support industry efforts related to integrating emerging technologies and security enhancements into conventional planning, operations, and design practices:

- Technical reference documents, technical reports, white papers, and tools
- Reliability and Security Guidelines
- Compliance Implementation Guidance
- Standard Authorization Requests
- Supporting materials to other NERC work products (e.g., NERC Long Term Reliability Assessment)
- Other educational materials (webinars, workshops, conferences, etc.)

Membership

The SITES will include members with expertise in the following areas:

- Designing and implementing cybersecurity systems and networks in BPS control centers, generation facilities, and transmission facilities

- Understanding state-of-the-art and emerging practices (e.g., cloud computing) and how these practices could impact BPS reliability and resilience
- Overall cybersecurity threats or risks posed by changing technologies and new operating paradigms for the BPS (e.g., distributed energy management systems)
- Identifying and defining physical and cyber-security risks with respect to BPS reliability and resilience
- Security-related industry standards and relevant NERC Reliability Standards
- BPS planning practices and how security concepts could be integrated into these practices more effectively and efficiently
- BPS operating processes and procedures and how cybersecurity concepts could be integrated into these practices
- BPS design practices (e.g., field operations and design) and how cybersecurity concepts could be integrated into these practices

The SITES will consist of a Chair and Vice Chair with a two year term limit, appointed by the RSTC leadership. NERC staff will be assigned as Coordinator(s). Decisions will be consensus-based of the membership, led by the chair and staff coordinators. Any minority views can be documented, as necessary. The RSTC will assign a Sponsor to help advocate SITES activities and to coordinate with RSTC and its other sub-groups.

Reporting & Duration

The SITES will report to the NERC RSTC. The group will submit a work plan to the RSTC following its inception and maintain its work plan throughout its existence. The duration of the SITES is expected to be indefinite so long as the group is deemed by the RSTC to be effectively accomplishing its purpose.

Meetings

The SITES is expected to have two to three meetings (in-person or remote) per year, supplemented with regular conference calls to continue workload as needed.

Approved by the NERC Reliability and Security Technical Committee on ______, 2020.

Reliability and Security Technical Committee (RSTC) Notional Work Product Flow Process

The Notional Work Product Process document is being developed to promote a clear and consistent process for introducing new work items to the RSTC Work Plan and the respective RSTC subcommittees, working groups, and task force's Work Plans and guiding Work Scopes based on authorities, responsibilities, and processes contained in the RSTC Charter. RSTC Leadership is seeking input from RSTCEC and RSTC members, Technical Group leaders, and RSTC observers on this draft. Once approved by the RSTC, the work flow process will be added to the RSTC Work Plan as an attachment.

Background

The RSTC appoints technical subcommittees, task forces, and working groups ("Technical Groups") as needed to accomplish objectives contained in the RSTC Strategic Plan, ERO Reliability Risk Priorities Report (RISC Report), and other ERO Enterprise strategic guidance.[1] The RSTC is responsible for directing and overseeing the work of the Technical Groups (Technical Group's Work Scopes) and for their work products (Technical Group's Work Plans). The RSTC Executive Committee (RSTCEC) reviews work scopes, provides guidance and advice, and is responsible for determining which Technical Group is most appropriately suited to execute a given assignment.[2] The following notional process describes how reliability and resilience issues can be added to a Technical Group's Work Scope and be addressed through the respective Technical Group's Work Plan and the RSTC Work Plan.

Process Flow Chart

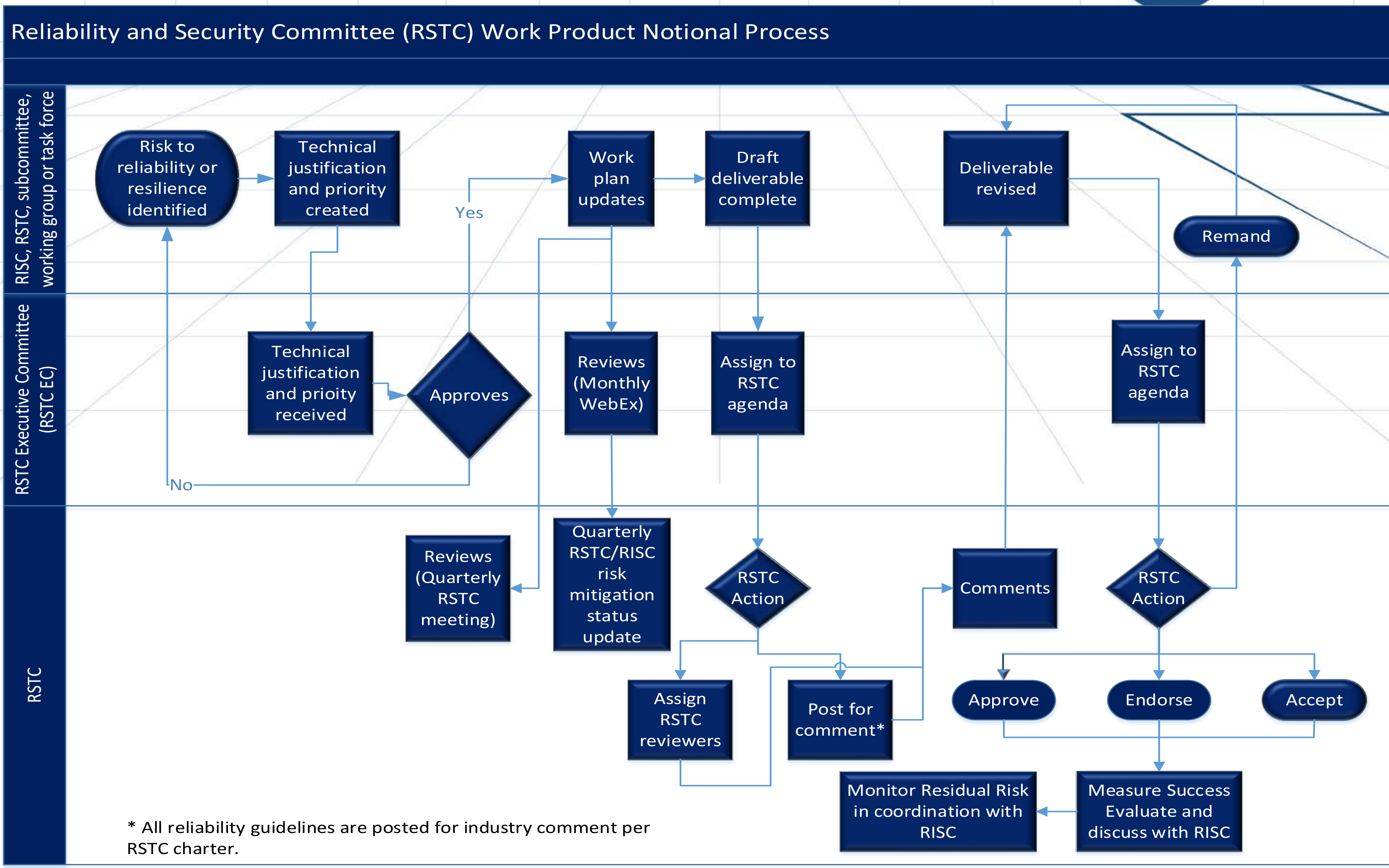
The figure and accompanying table below show typical Technical Group, RSTCEC, and RSTC interactions that occur in the development and approval of RSTC deliverables.[3] In broad terms, the following steps are involved in this process: 1) Risk Identification and Validation, 2) Risk Prioritization, 3) Remediation and Mitigation Identification and Evaluation, 4) RSTC Deploy Mitigation, 5) Measure Success, and 6) Monitor Residual Risk.

Table 1 contains additional details and guidance for each step.

1 See strategic documents:
RSTC Strategic Plan: NEED TO ADD LINK WHEN DEVELOPED
RISC Report:https://www.nerc.com/comm/RISC/Related%20Files%20DL/ERO-Reliability-_Risk_Priorities-Report_Board_Accepted_February_2018.pdf
ERO Enterprise Operating Plan:
https://www.nerc.com/gov/Annual%20Reports/ERO_Enterprise_Operating_Plan_Approved_by_the_NERC_Board_on_November_9_2017.pdf

2 Responsibilities of the RSTC and the RSTCEC with respect to Technical Groups are specified in the RSTC Charter, Sections 5 and 6.
https://www.nerc.com/comm/RSTC/Related%20Files%202013/RSTC_Charter_RSTC_Approved_Board_May_2018.pdf

3 Reports directed by the NERC Board or prescribed by NERC Rules of Procedure which are developed by NERC Staff and RSTC subcommittees (e.g., State of Reliability Report, Long-term and seasonal assessments) have established review and endorsement processes that may differ from the notional process described here.



* All reliability guidelines are posted for industry comment per RSTC charter.

Notional RSTC Work Product Process		
Activity	**Group**	**Description**
Risk Identification and Validation	Technical group[4]	Prepare a technical justification that documents the technical need and banding for an identified reliability or resilience issue. Banding includes answering the following questions: • What is the technical issue and how does it impact the reliability of the BPS? • How this is within current scope of ERO goals and objectives? • What is the involvement required from other ERO functional groups? • What is the level of current technical awareness in industry? • What subject-matter expertise has been involved, or is needed to be involved in order to comprehensively understand the issue? Provide the technical justification to the RSTCEC. (Normally considered at next monthly RSTCEC web meetings) The RSTCEC will also have discussions with RISC leadership to coordinate risk identification and validation.
Risk Prioritization	RSTCEC and Sponsors	Prioritizing risks is accomplished through an analysis of their exposure, scope, and duration as well as impact and likelihood. Among other sources, the RISC Report identifies and prioritizes short-term and long-term risks to reliability. The RSTC will incorporate the prioritized risks into the annual work plan.
Remediation and Mitigation Identification and Evaluation	Technical group, RSTCEC and Sponsors	Technical group, RSTCEC and Sponsors discuss the reliability / resilience issue, technical justification, and consider potential solutions. Potential outcomes or solutions include deliverables in the RSTC Charter such as white papers, reference documents, technical reports, reliability guidelines, and compliance implementation guidance.[5] Other potential solutions are contained in NERC Rules of Procedure (RoP), ERO Event Analysis Process, NERC Alerts, and other risk management measures. The RSTCEC authorizes tasks to be added to the RSTC Work Plan (which could include collaboration with other groups), rejects proposed tasks, or refers matter(s) to the RSTC for further discussion. Technical group provides updates on progress by: • Reviewing and updating the RSTC Work Plan (monthly) • Presenting updates to the RSTCEC (monthly webex meeting; leaders can update more often if necessary) ▪ Presenting updates to the RSTC (Quarterly in-person meeting) The RSTC and will communicate with the RISC to inform of actions being taken.

4 Risks to be addressed by the RSTC could come from an existing Technical Group, or other sources (e.g., an individual, other ERO committee, ERO governing body, or stakeholder group). When necessary, the RSTCEC can assign a Technical Group to support development of a technical justification.

5 See the RSTC Charter, Section 8, for a description of RSTC deliverables.

		When the technical group has completed a draft deliverable, it will be presented to the RSTCEC for assignment to the RSTC meeting schedule as a review item. Deliverables are reviewed as follows: ▪ Reliability Guidelines must be posted for 45-day stakeholder comment period[6] ▪ Other deliverables are normally assigned to RSTC members for review Technical groups review each comment received, consider revisions to the deliverable, and prepare a response matrix for the RSTC and stakeholders.
RSTC Deploy Mitigation[7]	RSTC and Sponsor	When the technical group has completed review and revisions, the draft deliverable shall be presented to the RSTCEC by the Sponsor for assignment to the RSTC meeting schedule for final action.[8] Once the RSTC has approved, endorsed or accepted the deliverable(s), it (they) will be implemented for industry action.
Measure Success	RSTC, RISC and ERO	Once a solution(s) has been deployed, the effectiveness of the mitigation must be measured to determine if the residual risk has achieved an acceptable level. The RSTC will evaluate mitigation strategies/plans for effectiveness and discusses with the RISC, highlighting any necessary next steps.
Monitor Residual Risk	RSTC, RISC and ERO	Once the level of residual risk is at an acceptable level, the risk is monitored through ongoing performance measures to ensure that risk remains at acceptable risk levels. The residual risk should be monitored for progress and to ensure that the mitigations that are in place continue to address the risk. The RSTC will continue to coordinate with the RISC on maintaining an acceptable level of residual risk.

6 Reliability Guidelines receive special vetting in the RSTC charter. The process for review, approval, and updating of Reliability Guidelines is specified in the Charter, Section 8.

7 RSTC actions on deliverables are described in the Charter, Section 8.

8 Both the RSTC and the RSTCEC are authorized to act between regularly scheduled meetings. Provisions are described in the Charter, Section 4. Due to the need for flexibility in the review and approval process, timelines are provided as guidelines to be followed by the committee and its subgroups. A default review period of no less than 10 business days will be provided for all committee deliverables. Requests for exceptions may be brought to the RSTC at its regular meetings or to the RSTCEC if the exception cannot wait for a RSTC meeting. In all cases, a final report may be considered for approval, endorsement, or acceptance if the RSTC or RSTCEC, as outlined above, decides to act sooner.

Concept Paper: Integrating Security Topics into RSTC Technical Groups

NERC BPS Security and Grid Transformation Group
August 2020

Purpose

This paper is intended to support efforts of the NERC Reliability and Security Technical Committee (RSTC) to incorporate cyber and physical security considerations within the scope of every RSTC technical group. For purposes of this discussion, "security" will be used as a comprehensive term that can refer to cyber and/or physical security of a system, process, environment, or device.

These suggestions are intended to fuel discussions that support a holistic approach to security, in the context of Bulk Power System (BPS) reliability activities that the RSTC supports. It is intended that each group, under the direction of the RSTC, uses this information as a starting point for considering how their work plans can reflect high priority security-related topics.[1]

Review of NERC Technical Groups and Considerations for Security Topics

The following suggestions are examples of the physical and cyber security topics that may be appropriate for RSTC subcommittees, working groups, or task forces to consider or address:

- **Performance Monitoring:**
  - **Real-Time Operations Subcommittee (RTOS):** The RTOS, being focused primarily on real-time operations, should consider how cyber threats may pose potential risks to BPS reliability and ensure that operating plans and operating procedures clearly specify how security incidents will be handled. This should include guidance and recommended practices for system restoration and blackstart under possible cyber threat scenarios.
  - **Performance Analysis Subcommittee (PAS):** The PAS may consider ways to track cybersecurity incidents in a manner that provides useful information for the annual NERC State of Reliability report.
  - **Event Analysis Subcommittee (EAS):** The EAS may look at security threats and consider what constitutes a "reportable incident," in coordination with NERC E-ISAC activities. An outcome of this effort could be a lessons learned document or other work product that could bring value to the entire industry.

[1] These activies can further support other industry references and guidance materials that can help organizations better understand and improve their management of security risks. The National Institute of Standards and Technology (NIST) Cybersecurity Risk Framework (CSF) is a widely used resource that specifically addresses critical infrastructure. Other resources include those from the Department of Homeland Security (DHS) or organizations such as ASIS International or (ISC)².

    - **Resources Subcommittee (RS):** The RS could provide guidance about the impact that security incidents could have on balancing issues and how those threats relate to balancing reserves, system frequency, and other relevant factors.

- **Risk Mitigation:**
    - **Inverter-Based Resource Performance Working Group (IRPWG):** The IRPWG should use its expertise to provide clear guidance and recommended practices for ensuring security threats are minimized at inverter-based facilities. This includes potential physical and cybersecurity threats that may affect individual inverters or plant-level controllers or threats that could have a more wide-ranging impact.
    - **Electromagnetic Pulse Task Force (EMPTF):** EMPTF is continuing its efforts related to EMP threats to the BPS. The EMPTF will be providing guidance on potential EMP threats and how to mitigate them; no further action needed.
    - **System Planning Impacts from Distributed Energy Resources Working Group (SPIDERWG):** The SPIDERWG should consider how security threats, predominantly cybersecurity, may pose risks to the BPS due to the widespread nature of distributed energy resources. In particular, the introduction of distributed energy resource management systems (DERMS) should be addressed, particularly how DERMS may introduce cybersecurity threats to the overall BPS and how industry could address those risks.
    - **Geomagnetic Disturbance Task Force (GMDTF):** The GMDTF is addressing impacts of geomagnetic disturbances as a possible BPS reliability risk. Physical and cyber security aspects are outside the scope of GMDTF activities.
    - **Power Plant Modeling and Verification Task Force (PPMVTF):** The PPMVTF could provide guidance regarding physical and cybersecurity threats to different types of power plants across North America and ways to mitigate BPS risks imposed by those threats.
    - **Security Working Group (SWG):** With its legacy of focusing on both cyber and physical security issues that threaten BPS reliability, the SWG is positioned to continue addressing those topics. In addition, it should be recognized as a resource pool for other RSTC groups as they seek feedback or participation related to their relevant security matters.
    - **Load Modeling Working Group (LMWG):** The LMWG recommends practices and guidance to industry related to load modeling in reliability studies, so physical and cyber security topics are likely to be outside their scope.
    - **Electric-Gas Working Group (EGWG):** The EGWG has focused on how threats or contingencies to the gas network may impact BPS operations on the electric side, primarily from a physical security perspective. This effort could be expanded to perform similar evaluations of cyber threats that could impact BPS operations through the electric-gas interface. Identifying these types of threats could help BPS planners and operators be aware of potential widespread impacts and help industry develop mitigating actions.

- **Supply Chain Working Group (SCWG):** The SCWG is providing clear guidance regarding supply chain risks that can pose cybersecurity threats to the BPS. No further action is needed by SCWG to consider security aspects.
- **System Protection and Control Working Group (SPCWG):** The SPCWG could provide significant guidance to industry regarding ways in which BPS protection systems may be impacted by physical and cyber security threats. Specifically, the SPCWG could provide guidance on the types of security threats to which protective relaying and control systems are vulnerable and possible approaches to mitigating those threats.
- **Security and Reliability Training Working Group (SRTWG):** The merger of security, planning, and operating functions within the RSTC is well suited for a combined effort. Training and outreach can address all three formerly distinct topics with a focus on areas of common concern.

- **Reliability and Security Assessment:**
  - **Reliability Assessment Subcommittee (RAS):** The RAS may consider including key takeaways and findings from the various groups in the NERC Long Term Reliability Assessment each year. This may include coordinating with other groups to determine possible future BPS reliability risks caused by security threats.
  - **Emerging Technologies and Grid Transformation Subcommittee (ETGTS):** The ETGTS will focus specifically on new technologies and the changing grid, and provide guidance and strategic vision to how industry can adapt to these changes in a reliable and resilient manner. The ETGTS may coordinate with other groups to determine and prioritize possible security risks, as well as provide industry with guidance and strategy needed to adopt new technologies in a secure manner.

These suggestions are examples of how RSTC groups can ensure that work plans sufficiently and completely address the security concerns implicit in BPS planning, operations, design, and restoration. Security has become an increasingly critical aspect of BPS reliability, so addressing physical and cyber security in the context of each facet is more important than ever before.

Ensuring Energy Adequacy with Energy-Constrained Resources

Action

Information

Background

Unassured fuel supplies[1] including the timing and inconsistent output from variable renewable energy resources, fuel location, and volatility in forecasted load can result in insufficient amounts of energy on the system to serve electrical demand and ensure the reliable operation of the bulk power system throughout the year.

Summary

This ERO Enterprise developed a whitepaper (Attachment 1) to explore the shortcomings of the application of historical capacity analysis to the grid transformation being experienced through North America. Based on this review, 11 questions are presented. The timeframes that impact energy adequacy, the potential Reliability Standard implications, the types of analysis required, and next steps.

The ISO/RTO Council (IRC) reviewed an earlier version of the whitepaper, considered the timeframes, and developed responses to the questions while grouping similar topics for the sake of efficiently prioritizing what work should be considered sooner rather than later (See Attachment 2).

[1] Some examples are: lack of firm gas transportation, pipeline maintenance or disruption, compressor station failures, emission limitations on fossil fuels. All resources have some degree of fuel uncertainty due to unavailability including coal (onsite stock-piles can be frozen) and nuclear (during some tidal conditions affecting cooling intake).

Ensuring Energy Adequacy with Energy-Constrained Resources

Problem Statement

Unassured fuel supplies[1] including the timing and inconsistent output from variable renewable energy resources, fuel location, and volatility in forecasted load can result in insufficient amounts of energy on the system to serve electrical demand and ensure the reliable operation of the bulk power system throughout the year.

Background

Electricity is fundamental to the quality of life for over 330 million people in North America. Electrification continues apace as new applications are developed for use in advanced technologies. For example, advanced computing now permeates every aspect of our economy, and policy makers are seeking to electrify transportation and heating in order to decarbonize the economy. The bulk power system is undergoing an unprecedented change requiring rethinking the way in which generating capacity, energy supply, and load serving needs are understood.

Historically, analysis of the resource adequacy of the bulk power system focused on capacity over peak time periods. Assessment of resource adequacy 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-years.[2] Reserve margins are calculated from probabilistic analysis using generating unit forced outage rates based on random equipment failures derived from historic performance. The targeted level has historically been one event-in-ten-years, based on daily peaks (rather than hourly energy obligations). Additional insights were traditional gained by also calculating Loss-of-Load-Hours (LOLH) and expected unserved energy (EUE) based on the mean-time-to-repair (MTTR) unit averages. Review and clarification of such traditional metrics is needed to understand their assumptions, and put forward additional meaningful measures that support key aspects of capacity and energy delivery.

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 as generally 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.

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[1] Some examples are: lack of firm gas transportation, pipeline maintenance or disruption, compressor station failures, emission limitations on fossil fuels. All resources have some degree of fuel uncertainty due to unavailability including coal (onsite stock-piles can be frozen) and nuclear (during some tidal conditions affecting cooling intake).

[2] The method determining planning reserve margins historically was based on only one data point (or hour) which is the peak load of the day. The inability to meet this single hour peak was considered an event for one day.

However, 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 wherein fuel assurance and forward energy supply planning becomes increasingly important. Generating capacity alone is not sufficient 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 critically important 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, in some areas natural gas fueled resources may, depending on the contract for fuel acquisition,[3] 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 Bulk Electric System (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, the impacts can be mitigated with the supply and geographical diversity from renewable and smaller distributed resources. However, these uncertainties are already causing many system operators to consider scheduling, optimization and commitment of resources over a multi-day timeframe. Replacing the existing generation fleet with energy limited resources 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.

Further, as demonstrated in California, when solar becomes a significant resource, the flexibility of the natural gas system (generating plant ramping capability plus pipeline flexibility to support needed ramp rates) also becomes a key planning consideration. This issue came into focus with the limitations placed on the Aliso Canyon natural gas storage facility causing operational challenges to ensure adequate pipeline pressure was available to support the late afternoon ramp. Provision of fuel flexibility will remain a concern as solar generation grows, at least until large scale electric storage or other solutions are available to attenuate the fuel draw requirements to support steep ramp rates.

Understanding energy adequacy, and by extension, fuel availability compared to capacity requires advanced consideration of multiple technologies and concepts. For example:

1) What flexibility is required to balance volatility in resource and load uncertainty through multiple operating horizons and seasons of the year?
2) Should emergency procedures be revised to reflect current fleet structure and operating needs?
3) When and how should demand response be considered when assessing fuel availability and energy adequacy?

[3] Contracts here should be considered in the broadest sense. Namely, beyond just firm/interruptible gas, but logistics of gas and fuel oil acquisition, transportation and delivery in a timely fashion to address emerging and projected energy requirements.

4) How should the fuel availability / energy adequacy of battery or long-duration storage be evaluated?
5) Does there need to be common practices on how Effective Load Carrying Capability (ELCC)[4] or other useful metrics are determined?
6) Does there need to be common planning practices for how forced outages are incorporated into resource adequacy analysis?
7) How does the availability of the interconnection's import transfer capability factor into the resource adequacy analysis?
8) Are there new tools needed to address not only the traditional capacity adequacy, but energy adequacy and meeting reliable operational requirements?
9) Could strategically overbuilding a similar technology (i.e. solar) augmented by either storage or some portion of the firm capacity fleet (albeit operating at low capacity factors only when needed) could provide for a resilient and reliable transition?
10) How should fuel availability through long-term fuel contracts (commodity plus transportation capacity) and on-site storage (e.g. oil, coal and reservoir-based hydro) be incorporated as part of the analysis, looking at a simultaneous demand on transportation capabilities over an extended period?
11) How should gas pipeline disruption scenarios be modeled, realizing that individual gas pipeline design and gas generators interconnections vary, which result in different impacts to the generator and the Bulk Power System?

Three Timeframes

Faced with transformation, grid operators must plan for energy adequacy requirements that need to be planned and available over three timeframes:

1. When undertaking **mid- to long-term planning** for resources to support the system in the one-to-five-year timeframe, ensure that sufficient amounts of energy are planned such that sufficient options are available to acquire needed energy to meet demand and flexibility requirements for reliably operating the bulk power system throughout all seasons of the year. Review of traditional approaches and metrics is required to put forward advances needed to support energy sufficiency. This includes considering fuel contract types, dual-fuel requirements, hybrid resource requirements, projected emission limitations, early unit retirements, forced outage uncertainty, and scenario analysis of wind, solar and water droughts, etc. under normal and N-1 scenarios.
2. When evaluating the **operational planning** timeframe (1 day to 1 year), ensure that sufficient units are available with the ability to provide the needed energy both to meet demand and off-set potential ramping requirements. Electrical energy production measurements need to reflect contracts in place, dual-fuel available, unit maintenance, fuel (e.g. LNG) levels, barge and other transportation requirements for short-term turnaround to re-supply. Fuel assurance must insure that energy is available for defined scenarios. The operational planning timeframe includes forecasting of variable renewable resources, the forward scheduling, optimization and commitment of power system resources to produce the needed energy to meet forecasted demand, which in turn leads to the scheduling, optimization, and commitment of the required fuel availability.

[4] ELCC results in a derating factor that is applied to a facility's maximum output (Pmax) towards its expected capacity value.

3. When evaluating the **operations** timeframe (0-1 day), provide situational awareness of energy adequacy to ensure sufficient amounts of energy and ramp flexibility are available from existing resources given contract status, start-up time, unit maintenance, dual fuel availability, etc. and are scheduled to be on-line to cover potential system contingencies, including ramping requirements while meeting real-time demand.

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 blocked by snow and ice, the wind not blowing (or blowing too much, or extremely cold or hot), and natural gas becoming unavailable (due to contract type, equipment failure or pipeline maintenance or failure). A NERC reliability guideline was recently drafted on fuel assurance and fuel-related reliability risk analysis. The goal is to begin considering design basis and potentially strengthening the Reliability Standards.

This need is increasingly becoming apparent as extreme weather has resulted in deficits in energy (rather than capacity). For example, in January 2019, temperature dipped below design basis for wind turbines, resulting in the need for quick action by the Reliability Coordinators (RCs), Transmission Operator (TOPs) and Balancing Authorities (BAs). Similarly, a 2019 report by FERC and NERC staff on the event of January 17, 2019 when cold weather resulted in a number of gas-fired units to become unavailable resulting again in energy deficits and the quick action to meet energy needs. As recommended in the FERC-NERC report, a Standard Authorization Request (SAR) towards writing a standard that ensures the ability to provide energy is communicated by Generator Operators (GOs) to the RC, TOP and BAs during Winter timeframes when local forecasted cold weather conditions are expected to limit BES generator unit performance or availability is being reviewed with industry.

These single points of failure require study by industry towards understanding impacts, and putting in place plans to address them. Namely, enhancement to existing NERC Reliability Standards (e.g. Transmission System Planning Performance Requirements or TPL-001-4) is needed to require the relevant entities to address the critical risks to reliability for planned and extreme events design basis.

For example, study of the loss of a large gas pipeline is already called for extreme event(s) in the transmission planning Reliability Standard TPL-001-4, but more scenarios for planning and extreme events are needed to represent the loss of solar, wind, water, and gas (e.g. not just the total loss of a pipeline, but partial loss of gas availability) resources for suitable periods of time (e.g. energy deficiency scenarios), towards understanding their impacts on the reliable operation of the bulk power. This would be demonstrated by entities performing assessments ensuring that they understand the risks. Further, 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 requires 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 industry when the system is planned, and would be a companion to the operational Reliability Standard mentioned above currently being considered by industry. Rather than a burden, these enhancements would provide certainty of risk mitigation between organizations and throughout the interconnections thereby ensuring an Adequate Level of Reliability for the bulk electric system is maintained.

Analysis Requirements[5]

The ability to model and address fuel limitations or shortages in BPS planning is a critical part of system planning and operations. Therefore, there is a need for improved models as well as required data and information to support this planning to ensure the continued reliable operation of the BPS.

- **Identify Energy Limitations and Constraints:** Every generator has some level of energy limitation. For example, solar resources are limited by the availability of the sun's irradiance; hydro-resources are limited by the amount of water stored behind dams or run-of-river capacity; natural gas resources are limited by the transport capability of the pipeline system under normal and outage conditions as well as response capability; dual fuel resources are limited by the amount of on-site back-up fuel plus replenishment capability, and coal resources are limited by frozen or wet coal. All resources are limited by forced outages (and partial outages) due to thermal stresses, equipment failure, and, in some cases, emission allowances and discharge water temperature values. For all fossil-fire resources, energy limitations can also be experienced due to emission limitations which are expected to increase over time. In addition, transmission maintenance that limits energy delivery and market rules that might reserve limited-energy resources for a later time.
- **Identify the tools needed**: For the planning, operational planning, and operations time horizons, tools and methods are needed that can identify the right mix of resources to ensure sufficient amounts of energy are available to serve demand, meet ramping requirements at all times, and ensure the required energy can be delivered from the source to the end user. In addition, in organized markets, market-based incentives or rules, tariff changes, and other market tools need to be investigated. For example, some jurisdictions have evolved to performing 8,760 stochastic simulations to assess hourly levels risk. In addition, some jurisdictions also have established locational, flexible, capability, and performance requirements into their resource adequacy programs. Review of existing tools and methods already developed, identification of any gaps, and providing guidance in their use will support creation of systems that will have sufficient amounts of energy for the reliable operation of the bulk power system.
- **Loss-of-Load Assessment:** The system must be planned (in both planning time horizons) to provide a set of options to the operator so sufficient amounts energy are available for the reliable operation of the bulk power system throughout all seasons of the year. Energy limitations need to be incorporated into the electric power resource adequacy models to more accurately estimate the key adequacy metrics, such as Loss-of-Load Expectation (LOLE), Loss-of-Load Hours (LOLH), and Expected Unserved Energy (EUE). As the applications of electricity grows in North America,

[5] NERC currently has an in-house project to complete a Composite Reliability Study (assessment) of two Planning Coordinator footprints that aims to incorporate the requirements detailed in this section. This pilot project will use NERC staff and existing tools to achieve a probabilistic, rather than a deterministic assessment to assess adequacy of deliverable resource energy. The pilot should identify specific input data needed for similar industry studies.

the value of lost load will further increase and, as result, the value of energy assurance to serve load will also grow in importance. Further, as micro-grid developments increase, assessment of contributions to reliability, and consequences on energy adequacy need to be more fully understood. An important feature of integrating these suggested analyses with existing tools is the ability to incorporate operational solutions into the planning models For example incorporation of demand response, voltage reduction, and public appeals would be valuable. By recognizing cross-energy sector study results from the energy limitations, such as fuel or pipeline infrastructure limitations into probability-based resource adequacy models, an accurate representation of risk can be quantified and then translated into risk-based planning solutions. Cross-energy sector studies should include agreed upon study criteria between the sectors on what it means to be reliable and implications on resilience.[6] This is important as one sector may have a view of reliability that does not translate into other dependent sectors. For example, should sustaining the loss of a large gas storage field be considered a credible event impacting reliability that should be addressed by both the gas and electric sectors? Additionally, agreed upon contingencies impacting fuel transportation or severe weather event scenarios that impact multiple energy sectors require agreement. This analysis can be used for all time frames, incorporating more granular information as the system approaches the operations timeframe.

Appropriate reliability metrics and criteria for the three time frames must be developed, as the degree of uncertainty in the assumptions varies across each of them. Study is needed to determine if the same or different metrics are needed when the three time frame assumptions have varying risk profiles.

Next Steps

Advancing these concepts with industry requires discussions with appropriate NERC technical committees. This document should be forwarded to these committees for their consideration and incorporation into their work plans. In addition, the following actions should be initiated:

1. Coordinate developments of energy assurance activities with industry working groups.
2. Subject matter experts should be assembled (e.g. task forces or working groups) to develop:
    a. the technical foundation for the three time horizons
    b. ways to identify the levels of energy that are required to meet the operational needs
    c. the tool specifications needed to incorporate energy considerations into planning, operational planning and operations assessments
3. Engage industry R&D organizations (EPRI, DOE, Natural Resources Canada, national laboratories, etc.) to validate the technical foundation(s) and development of the tool(s) and methods.
4. Coordinate studies and plans with adjacent Balancing Authorities to identify enhanced collaborative regional support.
5. Create a Standard Authorization Request to enhance existing or create new Reliability Standards to address fuel assurance and resulting energy limitations for the planning timeframe.

[6] See the Reliability Issues Steering Committee's Report on Resilience.

IRC EGCTF Energy Security Review

Executive Summary

The ISO/RTO Council Electric Gas Coordination Task Force (IRC EGCTF) has reviewed the Energy Security whitepaper (Ensuring Energy Adequacy with Increasing Fuel Constrained Availability) drafted by NERC in 2019. Throughout the course of the review, the IRC EGCTF collected responses from each member for each planning time horizon, and then grouped specific topics, based on areas of overlap and synergies between topic areas.

The IRC ECGTF is in alignment that the two groupings of topics to prioritize and engage in further industry discussion at this time are (1) Energy Adequacy and Flexibility for Evolving Resource Mix, questions 1, 4, 8, and 9 below, and (2) Gas Delivery Security, questions 10 and 11 below.

> Questions 10 and 11 - which are more closely aligned with the IRC EGCTF core charter focus of gas-electric coordination.
>
> Questions 1, 4, 8 and 9 – which are all related to energy adequacy and flexibility related to an evolving resource mix. From an IRC EGCTF charter applicability perspective, there is a correlation back to gas electric correlation in that gas fired resources will need to be part of the flexibility solution in conjunction with energy adequacy for an evolving resource mix.

Energy Security Review Key Topic Summary

The following is summary level review of the topics and questions presented in the whitepaper with common themes in each planning timeframe.

Question 1: What flexibility is required to balance volatility in resource and load uncertainty through multiple operating horizons and seasons of the year?

- **Mid to Long Term Planning (1-5 years) Timeframe:** This is something that should be assessed by RTOs/ISOs, and although there aren't many examples of this currently in place, most report examples of approaches that are being considered to identify flexibility requirements as part of a long term plan.
- **Operational Planning (1 day to 1 year) Timeframe:** RTOs/ISOs all have Operations Planning and Operations processes/tools for addressing resource and load uncertainty in the day-ahead / real-time operations timeframes.
- **Operations (0-1 day) Timeframe:** RTOs/ISOs all have Operations Planning and Operations processes/tools for addressing resource and load uncertainty in real-time operations.

Question 2: Should emergency procedures be revised to reflect current fleet structure and operating needs?

- **Mid to Long Term Planning (1-5 years) Timeframe:** RTOs/ISOs should be responsible for revising emergency procedures.
- **Operational Planning (1 day to 1 year) Timeframe:** RTOs/ISOs have processes in place for periodic review and revision of emergency procedures as needed
- **Operations (0-1 day) Timeframe:** RTOs/ISOs have processes in place for periodic review and revision of emergency procedures as needed

Question 3: When and how should demand response be considered when assessing fuel availability / energy adequacy?

- **Mid to Long Term Planning (1-5 years) Timeframe:** Many RTOs/ISOs include some form of Demand Response (DR) in the analysis of fuel availability and/or energy adequacy in the mid- to long-term planning timeframe. There are varying forms of DR, each with its own set of considerations.
- **Operational Planning (1 day to 1 year) Timeframe:** There are two opposing points of view in the operational planning timeframe regarding DR. Some RTOs/ISOs account for DR in some form, and others do not. Those who do not, go further to assert that DR should not be considered.
- **Operations (0-1 day) Timeframe:** In the Operations Timeframe, there are three main classifications of DR treatment. The first is to not account for DR. The second only uses DR as an emergency or abnormal action. The third includes DR as a normal course of resource dispatch.

Question 4: How should the fuel availability / energy adequacy of battery or long-duration storage be evaluated?

- **Mid to Long Term Planning (1-5 years) Timeframe:** Inclusion of storage is in varying stages of adoption across the different regions, which should be addressed by ISOs/RTOs. Evaluation of energy limitations for storage resources is still evolving in different regions based on their relative rates of storage penetration.
- **Operational Planning (1 day to 1 year) Timeframe:** There is minimal inclusion of storage in the Operational Planning timeframe. Evaluation of energy limitations for storage resources is still evolving in different regions based on their relative rates of storage penetration.
- **Operations (0-1 day) Timeframe:** RTOs/ISOs have some existing measures to account for storage when committing and dispatching resources in the operations timeframe. Evaluation of energy limitations for storage resources is still evolving in different regions based on their relative rates of storage penetration.

Question 5: Does there need to be common practices on how Effective Load Carrying Capability (ELCC) or other useful metrics are determined?

- **Mid to Long Term Planning (1-5 years) Timeframe:** ELCC is viewed as an industry accepted practice and RTOs/ISOs perform analysis with variations to meet specific operating or market needs.
- **Operational Planning (1 day to 1 year) Timeframe:** ELCC is generally not applicable with a few RTOs/ISOs considering forced outage rates in analysis for this medium time horizon.
- **Operations (0-1 day) Timeframe:** RTOs/ISOs generally do not feel that this is applicable for the operations timeframe.

Question 6: Does there need to be common planning practices for how forced outages are incorporated into resource adequacy analysis?

- **Mid to Long Term Planning (1-5 years) Timeframe:** RTOs/ISOs generally incorporate historical or seasonal forced outage rates from relevant system resources into resource adequacy analysis performed by internal planning or resource adequacy groups.
- **Operational Planning (1 day to 1 year) Timeframe:** RTOs/ISOs generally incorporate actual forced outage rates for specific times of the year and specific outage conditions into outage planning analysis.
- **Operations (0-1 day) Timeframe:** RTOs/ISOs generally agree that common planning practices are not applicable in the operations timeframe, although some RTOs/ISOs are including an analysis in the determination of daily capacity requirements.

Question 7: How does the availability of the interconnection's import transfer capability factor into the resource adequacy analysis?

- **Mid to Long Term Planning (1-5 years) Timeframe:** Some type of assumption(s) are generally made when analyzing import transfer capability factor (interchange) for resource adequacy. These assumptions vary from using normal transfer limits and long-term transactions, historical data and averaging, and conservative assumptions or limitations to prevent overreliance on the external systems support.
- **Operational Planning (1 day to 1 year) Timeframe:** Conservative assumptions are used to ensure reliability and address the variability during this period.
- **Operations (0-1 day) Timeframe:** In the Operations timeframe, import transfer capability is treated similar or the same as other resources when determining resource adequacy or the ability of a Control Area to meet load. In addition to the processes and procedures that define interchange 24/7/365 multiple members mentioned emergency purchases as a means to utilize transfer capability.

Question 8: Are there new tools needed to address not only the traditional capacity adequacy, but energy adequacy and meeting reliable operational requirements?

- **Mid to Long Term Planning (1-5 years) Timeframe:** New tools are/will be needed to address these requirements. Most RTOs/ISOs are either looking for, or are working on developing, models, tools and applications to serve these growing needs. The need to use common terminology in the different regions, to describe the challenges/energy limitations that affect certain resources (such as batteries, renewables, hybrids, demand response) is a common theme, which would help drive development of the appropriate tools.
- **Operational Planning (1 day to 1 year) Timeframe:** There is no commonality among RTOs/ISOs in the Operational Planning Timeframe. It seems logical that assessments in this Timeframe could be improved with the incorporation of additional tools, and leveraging tools developed in the planning horizon could be a logical first step. A process is being developed for a new set of day-ahead products that will address ramping needs and uncertainty that can occur between day-ahead and real-time markets.
- **Operations (0-1 day) Timeframe:** There is no commonality among most of the RTOs/ISOs in the Operations Timeframe. It seems logical that assessments in this Timeframe could be improved with the incorporation of additional tools, and leveraging tools developed in the planning horizon could be a logical first step.

Question 9: Could strategically overbuilding a similar technology (i.e. solar) augmented by either storage or some portion of the firm capacity fleet (albeit operating at low capacity factors only when needed) could provide for a resilient and reliable transition?

- **Mid to Long Term Planning (1-5 years) Timeframe:** This could be a potential benefit under specific scenarios; however there have been little studies performed that explore this option. Resource Adequacy-focused working groups in the ISOs' regions would likely provide the best forum for further engagement of such discussions. Operations Planning/Operations type studies should be included in the analysis for the longer term planning resource portfolios (Dispatch/Operations Planning simulations should be performed).
- **Operational Planning (1 day to 1 year) Timeframe:** This question is more appropriate for the Mid- to Long-term Planning Timeframe than it is the Operational Planning Timeframe. This could be a potential benefit; however there have been little studies performed that explore the benefits in the Operational Planning Timeframe. New tools/procedures may need to be considered for managing a combination of these resources in the closer in timeframes, when deployed into the operating capacity.
- **Operations (0-1 day) Timeframe:** This question is more appropriate for the Mid- to Long-term Planning Timeframe than it is the Operations Timeframe. While this could be a potential benefit, the performance requirements, as well as the duration under study for that performance, should be defined in advance. New tools/procedures may need to be considered for managing a combination of these resources in the closer in timeframes, when deployed into the operating capacity.

Question 10: How should fuel availability through long-term fuel contracts (commodity plus transportation capacity) and on-site storage (e.g. oil, coal and reservoir-based hydro) be incorporated as part of the analysis, looking at a simultaneous demand on transportation capabilities over an extended period?

- **Mid to Long Term Planning (1-5 years) Timeframe:** Some RTOs/ISOs have shown interest in natural gas availability. At least one RTO/ISO has shown interest in on-site fuel storage for black start resources. Many RTOs/ISOs believe these analyses should be handled by RTOs/ISOs resource adequacy or other long-term planning groups. Aspects of this fuel availability question were addressed in the NERC Gas/Electric Reliability Guidelines.
- **Operational Planning (1 day to 1 year) Timeframe:** Some RTOs/ISOs conduct surveys of fuel inventories and firm/non-firm contract status, one of which incorporates fuel availability into operational (day-ahead) planning. Aspects of this fuel availability question were addressed in the NERC Gas/Electric Reliability Guidelines.
- **Operations (0-1 day) Timeframe:** Some RTOs/ISOs are explicitly incorporating fuel supply into intra-day operations. Aspects of this fuel availability question were addressed in the NERC Gas/Electric Reliability Guidelines.

Question 11: How should gas pipeline disruption scenarios be modeled, realizing that individual gas pipeline design and gas generators interconnections vary, which result in different impacts to the generator and the Bulk Power System?

- **Mid to Long Term Planning (1-5 years) Timeframe:** Most, if not all, RTOs/ISOs analyze some kind of gas supply disruption but not every member models the full, detailed pipeline configuration.
- **Operational Planning (1 day to 1 year) Timeframe:** Several RTOs/ISOs look to NERC EGWG Reliability Guidelines to develop gas pipeline contingencies but most are not currently analyzing gas supply disruptions. Several express interest in providing a medium-term projection/outlook of risks.
- **Operations (0-1 day) Timeframe:** Several RTOs/ISOs use NERC EGWG Reliability Guidelines to coordinate with gas generator owners and pipeline operators, especially for developing contingencies. However, contingencies seem to be managed through standard emergency procedures. Several members would like to develop or improve short-term outlooks for fuel availability risk

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Supply Chain Vendor ID

Industry Pilot Project

Ryan Quint, PhD, PE

BPS Security and Grid Transformation, NERC

RSTC Meeting – September 15, 2020

RELIABILITY | RESILIENCE | SECURITY

NERC BPS Security and Grid Transformation Department

- Security integration into conventional planning, operations, design, and system restoration activities
- Concerted effort to bring security to forefront of our collective efforts to ensure BPS reliability, resilience, and security
- Industry support through coordination with RSTC technical groups, industry partnerships, and E-ISAC
  - Development and sharing of industry best practices
  - Assessments of security landscape
  - Strategic guidance and leadership around improved security coordination
  - Enabling use of emerging technologies
  - Industry support to emerging topics (security and engineering)
- Strictly unrelated to CIP compliance activities

Background

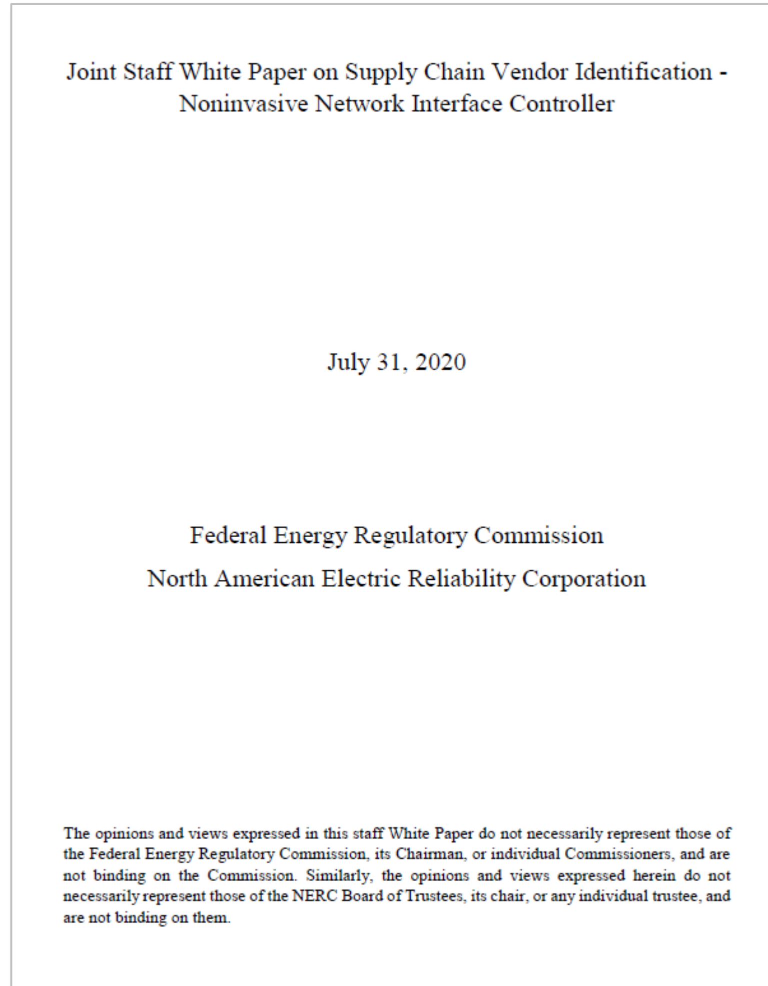
- **2012:** U.S. gov't report assessing security threat posed by Chinese telecommunication companies; recommended against use of equipment manufactured by Huawei or ZTE
- **2013:** U.S. gov't report released highlighting potential ways to exploit vulnerabilities in communications equipment supply chain by injecting malicious code in components
- **2018:** U.S. National Defense Act bars U.S. DOD from using telecom equipment produced by Huawei or ZTE for certain critical programs
- **2019:** Supply Chain Risk II NERC Alert released, gathering information on supply chain risks

Driver

- Pervasiveness of these manufacturers across marketplace
  - Partly stems from embedded Huawei or ZTE components in equipment from unrelated vendors
  - Utilities likely using significant amount of telecommunications equipment with Huawei or ZTE (or subsidiary) components
- Supply Chain Risk II NERC Alert sought information on “branded equipment”
- Alert language and the embedded nature of these components may not fully indicate the exposure of the BES to these manufacturers
- FERC and NERC teams developed joint white paper for non-invasive techniques to identify equipment vendors on network

FERC-NERC Report on Supply Chain Vendor Identification

- **Purpose:** Provide approaches on assessing the deployment of foreign adversary components on electric utility OT systems that could be used to impact the BPS.
- **Recommendation:** Industry should use approaches outlined to identify equipment suppliers and implement periodic tests to mitigate potential risks.



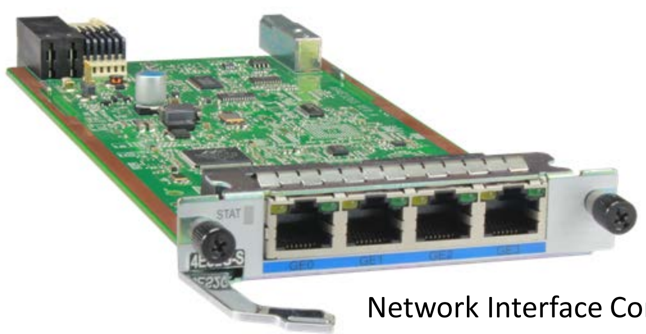
Joint Staff White Paper on Supply Chain Vendor Identification - Noninvasive Network Interface Controller

July 31, 2020

Federal Energy Regulatory Commission

North American Electric Reliability Corporation

The opinions and views expressed in this staff White Paper do not necessarily represent those of the Federal Energy Regulatory Commission, its Chairman, or individual Commissioners, and are not binding on the Commission. Similarly, the opinions and views expressed herein do not necessarily represent those of the NERC Board of Trustees, its chair, or any individual trustee, and are not binding on them.



Network Interface Controller

Network Interface Controller Identification

- White paper details possible noninvasive techniques to identify one component, the network interface controller (NIC)
  - NIC: hardware component that connects computer to a computer network
    - Generally takes form of an integrated circuit chip on motherboard or host bus adapter card
  - Research shows numerous avenues to compromise systems using NICs as a method for undetected access for an attacker
  - NIC is well-known and often-targeted component
- Identification techniques can be employed by security professionals to identify NIC vendors
  - Can easily identify devices often not readily labeled by suspect vendors or that may integrate suspect vendor components
  - Techniques described are not the only methods of detection nor do they encompass the only concerns industry should have about malicious activity and attacks

Pilot Project

- NERC seeking industry *voluntary* participation in pilot test of recommendations from FERC-NERC white paper
  - Applying the non-invasive techniques to identify NIC component vendors
  - Recommending to test on *test/development* network
- NERC developing a simple questionnaire to gather further information on extent of possible equipment and components from foreign adversaries
  - Is NOT seeking detailed or attributable information (e.g., IP addresses)
  - IS seeking aggregate information about possible extent of risk
- NERC developing secure data portal to provide responses confidentially under NERC Rules of Procedure
- Strictly unrelated to compliance with NERC CIP standards in any way; voluntary support of overall industry security posture

Timeline

- NERC gathering list of entities and contacts previously involved in cybersecurity-related activities at NERC
- Will seek *voluntary* participation from wide range of Registered Entities
  - If interested in participating, please reach out to Ryan Quint (ryan.quint@nerc.net)

- Expecting to begin outreach and engagement with industry in October timeframe
- Seeking responses (submitted questionnaires) by end of year

Questions and Answers

For more information, please contact:

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GMD Data Collection Program Update

Action
Information

Background
In August 2018, the NERC Board of Trustees approved a Request for Data or Information under Section 1600 of the NERC Rules of Procedure to obtain GMD data that is collected by NERC entities ("GMD Data Request"). The GMD Data Request was developed to meet Federal Energy Regulatory Commission (FERC) directives in Order No. 830 for collecting geomagnetically-induced current (GIC) monitoring and magnetometer data from registered entities for the period beginning May 2013, including both data existing as of the date of the order and new data going forward.[1] Furthermore, FERC directed that NERC should make the collected GIC and magnetometer data available to support ongoing research and analysis of GMD risk.[2]

NERC Staff is preparing to implement the approved GMD Data Request in October 2020 with a new GMD Data portal. When implemented, Transmission Owners and Generator Owners that collect geomagnetically-induced current (GIC) measurement data or magnetometer data will be requested to provide the data that they collect during strong GMD events designated by NERC. Entities will report their data to NERC using the GMD Data portal by the annual June 30 reporting deadline as specified in the GMD Data Reporting Instructions (GMD DRI). The first data collection reporting deadline is June 30, 2021.

NERC staff developed the GMD DRI with support from the NERC GMD Task Force. The purpose of the GMD DRI is to assist NERC and reporting entities in fulfilling reporting requirements of the board-approved GMD Data Request. In early 2020, PC members reviewed the draft GMD DRI. NERC staff reviewed all comments and revised the DRI to address suggestions.

NERC Staff and GMDTF leaders will provide the RSTC with an overview of the GMD data reporting requirements, GMD Data portal, and data collection roll-out plan.

Click for:

- Board-approved GMD Data Request
- GMD DRI
- PC Member Comments and Staff Responses

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[1] *Reliability Standard for Transmission System Planned Performance for Geomagnetic Disturbance Events*, Order No. 830, 156 FERC ¶ 61,215 at P 89 (2016). The directive applies to only U.S. responsible entities (*See id.* n. 118). However, responsible entities in other NERC jurisdictions including Canada are encouraged to participate in order to obtain relevant GMD data for the North American Bulk-Power System.

[2] Order No. 830 at P 93. In the order, FERC stated: "The record in this proceeding supports the conclusion that access to GIC monitoring and magnetometer data will help facilitate GMD research, for example, by helping to validate GMD models." If GIC monitoring and magnetometer data is already publicly available (e.g., from a government entity or university), FERC stated that NERC need not duplicate those efforts (*see id.* n. 122).

NAGF

the power to make a difference

North American Generator Forum
RSTC Update

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Senior Manager NERC Reliability Compliance
NextEra Energy
and
COO North American Generator Forum
Allen.Schriver@nexteraenergy.com
September 15, 2020

NAGF Mission

The NAGF mission is to promote the safe, reliable operation of the generator segment of the bulk electric system through generator owner and operator collaboration with grid operators and regulators.

Agenda

- **NERC Standard Drafting Teams**
  - **PRC-005**
  - **Cold Weather**

- **Collaboration With NATF**
  - **PRC-027**
  - **Supply Chain**

- **IRPTF/IEEE P2800**

NERC Standard Drafting Teams

- NERC Project 2019-04: Modifications to PRC-005-6
  - The original NAGF SAR requests to clarify the applicability of PRC-005-6 to the protective functions within an AVR and provide the prescribed maintenance activities.
  - PRC-005 should not apply to control systems.

- NERC Project 2019-06: Cold Weather
  - The NAGF Cold Weather Preparedness Working Group is updating existing NAGF Generator Cold Weather documentation.
  - The NAGF commented noting the Reliability Guideline: Generating Unit Winter Weather Readiness states in Assumptions 2, BAs and Market Operators should consider strategies to start-up and dispatch to minimum load prior to anticipated severe cold weather units that are forecasted to be needed for the surge in demand, since keeping units running through exceptional cold snaps can be accomplished much more reliably than attempting start-up of offline generation during such events.

NAGF Collaboration With NATF

- PRC-027-1: Coordination of Protection Systems
  - NAGF and NATF collaborating on the effort to revise NATF Protection System Coordination documentation to incorporate guidance related to PRC-027-1.Forums are focusing on neighboring entity coordination as it applies to generation - transmission data exchange and communication paths/methods.

- Supply Chain
  - NAGF continues to be actively engaged with the NATF and other industry organizations to provide a streamlined, effective, and efficient industry-accepted method for entities to assess supplier cyber security practices. This approach will reduce the burden on suppliers and provide entities with more information effectively and efficiently.

NAGF

- IRPTF/IEEE P2800
  - Reliability Guideline: EMT Modeling and Simulations
    - Goal: Provide industry with clear guidance and recommendations for use of EMT models and performing EMT simulations.
  - Reliability Guideline: BESS and Hybrid Plant Performance, Modeling, Studies
    - Goal: Provide industry with clear guidance and recommendations for battery energy storage and hybrid plant performance, modeling, and studies.
  - NAGF working on whitepaper on providing FFR and PFR from Hybrids

Q & A

NAGF

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Thank you!

www.GeneratorForum.org

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: August 17, 2020

Subject: NATF Periodic Report to the NERC RSTC (September 2020)

Attachments: NATF External Newsletter (July 2020)

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 July NATF external newsletter, which is also available on our public website: www.natf.net/news/newsletters.

Response to COVID-19 Challenges

Like NERC and other industry organizations, the NATF continues to work with its members on responding to the epidemic by sharing information and conducting virtual activities. We appreciate the successful and ongoing collaboration with NERC, DOE, and FERC on the epidemic/pandemic response plan resource. On August 14, we posted version 3 of the resource document; updates included details on cross-sector coordination, prioritized requests for government support, and misinformation.

Update on Pilot Collaborations with NERC, RF, and SERC

As previously reported to the NERC BOT and detailed in the NATF's April 2020 external newsletter, the NATF has been working with two of the regions—ReliabilityFirst (RF) and SERC—to pilot a collaboration approach to advance NATF and ERO mutual objectives, leverage respective strengths, and minimize duplication of effort on two important topics: facility ratings accuracy and supply chain risk mitigation. Although the pilot is centered on RF and SERC, the effort overall and associated learnings are being communicated to all the other regions.

For the supply chain collaborations, plans were well underway to conduct two regional workshops focused on mitigation practices that entities can employ on their systems, equipment, and networks as an additional line of defense to augment the supply chain risk assessment and procurement practices that are focused on addressing risks at the source. Unfortunately, these face-to-face workshops had to be postponed indefinitely due to the pandemic. In the meantime, we are working together to plan and conduct a webinar later in 2020 on a related supply chain cyber security risk mitigation topic that will be suitable for a virtual audience.

In the facility ratings collaboration, the NATF has published for its members a facility ratings best practices document, crafted by subject-matter experts from over 15 companies, providing a guide to members for establishing and maintaining accurate facility ratings. These practices address issues and controls described in the ERO problem statement provided to the NATF as part of the collaboration. The NATF board and member representatives have approved an action plan, beginning in the fall 2020, for members' facility ratings practices implementation, monitoring, and reporting, including periodic status updates to the ERO.

Grid Security Emergency Work

The NATF-NERC Grid Security Emergency (GSE) Communication Project Team has reached a milestone in its GSE communications work. The team was formed in late 2019 to implement shorter-term communications solutions for Bulk Electric System activities during GSE events. The NATF has led the team's work during the first half of 2020, culminating in the development of a "GSE Communications Implementation Outline" in mid-June.

The outline contains protocols, technical details, necessary security provisions, and cost estimates for both verbal and electronic GSE communications solutions. The outline, which will be used to guide the expansion of current processes and tools for use during GSE events, was provided to NERC, who will lead the implementation phase. As we engage and work closely with the U.S. Department of Energy (DOE) on implementation, the GSE Communications Project Team will remain in place for support and consultation. NERC will provide periodic updates to report implementation progress.

Supply Chain Executive Order

The NATF has been in contact with the DOE to offer support for aspects of the implementation of the Executive Order 13920 *Securing the United States Bulk-Power System*, outlining several potential roles and activities where the NATF would bring value to the DOE's efforts. In particular, the NATF highlighted the ongoing work and resources of the NATF-led Supply Chain Industry Organizations Team, bringing together industry, suppliers, assessment organizations, and solution providers for a congruent approach to supplier risk assessment with a common set of criteria and questions to help identify supplier security practices, including an indication of the source of supplier products. These resources can form a foundation for the DOE efforts.

Further, the NATF is working with members on potential ways to assist with member responses to the associated NERC Alert and DOE request for information.

North American Transmission FORUM

Community *Confidentiality* *Candor* *Commitment*

North American Transmission Forum External Newsletter

July 2020

Resource Developed to Help Organizations Update Pandemic Response Plans

The COVID-19 pandemic has resulted in unprecedented challenges for utility planning, operations, and response, prompting organizations to review existing or create epidemic/pandemic-response plans. To assist in these efforts, the North American Transmission Forum, North American Electric Reliability Corporation, U.S. Department of Energy, and Federal Energy Regulatory Commission jointly developed a resource to help utilities create, update, or formalize their plans.

The *Epidemic/Pandemic Response Plan Resource*—which focuses on planning/preparedness, response, and recovery activities for a severe epidemic/pandemic—was issued in May and recently updated with additional information on testing and an overview of contact tracing. Due to current circumstances, the document contains COVID-19-specific information; however, the intent is to evolve and maintain the document over time so it can be used as an effective resource for any epidemic or pandemic.

For more information, please visit: https://www.natf.net/industry-initiatives/covid-19.

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NATF Continues Monitoring COVID-19 and Implementing Virtual Activities

The NATF's primary focus during this pandemic has been the health and safety of our staff and members. From the start, we have been working closely with our members and tracking updates from the Centers for Disease Control and Prevention (CDC) and state and local authorities to help inform our decisions.

The NATF's physical office remains closed, as staff works from home, with travel cancelled until further notice. We have postponed near-term in-person events and are working with members and our industry partners to reschedule as appropriate. The NATF has also been working with industry partners to coordinate on response activities and reduce duplication of effort wherever possible.

Member Support and Engagement

We have continued existing and implemented new information-exchange mechanisms for ongoing and pandemic-specific activities to assist our members. As always, our members have actively engaged to help one another by sharing insights, approaches, and experiences. Our system operations webinars for COVID-19 have been a particularly successful endeavor, with member-wide attendance and support.

To ensure we continue to deliver our full range of services, we have recently been working with members to plan web-based peer reviews and to conduct more assistance activities virtually. While we have been unable to hold face-to-face workshop events as planned, we are drawing on workshop topics to conduct timely special webinars.

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Energy Sector Supply Chain Risk Questionnaire

The NATF posted the "Energy Sector Supply Chain Risk Questionnaire" for industry use.

This questionnaire, developed by a group of more than 20 U.S. energy companies, is designed to provide utilities with a set of supplier- and equipment-focused questions to obtain better information on a supplier's security posture. The questionnaire works in conjunction with the NATF Criteria, and together these complementary tools can help the industry drive convergence on information that is needed from suppliers.

The questionnaire gathers information to determine a supplier's level of adherence to the NATF Criteria and additional insight into a supplier's cyber security actions. Further, these tools had identified the need to understand a supplier's dependencies and sourcing from other countries and include questions to gather information that is pertinent to and will support the May 1 executive order. Specific information is obtained regarding a supplier's sourcing, activities, and staffing in other countries.

Consistent use of the tools will support the growing acceptance from suppliers. Currently, suppliers are recognizing the tools and beginning to have responses for the questionnaire and NATF Criteria prepared so the information can be readily available upon entities' requests.

The questionnaire and NATF Criteria are living documents that will be revised as industry continues to converge on what information is needed from suppliers. An Industry Organizations Team is developing a revision process, and you can submit your thoughts and comments on the questionnaire and NATF Criteria to supplychain@natf.net.

Learn more at https://www.natf.net/industry-initiatives/supply-chain-industry-coordination.

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Transmission Resilience Maturity Model (TRMM)

The NATF has been working with the Electric Power Research Institute, the Department of Energy, and Pacific Northwest National Lab to develop a transmission resilience maturity model as a tool that a transmission organization can use to objectively evaluate and benchmark its currently established transmission resilience policies, programs, and investments, in order to target and prioritize enhancements where needed. A draft of the model has been created and was piloted by NATF member companies in early 2020.

Improvements to the model based upon lessons learned from the pilots are being incorporated into a TRMM version 1.0, along with a suite of supporting documentation, planned for public release in the third quarter.

The NATF envisions incorporating the TRMM as an additional service offering for its members, including facilitated self-assessments, metrics, and targeted assistance (in areas where members seek improvements).

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Redacted Operating Experience Reports

Since our last newsletter, we have posted four reports to our public site for members and other utilities to use internally and share with their contractors to help improve safety, reliability, and resiliency.

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For more information about the NATF, please visit www.natf.net.

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