Agenda
Reliability and Security Technical Committee

March 12, 2024 | 8:30 a.m. – 4:00 p.m. Pacific
In-Person

Westin San Diego Gaslamp Quarter
910 Broadway Circle
San Diego, CA 92101

Call to Order

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

Introduction and Chair's Remarks;

Agenda

1. **Administrative items**
   a. Arrangements
   b. Announcement of Quorum
   c. Reliability and Security Technical Committee (RSTC) Membership 2023-2026*
      i. RSTC Roster
      ii. RSTC Newsletter
      iii. RSTC Charter
      iv. Participant Conduct Policy

Consent Agenda

2. **Consent Items* – Approve**
   a. December 6-7, 2023 RSTC Meeting Minutes
   b. Security Working Group Scope Document

Regular Agenda

3. **Remarks and Reports**
   a. Subcommittee Reports*
   b. RSTC Work Plan
   c. Report of February 14, 2024 Member Representatives Committee (MRC) Meeting and February 15, 2024 Board of Trustees Meeting
4. **Nominating Subcommittee Election* – Approve –** Chair Hydzik
5. **RSTC Work Plan Priorities* – Information –** Vice Chair Stephens

6. **RAS – Special Reliability Assessments Scope and Prioritization* – Approve –** RAS Chair Andreas Klaube
7. **SAR: Revisions to FAC-001 and FAC-002* – Accept to Post for a 30-day RSTC/Public Comment Period** – Alex Shattuck, NERC Staff | Jody Green, Sponsor
8. **White Paper: Transmission-Distribution Coordination Strategies* – Approve –** Shayan Rizvi, SPIDERWG Chair | Wayne Guttormson, Sponsor
9. **FERC Order 901 Update – Information –** Jamie Calderon, NERC Staff
10. **Reliability Guideline: BPS Planning under high DER penetration – Accept to Post for a 45-day Public Comment Period** – Shayan Rizvi, SPIDERWG Chair | Wayne Guttormson, Sponsor
11. **SAR: Clarifications to Operational Planning Analysis and Real-time Assessment – Accept to Post for a 30-day Public Comment Period** – Shayan Rizvi, SPIDERWG Chair | Wayne Guttormson, Sponsor
12. **Review of Reliability Risk Framework – Information** – John Moura, NERC Staff
13. **Emerging Loads and Electric Vehicles Panel Session – Information –** Marilyn Jayachandran, John Skeath, NERC Staff & Industry Experts
14. **Probabilistic Planning for Tail Risks* – Approve –** Bryon Domgaard, PAWG Chair
15. **PRC-023-5 R1 Determination of Practical Transmission Relaying Loadability Settings Paper* – Approve –** Lynn Schroder, SPCWG Chair | David Mulcahy, Sponsor
16. **Review and update Transmission System Phase Backup Protections* – Request RSTC Reviewers –** Lynn Schroder, SPCWG Chair | David Mulcahy, Sponsor
17. **Steady-state approach for PRC-024-3 Evaluation for Inverter-Based Resources White Paper* – Request RSTC Reviewers –** Lynn Schroder, SPCWG Chair | David Mulcahy, Sponsor
18. **Chair's Closing Remarks**

*Background materials included.

Agenda Item 2
RSTC Meeting
March 13, 2024

Security Working Group (SWG) Scope Document Revision

Action

Approve

Background

The Security Working Group (SWG) scope was developed in 2019 and last reviewed in 2021. We have performed a 2024 review and made some minor changes to the document. The scope review was performed by the SWG leadership and RSTC sponsor.

SWG Scope URL: https://www.nerc.com/comm/RSTC/SWG/SWG Scope.pdf

Summary

Summary of changes:

- Language specifying co-chairs structure
- Verbiage to address potential overlap with S.I.T.E.S scope
- Errata

SWG is seeking RSTC approval of amended scope document.

Security Working Group Scope

Purpose

The 2019 ERO Reliability Risk Priorities Report highlighted “Grid Transformation” (Increased Complexity in Protection and Control Systems), “Security Risks” (Physical and Cyber Security Threats), and “Critical Infrastructure Dependencies” (Communications) as three high level risk categories for the ERO Enterprise and electric industry. At the same time, the operational and technological environment of the electrical grid is undergoing rapid transformation. The Security Working Group (SWG) serves the Reliability and Security Technical Committee (RSTC) in providing a formal input process to enhance collaboration between the ERO and industry with an ongoing working group. The SWG also supports industry efforts to mitigate emergent risks by providing technical expertise and feedback to the ERO Enterprise Compliance Assurance group in developing and enhancing security compliance-related products, including guidelines, guidance, best practices and lessons learned.

SWG Objectives/Duties

RSTC oversees the SWG. The SWG will develop a portfolio of technical expertise from industry and other willing participants who will conduct the following activities:

- Develop a process for handling requests from ERO Enterprise compliance assurance staff
- Provide feedback from industry to the ERO Enterprise to improve the Compliance Monitoring and Enforcement Program (CMEP), including a process to deliver that feedback
- Provide guidance to the RSTC on prioritization of compliance assurance products under development
- Provide guidance and feedback for CMEP materials brought before the RSTC for discussion
- Provide timely technical reports to RSTC on CMEP matters related to cyber and physical security
- Attend the RSTC face-to-face meetings to facilitate discussion and allow discourse on CMEP topic areas
- Promote registered entity involvement in the NERC Reliability Standards review and comment process
- Develop materials from organized industry activities (such as tabletop exercises) led by or in collaboration with the SWG
- Review lessons learned published by NERC where the RSTC seeks additional industry feedback to help determine whether additional guidance to industry is necessary
- Coordinate with other industry technical groups
- Collaborate with other NERC stakeholder groups within the RSTC to eliminate potential overlaps, avoid duplicative efforts, and ensure alignment of assignments and responsibilities by coordinating and leveraging expertise across groups to the best extent possible. This includes:

- Coordination with the NERC Security Integration and Technology Enablement Subcommittee (SITES) regarding compliance products being developed and other issues that should inform their discussions about security matters.
- Coordination with other NERC technical groups focused on security and compliance issues to provide useful perspectives on security-related issues that may affect them.

Members, Structure, and Roles and Responsibilities

The SWG will include members with expertise in the following areas:

- Technology design, architecture and engineering in Operational Technology (OT) computing applications, software and hardware platforms, network, carrier and telecom experience at entity data center, OT and industrial control systems (ICS) at transmission and generation control centers, substation and operating station facilities and generation plant and energy centers.
- Design, implementation, and operation of security infrastructure and controls (both physical and cyber) for systems and networks in bulk power system (BPS) control centers, transmission systems, generation facilities, systems critical to BPS restoration, special protection systems, and other systems impacting users, owners, and operators of the BPS
- State-of-the-Art and emerging technologies (e.g., software-as-a-service (SaaS), cloud computing) and how these innovative technologies can be effectively leveraged to improve physical and cyber security, as well as their relationship to compliance with NERC's Reliability Standards.
- Physical and cyber security threat vectors and risks posed by changing technologies for owners, operators, and end-users of the BPS.
- Relevant information security standards and NERC Reliability Standards.
- NERC CMEP and responsible entity compliance programs and processes.
- Various physical and cyber security frameworks, including National Institute of Standards and Technology (NIST), ISO 27001, and others.
- Process development with technical writing and program development.

The SWG will consist of two co-chairs with a two-year term limit, nominated by the SWG and approved by the RSTC leadership. The co-chairs may be reappointed, as necessary. The SWG sub-team leads may be reappointed, as necessary. NERC staff will be assigned as coordinator (secretary).

Decisions made by the membership will be consensus-based, led by either co-chair. Any minority views will be documented, as necessary. The RSTC will assign a sponsor to advocate on behalf of the SWG and to coordinate with RSTC and its other sub-groups.

Members are those participants who actively participate on SWG initiatives and require "collaborator" access to the SWG extranet site. Observers are those participants who do not need to collaborate on active projects yet desire to remain aware of SWG activities. Members and observers are documented on the mailing lists maintained by NERC.

The RACI (Responsible, Accountable, Consulted, and Informed)[1] chart in **Appendix A** shows the main roles and responsibilities for the SWG.

Reporting and Duration

The SWG will report to the NERC RSTC. The duration of the SWG is expected to be indefinite so long as the group is deemed beneficial by the RSTC and effectively accomplishing its purpose.

SWG Deliverables and Work Plan

The SWG will develop a work plan that will be submitted to the RSTC. Work products that support industry efforts relating to leveraging emerging technologies and security enhancements into conventional planning, operations, and design practices will address one or more of the following areas:

- Technical reference documents, technical reports, white papers, best practices, and tools
- Reliability guidelines and security guidelines as assigned by the RSTC or through periodic review
- Compliance implementation guidance
- Lessons Learned
- Standard Authorization Requests (SAR)
- Supporting materials and expertise to other NERC working groups / subcommittees

The SWG work plan will be maintained throughout the group's existence and will be documented in the RSTC Strategic Plan and updated as needed by the RSTC.

Meetings

The SWG conducts a minimum of four meetings per year and strives to conduct monthly meetings. Emphasis will be given to conference calls and web-based meetings prior to the RSTC quarterly meetings. If face-to-face meetings are required, every effort will be made to meet at the same location as the RSTC quarterly meeting.

The SWG co-chairs or their designee provides a report at each RSTC quarterly meeting as needed. The SWG has a process for handling RSTC requests in consultation with the RSTC sponsor and NERC staff coordinator. Sub-team meetings are conducted by the sub-team leads on a frequency determined by the sub-teams that are appropriate to the project and workload. Sub-team updates are given at the periodic SWG meetings.

[1] https://www.softwareadvice.com/resources/what-is-a-raci-chart/

Appendix A: Roles and Responsibilities

Table A.1: SWG RACI (Responsible, Accountable, Consulted, Informed)

Description	RSTC Sponsor	SWG Co-Chairs		Sub-Team Member	NERC Staff (Secretary / Coordinator)	NERC Staff (Support)	SWG Member	SWG Observer
Organize monthly/quarterly SWG Meetings	I	A, R	I	I	C	I	C	I
Organize Sub-team meetings	I	A	A, R	C	C	I	I	I
Coordinate Sub-team activities, ensure completion of Sub-team tasks	I	I	A	R	I	I	I	I
Administrative review of products completed	C	A	R	C	C	I	I	I
Drive RSTC review/acceptance process	C	A, R	C	C	C	I	I	I
Perform sub-team tasks	N/A	I	A	R	I	I	I	I
Coordinate with other working groups	I	A, R	C	C	I	I	I	I
Meet with SWG chair/co-chair for status, problem-solving	C	C	A, R	C	I	I	N/A	N/A
POC for SWG for industry groups	C	A, R	C	I	I	I	I	I
Problem-solve for delivery dates	I	C	A, R	R	C	I	I	I
Maintain extranet site	I	A, R	A, R	R	I	I	I	I
Send out and collect calls for volunteers	I	A, R	C	C	C	C	I	I
Drive continuous improvement for SWG processes	C	A, R	R	C	C	C	C	I
Endorse SWG products	C	A, R	C	I	C	I	I	I
Provide SWG Scope Guidance	A	R	C	C	I	I	I	I
Provide daily guidance to sub-teams	N/A	A	R	C	I	I	I	I
Extranet design changes, tools	I	A, R	C	C	I	I	I	I
Manage project input process	C	A, R	C	C	I	I	I	I
Maintain and monitor work processes	I	A	R	C	C	I	I	I
Approve SWG Work Plan	C	A	R	C	C	I	I	I
Manage mailing lists and overall SharePoint environment (extranet)	N/A	A	C	C	C	R	I	I

Appendix B: Version History

Table B.1: SWG Scope Version History			
Date	**Page**	**Description**	**Version**
2/3/2021	All	Draft SWG Scope Approved by the Security Working Group	0.1
3/2/2021	All	SWG Scope approved by the Reliability and Security Technical Committee	1.0
1/31/2024	All	Reviewed by SWG leadership; co-chair changes from vice chair verbiage; RACI review, etc.	2.0

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Scope Revision

Security Working Group (SWG) Scope Document Revision

Brent Sessions, Co-Chair, Western Area Power Administration
John Tracy, Co-Chair, Tennessee Valley Authority
Reliability and Security Technical Committee Meeting
March 12-13, 2024

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SWG Scope Amendments

- SWG has reviewed the SWG scope and made minor adjustments:
  - Co-chairs
  - Review of mission / scoping etc.
  - Errata
- SWG is looking for physical security Subject Matter Experts to join a new physical security sub-team.
- SWG is considering future action for adding a vice-chair or third co-chair role.

Questions and Answers

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6GHZTF Status Report

RSTC Status Report 6 GHZ Task Force (6GHZTF)

Chair: Jennifer Flandermeyer
Vice Chair: Larry Butts
March 12, 2024

● On Track
● Schedule at risk
● Milestone delayed

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

Items for RSTC Approval/Discussion:

- **None**

Recent Activity

- Communication Interference Whitepaper approved and posted.

Upcoming Activities

- Conduct a webinar to raise awareness for the industry (target date 5/1/24)
- Support development of a Level 2 Alert that encompasses the recommendations from the Communication Interference Whitepaper
- Support the development of a public-facing summary report of the responses to the Level 2 Alert

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

Milestone	Status	Comments
Conduct Awareness Webinar	●	Planning phase Q2/2024
Communicate/Launch Interference Reporting Email	●	Q2/2024
Support the NERC Level 2 Alert	●	Planning phase Q1/2024
Develop public-facing summary report of the Alert	●	Q3/2024
Develop Transition Plan to Potential TWG or Disband	●	Q4/2024

RSTC Status Report – Event Analysis Subcommittee (EAS)

Chair: Chris Moran
Vice-Chair: James Hanson
March 12, 2024

- On Track
- Schedule at risk
- Milestone delayed

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

Items for RSTC Action:

- None

Recent 2024 Activity

- Development of Lessons Learned – 1 approved; 2 in development
- Development of FMM Diagrams – 1 approved; 1 in development
- RSTC Work Plan Summit

Ongoing & Upcoming Activities

- Development of Lessons Learned
- Development of Lessons Learned Webinar in 2024
- FMMWG Development of Failure Mode & Mechanism Diagrams
- Develop EAP v5 Industry Webinar

Workplan Status *(6 month look-ahead)*

Milestone	Status	Comments
Lessons Learned for 2024	On Track (green)	On Track
Event Analysis Data & Trends for 2024 SOR	On Track (green)	On Track
Winter Weather Webinar	On Track (green)	On Track
FMM Diagrams for 2024	On Track (green)	On Track
12th Annual SA Conference	On Track (green)	On Track
EAP v5 Webinar	On Track (green)	On Track

RSTC Status Report – Electric Gas Working Group

Chair: Mike Knowland
Vice-Chair: Daniel Farmer
March 12 - 13, 2024

On Track
Schedule at risk
Milestone delayed

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

Items for RSTC Approval/Discussion:

- *None.*

Workplan Status *(6 month look-ahead)*

Milestone	Status	Comments
FERC/NERC joint inquiry coordination	● (On Track)	On track

Recent Activity

- Sub-team formed to review and revise the EGWG scope document.
- The team received an update on the Gas Infrastructure study.
- The Reliability Alliance, Reliability Guideline.
- Winter Cold Best Practices were shared with the team.

Upcoming Activity

- Develop Coordination Plan for potential electric related risks/objectives in natural gas related standards.
- The next EGWG team meeting is on Thursday, April 17, 2024.

RSTC Status Report: Electromagnetic Transient Modeling Task Force (EMTTF)

Co-Chairs: Adam Sparacino, Miguel Acosta

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

Purpose: To support and accelerate industry adoption of electromagnetic transient (EMT) modeling and simulation in their interconnection and planning studies of bulk power system (BPS)-connected inverter-based resources

Items for RSTC Approval/Discussion:

- Sending survey to TPs and PCs (Info Only)

Recent Activity

- Technical Presentation on Australia Energy Market Operator (AEMO) Experience with Wide-Area EMT Simulation
- Technical Presentation on Dynamics and Stability of Power Systems With High Shares of Grid-Following Inverter-Based Resources: A Tutorial

Upcoming Activity

Workplan Status *(6 month look-ahead)*

Milestone	Status	Comments
Item 2 - Electromagnetic Transient Modeling and Simulations	Green	In progress
Item 3 - Organized Repo of Curated EMT Modeling Resources ("EMT Curriculum")	Green	In progress
Item 4 - Case Study on Adoption of EMT Modeling and Studies in Interconnection and Planning Studies for BPS-connected IBRs	Yellow	In Progress
Item 5 - White Paper: EMT Analysis in Operations	Green	In Progress

RSTC Status Report – Energy Reliability Assessment Working Group (ERAWG)

Chair: Mike Knowland
Vice: Chair David Mulcahy
March 12 - 13, 2024

On Track
Schedule at risk
Milestone delayed

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

Recent Activity:

- Vice Chair David Mulcahy is appointed.
- The Tiger Team continues to draft Volume 2, a technical paper that documents detailed scenarios on conducting energy reliability assessments in the operations time horizon and the planning time horizon.

Items for RSTC Approval/Discussion:

- *None.*

Upcoming Activity:

- Provide technical assistance for the SDT, as needed.
- Continue the Tiger team meetings on drafting Volume 2.
- The next ERAWG team call is scheduled for March 6, 2024.
- Scheduled completion date: Q2/2024.

Workplan Status *(6 month look-ahead)*

Milestone	Status	Comments
Supporting SDT for Project 2022-03.	On Track	On track.
The Tiger team is currently drafting the Volume 2 document on conducting an energy reliability assessment.	On Track	On track.

RSTC Status Report: Facility Ratings Task Force (FRTF)

Chair: Tim Ponseti
Vice-Chair: Jennifer Flandermeyer
March 2024

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

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

Items for RSTC Approval/Discussion:

- None

Recent Activity

- Hold regular leadership meetings to discuss progress and strategy on deliverables.
- All three sub-teams holding regular meetings and working on deliverables.
- Held meeting with full task force on November 17th to provide updates on the individual work plan items.

Upcoming Activity

- Sub-teams working on deliverables.
- Support for Project 2021-08 Modifications to FAC-008 SDT continues but the project priority has been set as 'low' by the NERC Standards Committee. Low priority projects will have completion dates of 2025 and beyond.

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

Milestone	Status	Comments
Item 1 – Implementation Guidance on sustaining accurate facility Ratings Estimated completion: June 2024	Green (On Track)	In Progress
Item 2 – Support Project 2021-08 Modifications to FAC-008 SDT Estimated completion date of 2025	Green (On Track)	In Progress
Item 3 – Whitepaper on Sampling for Facility Rating programs Estimated completion: June 2024	Green (On Track)	In Progress

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

On Track
Schedule at risk
Milestone delayed

Chair: Julia Matevosyan
Vice-Chair:Rajat Majumder

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

Items for RSTC Approval/Discussion:

- Item 16: SAR for FAC-001 and FAC-002 Enhancements
  - Accept for 30-day joint RSTC and public comment period

Workplan Status *(6 month look-ahead)*

Milestone	Status	Comments
Item 8 - Reliability Guideline: Recommended Approach to Interconnection Studies for BPS-Connected Inverter-Based Resources	On Track	In progress
Item 24 - White Paper: BPS-Connected IBR Commissioning Best Practices	On Track	In Progress
Item 16: SAR for FAC-001 and FAC-002 Enhancements	On Track	In Progress

Recent Activity

- Approval of Item 22: Grid Forming White Paper

Upcoming Activity

- Work Plan Item #8: Reliability Guideline: Recommended Approach to Interconnection Studies for BPS-Connected Inverter-Based Resources
- Work Plan Item #24: Commissioning Best Practices for IBRs

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LMWG Status Report

RSTC Status Report – Load Modeling Working Group (LMWG)

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

On Track
Schedule at risk
Milestone delayed

Purpose:
The LMWG is preparing modeling for the emerging loads and transitioning utilities from the CLOD model to the CMLD Composite Load Model.

Items for RSTC Approval/Discussion:

- **Review**: LMWG *Work Plan*

Recent Activity

- Reviewed responses to Data Center Questionnaire
- RSTC Approval of EV Reference Report and Electric Vehicle Charger Model parameterization
- LMWG Winter Webinar
- Webinar on EV Load Shapes

Upcoming Activity

- *Explore NERC Role in Acquisition of EV Charger Test Data*
- *Explore the Usage of EV Load Shape Data*
- *Refine EV Chargers Models*
- *Develop Process to include EV Load Composition in the LMDT Tool.*
- *Improve EV Load Models*
- *Conduct Reliability Studies with EV Load Models*
- *Continue Review of Responses to Data Center Questionnaire*

Workplan Status *(6 month look-ahead)*

Milestone	Status	Comments
Refinements to EV Charger Models and usage of EV Load Shapes	On Track	In progress
Refinements to Center Modeling	On Track	In progress
Refinements to Heat Pump Modeling	On Track	In progress
Reliability Studies Using EV Models and EV Loads shapes	On Track	In progress
Modular Implementation of the CMLD Model	On Track	In progress

RSTC Status Report – Performance Analysis Subcommittee (PAS)

Chair: David Penney
Vice-Chair: Heide Caswell
March 12, 2024

On Track
Schedule at risk
Milestone delayed
Not started
Complete

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

Items for RSTC Approval/Discussion:

- N/A

Recent Activity

- Planning the 2024 State of Reliability Report issuance.

Upcoming Activity

- Execute the 2024 State of Reliability Report.

Workplan Status *(6 month look-ahead)*

Milestone	Status	Comments
2024 State of Reliability Report	On Track	2024 SOR planning and preparation has begun. The expected publish date is early June 2024.

RSTC Status Report – Probabilistic Assessment Working Group (PAWG)

Chair: Bryon Domgaard
Vice-Chair: Anaisha Jaykumar
March 12-13, 2024

On Track
Schedule at risk
Milestone delayed

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

Items for RSTC Approval/Discussion:

- Ask for RSTC Approval for White Paper: Probabilistic Planning for the Tail Risks

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

Milestone	Status	Comments
White Paper: Probabilistic Planning for the Tails	On Track	Plan to complete by Q1 2024

Recent Activity

- Met in February 2024 to finalize the data form and narrative questions for 2024 ProbA . Addressed RSTC reviewers' comments for the White Paper: Probabilistic Planning for the Tail Risks.
- Finalized the PAWG 2024 meetings schedule
- Ongoing engagement with RAS with probabilistic components of their assessments.

Upcoming Activity

- Update the PAWG workplan to include the Probabilistic Analysis Forum (PAF) that will be in the Q3/Q4 2025.
- Address the comments provided to data form and narrative questions for 2024 ProbA and send the letter of request in the 2nd week of April 2024.

RSTC Status Report – Reliability Assessment Subcommittee (RAS)

Chair: Andreas Klaube (12/2022)
Vice-Chair: Amanda Sargent (12/2022)
March 12-13, 2024

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

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

Items for RSTC Approval/Discussion:

- Work Plan Item #5 Interdependency Scope (Special Reliability Assessments Scope and Prioritization) related to the 2021 RISC report recommendation 2.1

Recent Activity:

- 2024 LTRA request materials sent to the Regional Entities in February 2024
- February 7-8, 2024 RAS meeting: Joint meeting with the Probabilistic Assessment Working Group (PAWG). Topics: RAS Work plan review, 2024 LTRA and ProbA planning, 2024 SRA planning, ERO Energy Assessments, PAWG Work plan review

Upcoming (RSTC) Activity:

- 2024 SRA RSTC commenting period (April 22 – May 3, 2024)
    - May 15, 2024 release

Workplan Status *(6-month look ahead)*

Milestone	Status	Comments
2024 Long-Term Reliability Assessment (LTRA)	Green (On Track)	Request letter sent to the Regions in February. Responses due back June 14.
2024 Summer Reliability Assessment (SRA)	Green (On Track)	In development. RSTC review April 22 – May 3, 2024.
Special Reliability Assessments Scope and Prioritization	Green (On Track)	Draft scope completed; for RSTC review and assignment to a task force

RSTC Status Report – Resources Subcommittee (RS)

Chair: Greg Park
Vice-Chair: William Henson
March 2024

On Track
Schedule at risk
Milestone delayed

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

Items for RSTC Approval/Discussion:

- Will be submitted for June RSTC meeting. Generating Unit Operations during Complete Loss of Communications Guideline

Workplan Status *(6 month look-ahead)*

Milestone	Status	Comments
Support ERSWG Measures 1,2,4, and 6	On Track	Periodic review and consultation with NERC staff ongoing
Reliability Guideline: Loss of Communications	Milestone delayed	Reviewing comments from posting. Plan to send for approval at June RSTC meeting.

Recent Activity

- Quarterly review of interconnection performance
- Reporting ACE and Associated Terms Standard Drafting Team – SDT finished work. All ballot items completed.
- Balancing Authority “High Speed Measurements” survey was sent out. Allowing additional time for responses.
- Selected OY 2023 BAL-003 Events for targeted March 1, 2024 posting.

Upcoming Activity

- In Person/Hybrid Meetings Scheduled
  - April 24th and 25th – Location TBD

RSTC Status Report – Real Time Operating Subcommittee (RTOS)

Chair: Christopher Wakefield
Vice-Chair: Derek Hawkins
March 2024

On Track
Schedule at risk
Milestone delayed

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

Recent Activity

Currently on track:

- Interconnection Time Monitors
  - Eastern Interconnection
    - IESO (Ontario) successfully completed the transition to NBP (New Brunswick Power) starting February 1, 2024
- Interconnection GMD Monitors
  - Eastern Interconnection
    - IESO successfully completed the transition to NBP starting February 1, 2024
  - Western Interconnection
    - AESO successfully completed the transition to CAISO RC West starting February 1, 2024

Items for RSTC Approval/Discussion:

RTOS Leadership changes: Approved via email 11/7/2023

Effective 2024-2025
Chair: Christopher Wakefield (SeRC)
Vice-Chair: Derek Hawkins (SPP)

Upcoming Activity

Continued work related to the Cold Weather Report
Feedback to SPIDERWG on EOP_005 SAR

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

Milestone	Status	Comments
Monitor development of common tools and act as point of contact for EIDSN.	On Track	On-going
Frequency Monitor Reporting (Standing RTOS agenda item to discuss).	On Track	On-going
Reference Document: Time Monitor Reference Document	On Track	Complete
Reliability Guideline: Methods for Establishing IROLs	On Track	In-progress

RSTC Status Report – Supply Chain Working Group (SCWG)

Chair: Roy Adams
Vice-Chair: Dr. Tom Duffey
March 2024

On Track
Schedule at risk
Milestone delayed

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

Items for RSTC Approval/Discussion:

- N/A

Recent Activity

- Two revised guidelines (Vendor Incident Response and Procurement Language) were updated to include metrics; the teams responsible are finalizing their responses to public comments, and updated guidelines are expected to be ready for publication Q2 2024.
- The Supply Chain Security gap assessment team is reviewing the supply chain security standards and a draft Standards Authorization Request (SAR) that the Standards Committee referred to the RSTC.

Upcoming Activity

- SCWG is considering additional guidelines that may be warranted based on industry feedback and observations pertaining to supply chain security issues.
- SCWG members participate as requested in projects and outreach events pertaining to cloud computing security risk topics.

Workplan Status *(6 month look-ahead)*

Milestone	Status	Comments
Periodic Review of Supply Chain Security Guidelines	On Track	Complete
Gap Assessment for Supply Chain Security Standards encompassing: • NERC CIP-013-2 Standard • NERC CIP-013-2 SAR • Trades/Stakeholder Coordination • Supplier Coordination • Regulator Feedback • Industry Perspective	On Track	In Progress

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

Chair: Brian Burnett
Vice Chair: Thomas Peterson
March 2024

- On Track
- Schedule at risk
- Milestone delayed

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

Items for RSTC Approval/Discussion:

- **N/A**

Recent Work Plan Activity

- Whitepaper: Zero Trust for Electric OT (PUBLISHED)
- Joint Whitepaper: Privacy & Security Impacts of DERA, (PUBLISHED)
- Whitepaper: BES Ops in Cloud (PUBLISHED)

Recent Activity – Cont.

- Whitepaper: New Technology Enablement & Field Testing draft has received feedback/redlines, and changes are being consolidated for final draft

Upcoming Activity

- Joint SWG, SCWG, SITES leadership meeting to coordinate / strategize on work plan priorities and overlaps
- Tentative kickoff of new SITES work plan item
- The Work plan survey is being sent out 2024

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

Milestone	Status	Comments
New Tech Enablement	On Track	Consolidating Feedback
Work plan survey	On Track	In-process

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SMWG Status Report

RSTC Status Report – Synchronized Measurement Working Group (SMWG)

Chair: Qiang "Frankie" Zhang
Vice-Chair: Clifton Black
March 2024

- On Track
- Schedule at risk
- Milestone delayed

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

Items for RSTC Approval/Discussion:

Recent Activity

- Held January SMWG Online Meeting (1/30).
- Kicked off the Synchrophasor Data Accuracy Maintenance Manual Drafting Effort.

Upcoming Activity

- Add oscillation as a category in RCIS.
- Draft a Roadmap for Integrating Synchrophasors into Real-time Operations.
- Draft a Synchrophasor Data Accuracy Maintenance Manual – Joint Effort with EMSWG.
- Supporting/Collaborating with SWG and SITES on developing a CIP implementation guidance for synchrophasors.

Workplan Status *(6 month look-ahead)*

Milestone	Status	Comments
Add Oscillation as a Category in RCIS	On Track	Initiated
April Hybrid Meeting	On Track	Scheduled
Synchrophasor Data Accuracy Maintenance Manual (with EMSWG)	On Track	Initiated
Roadmap for Operationalizing Synchrophasor Technology	On Track	Initiated
CIP Implementation Guidance for Synchrophasors	On Track	Initiated

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

Chair: Lynn Schroeder
Vice-Chair: Manish Patel
As of January 11, 2024

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

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

Items for RSTC Approval/Discussion:

- Create a team to the Practical Relay Loadability paper

Recent Activity

- Review and update documents: Determination of Practical Transmission Relaying Loadability Settings
- Review TRD: Transmission System Phase Backup Protections
- Develop Technical Reference document for Ethernet based P&C.
- Steady-state approach for PRC-024-3 Evaluation for Inverter-Based Resources" white paper

Upcoming Activity

- Work on projects
- Working to provide comments on TPL-001 Footnote 13

Workplan Status *(6 month look-ahead)*

Milestone	Status	Comments
Practical Relay Loadability	Green	Bring Submitted for RSTC Approval
Ethernet P&C TRD	Green	The outline is complete, and the writing portion has begun
Review and update Transmission System Phase Backup Protections	Green	Due to be submitted for RSTC Review at March Meeting
TPL-001	Yellow	Putting a team together to provide comments
Steady-state approach for PRC-024-3 Evaluation for Inverter-Based Resources" white paper	Green	Due to be submitted for RSTC Review at March Meeting

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

On Track
Schedule at risk
Milestone delayed

Chair: Shayan Rizvi (Jan 2024-2026)
Vice-Chair: John Schmall (Jan 2024-2026)
March 12, 2024

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

Items for RSTC Approval/Discussion:

- **Approve**: *White Paper: Transmission and Distribution Coordination Strategies*
- **Authorize**: SAR OPA-RTA for 45 day comment period
- **Authorize:** *Reliability Guideline: Bulk Power System Planning under Increasing Penetrations of DERs.*

Workplan Status *(6 month look-ahead)*

See next slide for details

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

Recent Activity

- Met in February 2024 to update work products and focus on high priority items.
- Engaged RTOS and RS related to EOP remanded SARs. Anticipated return in Q2.
- Building an extranet website for member participation and working out member access.
- Set priorities for new reliability guidelines per Reliability Standards White Paper.

Upcoming Activity

- *Set to draft new reliability guidelines per the development process*
- *Finalize work on the DER Aggregator modeling pieces*
- *Respond to previous meeting reviews and remanded materials.*

Work Look Ahead – non-SAR

- On Track
- Schedule at risk
- Milestone delayed

Workplan Status (6 month look-ahead)

Milestone	Status	Comments
S1 – Reliability Guideline: Bulk Power system Planning under Increasing Penetration of Distributed Energy Resources	On Track	Delayed. Seeking RSTC review in Q1 2024 due to other information delays
C11 – White Paper: Variability, Uncertainty, and Data Collection for the BPS with DER Aggregators	Milestone delayed	Delayed to reprioritize to reliability guideline development. RSTC review in Q4 2024.
A3 – White Paper: Modeling of DER Aggregator and DERMS Functional Impacts	On Track	Seeking RSTC review in Q2 2024.
C2 – White Paper: Communication and Coordination strategies for Transmission Entities and Distribution Entities regarding Distributed Energy Resources	On Track	Seeking approval in Q1 2024
Reliability Guideline: Detection of Aggregate DER Response during Grid Disturbances	On Track	In scoping and draft. Seeking post for public comment period near Q3 2024
Reliability Guideline: DER Forecasting	On Track	In draft. Seeking post for public comment period Q2 2024
Reliability Guideline: Aggregate DER in Emergency Operations	On Track	In draft. Seeking post for public comment period Q3 2024 or Q4 2024

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Work Look Ahead - SAR

On Track
Schedule at risk
Milestone delayed

Workplan Status (6 month look-ahead)

Milestone	Status	Comments
C15 – SAR EOP-004	Milestone delayed	In draft. Seeking RS prior to re-engaging RSTC. Engaged with RTOS already. Delayed to Q2 to build consensus activities
C16 – SAR EOP-005	Milestone delayed	In draft. Delayed from initial milestone due to industry comment period. Delayed to Q2 return to build consensus activities
C17 – SAR BAL-003	On Track	Seeking removal of item from SPIDERWG work plan
C18 – SAR PRC-006	On Track	Comment period ending 2/24/24. Responding to industry comments for Q2 turnaround.
C19 – SAR on OPAs and RTAs	On Track	Seeking authorization to post for 45 day comment period.

RSTC Status Report – Security Working Group (SWG)

Co-Chair: Brent Sessions
Co-Chair: John Tracy
March 2024

- On Track
- Schedule at risk
- Milestone delayed

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

Items for RSTC Approval/Discussion:

- SWG Scope document review / updates
- SWG Security Guideline retirement (3)

Recent Activity

- Completed
  - BCSI TTX
  - OLIR mapping CIP to CSF
  - FERC LL CIP-002
  - Cloud Encryption Guidance
    - ERO Compliance Endorsed / Approved
- On-going
    - *CIP Evidence Request Tool (ERT)*
- New Activity
    - *Physical Security SME / potential WP item*

Upcoming Activity

- Physical Security SME and sub-team

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

Milestone	Status	Comments
CIP IG for Incorporating Synchrophasor Data into Real-time Operations	On Track (green)	
Utility Essential Services Whitepaper	On Track (green)	
NIST 800-53 to NERC CIP Standards mapping	On Track (green)	
Communication Protection System Guideline	On Track (green)	
Physical Security Protections for BES Elements	On Track (green)	

Agenda Item 4
RSTC Meeting
March 12, 2024

RSTC Nominating Subcommittee Election

Action
Elect Nominating Subcommittee

Background
Per the RSTC Charter:

- The Nominating Subcommittee (RSTC NS) will consist of seven (7) members (the RSTC Vice-Chair and six (6) members drawing from different sectors and at-large representatives). Apart from the Vice-Chair, members of the RSTC Executive Committee (RSTC EC) shall not serve on the RSTC NS.
- The NS members are nominated by the RSTC chair and voted on by the full RSTC membership.
- The term for members of the NS is one (1) year.
- The RSTC NS is responsible for (a) recommending individuals for at-large representative seats, and, (b) managing the process to select the chair and/or vice chair of the RSTC. The RSTC vice-chair shall recuse him or herself from this process unless he or she is not seeking re-election. At-large members on the RSTC NS shall recuse themselves from recommendations for at-large representative seats if they are seeking reappointment.
- Open nomination period for RSTC NS February 6-21, 2024
- Chair Hydzik reviewed nominations and presents a proposed slate for RSTC NS members for full RSTC vote.

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RSTC Nominating Subcommittee

Rich Hydzik – RSTC Chair
RSTC Meeting
March 12, 2024

RELIABILITY | RESILIENCE | SECURITY




Nominating Subcommittee Overview

- The Nominating Subcommittee (RSTC NS) will consist of seven (7) members (the RSTC Vice-Chair and six (6) members drawing from different sectors and at-large representatives). Apart from the Vice-Chair, members of the RSTC Executive Committee (RSTC EC) shall not serve on the RSTC NS.
- The NS members are nominated by the RSTC chair and voted on by the full RSTC membership.
- The term for members of the NS is one (1) year.

Nominating Subcommittee Overview

- The RSTC NS is responsible for (a) recommending individuals for at-large representative seats, and, (b) managing the process to select the chair and/or vice chair of the RSTC. The RSTC vice-chair shall recuse him or herself from this process unless he or she is not seeking re-election. At-large members on the RSTC NS shall recuse themselves from recommendations for at-large representative seats if they are seeking reappointment.
- Open nomination period for RSTC NS February 6-21, 2024
- Chair Hydzik reviewed nominations and presents a proposed slate for RSTC NS members for full RSTC vote at the March 2024 RSTC meeting

Election Process

- The Chair presents the candidates.
- Elections will be held as follows:
  - The Committee will vote on the presented candidates. If the presented candidates are approved with a 2/3 majority, the presented candidates are selected and the election is closed.
  - Should the presented candidates not get elected the Chair will do the following:
    - Reconvene a review of the nominations already submitted;
    - Open for a second, shortened nomination process for additional submissions; and,
    - Convene a second meeting to evaluate the nominations and present candidates to be considered at the next RSTC meeting.

Recommended Slate

- For the Nominating Subcommittee members, the Chair nominates:
  - Jody Green – Sector 7
  - Monica Jain -At-large
  - Vinit Gupta – Sector 1
  - Wayne Guttormson – At-large, Canadian
  - Brett Kruse – Sector 6
  - Truong Le – At-large
- For reference: Vice Chair – John Stephens

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Questions and Answers

Agenda Item 5
RSTC Meeting
March 12, 2024

RSTC Work Plan Risk Priorities

Action
Information

Background
In June 2023, the RSTC appointed a Work Plan Review Team to review the RSTC Work Plan and the soon to be published ERO Risk Priorities Report (RISC). Each RSTC Subcommittee/WG/TF reviewed their work plan and completed the template for the review team to consider at the October work plan summit. The RSTC Review Team assessed work plan item priority (H/M/L) and applicability to the RSTC Strategic Plan. Per RSTC Strategic Plan, the team included the following in the review:

- Long-Term and Seasonal Reliability Assessments
- Special Assessments
- Event and Disturbance Reports
- State of Reliability Report
- FERC NOPR on IBRs
- Other reliability indicators, whitepapers, gap assessments
- 2023 ERO Enterprise Work Plan Priorities (https://www.nerc.com/AboutNERC/Pages/Strategic-Documents.aspx)

Task Name	Description	Task Type	Due Date	Subcommittee	Priority	Risk Registry	Subcommittee:Focus	RSTC Strategic Risk Priorities	Comments	Column2	Column3
6 GHz Task Force	The 6 GHz Task Force will provide recommendations to the NERC RSTC as follows: 1.Determine scope of issue (e.g., limited to 6 GHz, relationship to other telecommunications items, etc.) 2.Gather information related to risk of harmful interference in the 6 GHz spectrum. a.Identify penetration and Bulk Power System users relying on 6 GHz. b.Reach to industry for input on potential readiness issues (e.g., trade associations, membership organization, compliance forums, registered entities, etc.). c.Initiate or request industry information related to current harmful interference experience. d.Identify potential mitigation strategies. 3.Evaluate options for industry outreach. 4.Develop suggested recommendations related to the issue.	Recommendations	9/30/2024	6 GHz Task Force (6GHZTF)	(2) Normal	Increasing Complexity in Protection and Control Systems		N/A			
EGWG Triennial guideline review	Review 3/20 EGWG guideline on Fuel Assurance	Reliability Guideline	Complete	Electric Gas Working Group (EGWG)	(2) Normal	Energy Assurance	Risk Mitigation	Grid Transformation/Gas-Electric Coordination			
Whitepaper on Sampling for Facility Rating programs	Develop a whitepaper that discusses sampling approaches for generation and transmission Facilities, and Facility Rating methodologies in association with FAC-008. Explore all aspects of the sampling processes.	White Paper	3/29/2024	Facility Ratings Task Force (FRTF)	**(2) Normal**	Loss of Situational Awareness	Risk Mitigation	Resilience and Extreme Events/Planning for High-Impact Events:	I recall findings that suggested generators were not performing according to facility ratings, in both normal and extreme conditions.	Winter storm Elliot report linkage - 1 to strengthen generators' ability to maintain extreme cold weather performance; (b) the need for robust ERO monitoring of implementation of currently-effective and approved cold weather Reliability Standards, to determine if reliability gaps exist.	oNear-term action: NERC should identify the generating units that are the highest risk and perform cold weather verifications of these generating units.
Probabilistic Planning for the Tails White Paper	This whitepaper will explore current approaches and practices on how 'extreme events' are currently considered in probabilistic planning processes and how those are assessed seasonally	White Paper	3/31/2024	Probabilistic Assessment Working Group (PAWG)	**(1) High**	Energy Assurance	Reliability and Security Assessment	Resilience and Extreme Events/Planning for High-Impact Events:			

4- Special Reliability Assessments Scope and Prioritization	Workplan item to address RISC Report recommendation 2.1 RAS will draft one or more project scopes for special reliability assessment(s) of extreme event impacts by geographical areas that integrate the following: (i) critical infrastructure interdependencies from water and telecom; and (ii) analytic data and insights regarding resilience. Draft project scopes will specify that the special assessments include possible mitigation plans and implementation roadmaps. Draft project scopes will be provided to the RSTC for their review, feedback, and determination of further action/assignments.	Recommendations	6/30/2024	Reliability Assessment Subcommittee (RAS)	**(1) High**	Energy Assurance	Reliability and Security Assessment	Resilience and Extreme Events/Planning for High-Impact Events:	This item connects to Elliott report recommendations 8,9 and 10.
6- Cold Weather REC 10 - Assess Impact of Changes to Load Shedding Plans on Seasonal Reliability	Workplan item to address Cold Weather Inquiry Report recommendation 10. RAS will collect and analyze information on changes to rotating, manual load shedding plans and the potential effects these changes may have on mitigating impacts to firm load during energy emergencies within wide-area, long-duration extreme cold events. Findings will be included in future WRAs. RAS will coordinate collection and analysis with the RTOS.	Recommendations	12/31/2024	Reliability Assessment Subcommittee (RAS)	**(1) High**	FERC-NERC Cold Weather Inquiry	Reliability and Security Assessment	Resilience and Extreme Events/Wide-area Energy Assessments	This item connects to Elliott report recommendations 8,9 and 10.
7- Cold Weather RECS 20 and 25 - Assess Information from Transfer Studies and System Studies on Reliability of Planned System	Workplan item to address Cold Weather Inquiry Report recommendations 20 and 25. RAS will collect information, analyze, and report on results of the following system studies performed by NERC entities that are relevant to seasonal or long-term reliability: •bi-directional seasonal transfer studies between adjacent operating entities, including identified constraints that are anticipated in extreme weather events spanning multiple RC/BA areas. (RAS will coordinate collection and analysis with the RTOS) •transfer studies identifying constraints between sub-areas or load pockets. (RAS will coordinate collection and analysis with the RTOS) •ERCOT studies to evaluate additional links between ERCOT and other interconnections in mitigating energy emergencies or improving black start capabilities	Recommendations	12/31/2024	Reliability Assessment Subcommittee (RAS)	**(1) High**	FERC-NERC Cold Weather Inquiry	Reliability and Security Assessment	Resilience and Extreme Events/Planning for High-Impact Events:	

RS Review of Load Forecasting Impact on BAs	Balancing Authorities should have staff with specialized knowledge of how weather impacts load, including the effects of heat pump backup heating and other supplemental electric heating. Balancing Authorities should also broaden the scope of their near-term (seven-days prior to real-time) load forecast to include multiple models and sources of meteorological information to increase accuracy and should consider regional differences within their footprints. (Winter 2022-2023)	Support	12/31/2024	Resources Subcommittee (RS)	**(1) High**	FERC-NERC Cold Weather Inquiry	Performance Monitoring	Resilience and Extreme Events/Planning for High-Impact Events:	This item connects to Elliott report recommendation 8. ****Consider assigning to ERAWG or RTOS or LMWG****
Review intermittent Generation to Improve Load Forecasts	In performing their near-term load forecasts, Balancing Authorities should analyze how intermittent generation affects their ability to meet the peak load (including the effects of behind-the-meter intermittent generation) (for the entire footprint as well as sub-regions, such as MISO South and SPP's southern region), especially if peak load cannot be met without variable resources. Balancing Authorities should consider performing a 50/50 or 90/10 forecast for renewable resources three-to - five days before real time. (Winter 2022-2023)	Support	12/31/2024	Resources Subcommittee (RS)	**(1) High**	FERC-NERC Cold Weather Inquiry	Performance Monitoring	Resilience and Extreme Events/Planning for High-Impact Events:	This item connects to Elliott report recommendation 11. ****Consider assigning to ERAWG or RTOS****
White Paper - Energy Reliability Assessments – Volume 2	Document methods and processes for developing detailed scenarios to evaluate energy reliability that include critical infrastructure interdependencies	White Paper	6/30/2024	Energy Reliablity Assessment Working Group (ERAWG)	**(1) High**		Risk Mitigation	Resilience and Extreme Events/Planning for High-Impact Events:	**Responsive to Final Cold Weather Recommendation #8**
Provide input and feedback to NERC staff on Supply Chain security topics	As NERC staff determine the need for NERC Alerts, responses to Board initiatives and RISC priorities, the SCWG provides a source of industry experts to develop and vet potential solutions.	Support	On-Going	Supply Chain Working Group (SCWG)	**(1) High**		Risk Mitigation	Resilience and Extreme Events/Planning for High-Impact Events:	**Should we assign a "new" work item to advise/warn of supply chain bottlenecks that could impact resiliency and recovery from Extreme Events?**
Aggregate DER Conditions for Emergency Ops and Cold Weather	Emergency operations guideline for expectations and treatment of DERs during emergency operations. Includes voltage based emergency operations and cold weather.	Support	12/31/2024	System Planning Impacts from Distributed Energy Resources (SPIDERWG)	**(3) Low**		Performance Monitoring	Resilience and Extreme Events/Planning for High-Impact Events:	
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.	Support	On-Going	System Planning Impacts from Distributed Energy Resources (SPIDERWG)	**(2) Normal**		Risk Mitigation	Resilience and Extreme Events/Planning for High-Impact Events:	
Support Study: Reviewing Fuel Availability for Regional Flexible Resources to Support System Variability	As North America increases its reliance on variable energy resources, so too will the grid's need for firm flexible generation to support and accommodate the intermittent generation. During this transition, flexible generation and the availability of fuel, primarily natural gas, will play a critical role in maintaining reliability and providing Essential Reliability Services, specifically ramping capability. The EGWG would serve as a technical review board for this study.	Support	12/31/2024	Electric Gas Working Group (EGWG)	**(3) Low**		Risk Mitigation	Grid Transformation/Gas-Electric Coordination	

~~Bulk Power System (BPS) Performance Expectations for electromagnetic pulse (EMP) events (EMPWG work plan item 5)~~	~~Establish performance expectations for all sectors of the BPS regarding a predefined electromagnetic pulse (EMP) event.~~	~~Reference Document~~	~~3/31/2023~~	~~Electromagnetic Pulse Working Group (EMPWG)~~	~~**(3) Low**~~	~~Electromagnetic Pulse (EMP)~~	~~Risk Mitigation~~	~~Resilience and Extreme Events/Planning for High-Impact Events:~~
~~Critical Asset Identification: Identifying Assets that (EMPWG work plan item 12)~~	~~Develop guidance for identifying and prioritizing assets that should be hardened so the Bulk Power System can be maintained and restored if an EMP event occurs.~~	~~Reference Document~~	~~3/31/2023~~	~~Electromagnetic Pulse Working Group (EMPWG)~~	~~**(3) Low**~~	~~Electromagnetic Pulse (EMP)~~	~~Risk Mitigation~~	~~Resilience and Extreme Events/Planning for High-Impact Events:~~
Implementation Guidance on Sustaining Accurate Facility Ratings	Discuss the four themes identified by the ERO Enterprise as the primary issues that have impacted and posed challenges to the sustainability of accurate facility ratings, and provide guidance to registered entities to address them.	Guidance	6/12/2024	Facility Ratings Task Force (FRTF)	**(3) Low**	Loss of Situational Awareness	Risk Mitigation	Resilience and Extreme Events/Planning for High-Impact Events:
~~Industry and Public Education about electromagnetic pulse (EMP) threats (EMPWG work plan item 6)~~	~~Develop (or reference) educational material about EMP events and their impact on intelligent electronic devices and BPS reliability.~~	~~Reference Document~~	~~3/31/2023~~	~~Electromagnetic Pulse Working Group (EMPWG)~~	~~**(3) Low**~~	~~Electromagnetic Pulse (EMP)~~	~~Risk Mitigation~~	~~Resilience and Extreme Events/Planning for High-Impact Events:~~
~~Coordination with Other Sectors about Electromagnetic Pulse (EMP) issues and activities (EMPWG work plan item 7)~~	~~Develop guidance for the electricity industry about coordinating with interdependent utility sectors~~	~~Reference Document~~	~~3/31/2023~~	~~Electromagnetic Pulse Working Group (EMPWG)~~	~~**(3) Low**~~	~~Electromagnetic Pulse (EMP)~~	~~Risk Mitigation~~	~~Resilience and Extreme Events/Planning for High-Impact Events:~~
4-Whitepaper: Case Study on Adoption of EMT Modeling and Studies in Interconnection and Planning Studies for BPS-connected IBRs	Identify TPs and PCs adopting EMT modeling and studies in their interconnection and planning studies for BPS-connected IBR and document challenges and progress	White Paper	3/31/2024	Electromagnetic Transient Task Force (EMTTF)	(1) High		EMT	Inverter-based Resources
2-Reliability Guideline: Electromagnetic Transient Modeling and Simulations	Reliability Guideline on EMT modeling and simulations of BPS-connected inverter-based resources – Screening and Studies, Application and Implementation of Results	Reliability Guideline	6/30/2024	Electromagnetic Transient Task Force (EMTTF)	(1) High		EMT	Inverter-based Resources
3-Curated EMT Resources Repo	Repository of carefully curated EMT modeling and study references (recommended modeling and study practices, including verification, and validation of models, analysis approach and results, references to educational materials, tutorials and workshop presentations, case studies, automation approaches, frequently asked questions (FAQs) gathered from event Q&A sessions, webinars, and other outreach efforts), organized in such a way that a beginner can self-guide their learning curve	Reference Document	12/31/2024	Electromagnetic Transient Task Force (EMTTF)	(2) Normal		EMT	Inverter-based Resources

5-Assessment of The Need for EMT Modeling and Simulation in Offline Operation Studies and Requirements	Identify the EMT model use cases in offline operation studies, unique challenges and requirements that differ from interconnection and planning study use cases	Assessment	12/31/2024	Electromagnetic Transient Task Force (EMTTF)	(2) Normal		EMT	Inverter-based Resources	
White Paper - Energy Reliability Assessments – Volume 2	Document methods and processes for developing detailed scenarios to evaluate energy reliability that include critical infrastructure interdependencies	White Paper	6/30/2024	Energy Reliablity Assessment Working Group (ERAWG)	**(1) High**		Reliability and Security Assessment	Grid Transformation/Energy Assurance	
~~ERAWG Work Plan #3: Technical Reference document - Energy Management Plan~~	~~Write a technical reference document describing the development of and considerations for seasonal extreme weather energy management plans along with rolling operational planning plans that accommodate the ongoing weather forecasts and projections.~~	~~White Paper~~	~~9/30/2024~~	~~Energy Reliablity Assessment Working Group (ERAWG)~~	~~(2) Normal~~	~~Energy Assurance~~	~~Reliability and Security Assessment~~	~~Grid Transformation/Energy Assurance~~	Struck duplicative effort due to overlap with Project 2022-03, and with White Paper: Energy Reliability Assessments-Volume 2
ERAWG Work Plan #4: Tools & Metrics - Energy Reliability Assessments	Develop tools and metrics that are needed to perform energy reliability assessments.	Metrics	On-Going	Energy Reliablity Assessment Working Group (ERAWG)	(2) Normal	Energy Assurance	Reliability and Security Assessment	Grid Transformation/Energy Assurance	
Events Analysis Process Document Review	Events Analysis Process Document Periodic Review and Update including all EAP Appendices	Program	12/31/2024	Event Analysis Subcommittee (EAS)	(2) Normal		Performance Monitoring	N/A	
~~Develop & Publish Lessons Learned in 2024~~	~~Lessons Learned are developed in coordination with EAS review teams and accepted by the EAS prior to being published by NERC.~~	~~Industry Engagement~~	~~12/31/2024~~	~~Event Analysis Subcommittee (EAS)~~	~~(2) Normal~~		~~Performance Monitoring~~	~~Grid Transformation/Energy Assurance~~	Duplicate item
EAS Scope Document Periodic Review	EAS Scope Document Periodic Review	Program	12/31/2024	Event Analysis Subcommittee (EAS)	(2) Normal		Performance Monitoring	N/A	
~~Electromagnetic Pulse (EMP) Research Gaps (EMPWG work plan item 8)~~	~~Support additional research to close existing knowledge gaps into the complete impact of an EMP event to understand vulnerabilities, develop mitigation strategies, and plan response and recovery efforts~~	~~Reference Document~~	~~3/31/2023~~	~~Electromagnetic Pulse Working Group (EMPWG)~~	~~**(3) Low**~~	~~Electromagnetic Pulse (EMP)~~	~~Risk Mitigation~~	~~Resilience and Extreme Events/Planning for High Impact Events:~~	
~~Monitor research and development initiatives pertaining to electromagnetic pulse (EMP) threats (EMPWG work plan item 9)~~	~~Provide information to industry about current research pertaining to EMP and EMP-related national security initiatives that impact the BPS~~	~~Reference Document~~	~~3/31/2023~~	~~Electromagnetic Pulse Working Group (EMPWG)~~	~~**(3) Low**~~	~~Electromagnetic Pulse (EMP)~~	~~Risk Mitigation~~	~~Resilience and Extreme Events/Planning for High Impact Events:~~	
Failure Modes and Mechanism Diagrams for 2024	Failure Modes and Mechanism Diagrams for 2024 Develop Failure Modes and Mechanism Diagrams supporting the EA Program's Addendum for Events with Failed Station Equipment.	Documentation	12/31/2024	Failure Modes and Mechanisms Working Group (FMMWG)	(2) Normal		Performance Monitoring	Grid Transformation/Energy Assurance	All except Security

Review and approval of the Annual Frequency Response Analysis Report during Q3 of each year.	Review and approval of the Annual Frequency Response Analysis Report during Q3 of each year.	Analysis	9/30/2020	Frequency Working Group (FWG)	(2) Normal	N/A	Performance Monitoring	Grid Transformation/Energy Assurance	
Review and vet the Frequency Bias Settings and L10 values; scheduled to be implemented in April of each year. Repeated annual in accordance with the BAL-003-1 standard.	Review and vet the Frequency Bias Settings and L10 values; scheduled to be implemented in April of each year. Repeated annual in accordance with the BAL-003-1 standard.	Review	12/31/2020	Frequency Working Group (FWG)	(2) Normal	N/A	Performance Monitoring	Grid Transformation/Energy Assurance	
20-White Paper: Gap Analysis of Any IBR-Related Issues Not Addressed by NERC Standards	IRPS will conduct a comprehensive assessment, considering all guidelines and technical reference documents developed thus far, including IEEE P2800, to determine any performance gaps not addressed by the NERC Reliability Standards and will provide recommendation for additional SARs, where applicable. Any modifications will seek to ensure the same outcome across resource types and ensure a similar intent is met with the language used in each standard requirement.	White Paper	6/1/2024	Inverter-Based Resource Performance Subcommittee (IRPS)	(2) Normal		Risk Mitigation	Inverter-based Resources	Changed to (2) Normal Priority
8-Reliability Guideline: Recommended Approach to Interconnection Studies for BPS-Connected Inverter-Based Resources	Focused guidance on improving the study process for BPS-connected inverter-based resources, particularly with increasing penetrations of these resources and the growing complexity of performing sufficient studies to ensure BPS reliability.	Reliability Guideline	6/30/2024	Inverter-Based Resource Performance Subcommittee (IRPS)	(1) High	Increased Penetration of Renewables	Risk Mitigation	Inverter-based Resources	
24-White Paper: BPS-Connected IBR Commissioning Best Practices	*White paper to highlight best practices for commissioning BPS-connected inverter-based resources to ensure appropriate protection and controls are configured and that models and studies match actual installed operational capabilities.*	White Paper	6/1/2024	Inverter-Based Resource Performance Subcommittee (IRPS)	(2) Normal		Risk Mitigation	Inverter-based Resources	
25-Reliability Guideline Consolidation and Updating	Consolidating IRPS Guidelines on IBR Performance and Improvements to Interconnection Requirements into a new guideline with plans to retire the two existing guidelines.	Reliability Guideline	Complete	Inverter-Based Resource Performance Subcommittee (IRPS)	(2) Normal		Risk Mitigation	Inverter-based Resources	

16-SAR: Revisions to FAC-001 and FAC-002	Enhancements to FAC-001-3 and FAC-002-2 to ensure 1) TOPs, RCs, and BAs that identify abnormal performance issues have the authority to seek corrective actions for resources not meeting their established interconnection requirements, 2) seek improvements to the requirements developed by the TO, TP, or PC (per FAC-001-3 or FAC-002-2) if gaps are identified, and 3) that those abnormal performance issues are reported to NERC for continued risk assessment.	SAR/RFI	6/30/2024	Inverter-Based Resource Performance Subcommittee (IRPS)	(1) High	Inverter - Other	Risk Mitigation	Inverter-based Resources
19-Tracking and Supporting NERC Standard Drafting Activities	IRPS will monitor and support (as needed) NERC Standard Drafting Teams related to modifications for BPS-connected inverter-based resources. Projects currently include: · Project 2021-04 Modifications to PRC-002-2 · Project 2020-02 Modifications to PRC-024 (Generator Ride-Through) · Project 2020-06 Verification of Models and Data for Generators · Project 2021-01 Modifications to MOD-025 and PRC-019 · Project 2022-04 EMT Modeling · Project 2021-02 Modification to VAR-002 · (Future Project) Updates to EOP-004 · (Future Project) IBR Performance Issues IRPS will ensure that past recommendations are addressed in NERC Standards revisions and will submit follow-on SARs if any recommendations outlined in IRPS documentation or NERC reports are not adequately addressed.	Monitor	12/31/2025	Inverter-Based Resource Performance Subcommittee (IRPS)	(3) Low		Risk Mitigation	Inverter-based Resources

19-Tracking and Supporting NERC Standard Drafting Activities	IRPS will monitor and support (as needed) NERC Standard Drafting Teams related to modifications for BPS-connected inverter-based resources. Projects currently include: · Project 2021-04 Modifications to PRC-002-2 · Project 2020-02 Modifications to PRC-024 (Generator Ride-Through) · Project 2020-06 Verification of Models and Data for Generators · Project 2021-01 Modifications to MOD-025 and PRC-019 · Project 2022-04 EMT Modeling · Project 2021-02 Modification to VAR-002 · (Future Project) Updates to EOP-004 · (Future Project) IBR Performance Issues IRPS will ensure that past recommendations are addressed in NERC Standards revisions and will submit follow-on SARs if any recommendations outlined in IRPS documentation or NERC reports are not adequately addressed.	Monitor	12/31/2025	Inverter-Based Resource Performance Subcommittee (IRPS)	(2) Normal		Risk Mitigation	Inverter-based Resources
Coordination with SPIDERWG on DER models	Coordinated approach to adaptive UFLS (and UVLS) in the presence of substantial quantities of highly variable DER	Support	12/31/2024	Load Modeling Working Group (LMWG)	(3) Low	Model Fidelity	Risk Mitigation	Grid Transformation/Distributed Energy Resources
Implementation of single-phase motor models in software and testing	Work with Industry SME to develop Single Phase Motor Models Compare the model against the existing performance model to make the determination whether to proceed with dynamic phasor model in all other programs.	Research	6/30/2025	Load Modeling Working Group (LMWG)	(3) Low	Model Fidelity	Risk Mitigation	Grid Transformation/Demand Growth
Adjustable Speed Drive (ASD)	EPRI and BPA have tested a number of ASDs. EPRI has in the past developed a model for ASD anticipated to be sufficient for large-scale simultations. EPRI is considering a more detailed model for ASD.	Research	3/31/2025	Load Modeling Working Group (LMWG)	(3) Low	Model Fidelity	Risk Mitigation	Grid Transformation/Demand Growth
Modular implementation of the dynamic load model	GE PSLF and PowerWorld aready implemented dynamic load models in their software packages. PTI PSS®E will require the next release of the software - Version 35.; Testing of Modular Structure	Implement	3/31/2025	Load Modeling Working Group (LMWG)	(3) Low	Model Fidelity	Risk Mitigation	Grid Transformation/Demand Growth
Electric Vehicle (EV) Charger Model	A variety of Electric Vehicle Chargers have been tested. Lawrence Berkley National Lab (LBNL) is in the process of developing a model for EVs.	Research	6/30/2024	Load Modeling Working Group (LMWG)	(1) High	Model Fidelity	Risk Mitigation	Grid Transformation/Demand Growth
Heat Pump Model	Deployment of dynamic data records in distribution substations and commercial buildings for purpose of load monitoring. DOE will provide resources to support data analysis	Implement	12/31/2025	Load Modeling Working Group (LMWG)	(2) Normal	Model Fidelity	Risk Mitigation	Grid Transformation/Demand Growth

2024 State of Reliability Report	Rules of Procedure Section 800 states that NERC will: "conduct and report the results of an independent assessment of the overall reliability and adequacy of the interconnected North American Bulk Power Systems, both as existing and as planned" and "develop reliability performance benchmarks. The final reliability assessment reports shall be approved by the Board for publication to the electric industry and the general public" *Rules of Procedure - https://www.nerc.com/FilingsOrders/us/RuleOfProcedureDL/NERC_ROP_Effective_20190125.pdf - Section 800	Assessment	6/12/2024	Performance Analysis Subcommittee (PAS)	(2) Normal	N/A	Performance Monitoring	Grid Transformation/Energy Assurance
Improved Load Loss Measurement - Whitepaper	Section 1600 data request for improved load loss measurement for reliability of the BES.	Data Collection	1/1/2026	Performance Analysis Subcommittee (PAS)	(2) Normal	Changing Resource Mix	Performance Monitoring	Grid Transformation/Energy Assurance
2023 Probabilistic Analysis Forum (PAF)	PAWG is planning the third PAF (previously 2019 and 2021) that promotes and discusses industry best practices and approaches of probabilistic-based reliability assessments	Industry Engagement	12/31/2024	Probabilistic Assessment Working Group (PAWG)	(2) Normal	Energy Assurance	Reliability and Security Assessment	Grid Transformation/Energy Assurance
~~Hardening Equipment to mitigate effects of Electromagnetic Pulse (EMP) (EMPWG work plan item 10)~~	~~Support efforts to design equipment specifications for the electric sector utility industry that address EMP hardening and mitigation strategies~~	~~Reference Document~~	~~3/31/2023~~	~~Electromagnetic Pulse Working Group (EMPWG)~~	~~**(3) Low**~~	~~Electromagnetic Pulse (EMP)~~	~~Risk Mitigation~~	~~Resilience and Extreme Events/Planning for High Impact Events:~~
~~Tools and Methods for assessing Electromagnetic Pulse (EMP) vulnerabilities~~	~~Support development of tools and methods (and make available) for system planners and equipment owners to use in assessing EMP impacts on the BPS. (EMPWG work plan item 11)~~	~~Reference Document~~	~~3/31/2023~~	~~Electromagnetic Pulse Working Group (EMPWG)~~	~~**(3) Low**~~	~~Electromagnetic Pulse (EMP)~~	~~Risk Mitigation~~	~~Resilience and Extreme Events/Planning for High Impact Events:~~
~~Enhance Operating Plans and Procedures to address EMP (EMPWG work plan item 17)~~	~~Develop EMP event criteria that industry can incorporate into operating plans, operating procedures, and system restoration plans.~~	~~Reference Document~~	~~3/31/2023~~	~~Electromagnetic Pulse Working Group (EMPWG)~~	~~**(3) Low**~~	~~Electromagnetic Pulse (EMP)~~	~~Risk Mitigation~~	~~Resilience and Extreme Events/Planning for High Impact Events:~~
1- 2024 Long-Term Reliability Assessment	Annual Reliability Assessment Required by NERC RoP Sect 800.	Assessment	12/31/2024	Reliability Assessment Subcommittee (RAS)	(2) Normal	Energy Assurance	Reliability and Security Assessment	Grid Transformation/Energy Assurance
~~Strategies for Supporting Recovery from EMP Events (EMPWG work plan item 14)~~	~~Develop training for system and plant operators about EMP events and what to anticipate and incorporate EMP events in industry exercises to test response planning and system restoration recovery efforts.~~	~~Reference Document~~	~~3/31/2023~~	~~Electromagnetic Pulse Working Group (EMPWG)~~	~~**(3) Low**~~	~~Electromagnetic Pulse (EMP)~~	~~Risk Mitigation~~	~~Resilience and Extreme Events/Planning for High Impact Events:~~
~~Response Planning for EMP events (EMPWG work plan item 16)~~	~~Develop response planning guidelines for electric utility industry members for pre and post-contingency of an EMP event that aligns with plans of applicable regulatory authorities.~~	~~Reference Document~~	~~3/31/2023~~	~~Electromagnetic Pulse Working Group (EMPWG)~~	~~**(3) Low**~~	~~Electromagnetic Pulse (EMP)~~	~~Risk Mitigation~~	~~Resilience and Extreme Events/Planning for High Impact Events:~~
~~Incorporate EMP Events into Industry Exercises and Training (EMPWG work plan item 18)~~	~~Develop training for system and plant operators about EMP events and what to anticipate and incorporate EMP events in industry exercises to test response planning and system restoration recovery efforts.~~	~~Reference Document~~	~~3/31/2023~~	~~Electromagnetic Pulse Working Group (EMPWG)~~	~~**(3) Low**~~	~~Electromagnetic Pulse (EMP)~~	~~Risk Mitigation~~	~~Resilience and Extreme Events/Planning for High Impact Events:~~

Work Plan item detailed description: White Paper: End-Use Load Electrification	Work Plan item detailed description: White Paper: End-Use Load Electrification		12/31/2024	Load Modeling Working Group (LMWG)	(2) Normal	Model Fidelity		Grid Transformation/Demand Growth	
Support the efforts of the BAL-003-1 SDT	Support the efforts of the BAL-003-1 SDT	Collaboration	On-Going	Resources Subcommittee (RS)	(3) Low	N/A	Performance Monitoring	Grid Transformation/Energy Assurance	
Determine a more efficient method to collect CPS1, BAAL, and DCS data to eliminate voluntary submittal forms	Determine a more efficient method to collect CPS1, BAAL, and DCS data to eliminate voluntary submittal forms	Data Collection	12/31/2024	Resources Subcommittee (RS)	(2) Normal	N/A	Performance Monitoring	Grid Transformation/Energy Assurance	
SPCWG Request for further guidance on Reliability Standard PRC-006-5 and addressing slowly declining frequency	Provide further guidance		9/30/2023	Real Time Operating Subcommittee (RTOS)	**(3) Low**		Performance Monitoring	Resilience and Extreme Events/Planning for High-Impact Events:	This appears to be complete
Reliability Guideline: Methods for Establishing IROLs	Reliability Guideline: Methods for Establishing IROLs	Reliability Guideline	12/31/2023	Real Time Operating Subcommittee (RTOS)	**(3) Low**	N/A	Performance Monitoring	Resilience and Extreme Events/Planning for High-Impact Events:	I am not clear that this should be categorized under this Risk Priority
Quarterly review of BA's control performance.	Quarterly review of BA's control performance.	Analysis	3/31/2024	Resources Subcommittee (RS)	(2) Normal	N/A	Performance Monitoring	Grid Transformation/Energy Assurance	
Whitepaper: EV Charging & V2G Security Risks to BPS	Evaluate cybersecurity risks of EV charging and vehicle to grid technologies and architectures. Provide recommendations for standards, policies, and controls for industry.	Assessment	12/31/2024	Security Integration and Technology Enablement Subcommittee (SITES)	(2) Normal	Cyber Security	Reliability and Security Assessment	Security/Physical and Cyber Security	
State of Technology Report	Technical report providing industry with strategic guidance regarding new or emerging technology solutions and risk-based considerations for their successful implementation. (Scope Activity Technology Enablement #1)	Reference Document	12/30/2022	Security Integration and Technology Enablement Subcommittee (SITES)	(2) Normal	Cyber - Other	Reliability and Security Assessment	Security/Physical and Cyber Security	
SITES Industry Workshop	An industry-wide technical workshop (likely remotely) to highlight strategic areas of focus related to new technologies, technology enablement, and security integration. (Scope Activity Technology Enablement #2)	Workshop	12/30/2022	Security Integration and Technology Enablement Subcommittee (SITES)	(2) Normal	Cyber - Other	Reliability and Security Assessment	Security/Physical and Cyber Security	
Reliability / Security Guideline: Integration of Cyber and Physical Security with BPS Planning, Operations, Design, and System Restoration	Recommendations for industry regarding ways that BPS planning, operations, design, and restoration activities can be enhanced by considering cyber and physical security aspects to improve BPS reliability and resilience; recommendations regarding the convergence of IT and OT networks. (Scope Activity Security Integration #1 and #2)	Reliability Guideline	12/30/2022	Security Integration and Technology Enablement Subcommittee (SITES)	(2) Normal	Cyber and Physical Security into BPS Planning	Reliability and Security Assessment	Security/Physical and Cyber Security	
White Paper: Review and Enhancement of Cybersecurity Maturity Metrics	Review and enhance the development of metrics to track the capabilities and maturity of cybersecurity and its integration with BPS reliable operation on a broad level; considerations at a macro-scale, integrating all aspects of overall BPS security, reliability, and resilience. (Scope Activity Security Integration #3 and #5)	Reference Document	12/30/2022	Security Integration and Technology Enablement Subcommittee (SITES)	(2) Normal	Cyber - Other	Reliability and Security Assessment	Security/Physical and Cyber Security	

White Paper: Risk-Based Physical and Cybersecurity Threats and their Impacts to BPS Reliability and Resilience	Guidance and reference materials providing information about security threats and how Registered Entities can plan, design, and operate the system to mitigate these potential risks. High-level recommendations for industry to consider in their own engineering and security practices for mitigating potential BPS reliability risks. Considerations for generation, transmission, and distribution-level risks as well as such as the natural gas infrastructure, and end-use (Scope Activity Security Integration #4)	Reference Document	12/30/2022	Security Integration and Technology Enablement Subcommittee (SITES)	(2) Normal	Physical Security - Other	Reliability and Security Assessment	Security/Physical and Cyber Security
Whitepaper: BES Operations in the Cloud	Breakdown concepts. Explain risks and challenges. Provide guidance and recommendations for adoption. Address cybersecurity and CIP compliance.	White Paper	9/30/2023	Security Integration and Technology Enablement Subcommittee (SITES)	(2) Normal	Cyber Security	Reliability and Security Assessment	Security/Physical and Cyber Security
Collaboration Whitepaper: Privacy & Security Risks of DER Aggregators	Collaboration with SPIDERWG. Identify present architectures, technologies, threats, and risks, and controls. Provide recommendations to ensure security, reliability, and resilience.	White Paper	12/30/2023	Security Integration and Technology Enablement Subcommittee (SITES)	(2) Normal	N/A	Reliability and Security Assessment	Security/Physical and Cyber Security
Whitepaper: AI Benefit and Risk Assessment for the BPS	Evaluate benefits and cybersecurity risks of AI technology use cases for industry including bulk and distribution sides. Provide recommendations for beneficial use cases, secure and reliable implementation, and mitigating controls for cyber risks.	White Paper	12/31/2023	Security Integration and Technology Enablement Subcommittee (SITES)	(2) Normal		Reliability and Security Assessment	Security/Physical and Cyber Security
Whitepaper: New Technology Enablement & Field Testing	Identify strategies to safely and securely trial new technology within BCS environments. Address roadblocks including compliance.	White Paper	3/31/2024	Security Integration and Technology Enablement Subcommittee (SITES)	(2) Normal	Cyber Security	Reliability and Security Assessment	Security/Physical and Cyber Security
1 CIP Evidence Request Tool (ERT) - Tools to support internal controls initiatives	Ongoing task to support industry users by providing updates and enhancements to the Evidence Request Tool (ERT) tool to faciliate positive compliance outcomes.	Evaluation	12/31/2024	Security Working Group (SWG)	(2) Normal	N/A	Risk Mitigation	N/A
3 Guideline Review - Various	Control Systems Electronic Connectivity (SG-CYB-1013-1) Physical security guidelines (SG-PHY-1013-1, SG-PHY-0319-1, SG-PHY-0619-1) Security Guideline: Primer for Cloud Solutions and Encrypting BCSI (SG-CYB-0620-1) 20231027 Status: In progress. SWG membership surveys complete for assigning priority to these reviews Brent Comments: Probably will be archiving / retiring these 4 items;	Security Guideline	12/31/2024	Security Working Group (SWG)	(2) Normal	N/A	Risk Mitigation	Security/Physical and Cyber Security

2 CIP Implementation Guidance for Incorporating Synchrophasor Data into Realtime Operations	The Security Working Group has been asked by the**Synchronized Measurement Working Group (SMWG)** to develop CIP Implementation Guidance for incorporating synchrophasor data into realtime operations. Industry has hesitation to integrate such data under the CIP framework due to a lack of guidance. The SWG is seeking volunteers to join the team to develop CIP Implementation Guidance for integrating synchrophasor data into realtime operations, specifically into BES Cyber Systems used by realtime operating and support personnel for situational awareness.	Guidance	12/31/2024	Security Working Group (SWG)	(3) Low	N/A	Risk Mitigation	Security/Physical and Cyber Security	
5 NIST National Online Informative References (OLIR) Project	NIST National Online Informative References (OLIR) Project Phase 1: Map NIST CSF to CIP Standards - Complete Phase 2: Map NIST 800-53 to CIP standards	Documentation	12/31/2024	Security Working Group (SWG)	(2) Normal		Risk Mitigation	Security/Physical and Cyber Security	
6 Communication Protection System Guideline	Develop Security Guideline for protection of communications to and between assets containing low impact BES Cyber Systems across publicly accessible networks		7/1/2024	Security Working Group (SWG)	(3) Low		Risk Mitigation	Security/Physical and Cyber Security	
Security Guidelines: Vendor Incident Response and Procurement Language	Revise to add metrics and place on RG/SGTemplate	Security Guideline	3/13/2024	Supply Chain Working Group (SCWG)	(2) Normal	Supply Chain	Risk Mitigation	Security/Supply Chain Assurance & Protection	
Security Guideline: Cloud Computing	Revise to add metrics and place on RG/SG Template Q3/Q4 2022	Security Guideline	3/14/2024	Supply Chain Working Group (SCWG)	(2) Normal	Supply Chain	Risk Mitigation	Security/Supply Chain Assurance & Protection	
Standards Committee Engagement	SPIDERWG Coodination subgroup task to provide technical support to Standards Committee Projects from SARs that originated in SPIDERWG.	Coordination	On-Going	System Planning Impacts from Distributed Energy Resources (SPIDERWG)	(2) Normal	Distributed Energy Resources	Risk Mitigation	Grid Transformation/Distributed Energy Resources	
SPIDERWG EOP-004 SAR	SAR EOP-004-4 Ensure the reporting of aggregate loss of DER is sent to NERC for large disturbances.	SAR/RFI	3/14/2024	System Planning Impacts from Distributed Energy Resources (SPIDERWG)	(2) Normal	Distributed Energy Resources	Risk Mitigation	Grid Transformation/Distributed Energy Resources	
C10 - White Paper: Security Risks Posed by DER and DER Aggregator	*Follow up White Paper on the security risk posed by DER and DER aggregator. Covers both physical and cyber related impacts.*	White Paper	9/14/2023	System Planning Impacts from Distributed Energy Resources (SPIDERWG)	(2) Normal	Distributed Energy Resources	Risk Mitigation	Grid Transformation/Distributed Energy Resources	I think this is done isn't it. Answers one of the items in the strategic plan

C2-White Paper: 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.	White Paper	3/14/2024	System Planning Impacts from Distributed Energy Resources (SPIDERWG)	(3) Low	Distributed Energy Resources	Risk Mitigation	Grid Transformation/Distributed Energy Resources
SPIDERWG BAL-003 SAR	SAR BAL-003-2 Ensure consistent DER Accounting	SAR/RFI	3/14/2024	System Planning Impacts from Distributed Energy Resources (SPIDERWG)	(2) Normal	Distributed Energy Resources	Risk Mitigation	Grid Transformation/Distributed Energy Resources
SPIDERWG EOP-005 SAR	SAR EOP-005 to revise the standard to establish telemetry requirements for DERs and/or Distribution Providers (DPs).	SAR/RFI	3/14/2024	System Planning Impacts from Distributed Energy Resources (SPIDERWG)	(2) Normal	Distributed Energy Resources	Risk Mitigation	Grid Transformation/Distributed Energy Resources
SPIDERWG PRC-006 SAR	SAR PRC-006-3 Clarity on imbalance equations	SAR/RFI	12/13/2023	System Planning Impacts from Distributed Energy Resources (SPIDERWG)	(2) Normal	Distributed Energy Resources	Risk Mitigation	Grid Transformation/Distributed Energy Resources
SPIDERWG OPA/RTA SAR	SAR - OPA/RTA definition revision to enumerate aggregate DER	SAR/RFI	3/14/2024	System Planning Impacts from Distributed Energy Resources (SPIDERWG)	(2) Normal	Distributed Energy Resources	Risk Mitigation	Grid Transformation/Distributed Energy Resources
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.*	Reliability Guideline	6/14/2024	System Planning Impacts from Distributed Energy Resources (SPIDERWG)	(2) Normal	Distributed Energy Resources	Risk Mitigation	Grid Transformation/Distributed Energy Resources
C11-White Paper: Impacts on BPS Variability, Uncertainty, and Data Collection from DER Aggregators	White paper that is tackling the planning and operational uncertainty as a follow up from the BPS Reliability Perspectives on DER Aggregators. This task is assigned to SPIDERWG.	White Paper	12/20/2023	System Planning Impacts from Distributed Energy Resources (SPIDERWG)	(3) Low	Distributed Energy Resources	Risk Mitigation	Grid Transformation/Distributed Energy Resources
White Paper: Modeling of DER Aggregator and DERMS Functional Impacts	*White paper to explore the modeling, verification, and study impacts of a DER aggregator and DERMS functions in planning simulations.*	White Paper	12/20/2023	System Planning Impacts from Distributed Energy Resources (SPIDERWG)	(2) Normal	Distributed Energy Resources	Risk Mitigation	Grid Transformation/Distributed Energy Resources
Review Determination of Practical Transmission Relaying Loadability Settings and Review Technical Reference Document: Transmission System Phase Backup Protections	Review the Determination of Practical Transmission Relaying Loadability Settings document and address the concers of the isue in appendix C where it says a trip can be issued instead of stating that the scheme can be unblocked, as well as do a 5 year review of it. In addition Review Technical Reference Document: Transmission System Phase Backup Protection as the second in the series of reviewing older reference material and bringing it into the three year review cycle.	White Paper	3/31/2024	System Protection and Control Working Group(SPCWG)	(2) Normal	Increasing Complexity in Protection and Control Systems		Grid Transformation/Energy Assurance

PRC-024-3 IBR White paper	The SPCWG has developed a white paper to illustrate how a Generator Owner of an inverter-based resource (IBR) may evaluate their compliance with NERC Reliability Standard PRC-024-3. The example provided in this white paper is not exclusive, as there are likely other methods for implementing a standard. This white paper provides an example of how NERC Registered Entities can project their IBR unit voltage protection settings to a corresponding MPT high-side voltage, or conversely, project the MPT high-side voltages to the corresponding IBR unit voltage protection settings. They can then directly compare the voltage protection settings to the PRC-024-3 voltage boundary curve since both values are on the same basis.	White Paper	3/31/2024	System Protection and Control Working Group(SPCWG)	(2) Normal	Increasing Complexity in Protection and Control Systems		Inverter-based Resources
Review and update Transmission System Phase Backup Protections	Review Transmission System Phase Backup Protections. This is an older paper that is still useful and is being reviewed as part of the document cycle. It may also need to be slightly revised to place it in a newer format.	Administrative	6/30/2024	System Protection and Control Working Group(SPCWG)	(2) Normal	Increasing Complexity in Protection and Control Systems		Grid Transformation/Energy Assurance
Maintenance for Ethernet based Protection and Control Tech Reference document outline	With changes in technology coming, there is a need to review NERC Standards and how maintenance for Ethernet based P&C systems will fit into those standards. To that end, the SPCWG proposes developing a Technical Reference Document to provide industry guidance for impacts of systems such as 61850 architecture on NERC Protection System definition and related standards. Many utilities are incorporating these Ethernet network based P&C systems into new stations or retrofitting them into existing Protection and Control (P&C) designs. Functions traditionally done by hard wired circuits are being replaced by networking architecture, configured Ethernet messaging, merging units and high-level automated system engineering processes. Reference to include clarity in systems such as 61850 P&C designs regarding Protection System definition, relay maintenance requirements, and recommended documentation to support design. SPCWG to coordinate with team that is concurrently reviewing the definition of a Protection System, and ensure technical reference supports the outcome. This initiative also provides groundwork for future industry growth in generic platform	Reference Document	12/31/2024	System Protection and Control Working Group(SPCWG)	(2) Normal	Increasing Complexity in Protection and Control Systems		Grid Transformation/Energy Assurance
Reliability Guideline: Detection of Aggregate DER Response during Grid Disturbances	*Identified in the Standards Review white paper, this reliability guideline will provide state-of-the-art detection methods to assign higher confidence values for the response of aggregate DERs during many different grid conditions.*	Reliability Guideline	12/14/2024	System Planning Impacts from Distributed Energy Resources (SPIDERWG)	(2) Normal	Distributed Energy Resources	Risk Mitigation	Grid Transformation/Distributed Energy Resources

Reliability Guideline: Aggregate DER Conditions for Emergency Operations and Cold Weather	*Identified in the Standards Review white paper, this reliability guideline will cover expected conditions of aggregate DERs during emergency operation conditions and cold weather conditions as well as provide best practices to account for this expected performance during the conditions.*	Reliability Guideline	12/14/2024	System Planning Impacts from Distributed Energy Resources (SPIDERWG)	(3) Low	Distributed Energy Resources	Risk Mitigation	Grid Transformation/Distributed Energy Resources	
Annual Monitoring and Situational Awareness Conference 2024	Plans, arrangements and agenda for Annual Monitoring and Situational Awareness Conference	Industry Engagement	12/31/2024	EMS Working Group (EMSWG)	(2) Normal	Loss of Situational Awareness		N/A	
Biennial Review of the Risk and Mitigations for Losing EMS Functions Reference Document	Biennial Review of the Risk and Mitigations for Losing EMS Functions Reference Document to be Endorsed by the RSTC	Program	12/31/2024	EMS Working Group (EMSWG)	(2) Normal	Loss of Situational Awareness		N/A	
2024 State of Reliability Report	Play a lead role in the development of the 2024 State of Reliability Report in coordination with the PAS.	Program	8/1/2024	Event Analysis Subcommittee (EAS)	(2) Normal		Performance Monitoring	N/A	
Events Analysis Process Version 5 Industry Webinar	Conduct Industry Webinar to Review Changes to Events Analysis Process (EAP) Document Version 5	Industry Engagement	3/31/2024	Event Analysis Subcommittee (EAS)	(2) Normal		Performance Monitoring	Grid Transformation/Energy Assurance	
Develop & Publish Lessons Learned in 2024	Lessons Learned are developed in coordination with EAS review teams and accepted by the EAS prior to being published by NERC.	Program	12/31/2024	Event Analysis Subcommittee (EAS)	(2) Normal		Performance Monitoring	N/A	
Generating Unit Winter Weather Readiness Webinar	Generating Unit Winter Weather Readiness Webinar	Industry Engagement	9/30/2024	Event Analysis Subcommittee (EAS)	(1) High		Performance Monitoring	Grid Transformation/Energy Assurance	Also classify as resilience?
Industry Webinar – Lessons Learned	Industry Webinar – Lessons Learned	Industry Engagement	12/31/2024	Event Analysis Subcommittee (EAS)	(3) Low		Performance Monitoring	Grid Transformation/Energy Assurance	
NEW - Leverage existing GridEx events to assess readiness from a confluence of extreme weather and cyber events. (Pg 17, RSTC 2024 Strategic Plan)	Assess impacts from coincidence of extreme weather and cyber incidents using pre-existing forums.	Industry Engagement			(2) Normal		Risk Mitigation	Resilience and Extreme Events/Planning for High-Impact Events:	This appears to be the only missing item from the RSTC Strategic Plan Resilience and Extreme Events category.
Support Project 2022-03: Energy Assurance with Energy Constrained Resources	Providing technical leadership and guidance on matters relating to Energy Reliability Assessments for the Standards drafting team.	Collaboration	On-Going	Energy Reliablity Assessment Working Group (ERAWG)	(2) Normal		Reliability and Security Assessment	Grid Transformation/Energy Assurance	
Cold Weather Report Recommendation #6	In preparing for winter weather conditions, natural gas infrastructure facilities should implement measures to protect against freezing and other cold-related limitations which can affect the production, gathering and processing of natural gas.	Monitor	On-Going	Electric Gas Working Group (EGWG)	(1) High		Performance Monitoring	Grid Transformation/Gas-Electric Coordination	

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RSTC Work Plan Risk Priorities

John Stephens, RSTC Vice Chair
Reliability and Security Technical Committee Meeting
March 12, 2024

RELIABILITY | RESILIENCE | SECURITY




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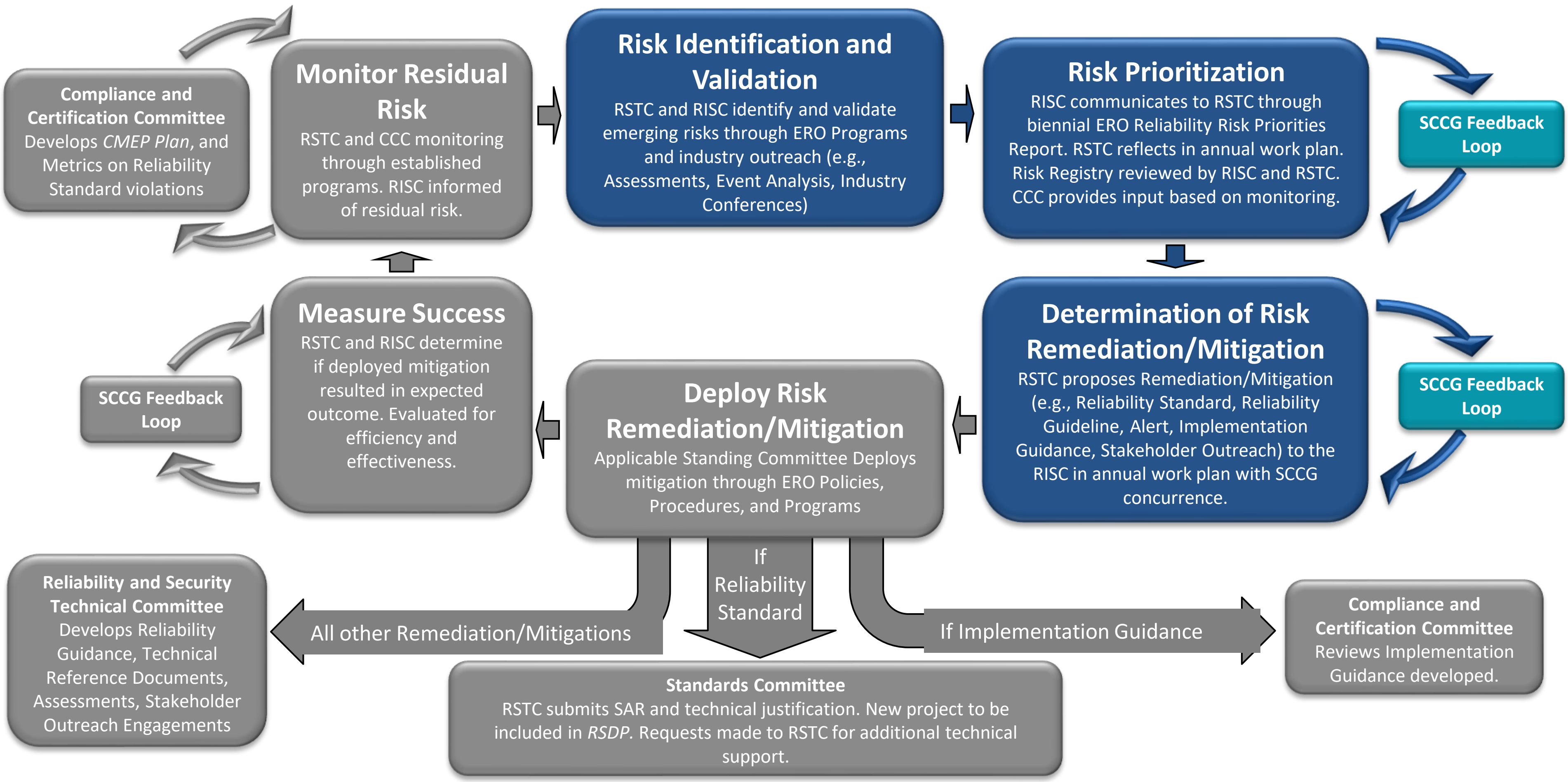
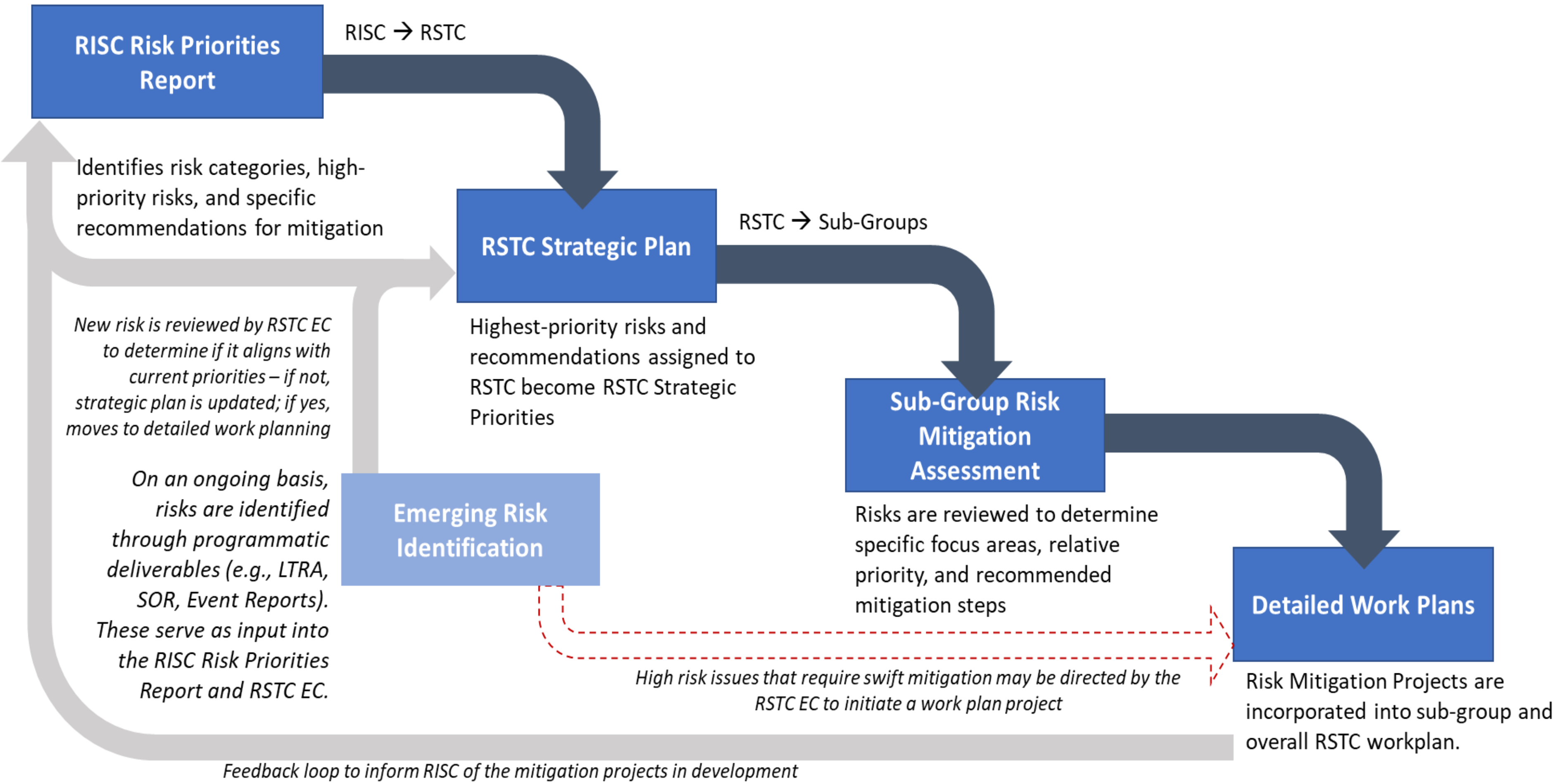
ERO Risk Management Framework:
Standing Committees and RISC Coordination



New Strategic Plan (2024-2025):
Aligning RISC's Risk Priorities with the RSTC Work Plan



Work Plan Summit

- In June 2023, the RSTC appointed a Work Plan Review Team to review the RSTC Work Plan and the soon to be published ERO Risk Priorities Report (RISC)
- Each RSTC Subcommittee/WG/TF reviewed their work plan and completed the template for the review team to consider at the October work plan summit.
- The RSTC Review Team assessed work plan item priority (H/M/L) and applicability to the RSTC Strategic Plan.

Work Plan Summit

- **Review Team Members**
- John Stephens, RSTC Vice Chair, City of Springfield
- Rich Hydzik, RSTC Chair, Avista
- Brad Little, Canadian Federal Government member, Natural Resources Canada
- Monica Jain, RSTC At-large member, Southern California Edison
- Todd Lucas, RSTC Executive Committee, Southern Company
- Mark Spencer, Sector 6 Representative, LS Power
- Peter Brandien, ERATF Chair, ISO New England

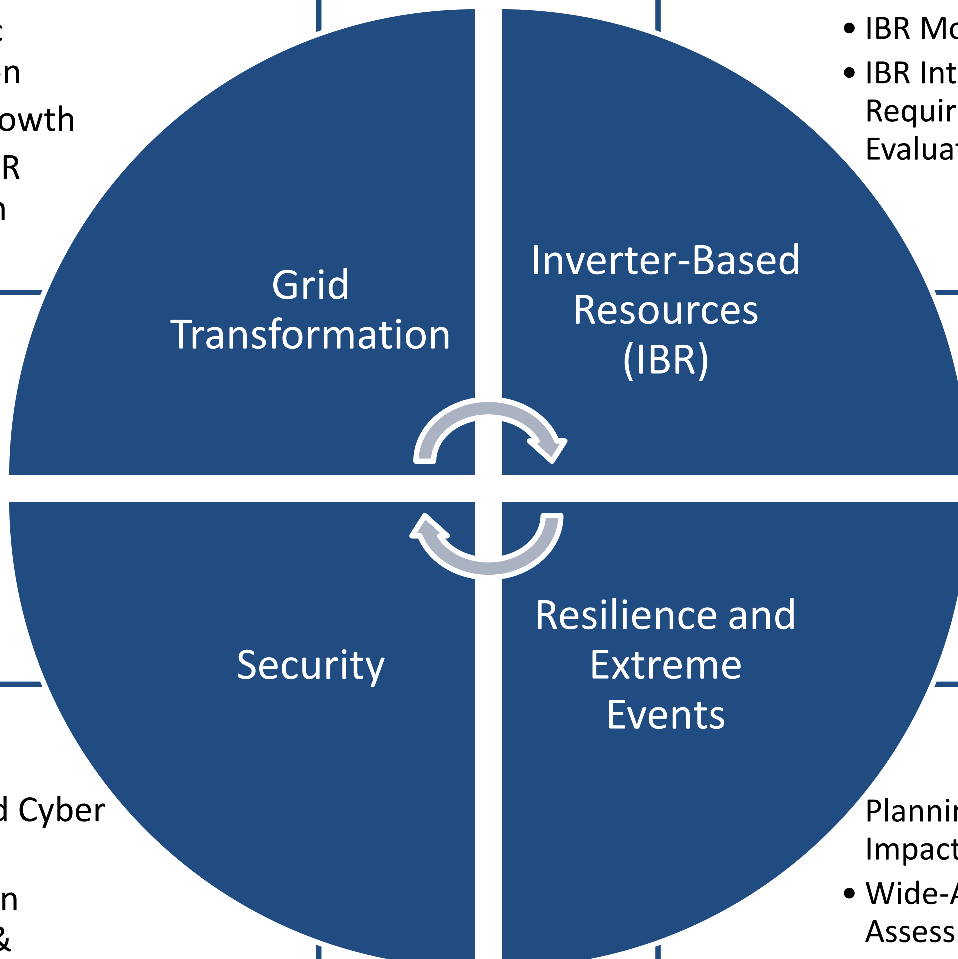
Work Plan Summit

- Per RSTC Strategic Plan, the team included the following in the review:
  - Long-Term and Seasonal Reliability Assessments
  - Special Assessments
  - Event and Disturbance Reports
  - State of Reliability Report
  - FERC NOPR on IBRs
  - Other reliability indicators, whitepapers, gap assessments
  - 2023 ERO Enterprise Work Plan Priorities (https://www.nerc.com/AboutNERC/Pages/Strategic-Documents.aspx)
- Develop priorities for work plan items.

2024 Strategic Risk Priorities Efforts

- Energy Assurance
- Gas-Electric Coordination
- Demand Growth
- DER and DER Aggregation

- IBR Performance
- IBR Modeling
- IBR Interconnection Requirement and Evaluation



- Physical and Cyber Security
- Supply Chain Assurance & Protection

Planning for High Impact Events
- Wide-Area Energy Assessment

High Priority Work Plan Items

- White Paper: Energy Reliability Assessments Vol. 2
- Monitor Performance of Electric-Gas Interface during Extreme Events
- Generating Unit Winter Weather Readiness Webinar
- Monitor and Share Development of EV Charging Model
- SAR: Revisions to FAC-001 and FAC-002—IBR Performance
- Reliability Guideline: Recommended Approach to Interconnection Study of BPS-Connected IBRs
- Reliability Guideline: EMT Modeling and Simulations of IBR
- White Paper: Case Study on Adoption of EMT Modeling

High Priority Work Plan Items

- White Paper: Probabilistic Planning for the Tails
- Response to Cold Weather Recommendations:
  - Effects of Load-Shedding during Long-duration Events
  - Impacts of Transfer Limits
  - Improvements to Load Forecasting
  - Impacts of Forecasting Intermittent Generation
- Special Reliability Assessment of Resiliency and Interdependencies Scoping
- Monitor and Support NERC Alerts for Supply Chain Issues

Questions and Answers

Special Reliability Assessments Scope and Prioritization

Action
Approve

Background
The NERC Reliability Assessment Subcommittee (RAS) leadership and NERC Staff produced the submitted presentation to update the RSTC on the “Special Reliability Assessments Scope and Prioritization” work plan item status. The RAS produced a scope document for the special assessment and recommends the RSTC reconsider the approach of this project and assign to a diverse task force of stakeholders and SMEs from RSTC groups, including RAS, and relevant infrastructures. RAS Chair will discuss issues and challenges with RAS completion due to the scope of project and required subject matter expertise.

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RAS Special Reliability Assessments Scope and Prioritization

Andreas Klaube, RAS Chair

Amanda Sargent, RAS Vice Chair

March 12 - 13, 2024

RELIABILITY | RESILIENCE | SECURITY

RAS Work Plan Item #5

- Work Plan item name: Special Reliability Assessments Scope and Prioritization
- Work Plan item detailed description: 2021 RISC Report calls for Special assessments of certain extreme event impacts arising from critical infrastructure interdependencies. Assessment should capture lessons learned, creating simulation models, and establishing protocols and procedures for system recovery and resiliency.
  - NERC and RAS Leaders met with DOE in 2023 to understand the North American Energy Resilience Model (NAERM) and interdependency modeling tool capabilities
  - Critical Infrastructure Interdependencies remains on the 2023 RISC Report (Risk Profile #5)
  - As discussed at the October 2023 RSTC Work Plan Summit, Work Plan Item is beyond the RAS scope and should be performed by a diverse task force
- Applicability to address (choose all that apply):
  - RISC Report Recommendation 2.1; Information requested by the RSTC
- Priority (H/M/L): M

2021 RISC Recommendation 2.1

- Special assessments of extreme event impacts, including capturing lessons learned, creating simulation models, and establishing protocols and procedures for system recovery and resiliency: The ERO Enterprise should conduct detailed special assessments of extreme event impacts by geographical areas that integrate the following:
  - Critical Infrastructure interdependencies (e.g., telecommunications, water supply, generator fuel supply)
  - Analytic data and insights regarding resilience under extreme events
  - Based on those assessments, the ERO Enterprise should develop detailed special assessments on possible mitigation plans and provide a roadmap for their implementation. The roadmap should include specific protocols and procedures for system restoration and system resiliency.

RAS Efforts

RAS LTRA request materials solicit information on "Activities to address studies on evolving interdependencies of critical infrastructure sectors (e.g., water/wastewater, transportation, fuel supply)"

RAS developed a scope framework for the interdependency special assessment

Met with DOE team to discuss the North American Electricity Resilience Model (NAERM) model capabilities

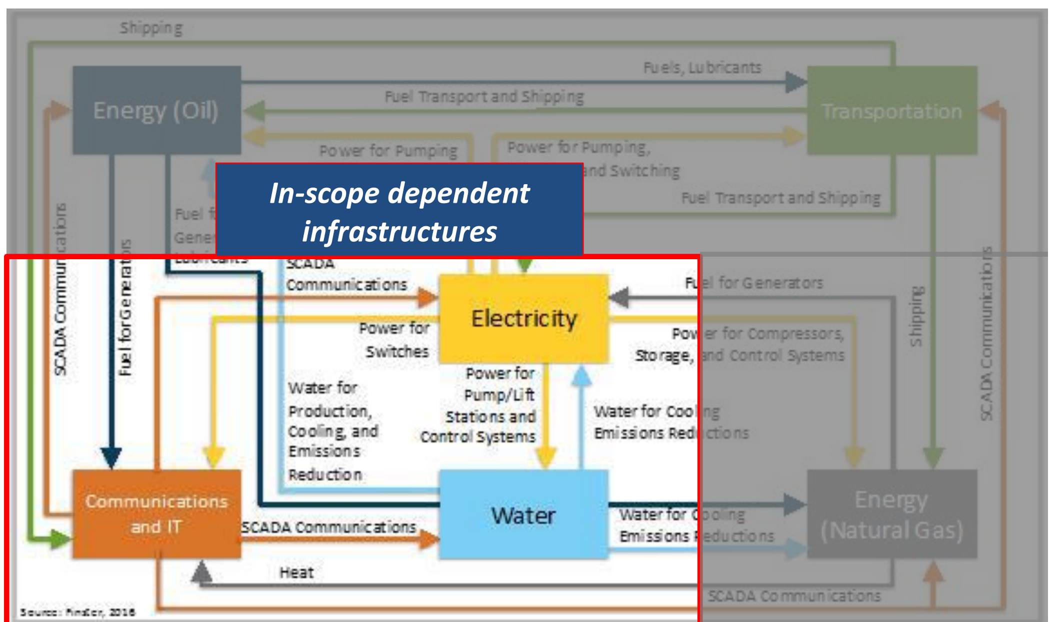
Using the model will require inputs from interdependent infrastructures (e.g., telecom and water industries), which is beyond the scope of the RAS

The RAS lacks sufficient information and expertise to complete an executable scope document and special assessment

RAS Thoughts on Assessment Objective

- Assess potential impacts from certain extreme events on the reliable operation of the BPS due to interdependencies with the following infrastructures:
  - Telecommunications
  - Water supply infrastructure (and wastewater infrastructure)
- Evaluate the availability and efficacy of procedures and protocols for BPS recovery and resilience to reduce impacts on the BPS during the specified extreme events
- Recommend actions or priorities for reducing risks and promoting BPS resilience

Requires a specialized and diverse task force to carry out the objective



NAERM is not fully matured for analyzing all infrastructures

Next Steps

The RAS recommends the RSTC reconsider the approach of this project and assign to a diverse task force of stakeholders and SMEs from RSTC groups, including RAS, and relevant infrastructures

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Questions and Answers

SAR: Revisions to FAC-001 and FAC-002

Action
Accept the draft Standard Authorization Request (SAR): Revisions to FAC-001 and FAC-002 for 30-day comment period

Background
The Inverter-Based Resource Performance Subcommittee (IRPS) has developed the draft Standard Authorization Request (SAR): Revisions to FAC-001 and FAC-002. This draft SAR is intended support standard drafting team efforts to enhance FAC-001 and FAC-002 to help ensure that Transmission Operators (TOPs), Reliability Coordinators (RCs), and Balancing Authorities (BAs) that identify abnormal performance issues can work with the relevant Generator Owner (GO) to seek corrective actions, seek improvements to the requirements developed by the TO, TP, or PC (PerFAC-001 or FAC-002), and that abnormal performance is reported to NERC for continued risk assessment. This work item is the last high priority SAR on the IRPS work plan.

This draft SAR was created by a team of IRPS members and then reviewed by the IRPS with all comments considered and incorporated in the document. After the IRPS review period, an off-cycle IRPS meeting was held to resolve final comments from IRPS stakeholders and to reach consensus to bring the draft SAR to the RSTC.

With approximately 60 members on the call, there were 27 “Yes” votes and 0 “No” votes. Two members abstained. With this consensus, IRPS requests the RSTC accept this draft SAR and begin a 30-day joint RSTC and public comment period.

Conclusion
This draft SAR has been drafted and reviewed by the IRPS with all comments considered and the IRPS has reached consensus to bring the draft SAR to the RSTC to request authorization to post for broader comment. The IRPS requests the RSTC accept this draft SAR and begin a 30-day public comment period.

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Standard Authorization Request (SAR)

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

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

Requested information			
SAR Title:	Revisions to FAC-001-4 and FAC-002-4		
Date Submitted:	_/_/2024		
SAR Requester			
Name:	Julia Matevosyan, ESIG (NERC IRPS Chair) Rajat Majumder, Invenergy (NERC IRPS Vice Chair)		
Organization:	NERC Inverter-Based Resource Performance Subcommittee (IRPS)		
Telephone:	Julia – 512-994-7917 Rajat –	Email:	julia@esig.energy RMajumder@invenergy.com
SAR Type (Check as many as apply)			
☐ New Standard ☒ Revision to Existing Standard ☐ Add, Modify or Retire a Glossary Term ☐ Withdraw/retire an Existing Standard		☐ Imminent Action/ Confidential Issue (SPM Section 10) ☐ Variance development or revision ☐ Other (Please specify)	
Justification for this proposed Standard development project (Check all that apply to help NERC prioritize development)			
☐ Regulatory Initiation ☐ Emerging Risk (Reliability Issues Steering Committee) Identified ☐ Reliability Standard Development Plan		☒ NERC Standing Committee Identified ☐ Enhanced Periodic Review Initiated ☒ Industry Stakeholder Identified	
What is the risk to the Bulk Electric System (What Bulk Electric System (BES) reliability benefit does the proposed project provide?):			
The bulk power system (BPS) in North America is undergoing a rapid transformation towards high penetrations of inverter-based resources. This grid transformation adds significant complexity and a changing risk landscape that require IBR-specific Standards requirements. Recent NERC disturbance reports such as San Fernando, Odessa I and II, Southwest Utah, etc.[1] as well as the November 2023 *NERC Inverter-Based Resource (IBR) Performance Issues Report Findings from Level 2 Alert*[2] strongly point toward:			

[1] https://www.nerc.com/pa/rrm/ea/Pages/Major-Event-Reports.aspx
[2] https://www.nerc.com/comm/RSTC_Reliability_Guidelines/NERC_Inverter-Based_Resource_Performance_Issues_Public_Report_2023.pdf

Requested information
• Significant gaps in (or entire absence of) comprehensive and uniform technical minimum interconnection requirements, particularly for IBRs in addition to the FERC GIA • Failures in the voluntary adoption of NERC recommendations and guidance to enhance interconnection requirements and ensure reliable connection IBRs • Significant gaps in (or entire absence of) assessing IBR plant capability and performance against applicable interconnection requirements (i.e., conformance testing) during the interconnection process • Lack of requirements associated with appropriate and reliable commissioning of IBR facilities during the interconnection process, due to gaps in current IBR commissioning practices. ○ Lack of adequate or sufficient performance tests during commissioning ○ Lack of truing up the as-built models as part of feedback loop ○ Lack of adequate benchmarking of models against each other and real product performance If the above gaps are not addressed, large disturbances involving non-consequential tripping of many IBRs or other abnormal power changes from IBRs will continue with increased frequency and likelihood, subsequently increasing risks to BPS reliability. NERC continues to highlight the increased risk profile of IBRs due to the rapidly changing resource mix, inverter technology on the BPS, and significant gaps in the interconnection process to avoid IBR-related reliability issues.
Purpose or Goal (What are the reliability gap(s) or risk(s) to the Bulk Electric System being addressed, and how does this proposed project provide the reliability-related benefit described above?):
The purpose of this Standards project is to address the reliability risks presented to the BPS due to abnormal IBR performance issues, which stem from gaps in the interconnection requirements and interconnection process. This has been reported by NERC in numerous disturbance reports and other NERC publications. Transmission Owners (TOs) need to implement uniform comprehensive interconnection requirements and conformity assessment processes for IBRs connecting to the BPS (i.e., all registered IBRs), which are paramount to ensure reliable IBR operation and to prevent large disturbance events involving tripping for events or other simultaneous abnormal power reduction from multiple IBRs in the future. A series of NERC disturbance reports highlight systemic performance issues that have led to unexpected IBR plant reductions during normal grid faults. For instance, phase jump or phase lock loop (PLL) synchronization issues were described as one cause of IBR plant tripping in three reports.[3,4,5] Similarly, other reports describe tripping causes that include overvoltage,[6] undervoltage,[7]

[3] *Odessa Disturbance,* NERC. September 2021.https://www.nerc.com/pa/rrm/ea/Documents/Odessa_Disturbance_Report.pdf
[4] *2022 Odessa Disturbance,* NERC. Atlanta, GA: December 2022. https://www.nerc.com/comm/RSTC_Reliability_Guidelines/NERC_2022_Odessa_Disturbance_Report%20%281%29.pdf
[5] *900 MW Fault Induced Solar Photovoltaic Resource Interruption Disturbance Report*, NERC. Atlanta, GA: February 2018. https://www.nerc.com/pa/rrm/ea/October%209%202017%20Canyon%202%20Fire%20Disturbance%20Report/900%20MW%20Solar%20Photovoltaic%20Resource%20Interruption%20Disturbance%20Report.pdf
[6] *April and May 2018 Fault Induced Solar Photovoltaic Resource Interruption Disturbances Report*, NERC. Atlanta, GA: January 2019. https://www.nerc.com/pa/rrm/ea/April_May_2018_Fault_Induced_Solar_PV_Resource_Int/April_May_2018_Solar_PV_Disturbance_Report.pdf
[7] *Panhandle Wind Disturbance*, NERC. Atlanta, GA: August 2022. https://www.nerc.com/pa/rrm/ea/Documents/Panhandle_Wind_Disturbance_Report.pdf

Requested information
frequency protection,[8] momentary cessation,[9] and slow active power recovery,[10] among other causes. Gaps in interconnection requirements and conformity assessments[11], in the aforementioned technical areas and others, must be addressed to prevent future unexpected IBR plant tripping risks that could compromise system reliability. Furthermore, insufficient commissioning practices have led to many facilities having incorrect protection and control settings or modes of operation going unnoticed until a major grid disturbance occurs. The proposed project addresses reliability issues identified in the NERC disturbance reports by accomplishing the following: 1. Enhancing the latest FAC-001 Standard to require that TOs establish uniform IBR performance requirements covering specific topics of paramount importance for BPS reliability while leveraging technical aspects of work already completed within the industry. 2. Enhancing the latest FAC-002 Standard to require Transmission Planners (TPs) and Planning Coordinators (PCs) to assess IBR plant capability and performance conformity for example through a combination of review of documentation, simulation studies, and physical tests that a newly interconnecting IBR complies with applicable IBR performance requirements. 3. Modifying either FAC-001 or FAC-002 to include requirements for applicable entities (TOs, TOPs, BAs, etc.) to establish requirements for prospective Generator Owners to appropriately and reliably commission IBR facilities and provide adequate proof that commissioning checks (i.e., as-built evaluation, commissioning testing, etc.) were conducted and that the as-modeled IBR facility matches the as-built IBR plant used in interconnection studies during the interconnection process. Reliability-related benefits of each of the above proposals are further clarified below. Language in the latest FAC-001 Standard requires a TO to document Facility Interconnection Requirements, update them as needed, and make them available upon request; however, there is no specificity regarding what the requirements should entail other than some generic statements regarding procedures for coordinating studies and notifying affected owners. Some entities rely heavily or entirely on high-level requirements established in the *pro forma* FERC Large Generator Interconnection Agreement (LGIA) and have not written detailed requirements for their systems beyond those levels. NERC disturbance reports highlight repeated causes of tripping that are not captured by existing requirements in the LGIA, nor should industry rely solely on the GIA for the establishment of performance-based requirements. This SAR proposes the inclusion of specific categories of requirements (i.e., voltage ride-through, fault ride-through performance, validation between models

[8] *Multiple Solar PV Disturbances in CAISO*, NERC. April 2022. https://www.nerc.com/pa/rrm/ea/Documents/NERC_2021_California_Solar_PV_Disturbances_Report.pdf

[9] *1,200 MW Fault Induced Solar Photovoltaic Resource Interruption Disturbance Report*, NERC. June 2017. https://www.nerc.com/pa/rrm/ea/1200_MW_Fault_Induced_Solar_Photovoltaic_Resource_/1200_MW_Fault_Induced_Solar_Photovoltaic_Resource_Interruption_Final.pdf

[10] *San Fernando Disturbance*, NERC. November 2020. https://www.nerc.com/pa/rrm/ea/Documents/San_Fernando_Disturbance_Report.pdf

[11] https://www.iec.ch/conformity-assessment/what-conformity-assessment

Requested information
and installed equipment, etc) to be included in FAC-001 and, subsequently, in TOs' interconnection requirements that address the causes of tripping observed in NERC disturbance reports and also address emerging reliability concerns. These requirements must be coordinated with current and future NERC Standards and existing interconnection requirements. Having a uniform minimum set of interconnection requirement categories across North America will help ensure clarity and consistency among equipment manufacturers, IBR developers, GOs, and TOs, and lead to new BPS-connected IBR plants designed with the capabilities necessary for reliable operation of the BPS. Currently, the latest version of FAC-002 requires TPs and PCs to study the reliability impact of interconnecting generation and existing generation seeking to make a qualified change, as defined by the PC under requirement R6. There is currently no requirement to ensure that these generators as-designed and as-installed or to-be-installed in the field, are assessed for conformity with applicable interconnection requirements (as created per FAC-001-4) during the interconnection process. Having a specific conformity assessment process (in addition to currently performed interconnection studies) will ensure that the TP and PC verify generator conformity with applicable interconnection requirements, prior to IBR plant commissioning. Clear conformity assessment processes as part of the generator interconnection process will ensure that new BPS-connected IBR facilities are designed with the capabilities necessary for reliable operation. Lastly, IBR facility commissioning issues have been documented numerous times by NERC in the disturbance reports and alert findings. Entities adhere to the FERC interconnection agreements, procedures and then NERC Standards are effective on the new facility upon commercial operation. Therefore, there is a handoff that occurs between the developer and GO, as well as between the FERC process and the NERC Standards. Because of these sensitive issues and the urgency to connect renewable energy resources to the BPS due to policies, tax credits, economics, etc., IBR commissioning is under intense pressure to be completed as quickly as possible. Therefore, there is a need to focus on the quality of commissioning and assurance that the as-built or to-be-built facility is consistent with the models used in the studies conducted during the process and to reduce the risk of expected performance during real-time operations Therefore, some degree of as-built evaluation and commissioning requirements should be placed on the GO of an IBR facility to ensure that the resource will operate as expected and that documentation has been provided to applicable TOs and TPs.
Project Scope (Define the parameters of the proposed project):
This project will modify the latest versions of NERC FAC-001 and FAC-002. The scope of the project is to modify NERC Standards to: 1) Include specific IBR interconnection topics in FAC-001-4 for which interconnection requirements shall be defined by TOs/TPs 2) Include specific steps for a conformity assessment intended to assess FAC-001-4 conformity in FAC-002-4 3) Include requirements for TOs to include pre-commissioning requirements for GOs to provide evidence that the facility: a. Successfully passes an evaluation with performance that meets commissioning requirements

Requested information
b. Ensure that what is intended to be placed in-service matches what was studied during the interconnection process 4) IBR control parameter updates made during the comissioning process are updated in the facility model and studied to ensure reliability
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[12] of developing a new or revised Reliability Standard or definition, which includes a discussion of the risk and impact to reliability-of the BES, and (2) a technical foundation document (*e.g.,* research paper) to guide development of the Standard or definition):

The proposed project will produce the following deliverables: modifications to the latest FAC-001 and modifications to the latest FAC-002.
 	
NERC FAC-001-4 Enhancements to the requirement R1:
• Each TO shall document Facility Interconnection Requirements, update them as needed and make them available upon request. IBR facilities interconnection requirements shall, at a minimum, include some or all of the following scope leveraged from IEEE Standard for Interconnection and Interoperability of Inverter Based Resources Interconnecting with Associated Transmission Electric Power Systems (IEEE 2800-2022), NERC Standards and other NERC Publications, and other industry works. The Standard Drafting Team shall ensure coordination with FERC Order 901 and already-approved NERC Standards.
  • General interconnection technical specifications and performance requirements
    o Reference points of applicability (e.g., specifying[13] where the interconnection requirements apply, e.g., point of interconnection)
    o Applicable voltages and frequencies (e.g., specifying the meaning of voltage and frequency for each of the following interconnection requirements (e.g., phase or instantaneous values, etc.))
    o Measurement accuracy (e.g., specifying the accuracy of steady state and transient measurement, accuracy requirements for an IBR Facility's performance monitoring and validation)
    o Operational measurement and communication capability (e.g. specifying communication capabilities required from an IBR Facility for providing real-time operational information)
    o Control capability requirements (e.g., specifying the capability of an IBR Facility to respond to external control inputs, e.g., capability to limit active power as specified by a TO)
    o Prioritization of IBR responses (e.g., specifying the priority of IBR Facility responses to TO's interconnection requirements)

[12] 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.
[13] For the purpose of this document, specifying means developing or referring to a requirement within a certain category.

Requested information

o Isolation device (e.g., specifying the requirement for break isolation device between the TO's network and the IBR Facility)
    o Inadvertent energization of the transmission system (e.g., specifying requirements for IBR Facility, when the TO's network is de-energized)
    o Enter service (e.g., specifying requirements for IBR Facility performance when entering service after an IBR Facility was out of operation)
    o Interconnection Integrity (e.g., specifying protection from electromagnetic interference, surge-withstand performance, and interconnection switchgear)
    o Integration with TS grounding (e.g., specifying requirements for the integration of grounding scheme between an IBR Facility and TO's network)
• Reactive power-voltage control requirements within the continuous operation region
    o Reactive power capability (e.g., specifying reactive power capability at the reference point of applicability)
    o Voltage and reactive power control modes (e.g. specifying voltage regulation capability by changing reactive power output, and voltage control modes during normal operation)
• Active power and frequency response requirements
    o Primary frequency response (e.g., specifying requirements for the primary frequency response)
    o Fast frequency response (e.g., specifying requirements for any fast frequency response, i.e., response to changes in frequency during the arresting phase of a frequency excursion to improve the frequency nadir or initial rate-of-change of frequency)
    o Active power ramp rate performance (e.g., specifying performance requirements for active power ramping. Alternatively, this requirement can be embedded in other performance requirements (e.g., Enter Service, Primary Frequency Response Requirement, etc.) as appropriate).
• Response to transmission system abnormal conditions
    o Voltage (e.g., specifying requirements for IBR Facility performance during and after large-signal voltage disturbances, including transient overvoltage ride-through and dynamic voltage support requirements)
    o Frequency (e.g., specifying requirements for IBR Facility performance during and after a large-signal frequency disturbance, including rate-of-change of frequency and voltage phase angle ride-through requirements)
    o Return to service after an IBR plant trip (e.g., specifying requirements for IBR Facility performance if it trips during or after a large-signal voltage or frequency disturbance)
• Protection (defining requirements for protective functions at an IBR Facility and coordination with the TO)
• Modeling Data (e.g., specifying requirements for IBR Facility models to be provided to TOs)
    o Verification Report comparing modeled parameters against to-be-commissioned parameters.

Requested information
○ Model Validation report showing benchmarking between all submitted model types (Standard Library Model, Positive Sequence User-defined model, and Electromagnetic Transient (EMT)) and the real equipment as per FERC Order 2023[14] • Measurement data for performance monitoring and validation (e.g., specifying measurements, data recording, and retention requirements at an IBR Facility for the purpose of performance monitoring and validation during an IBR Facility operation) • Test and verification requirements (e.g., specifying requirements for testing and verifying an IBR Facility's conformity with applicable interconnection requirements during the interconnection process, at the commissioning stage, and during IBR Facility operation) **NERC FAC-002-2 Enhancements:** • Additional requirement: TPs and PCs shall develop the process for assessment and assess conformity with applicable interconnection requirements (as per FAC-001-4) for interconnecting IBR facilities and existing IBR facilities seeking to make a qualified change as defined by the Planning Coordinator under requirement R6. The assessment may include physical testing or simulation-based assessment using detailed, accurate models representative of the IBR Facility that will be built in the field. These assessment processes should again leverage the work being done in the IEEE 2800.2 WG, which has the goal of publishing a recommended practice Standard in 2024. • The Standard Drafting Team shall ensure coordination with FERC Order 901 and already-approved NERC Standards. **IBR Facility Commissioning Enhancements:** • New requirements created by applicable entities that require the GO of a registered IBR facility provide adequate proof that the facility was commissioned reliably. • Documentation to the TO, Transmission Operator (TOP), TP, PC, Reliability Coordinator (RC), and Balancing Authority (BA) regarding commissioning checks related to protection and control systems as well as plant capability. • Documentation that the commissioned in-service facility matches the model used during the interconnection process. Any discrepancies should be identified and reported to the ERO Enterprise and the aforementioned transmission entities for corrective action as needed. (NOTE: As-built settings, controls, or protections that do not match what was studied during the interconnection process present serious adverse BPS reliability impacts, leaving the TOP, RC, and BA operating the system in an "unknown operating state" since grid performance cannot be predicted.)
Cost Impact Assessment, if known (Provide a paragraph describing the potential cost impacts associated with the proposed project):
The exact costs for this project are unknown. Near-term and long term costs are likely to increase as industry develops practices around IBR interconnection requirements and conformity assessment. GOs will need to familiarize themselves with newly developed and implemented interconnection

[14] E-1 | Order 2023 | RM22-14-000 | Federal Energy Regulatory Commission (ferc.gov)

Requested information
requirements, procure equipment, and design IBR facilities in conformity with these. They will also need to do their own IBR Facility design evaluation to verify the IBR Facility's conformity with applicable interconnection requirements. TOs will need to develop IBR interconnection requirements, leveraging existing Standards insofar possible. TPs and PCs will need to develop conformity assessment and testing practices. Additionally, more testing and study work will be added during the interconnection process in order to conduct the conformity assessment, which will demand engineering staff's time and result in increased costs of interconnection studies overall. These initial costs may lead to reduced transmission expansion costs, as increased IBR performance and modeling should lead to a more efficient use of the transmission system. These costs are recognized; however, the team has made a focused and concerted effort to minimize costs while achieving the necessary reliability outcomes for this project. Outcomes from this project will help ensure an adequate level of reliability for the BPS significantly outweighs the incremental costs of implementation from this proposed project.
Please describe any unique characteristics of the BES facilities that may be impacted by this proposed Standard development project (*e.g.*, Dispersed Generation Resources):
New BPS-connected IBR facilities and existing BPS-connected IBR facilities seeking to make a qualified change as defined by PC under requirement R6 of FAC-002-4 will be directly impacted as the Facility will need to be designed in conformity with the newly-implemented interconnection requirements.
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 NERC Rules of Procedure Appendix 5A:
This section presents two questions, and therefore the IRPS will address each separately. 1) Appropriate drafting team members could involve individuals from the following entities: TOs, TPs, PCs, GOs, OEMs, IBR commissioning contractors or consultants, TOPs, RCs, BAs 2) The proposed Standards changes should apply to the following: TOs, TPs, PCs, GOs
Do you know of any consensus building activities[15] in connection with this SAR? If so, please provide any recommendations or findings resulting from the consensus building activity.
This SAR was developed by the NERC IRPS, which is a consensus building stakeholder group under the NERC RSTC. Upon endorsement by the NERC Reliability and Security Technical Committee (RSTC) through its stakeholder process and associated industry comment periods, the IRPS submits this SAR with that consensus building as well.
Are there any related Standards or SARs that should be assessed for impact as a result of this proposed project? If so, which Standard(s) or project number(s)?
Project 2023-05 is currently working on modifications to both FAC-001-4 and FAC-002-4 but modifications focus on distributed resources and not IBR. This SAR helps meet the goals of FERC Order 901 and thus should be coordinated with ongoing NERC Order No. 901 activities.

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

Requested information
Are there alternatives (e.g., guidelines, white paper, alerts, etc.) that have been considered or could meet the objectives? If so, please list the alternatives with the benefits of using them.

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.	
2. A reliability Standard shall neither mandate nor prohibit any specific market structure.	
3. A reliability Standard shall not preclude market solutions to achieving compliance with that Standard.	
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.	

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

For Use by NERC Only

SAR Status Tracking (Check off as appropriate).	
☐ Draft SAR reviewed by NERC Staff ☐ 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
Risk Tracking.	
☐ Grid Transformation ☐ Resilience/Extreme Events	☐ Energy Policy ☐ Critical Infrastructure Interdependencies
☐ Security Risks	

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
5	August 14, 2023	Standards Development Staff	Updated template as part of Standards Process Stakeholder Engagement Group

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Development of Draft SAR - Enhancements to FAC-001 and FAC-002

IRPS – Work Plan # 16
Reliability and Security Technical Committee Meeting
March 12, 2024

RELIABILITY | RESILIENCE | SECURITY




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Draft SAR Background

- SAR: Enhancements to FAC-001 and FAC-002
  - IRPS created a draft SAR regarding revisions to FAC-001 and FAC-002 to ensure that:
    - TOPs, RCs, and BAs that identify abnormal performance issues can work with the GO to seek corrective actions for resources not meeting their established interconnection requirements
    - Seek improvements to the requirements developed by the TO, TP, or PC (per FAC-001 or FAC-002)
    - Abnormal performance issues are reported to NERC for continued risk assessment. The standard will need to consider how to handle legacy equipment that has equipment limitations and cannot be modified
    - Effective feedback loops for improvements are developed

Intent of the SAR

- This SAR is intended to enhance the technical minimum requirements used throughout the Interconnection Process by providing “Requirement Categories” to guide applicable entities in the creation of their interconnection requirements and study processes
    - These requirement categories align with currently published industry work to help ensure applicable entities have readily available technical information to leverage in the creation of their requirements
- This SAR includes suggested enhancements that align with FERC Order No. 901 directives, with coordination as part of the Standards development process

IRPS Drafting and Review Process

- The draft SAR was initially created by a group of expert members of the IRPS
- The draft SAR underwent an approximately 2 week-long comment period by IRPS membership which resulted in comments from numerous organizations with varied stakeholders
- All comments were considered with most resulting in clarifying and technical revisions
- After the resolution of comments and final IRPS discussion, the IRPS reached consensus to bring this draft SAR to the RSTC
- This Draft SAR received 27 “Yes” votes and 0 “No” votes during the consensus building process

Action

- IRPS is seeking RSTC acceptance to begin a 30-day joint RSTC and public comment period

Questions and Answers

White Paper – Transmission and Distribution Coordination Strategies

Action
Approve

Background
As many of the System Planning Impacts of Distributed Energy Resources Working Group (SPIDERWG) documents mention that coordination of multiple transmission entities and distribution entities are necessary, this document serves to identify specific available coordination strategies.[1] Work in industry has been ongoing in this area since SPIDERWG's inception in 2019.[2] These efforts have culminated in various methods[3] to allow distribution entities to collaborate with transmission entities to make reliability focused decisions for distributed energy resources (DERs). This document serves to highlight available strategies reviewed by the NERC SPIDERWG and key aspects for Bulk Power System (BPS) perspectives.

The SPIDERWG is seeking the RSTC to approve this paper with the response to RSTC comments included in the document.

[1] Other DER guidance and materials has been performed by NERC and the technical stakeholder committees (e..g, RSTC and SPIDERWG). The NERC DER Quick Reference Guide is available here: https://www.nerc.com/pa/Documents/DER_Quick%20Reference%20Guide.pdf
[2] One such effort is EPRI's work on collaboration and coordination. Available here: https://www.epri.com/research/products/000000003002021985
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Transmission and Distribution Coordination Strategies

SPIDERWG White Paper
March 2024

Statement of Purpose

As many of the System Planning Impacts of Distributed Energy Resources Working Group (SPIDERWG) documents mention, coordination of multiple transmission entities and distribution entities are necessary. Work in industry has been ongoing in this area since SPIDERWG's inception in 2019.[1] These efforts have culminated in various methods[2] to enable distribution entities to collaborate with transmission entities to make reliability focused decisions for distributed energy resources (DERs). This document serves to highlight available strategies reviewed by the NERC SPIDERWG and key aspects for bulk power system (BPS) perspectives. [3]

Applicable Entities

The NERC SPIDERWG anticipates that the Transmission Planners (TPs), Planning Coordinators (PCs), Balancing Authorities (BAs), Reliability Coordinators (RCs), Transmission Operators (TOPs), and Distribution Providers (DPs) Registered entities may find this whitepaper useful. Entities interfacing with other distribution entities (e.g., not registered DP or DP-UFLS) may also find this paper useful. Further, the SPIDERWG anticipates that state, federal, or provincial regulators may also find these strategies informative when addressing data sharing in their territories.

Collaboration in the Planning Horizon

Planning engineers require an accurate depiction of their system so that they can accomplish their reliability objectives. Thus, they readily dictate the data granularity and frequency of sharing updates to the data set to ensure they have the most accurate representation of electrical equipment in their footprint. This includes the transmission to distribution interface (T-D Interface), the equivalent distribution system, aggregate load, and aggregate DERs. The SPIDERWG identified in past materials[4] that the DER information for this representation is generally as follows:

- DER Model Information (steady-state and dynamic representation)
  - Capacity
  - Electrical Location

[1] One such effort is EPRI's work on collaboration and coordination. Available here: https://www.epri.com/research/products/000000003002021985
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[4] See SPIDERWG reliability guidelines available here: https://www.nerc.com/comm/Pages/Reliability-and-Security-Guidelines.aspx

- Operational Characteristics and applicable distribution practices affecting dynamic performance of DERs during abnormal system conditions (e.g., ride through).

- Underfrequency Load Shedding[5] and Undervoltage Load Shedding[6] coordination with DERs notification
- Distribution system information
  - Voltage relay settings
  - Voltage Regulator and LTC positions for the T-D transformer
  - Equivalent impedance of aggregate model
  - Available fault current at high-side bus

While the above information is generally assumed to flow from distribution entities to transmission entities, some of the above can be used for distribution planning. The NERC SPIDERWG did not identify any uses of equivalent distribution system modeling for distribution planning, but rather found that distribution utilities may have a use for available fault current and the voltage stability of the high-side transmission bus in planning for distribution system refinements.

Frequency of Sharing

Generally, planning information is updated based on the latest project's in-service date for individual projects, or on an annual or quarterly basis for aggregate information. These requests are generally sent by Interconnection-wide case builders to PCs and TPs such that the Interconnection-wide planning case can be built; however, individual transmission entities may update their models on a more frequent basis. One such example is the WECC Master Dynamics File (MDF). The WECC MDF is updated whenever a more up-to-date transient model is available for the equipment, typically a generator. This is then pushed to every new case build that includes that equipment. While frequency of data sharing for planning cases may span between the frequent and infrequent, it is a necessary decision to specify when deploying a transmission and distribution coordination strategy.

Balancing Distribution System and Transmission System Needs

The SPIDERWG has discussed the collaboration on balancing the transmission and distribution needs for growing penetrations of DERs. The SPIDERWG *Reliability Guideline: BPS Perspectives on the Adoption of IEEE 1547-2018*[7] has many instances where collaboration between transmission and distribution entities is needed to agree on specific setting values for a given area of the electric system. Coordination in the planning horizon should include this type of collaboration.

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[5] SPIDERWG's reliability on UFLS program design is available here: https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Recommended_Approaches_for_UFLS_Program_Design_with_Increasing_Penetrations_of_DERs.pdf

[6] SPIDERWG's white paper on UVLS programs is available here: https://www.nerc.com/comm/RSTC_Reliability_Guidelines/White_Paper-DER_UVLS_Impact.pdf

[7] Available here: https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Guideline-IEEE_1547-2018_BPS_Perspectives_PostPubs.pdf

Collaboration in the Operations Horizon

Data sharing in the transmission operations time horizon is impacted solely by the TOP, RC, and BA ability to maintain situational awareness and reliably operate the BPS. Each of these entities play a role in ensuring the BPS remains reliable and have various methods identified in the NERC Reliability Standards[8] to obtain their needed data. In the operations horizon, data flow is straightforward with the authority to specify data needs for the TOP, RC, and BA so those entities can operate the system. The responsible entities to supply information range from transmission (e.g., other BAs sharing data or Transmission Owner supplying telemetry to a TOP's control center) to distribution (e.g., DPs or DP-UFLSs) entities. Some information may come from non-registered entities (especially distribution entities) in order to maintain a TOP, RC, or BA's situational awareness, typically through a contractual, structured process. The NERC SPIDERWG did not identify a need for a broader collaboration of data sharing improvements to the operations horizon outside of ensuring the T-D Interface is monitored for their appropriate flow conditions and representations of the load and generation at the T-D Interface.

FERC Order 2222 Impacts to ISO/RTO Operational Collaboration

DERs can operate independently or as part of a DER Aggregator in markets[9] with rules in place to define the DER options to participate in a DER Aggregator. As such, there exists another potential entity that can alter the electrical impact of the DERs at their T-D Interface. In areas where DER Aggregators exist (i.e., areas of the BPS where an Independent System Operator or Regional Transmission Organization exist), their reliability impacts must be monitored by the TOP, RC, or BA in their real-time activities. The exact procedure of coordination will differ between markets, but as the SPIDERWG has identified in their previous white paper,[10] clear situational awareness, facilitated by data exchange between DER Aggregators, distribution utilities, and transmission entities, is necessary to ensure reliable BPS operation. This data exchange can include telemetered data used in TOP state estimation and outage coordination for planned or forced outages taken in the distribution system as part of the T-D collaboration in the operations time horizon.

Available Information Sharing Strategies

With the ongoing grid transformation, there is a direct benefit to ensure transmission and distribution entities are collaborating to address potential risk to the BPS. As seen in Figure 1 below, there are various stages and needs to obtain valuable information for distribution and transmission entities.

[8] Particularly TOP-003, available here: https://www.nerc.com/pa/Stand/Reliability%20Standards/TOP-003-3.pdf

[9] Market structure is not the focus here, but rather the need of another entity, the DER Aggregator, is part of the information sharing and monitoring of the impacts of DERs to the T-D Interface and the BPS.

[10] See *BPS Perspectives on DER Aggregators*, available here: https://www.nerc.com/comm/RSTC_Reliability_Guidelines/SPIDERWG_White_Paper_-_BPS_Persepectives_on_DER_Aggregator_docx.pdf

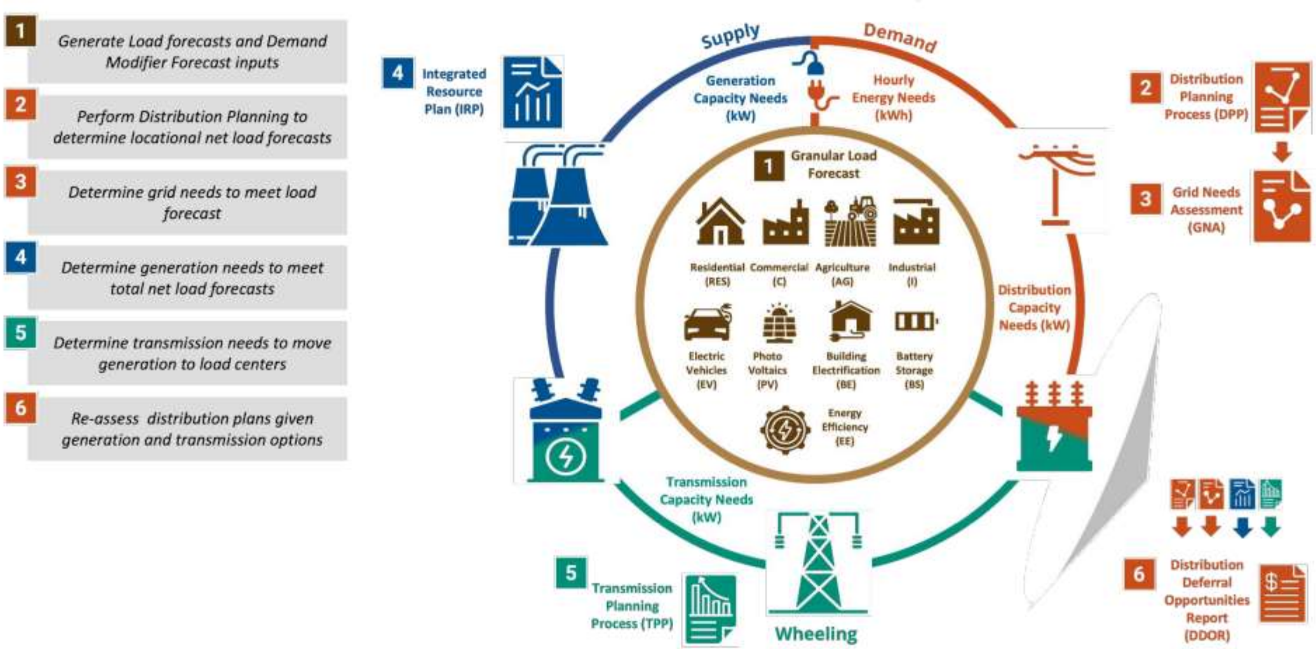

Figure 1: Potential Transmission and Distribution Benefits from Collaboration [Source: Kevala[11]]

Posting of Technical Interconnection and Interoperability Requirements (TIIR)

Some entities have found success in implementing transmission-focused postings of TIIRs to their stakeholders. While heavily influenced by the needs of the transmission system, this a pathway to sharing distribution information necessary to ensure the representation of the distribution system in transmission studies is accurate. However, due to the processes necessary to enforce forms that reference TIIRs, there can be some delay between the identified need for specific information and the procurement of that information to fill out the model. These lags can also be affected by sharing restrictions on model libraries; however, the sharing of specific parameter settings for DERs has found more success than a full model of the DER equipment. As such, there are joint needs addressed in posting of TIIRs. One such standard form comes from EPRI,[12] and is used by a few entities to convey the transmission system needs to entities responsible for DERs in their area. Outside of voluntary collaboration and sharing, there are some entities seeking tariff revisions or contractual updates to include specific items of a TIIR form. Thus, this method can be found in many different entity structures.

Statistically Representative Representations

Another method of sharing information comes from the statistical models that represent DER behavior. These models are representative of historic output of DERs using advanced metering infrastructure readings, system control and data acquisition (SCADA) information, or other information system outputs to drive a predictive model of DER behavior. The core information is found in the distribution utilities and DER owners who supply their equipment performance, ratings, and data from their end. Further, some entities

[11] Taken from: https://www.nerc.com/comm/RSTC/SPIDERWG/SPIDERWG_Presentations_May2023.pdf

[12] The EPRI information can be found here: https://www.epri.com/research/products/000000003002022563

have found use in aligning this “bottom-up” method[13] with “top-down” methods generally used by transmission entities to plan load and DER[14] growth. These statistical models interface between projected growth from the transmission side of load and DERs and the equipment performance expected from the “bottom-up” approaches. Further work in this area is needed on expected performance changes not represented by historical behavior and the different transmission requirements to model between long-term and short-term projections. Still, this is one strategy that can be used to coordinate between distribution system needs and transmission system needs for DERs.

DER Registry

At its core, a registry is a database that can describe the registered components in detail such that end-users of the data can readily poll the registry record for their uses. DER registries take this into account by ensuring that appliable fields are well articulated and electrically based so that policy and alterations in terms are not affecting the physical interconnecting qualities. One such registry effort underway proposed by Collaborative Utility Solutions,[15] deploys the Common Infrastructure Model (CIM) so that the registry can be used by utilities regardless of their chosen modeling software or practice. While originally developed by EPRI, the CIM models are now maintained under the International Electrotechnical Commission (IEC) and can be identified by the five-digit number assigned to that common model. Using CIMs as the basis of the DER registry, entities can ensure that no additional data translation is necessary to interface between entities if they can accommodate that common model. Controls on the data are available to the managing entity of the DER registry, and specific end-users can obtain only the information necessary to accomplish their task. The NERC SPIDERWG sees this registry having strong applications in the planning collaboration discussions; however, CIM models in the operations timeframe are also a possibility.

Recommendations

The NERC SPIDERWG reiterates its recommendation in its reliability guidelines that BAs, RCs, TOPs, TPs, PCs, TPs, DPs, and other distribution entities (e.g., nonregistered distribution service providers or DP-UFLS) begin collaborative efforts to facilitate data sharing and necessary changes to mitigate identified reliability risks from aggregate DER have on their footprint. Each of the listed efforts are aids that can be used to obtain and post information that facilitates the collaboration. The NERC SPIDERWG recommends entities begin proactive, good faith collaboration so that both transmission and distribution needs are met.

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[13] Due to the fact that it aggregates known equipment performance to a higher level. Hence the term, “bottom-up”.

[14] Not all entities project their own DER growth. The concept still applies for the entity that performs system level projections rather than the “bottom-up” approaches.

[15] See presentation to the SPIDERWG, available here: https://www.nerc.com/comm/RSTC/SPIDERWG/SPIDERWG_Presentations_May2023.pdf

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Transmission and Distribution Coordination Strategies

SPIDERWG White Paper

~~October 2023~~ March 2024

Statement of Purpose

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The NERC SPIDERWG anticipates that the ~~Registered Entity types of~~ Transmission Planners (TPs), Planning Coordinators (PCs), Balancing Authorities (BAs), Reliability Coordinators (RCs), Transmission Operators (TOPs), and Distribution Providers (DPs) Registered ~~E~~entities may find this whitepaper useful. Entities interfacing with other distribution entities (e.g., not registered distribution providers or DP-UFLS) may also find this paper useful. Further, the SPIDERWG anticipates that state, federal, or provincial regulators may also find these strategies informative when addressing data sharing in their territories.

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- Capacity
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- Operational Characteristics and applicable distribution practices affecting ~~ride-through~~dynamic performance of DERs during abnormal system conditions (e.g., ride through).

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~~That while~~ DERs can operate independently or as part of a DER Aggregator in markets~~,~~[10] with rules in place to define the DER options to participate in a DER Aggregator. As such, there exists another potential entity that can alter the electrical impact of the DERs at their T-D Interface. In areas where DER Aggregators exist (i.e., areas of the BPS where an Independent System Operator or Regional Transmission Organization exist), the~~re is a need to ensure that~~ir reliability ~~the DER Aggregator~~ impacts ~~are~~ must be monitored by the TOP, RC, or BA in their real-time activities. The exact procedure of coordination ~~his~~ will differ between markets ~~in the exact procedure of coordination~~, but as the SPIDERWG has identified in their previous white paper,[11] ~~that~~ clear situational awareness, facilitated by data exchange between DER Aggregators, distribution utilities, and transmission entities, is necessary to ensure reliable BPS operation. This data exchange can include telemetered data used in TOP state estimation and outage coordination for planned or forced outages taken in the distribution system as part of the T-D collaboration in the operations time horizon.

Available Information Sharing Strategies

With the ongoing grid transformation, there is a direct benefit to ensure transmission and distribution entities are collaborating to address potential risk to the BPS. As seen in Figure 1 below, there are various stages and needs to obtain valuable information for distribution and transmission entities.

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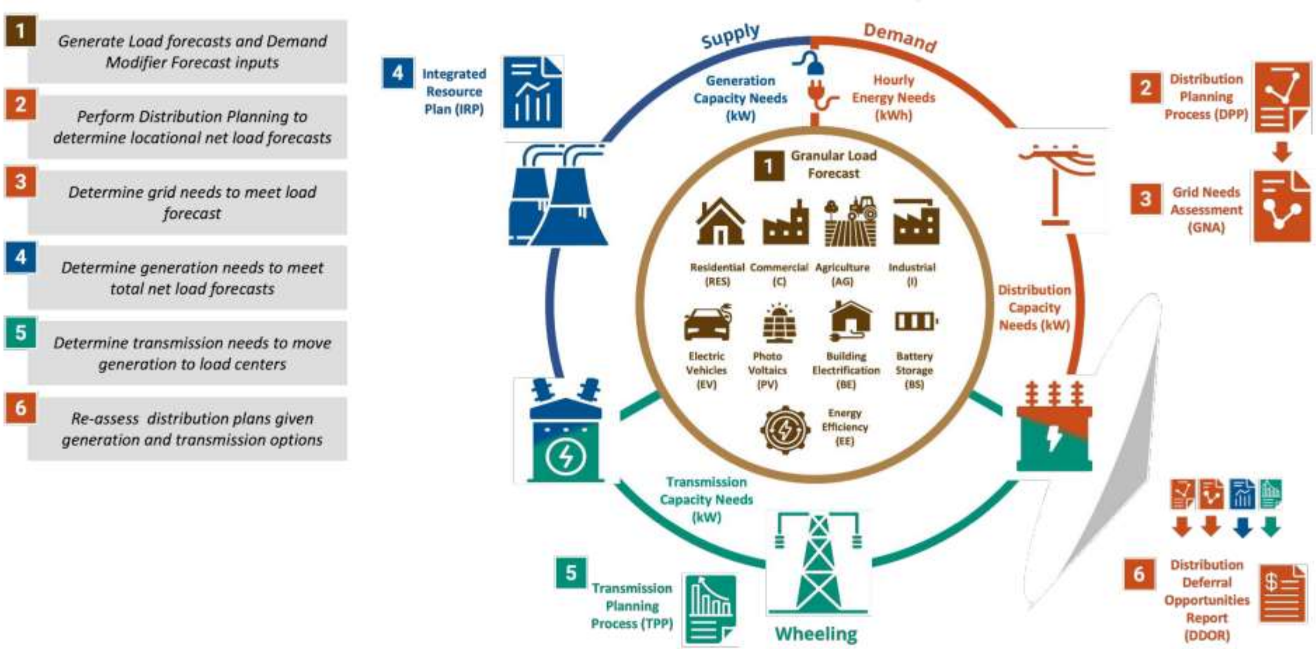

Figure 1: Potential Transmission and Distribution Benefits from Collaboration [Source: Kevala[12]]

Posting of Technical Interconnection and Interoperability Requirements (TIIR)

Some entities have found success in implementing transmission-focused postings of technical interconnection and interoperability requirements (TIIRs) to their stakeholders. While heavily influenced by the needs of the transmission system, this a pathway to sharing distribution information necessary to ensure the representation of the distribution system in transmission studies is accurate. However, due to the processes necessary to enforce forms that reference TIIRs, there can be some delay between the identified need for specific information and the procurement of that information to fill out the model. These lags can also be affected by sharing restrictions on model libraries; however, the sharing of specific parameter settings for DERs has found more success than a full model of the DER equipment. As such, there are joint needs addressed in posting of TIIRs. One such standard form comes from EPRI,[13] and is used by a few entities to convey the transmission system needs to entities responsible for DERs in their area. Outside of voluntary collaboration and sharing, there are some entities seeking tariff revisions or contractual updates to include specific items of a TIIR form. Thus, this method can be found in many different entity structures.

Statistically Representative Representations

Another method of sharing information comes from the statistical models that represent DER behavior. These models are representative of historic output of DERs using advanced metering infrastructure readings, system control and data acquisition (SCADA) information, or other information system outputs to drive a predictive model of DER behavior. ~~As such,~~T~~t~~he core information is found in the distribution utilities and DER owners who supply their equipment performance, ratings, and data from their end. Further, some

[12] Taken from: https://www.nerc.com/comm/RSTC/SPIDERWG/SPIDERWG_Presentations_May2023.pdf
[13] The EPRI information can be found here: https://www.epri.com/research/products/000000003002022563

entities have found use in aligning this "bottom-up" method[14] with "top-down" methods generally used by transmission entities to plan load and DER[15] growth. ~~As such,~~T ~~t~~hese statistical models interface between projected growth from the transmission side of load and DERs and the equipment performance expected from the "bottom-up" approaches. Further work in this area is needed ~~to inform~~ on expected performance changes not represented by historical behavior ~~as well as~~and the different transmission ~~needs~~ requirements to model between long-term and short-term projections. Still, this is one strategy that can be used to coordinate between distribution system needs and transmission system needs for DERs.

DER Registry

At its core, a registry is a database that can describe the registered components in detail such that end-users of the data can readily poll the registry record for their uses. DER registries take this into account by ensuring that appliable fields are well articulated and electrically based so that policy and alterations in terms are not affecting the physical interconnecting qualities. One such registry effort underway ~~is~~ proposed by Collaborative Utility Solutions,[16] ~~that take~~ deploys the~~a~~ Common Infrastructure Model (CIM) so that the registry can be used by utilities regardless of their chosen modeling software or practice. While originally developed by EPRI, the CIM models are now maintained under the International Electrotechnical Commission (IEC) and can be identified by the five-digit number assigned to that common model. Using CIMs as the basis of the DER registry, entities can ensure that no additional data translation is necessary to interface between entities if they can accommodate that common model. Controls on the data are available to the managing entity of the DER registry, and specific end-users can obtain only the information necessary to accomplish their task. The NERC SPIDERWG sees this registry having strong applications in the planning collaboration discussions; however, CIM models in the operations timeframe are also a possibility.

Recommendations

The NERC SPIDERWG reiterates its recommendation in its reliability guidelines that BAs, RCs, TOPs, TPs, PCs, TPs, ~~and~~ DPs, and other distribution entities (e.g., nonregistered distribution service providers or DP-UFLS) begin collaborative efforts to facilitate data sharing and necessary changes to mitigate identified reliability risks from aggregate DER have on their footprint. Each of the listed efforts are aids that can be used to obtain and post information that facilitates the collaboration. The NERC SPIDERWG recommends entities begin proactive, good faith collaboration so that both transmission and distribution needs are met.

[14] Due to the fact that it aggregates known equipment performance to a higher level. Hence the term, "bottom-up".
[15] Not all entities project their own DER growth. The concept still applies for the entity that performs system level projections rather than the "bottom-up" approaches.
[16] See presentation to the SPIDERWG, available here: https://www.nerc.com/comm/RSTC/SPIDERWG/SPIDERWG_Presentations_May2023.pdf

Reliability Guideline: Bulk Power System Planning under Increasing Penetration of Distributed Energy Resources

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Background
With the growing penetration of distribution-connected sources of power across the NERC footprint, it becomes paramount that the appropriate study procedures can properly reflect the performance of such distributed energy resources (DER) and their potential impact on BES reliability. This reliability guideline seeks to provide bulk system planners a set of recommended practices to study the various aspects of DER in the planning horizon, including practices of information sharing in a utility serving both distribution and transmission functions.

Purpose
There is an inherent risk associated with incomplete or incorrectly parameterized planning models. This reliability guideline seeks to provide best practices to include and adjust aggregate DER models when used in transmission planning studies.

NERC

NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Reliability Guideline

Bulk Power System Planning under Increasing Penetration of Distributed Energy Resources

Date: XX/XX/2024

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

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

The North American BPS is made up of six Regional Entities as shown on the map and in the corresponding table below. The multicolored area denotes overlap as some load-serving entities participate in one Regional Entity while associated Transmission Owners/Operators participate in another.

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

Preamble

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

Each entity registered in the NERC compliance registry is responsible and accountable for maintaining reliability and compliance with applicable mandatory Reliability Standards. Reliability guidelines are not binding norms or parameters nor are they Reliability Standards; however, NERC encourages entities to review, validate, adjust, and/or develop a program with the practices set forth in this guideline. Entities should review this guideline in detail and in conjunction with evaluations of their internal processes and procedures; these reviews could highlight that appropriate changes are needed, and these changes should be done with consideration of system design, configuration, and business practices.

Executive Summary

The NERC System Planning Impacts from Distributed Energy Resources Working Group (SPIDERWG) identified in this reliability guideline a set of planning practice enhancements for Transmission Planners (TPs), Planning Coordinators (PCs), and other relevant entities. With the growing penetration of distributed energy resources (DERs), the SPIDERWG had previously focused its guidance on the aggregate modelling practice enhancements and the procurement of data to parameterize and validate such models. Planning studies rely on accurate models, but also need robust practices that guide their study choices. Growing DER penetrations in the NERC footprint indicate a growing importance on the method TPs and PCs use to study the bulk system impact of DERs. overviewed better The SPIDERWG identified an adaptable framework that a TP or PC can apply to their planning practices associated with the TPL-001 standard to improve identification of potential reliability impacts of DER on the Bulk Electric System (BES). There are recommendations for each stage of the framework, highlighted in the following steps common to TPs and PCs:

1. Developing a Base Case
2. Developing credible contingencies
3. Developing a sensitivity case
4. Performing steady-state simulations
5. Performing stability simulations
6. Performing short circuit simulations

The SPIDERWG has also identified that of focus transmission planning departments are increasing the use of EMT studies within planning assessments. These studies are generally focused on a small area of the transmission system near bulk-connected IBR plants; however, sometimes these studies require translating the positive sequence transmission to distribution interface (T-D Interface) into the EMT domain. As such, SPIDERWG documented specific lessons learned and procedures when incorporating aggregate DER into EMT simulations.

Recommendations

Based on the SPIDERWG identification of enhancements to planning practices under high DER penetration conditions, SPIDERWG developed a set of high-level recommendations. These recommendations cover the general practices in a planning department, and the SPIDERWG identified more specific study refinements in **Appendix A:**. At a high level, TPs and/or PCs should:

1. Identify DER impacts in their steady-state, stability, and short-circuit assessments and highlight the role of DER in steady-state, stability, or short-circuit violations in their study reports.
2. Account for known levels of DER tripping in their steady-state contingency definitions.
3. Make sure the DER trip settings in the dynamic model representation are accurate.
4. Document DER-related common mode of failure in their set of contingencies applied to planning assessments (e.g., cyberattack, cloud cover). TPs should seek to improve their understanding of these common mode failures through studies on their system.
5. Review planning criteria to ensure that it is accurately flagging areas of risk under increasing penetration of DERs.
6. When developing Corrective Action Plans, TPs and PCs should clearly identify how growing DER penetration can impact the plan’s viability and refine their plans to account for the growing DER penetrations where needed.

Chapter 1: Guideline Purpose and Planning Function Overview

With the growing penetration of distribution-connected sources of power across the NERC footprint, it becomes paramount that the appropriate study procedures can properly reflect the performance of such distributed energy resources (DER) and their potential impact on BES reliability. This reliability guideline seeks to provide bulk system planners a set of recommended practices to study the various aspects of DER in the planning horizon, including practices of information sharing in a utility serving both distribution and transmission functions.

Purpose

There is an inherent risk associated with incomplete or incorrectly parameterized planning models. This reliability guideline seeks to provide best practices to include and adjust aggregate DER models when used in transmission planning studies.

Applicability

This reliability guideline is applicable to Transmission Planners (TPs), Planning Coordinators (PCs), Resource Planners (RPs). Other entities that perform reliability studies on the bulk system may also find this guideline useful in addition to its intended audience. Some recommendations may also be applicable to Reliability Coordinators (RCs) and Balancing Authorities (BAs).

Related Standards

The topics covered in this guideline are intended as useful guidance and reference materials as TPs and PCs study the growing penetrations of DERs on their system. While this guidance does not provide compliance guidance, the concepts apply generally to TPL-001. However, there are standards listed in the section **Non-TPL-001 uses for Base Cases.**

Applicable Planning Assessment Types

There are a few broad categories that describe the types of planning assessments performed in any given planning department. Those categories define the types and scope of study used to propose projects and design system upgrades. Each of these may be affected by the methods in this reliability guideline and their general function is summarized here. While these categories may be labeled differently throughout industry, they usually serve a similar if not the same purpose as one listed and described below:

- Model development, management, and maintenance
- Interconnection Planning
  - Generator Interconnection Studies
  - Line and Load Interconnection Studies
- Long-Term Planning Assessments (i.e., TPL Studies)
- Local Reliability Assessments
- Regional[1] Planning Studies
- Interregional or Wide-Area Planning Studies
- Interconnection-wide Reliability Studies

[1] Note that regional is typically the term used for these studies, but they are not the same footprint as a NERC Regional Entity.

Model Development, Management, and Maintenance

In many planning departments, typically one or more engineers develop, maintain, and manage their equipment models. Their responsibilities may not be limited to transmission level equipment but can also include the development of models for resources, loads, and flexible AC transmission system (FACTS) devices connected to their system. Sometimes the engineers are solely assigned to this one function; however, some utilities have these engineers coordinate with their region (e.g., WECC) to manage and maintain specific libraries of models. Some planning departments have even started developing and integrating models to represent the DER in their area. This function typically supports the other planning department functions.

Interconnection Planning

Required by each company's Tariff and FAC standards, TPs must perform a set of studies to ensure that proposed projects from developers (e.g., GOs or FERC Order 1000 type companies) do not adversely impact reliability. The goal of these studies is to determine what, if any, upgrades are required to reliably allow the project to interconnect to the system. These types of studies have recently increased due to the tremendous increase of proposals for bulk-connected projects. One thing to note is that the planners typically perform these studies for their own system, but sometimes are required to coordinate with other utilities or companies that can be impacted by the interconnection agreement. These types of studies may use positive sequence and/or Electromagnetic Transient (EMT) studies as specified in a TP's planning and interconnection processes.

Long-Term Planning Assessments

For planners, these assessments are sometimes referred to as simply "TPL Studies" as they are typically performed for TPL-001. Sometimes, a public utilities commission can request an ad-hoc study to support specific state requirements and at other times, planning departments may have a 10-year expansion plan that falls under these long-term studies. Typically, these studies are broken up into a near-term planning study for years 1 to 5 and a long-term planning study for years 5 to 10.

Local Reliability Assessments

These reliability assessments are performed for specific initiatives based on feedback from operators or other personnel to initiate a study of improvements to the transmission system. For example, the type of question a local reliability study can answer is "How can we most cost-effectively mitigate the congestion of our 230 kV line that overloads during certain summer conditions?" These studies typically support a local area's expansion plan such that as load increases, the utility can serve customers in their service territory. In market driven environments, these are typically signaled by an abnormally high local marginal price that triggers investment and design of the transmission system such that interconnection of resources is eased to reduce the overall cost of power delivery in the system. This reliability guideline proposes best practices for the expansion planning piece and not on market triggers for reduction of power delivery cost.

Regional Planning Studies

Planners across nearby utilities may meet to discuss expansion projects in their local reliability assessments to see if nearby utilities have a similar design or proposal that can also mitigate potential issues. These are sometimes done by committee engagement or with joint agreements across the utilities. Projects here also may span many service territories (i.e., TPs) and connect wide regions and may include HVDC projects as well as large AC transmission connection projects. These studies typically involve no more than two PC areas; studies involving more areas would be considered are classified as Interregional or Wide-Area study studies as described below.

Interregional or Wide-Area Planning Studies

In some Interconnections, PCs convene to study a very broad expansion plan that is to aid many areas of an Interconnection but may not affect the entire Interconnection. These types of projects include the HVDC projects mentioned above, but would also include transfer capability studies to determine an interface's import and export capability as well as identify weaker areas of the system that could be enhanced through a large project that strengthens the tie line(s) between multiple PCs. Another example is the Undervoltage Load Shedding program each PC designs per PRC-010.[2] Generally, these studies are not performed by one PC, but rather have strong input from each participating PC.

Interconnection-wide Reliability Studies

Sometimes, NERC or one of its regions performs a planning assessment that covers the entire Interconnection or requires Interconnection-wide cooperation and analysis in order to accomplish the study objective. For instance, NERC's Long Term Reliability Assessment takes each Interconnection into account for the assessment and requires strong Regional Entity input. Other regional specific assessments include the *Western Assessment of Resource Adequacy*[3] in WECC, which covers the entire Interconnection. These studies typically cover resource adequacy questions (e.g., does the Interconnection have sufficient energy to cover all hours of the year?) instead of typical planning objectives (e.g., does the Contingency cause thermal overload or voltage violations?). However, these Interconnection-wide studies also can account for frequency response studies and inter-area oscillation studies. Under Frequency Load Shedding studies may be considered Interconnection-wide reliability studies as some entities ensure the study assesses impact on the entire Interconnection. Sometimes a "special studies" team is formed for this type of study, but the scope of those teams can vary as they are topically focused, rather than footprint and entity focused.

Previous SPIDERWG Materials

Transmission system models are used to assess the future reliability of the bulk power system. As the recommended model framework in SPIDERWG's previous reliability guidelines suggests, the aggregate DER model is also an important representation for a planner to use when representing the powerflow and transient dynamic behavior of DERs. However, to properly study DER, TPs and PCs need to adjust the model to ensure the behavior appropriately reflects the study assumptions.

The NERC SPIDERWG has been active in providing guidance on the modeling and verification of DER models for use in Interconnection-wide planning base cases. Readers new to this process should review previously approved guidelines to better understand the starting point for this document. The current set of reliability guidelines can be found at the Reliability and Security Technical Committee (RSTC) website[4]. The practices contained in this reliability guideline assume that DER data have been collected, verified, and validated for use in the study. This means that the model has been built using the recommended modeling framework and populated with parameters based on data collection and engineering judgement. **Figure 1.1** summarizes key content of the past reliability guidelines.

[2] Available here: https://www.nerc.com/pa/Stand/Reliability%20Standards/PRC-010-1.pdf

[3] The 2022 version of this report can be found, as an example, here: https://www.wecc.org/Reliability/2022%20Western%20Assessment%20of%20Resource%20Adequacy.pdf

[4] Available here: https://www.nerc.com/comm/Pages/Reliability-and-Security-Guidelines.aspx

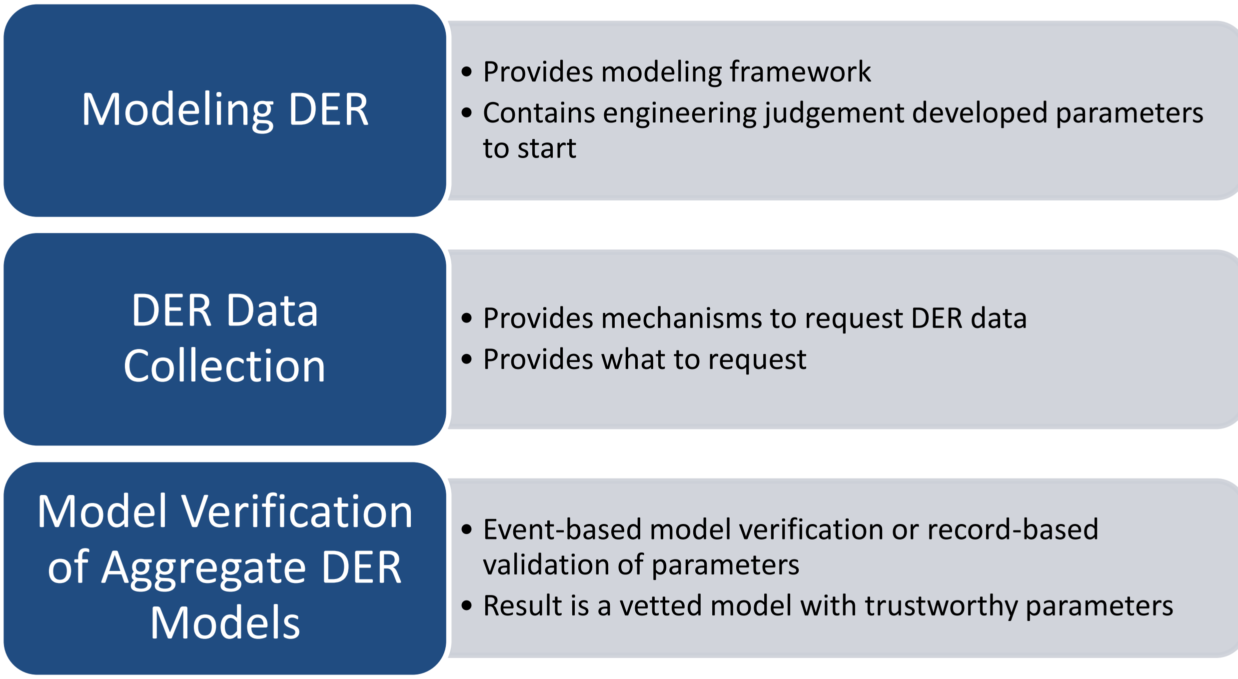

Figure 1.1: Previous SPIDERWG Guidance on DER Modeling

Previous SPIDERWG guidelines on modeling DER proposed a modeling framework (see **Figure 1.2**) and a process to allow for DER to be classified into utility-scale DER (U-DER) and retail-scale DER (R-DER) as well as a procedure for TPs and PCs to establish modeling thresholds. DER data or engineering judgement is needed to populate the DER models that are included in the Interconnection-wide cases; SPIDERWG has provided guidance on populating of the DER models[5]. An entity can utilize the past SPIDERWG data gathering and model verification guidance[6] to assess the accuracy of DER model parameters and improve the fidelity of the aggregate DER model by monitoring T-D Interface flows or large DER facility responses during recorded events. These past guidelines serve as a foundation for the content contained in this reliability guideline.

[5] Available here: https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Reliability_Guideline_ModelingMerge_Responses_clean.pdf
[6] Available here: https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Reliability_Guideline_DER_Data_Collection_for_Modeling_and_Model_Verification.pdf

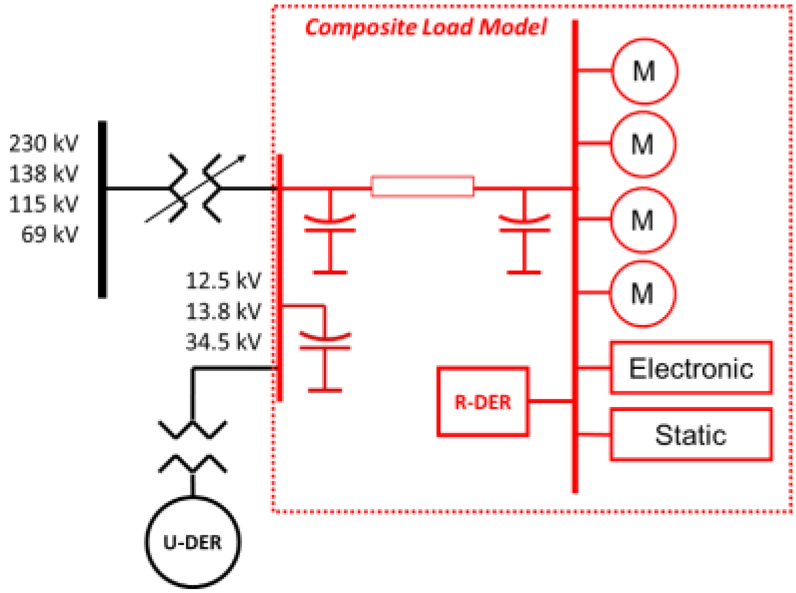

Figure 1.2: SPIDERWG Recommended DER Modeling Framework

The reliability studies discussed in this guideline build upon the basic DER modeling concepts covered in the previous reliability guidelines referenced above, as accurate studies rely on accurate model representation of the electrical equipment behavior. The aggregate DER model is no exception. Past SPIDERWG reliability guidelines outline the prerequisite DER modeling and model verification efforts entities should be familiar with prior to implementing the recommendations in this guideline. These guidelines are as follows:

1. *Reliability Guideline: Parameterization of the DER_A Dynamic Model for Aggregate DER*[7]
2. *Reliability Guideline: DER Data Collection and Model Verification of Aggregate DER*[8]

These guidelines may be subject to future revision or replacement under a new title; however, all currently approved reliability guidelines are posted at the RSTC webpage.[9] Per RSTC procedure, all approved reliability guidelines can be archived and retired.[10]

[7] Available here: https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Reliability_Guideline_ModelingMerge_Responses_clean.pdf
[8] Available here:
https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Reliability_Guideline_DER_Data_Collection_for_Modeling_and_Model_Verification.pdf
[9] The SPIDREWG set of reliability guidelines are available at the RSTC page here: https://www.nerc.com/comm/Pages/Reliability-and-Security-Guidelines.aspx.
[10] The listed documents in this document are the latest version and title of the active modeling related SPIDERWG guidelines.

Chapter 2: Planning Study Changes Due to Increasing DER

This chapter highlights the types of studies impacted by increasing penetrations of DER in a region. High level of DER penetration can have an impact on both bulk power system planning and operation. This guidance concentrates on the DER impact on transmission planning, but there may be some benefit for distribution engineers with the guidance.

Impacts from High Levels of DER on Transmission Studies

The following sections describe the DER impact by study type. Steady-state and dynamic transient studies complement each other by identifying reliability impacts from modeled equipment in the Bulk Power System. The impacts of DERs on steady-state or dynamic transient studies are typically unique to the study type in question. SPIDERWG split its guidance by type of study to capture the effects of increasing DERs.

Steady state power flow studies

Steady state planning studies include thermal assessment, voltage assessment and voltage stability analysis.[11] On thermal assessments, the impact of increasing penetration of DER is the change in flows not only on the distribution feeders where DERs are connected, but also in the transmission system.[12] These changes in flow may reduce loadings and mitigate some overloads, but they may also increase loadings and create new overloads post-contingency. Whether the loading will increase or decrease with addition of DER depends on the DER locations, the aggregate levels at the point of interconnection, and the topology of the network. With tripping DER following contingencies, usually due to low voltages, there also may be large changes in flows due to increase of net load, and possibly, overloads.[13] Another challenge with a large amount of DER is reverse flows in distribution feeders if DER output exceeds the magnitude of load connected to the feeder. Such conditions are often expected under spring or summer off-peak conditions[14]. Reverse flows may cause thermal overloads in the feeders if the installed DER capacity exceeds hosting capacity of the feeders, but it is usually not expected because the total DER installations are typically planned considering the feeder's hosting capacity.

The expected impact of increasing penetration of DER on voltage assessments includes high voltages due to reduction in net load with the addition of DER as well as low voltage issues.[15] Under light gross load conditions and high output of DER, distribution voltages may be excessively high and light net loading and reversed power flow across the transmission/distribution interface may cause high voltages on the transmission system as well. High transmission voltages may require installation of additional reactive support that would absorb reactive power (e.g., shunt reactors), which would not be needed without DER. At sunset with ramping of the net load due to reduction in the DER output, voltages may become lower. As such, reactive devices that might be required during high output of DER and low load will need to be turned off during low DER output. Thus, increasing penetration of DER is anticipated to impact both high and low voltage conditions studied in the voltage assessment.

Voltage stability issues that appear with increasing penetration of DERs are large voltage deviation with contingencies when DERs trip due to low voltage. In extreme cases with a large amount of DER tripping, it may cause voltage collapse. A challenge in the power flow studies is that it may not be clear which DER will trip for low voltages for a given contingency. DER may trip with faults due to low transient voltages, and to determine which DER will trip,

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11 Some initial work in these areas include presentations made to the SPIDERWG. One such presentation is available here: https://www.nerc.com/comm/PC/System%20Planning%20Impacts%20from%20Distributed%20Energy%20Re/Studies%20-%20NERC%20SPIDERS%20Challenges%20with%20Integrating%20Renewables%20-%20Bialek.pdf

12 An analysis on the various impacts of increasing DER penetration is available here: https://www.epri.com/research/products/000000003002019445

13 Such analysis on steady-state voltage impacts related to higher DER penetrations is available here: https://www.epri.com/research/products/000000003002010996.

14 For example, weekend afternoons when the load is low and the distributed solar PV output is high

15 WECC has a study that has identified some voltage shifts (high and low) related to DERS. Available here: https://www.wecc.org/Administrative/DER_Assessment_Report_Final.pdf

transient stability analysis is required. If transient stability analysis shows that there are DERs that are expected to trip and not recover in the timeframe of the transient simulation, then power flow studies should be repeated with the tripped DERs through updates to the steady-state contingency definition.

While this above back and forth process is uncommon, these updates should be well documented in the contingency files and reviewed for their applicability to changing study conditions. TPs should model its expected steady-state DER tripping performance to known or assumed DER tripping for that operating state in the steady-state study. Tripping of DER in the post-contingency operating state lends to a more conservative evaluation of expected performance. A dynamic transient stability simulation can inform this validation. Depending on the DER settings, the DER tripping may be partial so this value may not be the entire DER capacity at a given load bus.

Transient Stability Studies

In transient stability, the increasing growth of DER impact primarily the voltage and frequency response of a given planner's system.[16] When analyzing transient voltage performance, it should be considered that in the systems with high induction motor load, delayed voltage recovery may occur following faults. Fault-induced delayed voltage recovery (FIDVR) is mostly a concern during summer peak load conditions in the areas that have a large amount of residential air-conditioners or in areas of heavy motor load. Residential air-conditioning load is comprised of single-phase induction motors that are prone to stall during faults. DER may impact FIDVR conditions, especially when DER penetration coincides with high induction motor load operation. If DER can provide voltage support, they may be able to improve transient voltage recovery, and may even prevent induction motor stalling. A negative impact of DER regarding transient stability performance is that DER may trip following faults due to low voltage. This may degrade the system stability and exacerbate FIDVR conditions. Whether DER will trip or not depends on the ride-through capability, distribution utility practices, and on the voltage trip settings implemented for the DER facility.

Another concern for inverter-based DER is momentary cessation that may occur in addition to (and before) tripping.[17] During momentary cessation, inverters no longer inject current, yet they stay connected to the grid. Within 400 mS, the inverter's output is substantially restored, leading to less bulk system impact than if the DER were tripped. Momentary cessation may occur at a higher voltage than tripping, and this difference may be slightly detrimental for the bulk system transient stability[18]. This is anticipated in regions where distribution utilities require enablement of momentary cessation functionality (i.e., IEEE 1547-2018 Performance Category III) in their practices. Long delays in restoring to pre-disturbance output from tripping[19] can create reliability impacts to the post-disturbance voltage recovery. As recommended a previous SPIDERWG document,[20] Transmission planners should account for momentary cessation as well as DER tripping in their studies. A thorough understanding of known DER capability and performance requirements in a given jurisdiction can aid in making appropriate assumptions regarding DER modeling related to momentary cessation and tripping.

Systems with high DER penetration may potentially have inadequate frequency response or insufficient frequency reserve due to the displacement of bulk-connected generation by increasing amounts of DER. Inadequate frequency response is not solely related to DER, yet DERs contribute to the overall decline of frequency responsive equipment

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[16] An example presentation on a transient dynamic study is available here: https://www.nerc.com/comm/PC/System%20Planning%20Impacts%20from%20Distributed%20Energy%20Re/Coord%20-%20Duke-EPRI%20DER%20Case%20Study%20-%20Dowling,%20Ramasubramanian,%20Boemer,%20Gaikwad,%20Quiantance,%20Williams.pdf

[17] An example of a study that specifically looked into ride-through and tripping characteristics of DERs is available here: https://www.epri.com/research/products/000000003002019445

[18] However, note that momentary cessation was a response to the needs of the distribution system as an alternative to tripping. At this time, the use of momentary cessation is expected in areas where IEEE 1547-2018 Performance Category III is required of inverter-based DER .

[19] Momentary cessation in the distribution context is set at a 400 mS time frame, afterwards the inverter is considered to have tripped and needs to re-enter service. Tripping in this context can range from opening a breaker to entering into an "idle mode".

[20] Available here: https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Reliability_Guideline_DER_Data_Collection_for_Modeling_and_Model_Verification.pdf

due to their equipment design defaults. That is, unless the BAs procure other reserves, increasing DER dispatch (i.e., by default frequency non-responsive) may degrade the available frequency responsive reserve. Additionally, system inertia may be reduced if a large amount of DER is inverter-based (i.e., solar PV) which may contribute to higher rates of frequency decline that could trigger underfrequency load shedding for contingencies that involve the loss of large amounts of generation. DER interconnecting in accordance with IEEE Std. 1547-2018 are required to have and enable the capability to provide sustained primary frequency response, but utilities are not required to use the capability from the equipment or plant. Further, IEEE 1547-2018 does not require DER to maintain energy/power headroom to use for sustained frequency response by default. Thus, the impact of increasing penetrations of DER on frequency response is dependent not only on the capability of DER, but also the dispatch of DER to allow for frequency response. It is important that studies related to frequency response appropriately reflect the frequency response performance of the generation dispatch to identify any potential reliability issues, inclusive of the DER impacts. In the operations horizon, BA's should ensure their frequency responsive reserve procurement strategies and studies account for DER impacts to the growing frequency non-responsive generation growth. The TPs studies should identify if their study's case does not reflect the expected frequency responsive reserves when studying the response to credible contingencies and correct the case where appropriate. Further, TPs should ensure the frequency response of the aggregate DER model is reflective, in aggregate, of distribution utility practices, utility protection at the POI, and specific equipment and plant protection[21] at the DER facility.

Transfer Capability

Large amounts of DER in the system may impact transfer capability and transfer limits if DER displaces the conventional resources that are armed for Remedial Action Schemes (RAS) that allow for high path flows.[22] These conventional resources may not be dispatched at the time of high DER output or may even be retired . If there are not enough resources to be armed for tripping with the expected contingencies, then it may potentially influence allowable transfer paths ratings. Transfer capability studies should ensure that their path ratings account for any impact this capacity transfer brings to the studied path. Thus, transfer capability studies should incorporate appropriate DER modeling to identify any potential reliability issues that may be caused by increasing levels of DER.

Types of Studies Under Consideration

Historically, the transmission planners have studied reliability impacts with software that allowed for the positive sequence representation of the equipment, with more detailed representations being studied outside of the planning department. These were for focuses like protection systems that needed more detailed information. While that paradigm still holds true in many areas, some planners are seeing a need for representation of inverter-based resources outside of positive sequence tools to capture the control and tripping logic of the inverters. This is also true with respect to DERs in some areas. However, as more detail gets added to the model it becomes apparent that the distribution system itself plays a factor in how entities are studying the impact of DERs on the transmission system. SPIDERWG has a work product entitled *Technical Report: Beyond Positive Sequence*[23] that details situations where planners may consider moving outside of the positive sequence representation for their studies. **Table 2.1** lists a few of the studies described in the Technical Report. The table shows that the different time domains exist for DER studies with transmission level studies largely being in the positive sequence phasor domain (PSPD), with only some exceptions recommended for the EMT domain. Quasi-steady state conditions indicate that the analysis isn't performed on settled quantities, yet long-duration controls like automatic governor control may have an impact in

[21] Specifically, the settings of the IEEE 1547 standard for the equipment and plant's response to voltage and frequency. IEEE 1547 settings, are the specific equipment and plant protection information necessary to properly reflect equipment and plant performance and the specific version of 1547 (e.g., -2003 or -2018) is not consistent inside a given footprint. Thus, those specific settings are needed for accurate modeling of aggregate DER performance in a TP's transient stability study looking at underfrequency conditions.
[22] One such analysis looking at the transfer capacity impacts related to growing penetration of aggregate DERs can be found here: https://www.epri.com/research/products/000000003002019445
[23] Available here: https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Beyond_Positive_Sequence_Technical_Report.pdf

that study. The EMT average versus EMT switched relates to whether the controls on the IGBTs are modeled (in the switched domain) or compared against the reference waveform output (in the average domain).

It should be noted that TPs and PCs likely do not perform all these studies in their planning assessments, and specific studies that a DP may perform are called out in the table. In general, DER integration studies are solely performed by DP's; it is unlikely that a single DER would have a significant impact on transmission reliability. However, the aggregate impact of large amounts of DERs should be assessed by a TP or PC. For the studies that impact the electrical service at a T-D Interface, coordination among the DP, TP, and PC is recommended (e.g., ride-through studies).

Table 2.1: Study Type Time Scales and Type of DER Studies

Evaluation Category in Study	Duration of Study	DER Model Domain
Distribution Provider		
Harmonics	Steady-state	EMT switched or phasor
Branch current, filter dynamics	Transient	EMT switched, EMT average
Current controller tuning	Transient and Steady-state	EMT average or phasor
Cloud cover response*	Steady-state	PSPD quasi steady state
Volt-VAR response*	Steady-state	PSPD quasi steady state
Adverse Control Interaction*	Transient and steady-state	EMT average, PSPD dynamic
Transmission Planner		
Dynamic VAR response*	Transient	PSPD dynamic
Ride through*	Transient	PSPD dynamic
BPS Contingency Response	Transient and Steady-state	PSPD quasi steady-state
Resource Loss Performance	Transient and Steady-state	PSPD dynamic, PSPD steady-state
PLL response*	Transient	EMT average

*denotes where potentially both a TP and a DP may study this respective to their system and identify cross-system impacts

Priority for Modeling DER Performance Characteristics in Transmission Studies

DPs should always perform DER integration studies to assess the impact of DER on the distribution system. When DER capacity as a percentage of gross load (i.e., DER penetration at the T-D Interface) is low, it is unlikely that TPs and PCs are performing any DER impact studies. However, it is important to understand the aggregate impact of DER in a TP/PC area even at low penetration levels as seen in the *DER Modeling Study: Investigating Modeling Thresholds*[24] findings. The referenced study evaluated the system level impacts of aggregate DERs; however, even at low system level penetrations the local impacts of DER rich areas should be studied. At low penetrations, DER can reasonably be represented in transmission level studies using broad generalizations of DER behavior (assuming independent operation). At significant penetrations, it is more important to represent the expected aggregate dynamic behavior of DER (including ride-through) and coordinate more closely with the distribution entities. At higher or extremely high DER penetrations, coordination among DPs, TPs and PCs is necessary to ensure proper ride-through, phase-lock-loop (PLL) response, and equipment behavior is accounted for in transmission studies. As part of the process, this may include outreach to DER owners or operators as well as other distribution entities to ensure the collaboration is successful.

[24] Study available here: https://www.nerc.com/comm/RSTC_Reliability_Guidelines/DERStudyReport.pdf

TPs should review the priority order[25] in **Figure 2.1** for inclusion of DER performance characteristics in transmission studies, based on DER penetration as a percentage of gross load. This list is intended to identify approximate penetration where particular DER performance characteristics may become highly important to the assessment of bulk system reliability; entities should strive to accurately represent DER in transmission studies regardless of the penetration level and not intentionally neglect accurate DER modeling just because the DER penetration level is below the thresholds in **Figure 2.1**.

Low DER Penetration (0-5%)	Accounting of DER Response in BPS Contingencies
Significant DER Penetration (5-15%)	Impact of Frequency Response
	Impact of Volt-VAR Response
	Impact of Ride-through Response
	Impact of DER Protection Response
High DER Penetration (15-30%)	Impact of PLL Control*
	Impact of Current Controller Tuning*
Extremely High DER Penetration (30-100%)	Assess Control Interactions*
	Long Term and Near Term BPS Stability Assessments

Figure 2.1: Priorities for Including DER Response Characteristics in Transmission Studies Based on T-D Interface DER Penetration

An asterisk in the figure above demonstrates that while there is a loose connection between penetration of DERs and short circuit strength, the impacts of DERs to that row are related to system strength rather than penetration of load served by DERs. TPs should validate if the DER composition in these instances would warrant such a study due to the system conditions rather than using this as a bright line.

[25] Higher penetrations in the figure indicate performing that row and all the above.

Chapter 3: Practices for Running Planning Studies

After identifying the overall planning structure impacts for including DER at a high penetration, the SPIDERWG developed recommendations for running transmission planning studies that include DER. The following sections summarize the provided guidance.

TPL-001 Planning Assessment

NERC TPL-001[26] serves as the standard to "establish Transmission system planning performance requirements within the planning horizon to develop a Bulk Electric System (BES) that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies" that is applicable to Transmission Planners and Planning Coordinators[27]. The sections below follow the practices associated with various components of the TPL-001 Planning Assessment and can be extrapolated to studies that are performed outside of this framework (e.g., regional transmission plans). Typically, most large planning studies include the following tasks:

1. Development of base case
2. Development of credible Contingencies
3. Development of scenario case(s)
4. Steady-state study
5. Stability study
6. Short-circuit study

Development of a Base Case

Base case development lays a foundation for assumptions to represent a set of agreed-upon conditions for the transmission system. Historically, these base cases look at more stressed conditions than cases built from operations[28], and as such are highly dependent on the engineering judgement and assumptions in the case. Historically, a peak loading conditions have been assumed to present the most stressed system conditions to determine if there were performance criteria violations (e.g. thermal overloads, voltage dip, and voltage recovery) that would necessitate any infrastructure upgrades. If equipment capabilities (e.g. thermal line ratings and bus voltage limits) were not exceeded[29] under peak load conditions, it was assumed that the system would be sufficient for all other loading conditions. Industry practice acknowledges that not all issues can be observed in a single case. NERC TPL-001 requires assessment of both peak and off-peak cases. With the proliferation of DERs, it is becoming increasingly challenging to identify the most stressed system condition and it may be necessary to evaluate additional system conditions beyond just peak and off-peak.

For example, the concept of peak load is significantly impacted by DER. A net peak load condition would represent the highest load levels expected to be served by the transmission system. A gross peak load condition would represent the highest load levels expected prior to adding any DER output (i.e. the load if there was no DER) to the load representation. However, under a transmission contingency, DER output could reduce or be tripped, requiring the transmission system to serve a higher load than expected for those periods and may lead to potential thermal overload, low voltage, or even voltage stability issues. Thus, multiple base cases (peak net load, peak gross load, high

[26] Available here: https://www.nerc.com/pa/Stand/Reliability%20Standards/TPL-001-5.pdf

[27] SPIDERWG has performed an extensive review of TPL-001 to ensure clarity regarding DER in the requirements. This is available here: https://www.nerc.com/comm/PC/System%20Planning%20Impacts%20from%20Distributed%20Energy%20Re/SPIDERWG_White_Paper_TPL-001_Assessment_and_DER.pdf

[28] There can exist the possibility that the operational case's loading would match the planning case within a 1 year time window. In future year cases, the load growth obviously would make the planning case's loading greater.

[29] What is considered an "exceedance" in the base case can be determined by an individual planning practice. However, the sentiment that no exceedance in the base case meant no exceedance for other loading conditions is common among the planning practices.

DER output, etc.) may need to be built to comprehensively evaluate BPS reliability. Concerning DER dispatch in the base case, the major assumptions that a TP should review are:

1. Time of day
2. DER output
3. DER control logic (enabled/disabled for each control)
4. Case dispatch

Table 3.1 provides some guidance on how the assumptions play out during base case development. It is anticipated that for a rigorous study, more than one base case is developed to capture diverse system conditions. To be clear, these would not be considered sensitivity cases to be compared to a base case without DERs[30].

Table 3.1: Base Case Parameters

Base Case Parameter	Dependence on other parameters	Anticipated Outcome
Season, Month, or Time of Day	This is typically set by the case description.	A TP or PC building a base case should pay particular attention to historic values that drive base cases and to choose a time of day that aligns directly with the base case description, which tends to be for specific seasons and desired outcomes rather than specific time values. For instance, it makes sense to choose a base case that intends to capture peak loading conditions between the hours of 1400-1800 hours for summer due to the amount of air conditioning load that arises during that time. It would not make sense to choose early morning (i.e., 0300) for a peak load base case.
Expected DER Performance	As solar PV is the most common DER fuel type, output is dependent on weather conditions and installation factors affecting their case dispatch	Since most of the DER is solar PV, most if not all the output can be estimated using average irradiance[31] as a guide. Should other types of DER be included, engineering judgement based on their historical or projected operational characteristics should be used for the DER output. However, the goal is to identify the ability of the DER to inject power at its nameplate, and as such, historical profiles for operating aid in developing the anticipated DER output. This is especially true for heterogeneous mixes of aggregate DER (e.g., Solar PV plus BESS).
Base Case Assumption Review	No	TPs and PCs should pay close attention to the area where DERis located and how their control logic is set by the regulators of that interconnection. This step also considers protections applied by DPs that may supersede DER ride through performance. This a case quality check or “sanity check” to not accidentally input incorrect parameters from other assumptions where those assumptions do not hold. Typically, IEEE 1547 vintage provides some insight to possible DER settings. However, many DPs are slow to adopt IEEE 1547 changes and many specify parameter settings that are substantially different than the default values provide as a guideline by IEEE 1547. Particular control logic parameters to pay attention to are voltage and frequency control settings and ride-through parameters.

[30] An exception may be for areas with little to no distribution-connected resources. However, note that a planning area can be inclusive of geographic regions with significant DERs and geographic regions with almost no DERs.

[31] TPs and PCs should not apply single-point irradiance time-series values to a large amount of PV generation. Geospatial diversity greatly smooths aggregate outputs.

Table 3.1: Base Case Parameters		
Base Case Parameter	**Dependence on other parameters**	**Anticipated Outcome**
Bulk Generator Dispatch assumptions	No	Historically, case dispatch was performed under a priority each generator had to be committed for that particular loading. A TP and PC should build a case determining the expected net load served by the transmission system rather than adding in DER output after a generator dispatch is set. This will most assuredly change the amount of bulk connected generation online in a base case under growing amounts of DERs. If DERs are considered a "must-take" resource[32] in their independent operation, they are not a candidate for being offline when determining the base case dispatch unless known to be unavailable for a given base case condition (e.g. solar PV for night time conditions).

Non-TPL-001 uses for Base Cases

There are other uses for these Interconnection-wide base cases outside of the TPL Annual Planning Assessment performed by TPs and PCs. As the Interconnection-wide modeling cases are built using MOD-032, that standard is not listed. Notable uses are listed in **Table 3.2** and can be supplemented by local reliability studies that vary in nature between planning areas. TPs and PCs should ensure that appropriate representation of DER be included in the studies associated with these uses.

Table 3.2: Base Case Uses	
Associated NERC Standard	**Description of Use**
CIP-014	Study the impact and loss of an entire substation to determine if any instability, Cascading, or Uncontrolled Separation occurs.
FAC-002	Study the reliability impact of new Facilities or qualified changes to a Facility
FAC-013	Assess and report the capacity transfers between Planning Coordinators
FAC-014	Establish and communicate any System Operating Limits
MOD-026*	Verify generator exciter or Volt/VAR controls in the model data
MOD-027*	Verify generator active power and frequency controls in the model data
MOD-029	Establish and identify System Path ratings
MOD-033	Verify the steady-state and dynamic representation of the Interconnection-wide base case using known event data
PRC-006	Establish and study the PC UFLS scheme[33]
PRC-010	Establish and study the PC or TP UVLS scheme[34]
PRC-015	Document and study the actions taken for a Redial Action Scheme
PRC-023	Study the impacts of transmission relay loadability
PRC-026	Identify Elements susceptible to large power angle swings
TOP-002	Study and establish an Operating Plan through an Operational Planning Assessment
TPL-007	Study transformer thermal impact of geomagnetic induced current from geomagnetic disturbances

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[32] This assumes that the DER is not controlled via a DER Aggregator or other entity that can curtail the output of the DER. Utility owned DER are more likely to be able to take dispatch orders and challenge the "must-take" nature of the case dispatch for that kind of DER. TPs and PCs should validate their dispatch assumptions, including what is considered "must-take" in their dispatch orders.

[33] SPIDERWG developed separate guidance on this topic available here: https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Recommended_Approaches_for_UFLS_Program_Design_with_Increasing_Penetrations_of_DERs.pdf

[34] SPIDERWG developed a white paper on this topic available here: https://www.nerc.com/comm/RSTC_Reliability_Guidelines/White_Paper-DER_UVLS_Impact.pdf

Table 3.2: Base Case Uses	
Associated NERC Standard	Description of Use
IRO-017	Assess, establish, and coordinate outages across Reliability Coordinators

* denotes that while DER would not be the focus of the study and the methods are not applicable, this line is included for completeness of non-TPL-001 uses of Interconnection-wide base cases.

Development of Credible Contingencies

After a base case is developed, the next stage in a planning assessment is the performance of contingency analysis. Contingency analysis consists of considering the loss of k elements out of the N elements in the model, typically referred to as an N-k contingency analysis. In TPL-001 studies, contingency determination and translation into the modeled elements are an important task; The following should be used to determine when to include DER in the contingency:

1. Quantity of nearby DER that can trip in response to the contingency[35]
2. Common mode failure of DER that can impact the performance of the T-D interface

The loss of DER may need to be included in steady state contingency definitions because the occurrence of DER tripping as a consequence of the system disturbance (i.e. failure to ride through) is more likely than DER tripping as part of the equipment that trips along with the element in the contingency (e.g. isolated due to fault clearing actions). However, identification of common mode failures that can trip large amounts of DERs (e.g., security compromise that affects 300 MW of DERs) can itself be considered a contingency, albeit an "extreme" one per TPL-001.

Sensitivity Case Development

Sensitivity cases are required per TPL-001 to vary a particular set of assumptions in the base case and determine how the set of credible contingencies perform under those more stressed conditions. Developing a sensitivity case is very similar to the base case development process; however, the TP and PC can highlight the various potential risks posed to their system through the variation of the system parameters.

Sensitivity case design should capture stressed conditions that the TP or PC believe are credible. In TPL-001, the sensitivity analysis requires varying specified conditions by "a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in System response". Thus, a 2% change in real load may be a credible and measurable change in a system's response to contingencies; however, it may not create a sensitivity that would stress the local area. TPs and PCs should develop sensitivities that highlight the impact of notable changes to the greatest extent possible. For example, it could be that 100 MW of solar PV DER growth is added into the base case constituting a valid sensitivity case. However, the impact of that change may depend on how it is modeled and parameterized. The TP or PC in this example should ensure that assumed DER performance is credible (parameters aligned with local DER requirements, etc.) Thus, for the purpose of developing a sensitivity case, the TP and PC are given ample flexibility to build sensitivities that sufficiently stress their planning area in a credible manner. When building this sensitivity, the following factors that can affect the performance of DER in simulation Should be considered:

1. Load distribution and composition
2. Transmission topology changes
3. Inertia of the system
4. Flows on major transmission paths

[35] Primarily for steady-state analysis as DER tripping response would normally be reflected in the DER dynamic model

By changing the above major factors, a TP can stress the impact of DER performance on the BPS in their simulation.

TPs should evaluate following sensitivity cases and develop the appropriate case(s) to match the expected reliability impacts associated with high DER penetrations:

1. **Peak net load (demand)** – this case aligns with historical pre-DER peak load conditions. The heaviest (for a certain percentile) net load seen by the grid.
2. **Light net load (demand)** – light gross load with high DER output. There are potential congestion issues, high voltage issues, and post-fault frequency and voltage performance concerns for this case. This sometimes can be referred to a "High Solar" case in the summertime or a "No Solar" case in the springtime depending on the DER composition. DER should be adjusted according to its expected availability in this light gross load/high DER output case. TPs and PCs can plot gross load against DER output to find historic conditions[36] in areas with significant DER penetration.
3. **Peak Gross Load with Expected DER output** – DER output would be based on its expected availability rather than the maximum possible output of all DER types. Since post-fault loading is expected to be higher due to higher demand in areas where DER fails to ride-through disturbances, overloads and voltage stability are a concern here.
4. **Peak Gross load with Highest DER output** – This case should have a net loading less than the net peak demand level as the DER output is maximum for all resource types[37]. High net demand could be experienced if a large amount of DERs are tripped post contingency leading to potential overloads, low voltages, or voltage stability issues. This could be a "High Solar" case given the predominant technology type of DER is solar PV. This DER case should not be duplicative with other "High Solar" cases but rather included in such case builds.
5. **Minimum Net load** – This light net load condition may be the worst case for high voltage or congestion issues. This condition may be impacted by DER growth; currently, most light gross load conditions occur during the night, so the primary DER fuel type (i.e., Solar PV) would not be producing power. Battery storage DER could be dispatched but these conditions are typically beneficial for battery charging. This condition could be a "No Solar, High BESS" scenario or could be a case where the solar PV is sufficient to serve all load on a given system, offloading the flows from the bulk system. These conditions are commonly associated with widespread voltage control issues as the reduction of bulk connected generation destabilizes the transmission grid. SPIDERWG highly recommends this condition to be studied for all TPs regardless of DER penetration.

Steady-State Simulation

Several steady state voltage and thermal issues could increase with DER growth. DER output reduces net load and masks gross load growth, but also could trip post-contingency due to ride through capability limitations. In addition, although usually equipped with voltage control capability, it is not practical for DERs to regulate bulk power system voltage. Because distribution and transmission voltage levels are most often decoupled by OLTC or feeder regulators at or near the T/D interface, it is not possible for DER to provide the bulk power system with steady-state voltage support unless a communicated control system such as DERMS are applied. If not studied and planned properly, the bulk power system might experience high voltage and issues when DER output is high, and low voltage, voltage stability, and thermal issues post-contingency due to DER tripping. This section highlights the details of the steady-state simulation considerations; more specific study methods are found in Error! Reference source not found..

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[36] This can come up when performing steady-state validation as recommended in past SPIDERWG guidance. Available here: https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Reliability_Guideline_DER_Data_Collection_for_Modeling_and_Model_Verification.pdf

[37] It may be unlikely for ALL resources to be operating at maximum power output as some DER batteries are likely charging, some may be switched offline by the homeowner, etc. However, it may be a valid sensitivity to study for situational awareness if there are no explicit controls in place to prevent this condition. Since solar PV is the largest fuel type, it is likely that the two peak gross load conditions are very similar and only one may be needed.

High DER output levels could complicate thermal studies for either load-supply reliability issues or generation congestion issues. In a pocket which has lower net load combined with high output from transmission-connected baseload generation (e.g., wind, solar, nuclear, coal, etc.), congestion issues could occur. If a reduction of generation is needed to reduce the congestion, transmission-connected generation will typically need to be curtailed or a transmission upgrade enacted (through a Corrective Action Plan) due to the lack of DER output control. In these scenarios, the aggregate DER output could also reduce or some DER could trip following transmission system disturbances. This may increase the net load served from the transmission system causing potential thermal overload, low voltage, or voltage stability issues outside of typical congestion. For such studies, gross load is the primary factor that affects voltage stability,[38] but pre-contingency net load magnitude is also important as it can affect the status of voltage supportive equipment and thus determines if transient low voltage could happen post-contingency.

When DER output is high and offsetting the load that would be served from the transmission system, flow into this part of system may be reduced. This can potentially cause congestion issues in the other parts of the system or high voltage issues due to switched capacitor banks anticipating higher flows into the distribution system which may require a modification to capacitor switching practices.[39] For contingencies that trip DER or reduce DER output, thermal overloads could happen.[40] For these studies, gross load[41] is the primary key factor that drives flow and for any potential thermal overload. During conditions that trigger DER tripping load could also be tripped and offset the impact of DER tripping and potentially result in a non-overload post-contingency operating state. TPs should consider initiating causes that trip just DER against those that could trip both DER and load to identify the most stressed condition for their thermal assessment.

Thermal impacts of DERs that can be assessed by steady state studies include:

1. Facility overload (e.g. potential overload due to net load increase due to DER tripping after contingency)
2. Reverse power flow (potential thermal overload in reverse direction)

Voltage impacts of DERs that can be assessed by steady state studies include:

1. High voltage issue during light net load conditions
2. Low voltage caused by tripping of DER or reduction of DER output
3. Steady state voltage stability issue.

When integrating high penetrations of DER into the active power-voltage (PV) and reactive power-volage (QV) analysis, the transmission planner should ensure that the load composition is accurately represented and altered for lower voltages. An important parameter to pay attention to is the powerflow software's alteration of load values as voltage lowers, which is a true steady-state phenomenon for non-converter connected electrical motors. The

Key Takeaway

Alterations to load values under low voltage in order to achieve simulation convergence has historically aided in the ability for transmission planners to accurately identify steady-state stability. Such alterations should be disabled for high DER penetration.

[38] This is due to the relationship of active power and voltage as well as reactive power and voltage, typically called PV and QV analysis. Available information here: https://research.ijcaonline.org/ncipet2013/number5/ncipet1387.pdf

[39] Note that capacitor switching practices are generally seasonal for many areas and moving to inter-day switching may reduce the lifecycle of the switched capacitor. Such considerations should be covered when identifying such modifications.

[40] Other reliability issues can happen as well during this tripping; however, steady-state analysis is more concerned with identifying a stable operating point exists post-Contingency opposed to identifying the specific trajectory it takes to reach the new operating point.

[41] Assuming gross load also doesn't trip during the simulation.

parameter[42] is a voltage setpoint in the powerflow solution software for load buses that will alter the constant power representation of the load and convert it to a constant current or impedance representation below the specified voltage. As most software adds DERs as part of the load record, it is important that TPs review how this parameter affects the Pgen output of the DER portion of the record. These parameters are not sufficient to represent the behavior of DERs as the performance of DERs under sustained low voltage is not the same as its load counterpart. However, both aggregate DERs and load in the post-disturbance steady state should be accurate to the expected online equipment for that disturbance. TPs should accurately depict the low voltage logic of their DERs and load. One way to do so is to regularly (e.g., annually) perform Contingency updates based on the tripped DERs and load from a stability stimulation and verify that if that equipment is expected to stay offline till the next steady-state solution. If so, the TP should update the steady-state Contingency to reflect that condition. Based on the above points, TPs should perform the following actions:

1. Accurately represent low voltage and high voltage ride-through of DERs in their steady-state studies.
2. Study a sensitivity case where the deviation of net flow between the base case and the sensitivity case is high for areas of high DER penetration.
3. Ensure that the simulation's altering of load under low voltage for convergence does not alter DER injection in their steady-state studies and should consult their software vendor if necessary.
4. Update[43] their Contingency definitions to account for DER tripping response (utilizing known or expected DER performance – possibly based on results from stability studies. TPs should:
    a. Prioritize the areas with high penetration of legacy DER or where distribution utility practices would increase the likelihood of DER tripping due to a Contingency.
    b. Update their Contingencies based on their stability studies where tripping of load or DER is shown to have extended into the steady-state period. This should be done with load as the intent is to not hold load and DER to different modeling fidelity and to not duplicate work.

Stability Simulation

This section highlights the impacts of DER on stability simulations; more specific study methods are found in Error! Reference source not found.. Higher penetration of DERs can have various potential impacts on system dynamic stability, including:

- Contribution to Fault induced Delayed Voltage Recovery (FIDVR) due to tripping or momentary cessation of DERs following system disturbances.
- Adverse impact on frequency stability due to replacement of resources that provide frequency response with DERs[44]
- Widespread resource loss due to inadequate voltage or frequency ride-through capability of DERs

Increased DER penetration on the grid has made potential impacts from DER more relevant to dynamic studies. The impact of DERs on BPS angular, voltage, frequency or small signal stability should be assessed. A comprehensive dynamic analysis may require assessment of multiple sensitivity cases including high and low DER output at various load levels.

In transient dynamic assessments, aggregate DERs should be modeled explicitly and not netted with substation load. Further, they should have a properly parameterized model to represent installed or expected equipment behavior

[42] The name of this parameter changes based on specific powerflow software chosen for the steady-state study. For example, in PSS®E, the name is the "PQ breakpoint", in PSLF the name is "Load model minimum voltage", and in TARA, "Low voltage threshold to scale load down".
[43] At a minimum, TPs should perform the update annually.
[44] DERs can be designed to provide frequency response. However, the majority of existing DERs don't provide frequency response.

for large signal disturbances. DER voltage and frequency protection settings should be modeled.[45] When studying FIDVR, particular attention to the load components in the composite load model should also be considered.

Contingencies in Annual Planning Assessment (TPL-001) that should be considered include:

- Event for loss of DER capacity. Some cyber-based contingencies[46] may equal to 1-2 times the largest generator. Other physics or topological contingencies include normal BPS faults.
- Contingency type P3 modification such that the initial condition shall consider reduced DER capacity (i.e. cloud cover) followed by system adjustment and a subsequent contingency event.

The following factors should be considered in selection of fault location in dynamic studies:

- Testing 3PH and SLG events to assess DER ride-through performance.
- Applying faults near substations with high and low DER penetration.
- Applying faults that create large-area voltage depression.

When assessing dynamic analysis results, active and reactive power output of DERs, system bus voltages, and transmission line flows should be monitored to compare the trajectory and calculate stability margins for a TPs system. A known complication of DERs in the dynamic stability realm is the susceptibility to coincide with single phase motor stalling, as most retail scale DERs (R-DERs) are single-phase connections. A transient dynamic assessment that captures this interaction may require a three-phase simulation, EMT analysis, or other benchmarking study to confirm the results of any positive sequence dynamic study.

Further, small signal stability and low frequency inter-area oscillation analysis should be enhanced to include the impact of DERs. At the Interconnection-wide study level, the inter-area oscillatory impact of DERs should be studied to identify any of the oscillatory mode shifts and changes to known system interactions. As this study is typically more specialized than any one TP's planning area, it is likely PCs or Regional Entities may have a "special studies" team identify oscillatory model shifts. However, the small signal stability of a TP's system is important to assess as penetrations of DERs grow. As such, the TP should perform eigenvalue analysis to assess whether their system is stable. The linear analysis can be performed on the BES integrated with DERs with varying operating conditions and corresponding eigenvalues can be obtained from the system state-space matrix. As the penetration of DERs increase, the system's poles move towards the right half of the s-plane and make the system small-signal instable.

DERs are required to have islanding detection technology per requirements in IEEE 1547-2018 equipment standards that require DERs to not energize into an island. The standards do not specify how such functionality is implemented and thus there are a wide variety of schemes, most proprietary. However, many of the most common schemes are effectively "power system de-stabilizers" as their role is to drive distribution islands into voltage or frequency instability in the case that connection to the BPS is disrupted. The impacts of widespread penetration of such functionality across the BPS are not known and should be the subject of future investigation.

Based on the above, TPs should enhance their stability simulations to capture high DER penetrations by:

1. Ensuring DERs are not netted with load representation in their stability simulations and use proper frequency and voltage trip parameters to capture expected equipment behavior.

[45] The DER_A model has some trip settings included. However, other dynamic models are available such as VTGTPA or FRQTPA models

[46] While novel, these types of contingencies can occur through an OEM's compromised facilities. Presentations to the SPIDERWG have demonstrated large areas of a TP footprint can be a single OEM for DER inverter equipment. SPIDERWG presentation is available here: https://www.nerc.com/comm/PC/System%20Planning%20Impacts%20from%20Distributed%20Energy%20Re/Studies%20-%20NERC%20SPIDERS%20Challenges%20with%20Integrating%20Renewables%20-%20Bialek.pdf

Varying the depth and type of BPS faults to assess the ride-through performance of their DER in high penetrations of DER. The TP should ensure phase-to-phase interactions are benchmarked against a beyond positive sequence method to ensure their positive sequence representation is appropriately depicting this ride-through.

2. Ensuring and participating in their PC or other Regional Entities team studying the impact of wide-spread DER integration and subsequent inter-area oscillatory mode changes. These studies should focus on DER penetration, mode frequency, mode damping ratio, and mode shape changes.
3. Performing a small-signal stability study that assesses the stability of aggregate DER in their system. This study should focus on areas of the TPs system that includes high-IBR penetration at the bulk level and with high DER penetrations.

Further, TPs should update their contingency definitions used in the steady-state studies if the stability simulation shows a portion (or all) of the DER trips during the study. This recommendation can also be performed for the gross load that trips offline and does not expect to be returned to service by the end of the stability simulation.

Short-Circuit Simulation

Short-circuit studies historically assume a 1 p.u. voltage at generator terminals, determine the sequence components of the system and surrounding area, and calculate the available fault current for the types of faults (e.g., single line to ground). In recent studies, these assumptions are challenged, especially with close-in single line to ground faults on the distribution side of the substation.[47] The available fault current is heavily impacted by transformer winding configurations, grounding, and in the case of distribution systems, the quantity and size of motor loading close to the study area. While the models are system dependent, the goal is to assess the effect on system fault currents from DERs (and other sources of fault current), identify underrated breaker equipment, and propose upgrades to equipment where underrated.

The models themselves can be linked to the MOD-032 data requests jointly decided by the TP and PC for the area; however, the following should be addressed via modeling information or engineering judgement at the T-D Interface:

- Transmission to Distribution (T-D) Transformer winding configuration
- T-D Transformer sequence impedances
- T-D Transformer grounding resistance
- DER capacity to deliver fault current[48]
- The lumped circuit equivalent (including sequence components) for the distribution system

Entities performing a short circuit study involving areas known to have a high penetration of DER should include the fault current contributions from the aggregate DER and load from the distribution system to evaluate the required interrupting capability and breaker duty for nearby bulk connected breakers. SPIDERWG has found that these breaker duty impacts are typically only in areas of significant DER penetration due to the DER's electrical impedance to the fault, largely affected by the number and winding configuration of transformers from the DER terminals to the transmission system. Further, the following should be added as a method to evaluate if the "correct" amount of generation is "online" (and thus able to provide its fault current) in the case:

1. Determine the gross loading of the system and the area where the study is being conducted.
2. Determine the DER dispatch in that area.

[47] As seen in: https://ieeexplore.ieee.org/document/10078461

[48] As the DER definition used by SPIDERWG can include synchronous facilities, such facilities would supply greater amounts of fault current than current-limited inverter-based DER.

3. If the net quantity is 95% or less, account for the DER by performing one of the following modifications:
    a. Lower the quantity and location of bulk-connected sources.
    b. Add a generator record representing the aggregate DER behind the T-D transformer.[49]
    c. Assume that the fault interrupting capability will be higher by an increased margin as well as source technology that can interrupt lower fault currents in the same time required for the breaker action.

The above steps are assuming that the majority of DER will not provide high amounts of fault current for these studies; however, should there be significant penetration of synchronous DER sources, this assumption will likely not work. For these instances, treat the DER as a generation source capable of delivering significant amounts of fault current in the breaker studies. In general, as DER penetrations rise in each area, the assumptions around short-circuit studies (e.g., the 1p.u. voltage of all generator sources) should be reviewed to assure the adequacy of the study assumptions. Presentations to the SPIDERWG[50] have indicated that high PV penetrations on the distribution grid have not resulted in wide-spread protection coordination misoperation but rather indicated local areas that need enhancements to account for the impacts DER on relay operating times. Short-circuit studies should identify the target interruption current and required duty of breakers for DER penetrations, which can include transmission upgrades to correct, and ensure that the T-D Interface is adequately protected and can interrupt the expected fault current. Due to this, TPs should perform the following:

1. Ensure their short-circuit models accurately reflect the fault current contribution and expected ride-through of DERs
2. Ensure their short-circuit models have the expected fault current sources "online" in the case. For some areas, this means turning offline bulk system generation[51] under high DER penetrations and comparing to the case where no DER is online and all fault current comes from bulk system generation.
3. Ensure that all operating modes of DERs are studied for their short circuit contributions as reactive power impacts the total current seen by relays, potentially resulting in misoperation of protection schemes in the most severe case.

EMT Studies with DER

The use of electromagnetic transient (EMT) studies to augment traditional transmission planning assessments has been increasing. These studies are typically focused on the performance of high penetrations of bulk connected IBRs and associated reliability impacts that may not be observed in traditional (positive sequence) stability simulations. Industry has not yet found a Brightline threshold for entities to begin including DER into EMT studies, but there are a few entities that have identified specific motivations for incorporating DERs into EMT studies. Motivations for including DER in these studies are:

1. Identification of interactions with other nearby IBRs
2. Identification of reliability impacts that may not be observed in traditional (positive sequence) stability simulations when high penetrations of DER connect to weak transmission grids.
3. Identification of inadequate positive sequence models for protection settings and ride-through capability for BPS disturbances.
4. Benchmarking positive sequence power flows and dynamic performance at the high side of the T-D Interface

[49] Note that this also would require representing that transformer and its sequential components in the study as well.
[50] One such presentation is available here: https://www.nerc.com/comm/PC/System%20Planning%20Impacts%20from%20Distributed%20Energy%20Re/Studies%20-%20SPIDERWG%20-%20Impact%20of%20DERs%20on%20the%20Protection%20of%20Distribution%20Systems%20-%20Salmani.pdf
[51] One example of how the penetrations may change day to day is the ISO-NE's Easter Day load curve in 2023. Their DER penetration rose to nearly 36 percent instantaneous penetration.

ISO-NE requires DERs of 1 MW or greater to notify ISO-NE that they are seeking to interconnect and to follow a queue process similar to the bulk-connected side.[52] Further, ISO-NE gathers information about currently in-service DERs from a voluntary survey.[53] Based on this information, ISO-NE uses the monitored load, DER capacity, and irradiance data to develop representative models of the gross load and DER. EMT studies are run on those models to assess the BPS reliability to the surrounding transmission system of the aggregate of all DERs seeking interconnection. Based on ISO-NE's initial work in this matter, there are a few lessons learned in the process. These include the following points:

1. In 2018, ISO-NE started implementing processes to have distribution utilities and TOs provide model data for DERs connecting to their systems for purposes of performing EMT reliability studies. These processes continue to evolve over time and require major collaboration among the distribution entities, transmission entities, and their regulators.
2. OEM-developed EMT models can contain the actual control code and inverter protections such as rate-of-change-of-frequency, overvoltage, undervoltage, vector shift, and phase-lock-loop loss of synchronism. Thus, the OEM-developed models should better reflect actual performance than an EMT model that uses generic assumptions about protection and control. However, the use generic EMT representations and assumptions is better than netting DER with the load.
3. ISO-NE collected actual distribution feeder data and used the data to create equivalent feeder models in the EMT simulation. As the number of buses increases in an EMT simulation, the computational burden rises exponentially. It is a common practice to reduce the number of buses via a mathematical equivalent model, and ISO-NE's process does not require explicit and detailed representation of approximation distribution systemin a transmission level EMT simulation that reflects the impact and interaction of aggregate DERs.
4. ISO-NE used conversion software tools to translate the positive sequence transmission network model to EMT domain. These tools ensure topology consistency between positive sequence and EMT models and facilitate a more efficient EMT case development process.
5. ISO-NE explicitly models the dominant DER (i.e. largest MW capacity) behind a T-D interface. Other DER(s) behind the same interface are generally assumed to perform similarly to the dominant DER with respect to impacts at the T-D interface.
6. EMT studies at the transmission level are still in early stages in most areas and it is a best practice to use a disaggregated representation to ensure that potential control interactions can be evaluated. However, it is best to prioritize efforts for transmission system representation and prioritize inclusion of bulk connected IBRs over the representation of DERs.
7. ISO-NE in their processes acts as a coordinator of studies performed by their Transmission Owners (TOs) or the consultants of the TO. SPIDERWG notes that running an EMT study will increase the number of man-hours spent on a project due to the complexity and trouble-shooting challenges associated with EMT simulations. Increasing expertise should provide some reduction in necessary man-hours over time, but EMT studies are significantly more labor intensive than traditional stability studies to perform.

TPs and PCs should review the above lessons learned and adopt those practices that are relevant to their area.

[52] The 1MW threshold is uniquely low in this regard. SPIDERWG anticipates that these DER facilities are not likely going to have similar success in providing model information throughout the NERC footprint. Coordinated distribution utility practices to gather the DER information may improve success.

[53] Collaboration with the TOs helps to reduce double counting from future in-service projects into the voluntary survey information.

Chapter 4: Interpretation of Planning Study Results

While not a widely discussed piece of the planning analysis, the planner's interpretation of the study results is fundamental to planning assessments. A TP should evaluate performance against a wide array of criteria review in their and not all criteria violations will be mitigated by DER-specific Corrective Action Plans (CAPs). This chapter details the stages of results comparison and development of corrective actions. It also summarizes the broad recommendations of the reliability guideline.

Comparison of Results to Established Planning Criteria

After completing planning simulations, study results are evaluated against a set of planning criteria to identify violations and determine corrective actions, if necessary. Some examples planning criteria[54] are:

1. Thermal overload exceedance allowance (e.g., 5% over emergency rate)
2. Thermal emergency rate vs. normal operational rate exceedances and duration
3. Voltage limit exceedance
4. Existence of instability, Cascading, or uncontrolled separation
5. Transient voltage dip and voltage recovery criteria
6. No project reduces its output, trips, or goes unstable due to the addition of another project
7. No generator unit goes out of step in the Interconnection

As seen above, there are criteria that would impact the reliable operation of the BPS (i.e., instability, cascading, or uncontrolled separation) and would thus require corrective action to ensure that the proscribed event no longer results in a violation of those planning criteria. However, there are other listed criteria that are specific to a planning practice and may instead trigger a more specific study to confirm no reliability impact. For example, if a few units exhibit out of step behavior and drive the simulation to instability, some planners will trip those units at the simulation time and see if instead the instability is corrected or any other adverse impacts are observed. In this instance, no CAPs would be developed but the contingency definition revised to identify that the unit(s) goes out of step when a particular BPS disturbance is applied and would need to be tripped in the simulation.

Other comparisons may require an EMT study to confirm the planning criteria violation (e.g., unbalanced individual phase voltage limit exceedances). At this time, EMT criteria are in-development and current best practices are to translate the positive sequence criteria into EMT domain. For example, voltage limit violations would be checked based on the three-phase root-mean-square value of voltage rather than instantaneous voltage.[55]

In addition, the historic planning criteria that dictates acceptable performance of load buses in the simulation have been developed in the assumption of serving gross load. As DER penetrations rise, this challenges the assumption that the planning criteria is effective in identifying reliability issues stemming from the load bus performance. TPs should ensure that their criteria, especially their voltage criteria at the modeled load buses, are applicable for various penetrations of DER and load.

Development of Corrective Action Plans related to DERs

If a CAP is required, there are a wide variety of technologies and solutions that can be considered. Simulation results with and without the CAP implemented should be compared to identify if the CAP accomplishes its reliability objective. In addition, the most comprehensive CAPs rank alternatives that can mitigate the reliability gap such that

[54] Specific thresholds and/or exceedance levels may vary based on the disturbance event severity.

[55] The protection modeled in EMT, however, would use this instantaneous voltage for performance. Criteria violations would use the derived three phase quantity.

a variety of solutions are studied. When Transmission planners may need to evaluate equipment upgrades on the distribution system as a potential solution for criteria violations related to DERs. Per IEEE 1547-2018, there are a significant number of frequency and voltage control parameters and operational modes allowable for the DER equipment. Transmission Planners may be able to identify a CAP that includes DER adherence to a certain set of parameters and/or modes mitigates the violation(s). As a best practice, TPs should consider the following questions when developing CAPs for assessments that involve interactions of aggregate DER on the bulk system:

1. Are instabilities associated with aggregate DER observed throughout the system or is it a single T-D Interface that experiences the problem?
2. Does the DER model quality[56] limit ability to implement the CAP on DER equipment?
3. Are there criteria violations that only apply to steady-state, dynamic, or short circuit study analysis?

Summary of Recommendations

While planning practices may differ between regions, there are common improvements that can be made to planning practices and studies to capture the impact of DER as its penetration grows. TPs and PCs should consider the following recommendations:

1. TPs and PCs should explicitly identify DER impacts to their steady-state, stability, and short-circuit assessments in their study reports and highlight if they contributed to any steady-state, stability, and short-circuit criteria violations. TPs and PCs should review **Appendix A:** and incorporate the study-dependent recommendations.
2. TPs and PCs should reflect expected dynamic reactive power performance of DER equipment in stability simulations. Dynamic injection and withdrawal of reactive power by DER during system disturbances can significantly impact study results.
3. TPs and PCs should account for appropriate levels of DER tripping in their steady state contingency definitions and properly reflect expected DER trip characteristics in stability simulations.
4. PCs should ensure neighboring PCs understand the settings of DER (i.e. share appropriate DER models through interconnection wide case building processes) in their system when coordinating their planning assessments. PCs should also ensure that any DER related impact is highlighted in this coordination of the planning assessment.
5. TPs should document any DER-related common mode of failure in their set of contingencies applied to planning assessments. (e.g., cyberattack, cloud cover) TPs should seek to improve their understanding of these common mode failures through studies.
6. TPs and PCs should review their planning criteria to ensure that it is accurately flagging areas of risk under increasing penetration of DERs. TPs and PCs should choose relevant criteria[57] for their area and refine such criteria for the impact of growing penetrations of DERs in their transmission simulations as found in the **Impacts from High Levels of DER on Transmission Studies** section.
7. When developing Corrective Action Plans, TPs should ensure that the action taken in the plan solves the root cause of the issue and such actions clearly identify how growing DER penetration can impact the plan's viability.

[56] Aggregate DER poor model quality arises from inaccuracies and limitations from the data informing the DER model parameters. In poor model quality cases, CAPs should not be focused on the DER equipment but rather on transmission system investment. It is desirable for CAPs to not be derived under poor quality models.

[57] TPs and PCs should not view the growth of DERs separate from the need of revising their planning criteria. As DER percentage increases, TP and PC planning criteria should be revised to accommodate risk posed by the rising DER penetrations.

Appendix A: Type of Studies and How to Incorporate DER

While the chapters above provide high-level guidance, for the typical studies performed in a transmission planning department, this appendix will walk through specific study objectives and practices to explicitly integrate DER in the study methods, results, and analyses.

Specific Steady-State Study Methods

This following section provides the set of guidance for performing steady-state studies. Each study typically uses a base case specialized to the study and the SPIDERWG recommendations for the base case, methods to study, and recommended solutions to inadequate performance are listed for each specific study.

High Voltage Issues during Light Net Load Conditions due to DER

High voltages on the BPS will generally be observed due to a combination of low loads, lightly loaded lines, and generation and voltage support resources that have reached their VAR absorption capability limit. In addition, contingencies that trip a large amount of load and/or voltage control devices could drive voltage higher.

Each system configuration and condition may be unique. Thus, a wise approach would be to consider how each of the above would contribute to the system under study. The most obvious sensitivity to study would be lowest net loading. This may be the natural lowest loading that was traditionally studied (e.g. nighttime conditions where natural energy consumption was low). With heavy penetration of DER, lowest net loading could be the result of DER serving the load locally, such as during the afternoon on a mild spring Sunday, due to a large amount of solar DER and moderate gross load. The transition of lowest net load hour from night to daytime has already been observed in California,[58] while in other jurisdictions with high DER penetration, lowest net load during daytime has approached lowest net load level during nighttime.

From a load perspective the natural lowest loading condition (likely at night) and DER-driven lowest loading condition (which may be the middle of the day for a PV dominant system) may appear to be equivalent, but there is an important distinction such as where the resources and load are located and thus where the power flows; this is the key to thinking about the load as either ‘gross’ end user load, or ‘net’ load as served and observed by the transmission system. In a system where there is very little or no DER, gross and net load are about the same; in a DER heavy system (especially if dominated by PV) gross and net load can be very different depending on the time of day. In the no DER condition the lightest load may occur at night but be served by centralized resources that utilize the transmission system, albeit lightly. In a DER heavy system a light load condition may occur during the middle of the day, but the utilization of the transmission system may be considerably different due to differences in net load distribution and generation dispatch. As a result, high voltage might happen in different parts of the system in these two conditions. Therefore, additional conditions might be considered to study these light net load conditions caused by DERs. Lightly loaded lines may produce VARs which will exacerbate high voltages.

DER are decoupled from transmission system steady state voltages by OLTC or feeder regulators at or near the T/D interface. Thus, even for DER having voltage regulation capability (“volt-var function”), there is no transmission voltage regulation provided. Transmission-interconnected resources are required to provide dynamic reactive power support within the range of +/- 0.95 power factor at the transmission voltage side of the generator step-up transformer to comply with FERC Order 827. In addition, the NERC Reliability Standard VAR-002-4 requires BES-connected resources to operate in voltage control mode to maintain a specified voltage schedule as prescribed by the Transmission Operator. Further, DERs that may operate in voltage control mode are not likely to be directly regulating BPS voltage.

[58] Including when the drop of net demand hits negative in California. See here: https://pv-magazine-usa.com/2023/04/20/driven-by-solar-californias-net-demand-hit-zero-on-sunday/

Other factors that should be considered are distribution-connected voltage support devices and power factor of served load. Voltage support devices may have been installed to maintain appropriate voltage levels while accommodating high loads. Thus, shunt capacitors are likely more common than shunt reactors. Existing utility practices may have fixed shunt capacitors switched into service at the beginning of peak load season (e.g. May for a summer peaking system) and only turned off at the end of that season (e.g. October). This may result in more VAR producing devices online than are needed under conditions that were previously not contemplated. One such example would be a distribution system having their fixed shunt capacitors online during the summer for intended peak load conditions, but the transmission system may observe light net loading conditions as the DER (e.g., solar PV DER) output varies between zero and it's expected capacity. This may further contribute to high voltages in the distribution system and bulk power system due to that variation of DER output. A transmission study may only model these distribution system cap banks as a net MVAR, but care should be taken to understand that the aggregation of those values may not be driven exclusively by end user load (which may have an evolving pattern). The MW may be affected by DER, and the MVAR may be affected by voltage support devices that are relatively more fixed in nature. This means that TPs should ensure the proper equivalent distribution system load representation has the correct power factor that represents the reactive power switching practice for the season and time the case represents.

Base Case Recommendations

When studying high voltage issues in light loading conditions, a TP should include the following:

- TPs should model the lowest net load (either due to low gross load, or due to DER reducing net load, both conditions may need to be studied). TPs should consider the shape of DER and gross load to understand where this may occur.[59]
- TPs should model the lowest transmission line flows. These are likely correlated with lowest net load.
- TPs should review their transmission-connected shunt device statuses in the base case and confirm expected operation with field data.
- The modeled power factor of aggregate DER and load served should align with expected conditions at the T-D Interface.[60]

Assumptions

To study high voltage issues during light net load conditions, TPs should make the following study assumptions to capture the impact of high penetrations of DER:

- Distribution and Transmission shunt caps may still be on even when they ideally should not be. These shunt caps should remain on unless they have intelligent controls or there is a utility procedure to manually take them offline given specific conditions (e.g. time of day, year, loading, voltage, order).[61] The load that represents this distribution system should have a power factor reflective of the utility switching practices for seasonal reactive devices.
- Without better information, assume that DER will not provide any transmission voltage support and will operate at unity power factor.[62]

[59] High voltage may occur at either traditional light load times, or low net load times due to DER. Two cases should be considered; lowest energy activity (e.g. 3am when most people are sleeping and business are not operating) and lowest net energy delivery (e.g. the load as seen by the transmission system, likely at solar noon when PV DER are significant).

[60] SPIDERWG has guidance on model verification with respect to power factor. Available here https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Reliability_Guideline_DER_Data_Collection_for_Modeling_and_Model_Verification.pdf

[61] TPs should also note inconsistencies with utility practice and intended performance as a remedy for inadequate performance in developing CAPs related to this assumption.

[62] TPs should verify for each installation with distribution planning for how they maintain ANSI voltages along the feeders with DERs.

- Load power factor may be driven by shunt capacitors on the distribution system. Do not assume a fixed standard power factor. Gather historical data consistent with system conditions to be studied (e.g. noon on weekends). Use this data to better approximate load power factor.

Approach

TPs should study DER impacts to high voltage caused by light net load by incorporating the following method:

- Determine a typical gross load shape for the system under study (can be either system aggregate or can be more granular at a station level or somewhere in between). Do not include DER that may be embedded in a Distribution load forecast.
- Determine a DER output shape. If PV solar consider using historical data to shape, or if necessary, a "flat-topped" sinusoidal shape with peak at noon scaled to expected available power[63] and zero crossings at approximately sun rise and sunset.
- Scale the DER shape based on total installed capacity in the region to be studied and subtract from the gross load shape to find the net load shape; identify the DER output and gross load level at the lowest net load point.
- Perform steady state simulations for both pre-contingency and post-contingency for the lowest net load conditions.
- Include types of contingencies required by TPL-001 or other local planning criteria that would trip large amounts of load or voltage control devices, including generators that have been absorbing reactive power.

Potential Solutions:

To address the high voltage issues during light net load conditions, TPs should consider the following potential solutions when developing a CAP:

- Modify shunt switching practices
- Add voltage control devices on the transmission side of the T-D Interface
- Thorough coordination of voltage protection systems and control for post-contingency conditions
- In operations or planning, there have been mitigation measures that deal with high voltage by opening circuits pre-contingency. However, for high voltage issues caused by high DER output, this measure could be less desired, because it reduces the transmission redundancy, and therefore exposes the system with reliability risk (e.g., overload / low voltage / voltage stability issues) under contingencies that significantly reduces DER output and therefore increases net load (e.g., DER tripping). These risks were low when there was no DER but are higher with heavy DER penetration.

Low Voltage Issues Due to DER

Low voltage issues might be observed while DER penetration level increases. For areas with high DER penetration, higher DER output results in net load reduction, potential large-scale changes in generation dispatch,[64] and even local BPS-connected generation displacement to accommodate the increase in DER, which results in reducing reactive power resources connected to the BPS. As discussed in the High Voltage section, increased levels of DER output will cause net load reduction, which may lead to higher voltage profiles on the distribution network. In these cases, more shunt capacitors banks might be switched off-line to manage over-voltage under system normal (pre-contingency)

[63] Sometimes the available power and nameplate capacity overlap. The design of the solar PV array for a given location will determine its output shape which is not guaranteed to match inverter or panel nameplate. Engineering judgement should be used to determine the expected power available power for the season represented in the planning case.

[64] Significant reductions in net load could have BPS generating resources that typically run during daytime hours to be dispatched out-of-service, most notably being large synchronous generating resources with significant reactive power capability. These types of conditions will need to be carefully studied to ensure sufficient reactive reserves are maintained on the BPS.

operating conditions. In post-contingency state where DERs trip offline the system can then experience a low voltage condition (as the active power source no longer exists to prop up the distribution voltage). This is especially a concern where local reactive devices are unable to have automated switching for post-contingency use. The potential loss of local DER that is not expected to return to service post-clearing of the fault can thus lead to low voltages. To ensure a healthy voltage profile in areas with high DER penetrations, on-line status of existing capacitor banks and their switching logic (manual or automatic) should be properly considered.

Base Case:

TPs should, for studying low voltage issues, include the following for their base case:

- Model the expected highest gross load with high DER output displacing conventional generation. Consider the profile of DER output and gross loading to understand where this may occur.
- For pockets of the BPS with high DER output, reasonably model the expected least amount of local BPS generators on-line in that area (likely correlated with lowest net load) while respecting unit commitment, reliability must-run and spinning reserve requirements, and considering economic dispatch.
- Shunt device status should reflect expected operation: Normal voltage ranges should be met in the pre-contingency base case setup. Emergency voltage ranges should be met for N-1 and N-1-1 contingency conditions. Note that re-dispatch, including switching of shunt compensation and any automatic actions, can be considered for N-1-1 contingencies in most cases.

Assumptions:

To study low voltage issues resulting from high penetrations of DERs, TPs should make the following study assumptions:

- To the extent possible, the steady state load-flow controls should be represented allowing transmission and distribution LTCs and switched shunts to toggle for system normal conditions with respect to their control patterns (daily, seasonally, etc.)
- Static shunt devices may have to be switched off if high voltage occurs during periods of low net load due to high DER output where other voltage regulating elements (generator, SVC, LTC, etc.) reach their voltage regulating limits. These should be configured in the pre-contingency base case but should not be switched post-contingency.
- Assume that DER will not provide voltage support.[65] If specific voltage capability information is known, use the specific information.
- Load power factor may be driven by shunt capacitors on the distribution system. Do not assume a fixed standard power factor. Gather historical data consistent with system conditions to be studied (e.g. noon on weekends). Use this data to better approximate load power factor.

Approach

TPs should study DER impacts to high voltage caused by high penetrations of DERs by incorporating the following suggestions:

- Aggregate DERs should be modeled explicitly (with or without feeder impedance).
- DER-specific contingencies: include loss of significant amounts of DER generation as either part of the contingency definition or consequential generation trip, e.g. NERC TPL-001 Planning and Extreme Events combined with DER loss after the contingency (assuming some portion of DER would trip due to under/over

[65] Most interconnection requirements for DER currently do not allow for or recommend the use of voltage control. Rather, most DER are currently set to provide fixed power factor operation. Refer to local interconnection requirements.

voltage or frequency); NERC TPL-001 P1.1 inclusion of contingent event for loss of DER capacity (i.e. cloud cover)

Potential Solutions:

To address the low voltage concerns above, TPs should consider the following potential solutions when developing a CAP:

- Modify shunt switching practices and adding more automatic functions where manual switching still exists/
- Add voltage control devices on the transmission side of the T-D Interface
- Thorough coordination of voltage protection systems and control for post-contingency conditions

Thermal Overload Studies

Thermal overload studies aim to determine if the total magnitude of current flowing through specific transmission elements is above a physically identified limit. In steady-state simulation, this includes looking at line loading that exceeds the emergency thermal limit. These limits can range between 15 minutes to multiple hours before the circuit needs to trip on thermal overload. Because operator actions to mitigate an exceedance would be assumed to take at least 15 minutes, a potential cascading effect should be analyzed by tripping the overloaded element and tripping subsequently overloaded elements until all overloads are below the emergency rating and can be assumed no further tripping occurs prior to operator actions. For non-cascading analysis, a single trip and the evaluation of redirected flow can show areas of the system that may need reinforcement. Upgrades are then proposed to mitigate against the total magnitude of current in that element, which could be a bus reconfiguration, new transmission line, or increasing the ampacity of the affected equipment.

A specific DER related thermal overload implication can arise under reverse power situations. When generation resources are large, centralized power plants serving gross load, the direction of power flow is from larger generation resources to load centers during all system conditions. However, with the electric grid resource fleet changing from predominantly centralized power plants to a mix of large centralized and smaller decentralized intermittent resources, largely wind and solar PV, the magnitude of the power transfer into the T-D interface will reduce as DER grows until a point where power may flow in the reverse direction. Additionally, in the absence of mitigation measures, the reverse power flow from the high DER generation can cause reliability issues on the bulk power system, including protection issues and widely varying voltage profiles. Thermal overloading conditions are a concern for transformers with primary voltage greater than 100 kV, as some transformers currently in the system may not have bi-directional power transfer capability.

The design of transformers is optimized for flow of power in one direction; as an example, for transformers with load tap changers, depending on the location of the tap changer, the transformer design is optimized to directly control the LV or HV voltage. Reverse power flow in a transformer with a tap changer forces the transformer to go into an indirect mode of voltage regulation. In extreme cases, this may cause transformer core saturation.[66] Another complication arises with relatively obscure transformers that have dual LV windings connected to different feeders. Having reverse power flow in one of the feeders causes the current in connected LV windings to flow in reverse direction. This will result in magnetic flux being concentrated at the core of the transformer instead of the edges, increasing the core losses.[67] Consequently, this can cause extra heating of the core and severe damages to the transformer. Proper transformer maintenance can limit the impact of the above factors but may require additional designed transformer steps and cooling to reduce the added stress on the transformer. For TPs, the T-D Interface's transformers are not typically included for bulk system performance; however, the potential to overload the

[66] A common rule of thumb for what reverse power flow can cause transformer core saturation is 60% current for a three-winding transformer.
[67] See here for an impact on reverse flow from the distribution system:
https://energycentral.com/system/files/ece/nodes/463672/der_reverse_power_flow_impacts.pdf

transformer from DER can present needed reinforcements to ensure the transformer does not trip offline in abnormal system conditions.

Base Case and Sensitivity Case Development

TPS should begin development of a base case to study the thermal impacts of increasing penetrations of aggregate DER by focusing DER modeling efforts on areas that contain low gross load and high DER output. This case should also include other bulk-connected generation that can exacerbate flows on the local BPS network.

Assumptions

TPs should make the following generic assumptions when studying the thermal overload impact of high penetrations of DERs:

- The TP's load modeling should use gross load and use the most up to date steady-state active power representation.
- TPs should have their DER modeled explicitly and output should be selected consistent with the snapshot hour that the base case represents using a DER production profile. TPs should assume no additional active power is reserved as headroom.
- The TP's load power factor control device settings should reflect realistic in-service equipment control practices.
- DERs should use power factor control and be set to unity power factor unless other known distribution utility practices or interconnection requirements dictate otherwise.
- Both the BES and non-BES equipment maintenance outages should be represented in the base case. Sensitivity cases should assume deviations from known maintenance schedules.
- Transmission facility ratings should be consistent with the snapshot hour that the base case represents.[68]
- Intermittent resource dispatch should be consistent with the snapshot hour that the base case represents. Conventional resources should be dispatched based on the merit order if needed to serve load and/or satisfy unit commitment practices. Sensitivity analysis can elaborate on potential reliability risks when intermittent resource dispatch is higher than expected.

Approach

TPs should use the following method when conducting a thermal assessment analyzing the thermal impact of high penetrations of DERs:

- Perform power flow analysis for sensitivities that have high DER penetration during low load conditions and monitor flows for potential reverse power flow and facility overloads.
- Consider potential tripping of facilities by protection systems and automatic controls due to reverse power flow.
- Lastly, ensure that if the entire gross load was online with no DER penetration as well as the converse (no gross load and all DER) the T-D Interface would not surpass the ampacity of the BPS equipment (i.e., the transmission side of the T-D Interface).

[68] For example, ratings like high wind-speed ratings, which are only valid for certain hours of the day, should be removed if the net peak hour is outside of that window.

Potential Solutions

Potential solutions for reliability concerns resulting from thermal overloads driven by high DER penetrations are varied, but generally include involve increasing the ampacity of specific equipment or taking post-contingency action to alleviate the overload. The following potential solutions should be considered by TPs when developing CAPs:

- **Upgrading transmission and sub-transmission facilities to accommodate aggregated reverse power flow from DERs:** Sub-transmission facilities and protection equipment can be upgraded to accommodate the additional amperage requirements resulting from added flow from the aggregate DER. However, this solution is costly and not always feasible[69].
- **DER generation limits at planning stage of new connection of DER:[70]** As part of the planning procedures to interconnect new DER, the DP can assess the impact of new connection of DERs on reverse power flow capability of transformers. In some areas, the TP can also perform this assessment to study the bulk system impacts of the aggregate DER in addition to the DP's assessment. To make sure the reverse power flow limits are not violated, the DP or TP can limit the generation until upgrades can be made. These generation limits should be established based on the maximum reverse power flow limit of transformers and the minimum station load. By doing this, it is assured that the reverse power flow limits are not violated during high DER generation and low load condition.
- **Re-assessment of the limits:** As the thermal limits are generally mitigated by transformer cooling or ambient conditions, the TP can instead re-evaluate the thermal limits to identify if the exceedance would create adverse conditions. Further, specific entities may elect to enhance their transformer replacement schedules rather than invest in upgrades for temporary post-contingency overloads. These nuances will surface in a re-evaluation of the thermal rating.
- **Special protection schemes**: In other situations where generation is connected to a transmission line that serves a T-D interface with high amounts of DERs, a special system configuration might result in a major change of power flow beyond the level normally seen in a station with DERs. In these specific instances, a special protection scheme may be able to directly trip BPS generation or reconfigure the transmission system to accept the changes in power flow.

Specific Transient Dynamic Study Methods

The following sections detail specific studies performed to assess the transient dynamic behavior. Dynamic transient studies evaluate system behavior during and after normally cleared or delayed cleared transmission faults. This entails appropriately representing voltage and frequency trip settings[71] of DER in the transient dynamic simulation so that the reliability impact can be evaluated. These sections may not constitute the entire amount of transient dynamics studies that may need to be performed, but the methods here should be adopted when studying the impact of high penetrations of DERs.

Angular Stability Studies

An increase in DER penetration could displace existing synchronous machines, thereby lowering the reactive support from these conventional units and affecting the critical clearing times. Reduced reactive power support, and/or increased transfer of reactive power over longer transmission paths can lead to a larger difference in voltage angles across transmission areas. This larger difference in the angle would reduce the amount of available synchronizing torque and thus could affect critical clearing times. This effect is like the light load condition under which many conventional resources are not committed. Thus, increasing DER penetrations may reduce the available synchronizing

[69] Use of reverse power flow protection relays can be considered as a lower cost mitigation measure. However, the operation of these relays should be coordinated with other protection facilities, and some areas do not allow for complex control programs. When the complexity increases, so does the study requirements to ensure the complex scheme accomplishes the protection objective.

[70] It should be noted that these limitations can be alleviated with upgrades to improve the bidirectional ampacity of the system.

[71] While a tuning exercise may not be beneficial for DER that are already in service, it could help set specifications for future DERs that might interconnect to the studied portion of the system.

torque in the system. This can be exacerbated by tripping of a large cluster of DERs due to nearby faults or faults that cause wide area voltage depression.

The impact of transmission faults on DERs can vary depending on the due to variations in voltage across the distribution system. The DER voltage and frequency trip fractional settings of the aggregated model should reflect expected DER behavior. Individual distribution utility interconnection practices will largely dictate the voltage and frequency settings of the aggregate DER.[72] The relative dispatch of the bulk generation and the DER generation affecting transfers across the system are the most significant factors in evaluating angular stability.

Base Case and Sensitivity Case Development:

In areas of high DER penetration, the study case should use dynamic composite load models and the aggregate DER dynamic model.[73] Each TP should ensure DER dispatch level and the enabled control features in the base case and sensitivity case reflects DER capabilities for the study under consideration. For example, since the highest demand or load output may not coincide with the DER max output, TPs need to decide the appropriate load levels and DER output that meets their study condition for angular stability. The key dynamic model parameters for DER in running transient stability studies are the active power-frequency control settings, reactive power-voltage control settings, current and voltage limit settings, ride-through settings, and trip settings.[74] Angular stability studies largely will use the same parameter focus to evaluate the impact aggregate DER has on the "stiffness" or stability of the voltage angle. Sensitivity analysis on the case should be performed if the DER causes transient voltage recovery violations, frequency deviations, and damping or oscillation violations according to the local planning criteria as small signal instability may come into play for certain areas of the BPS.

Assumptions

Based on the needs for an angular stability study, TPs should not assume parameters where information is available. Rather, the SPIDERWG encourages TPs to initiate active coordination and information seeking on the distribution utility practices and interconnection procedures to reflect the DER impact to the T-D interface modeled in the TP's transmission system models. Where information does not exist to parameterize the aggregate DER model, TPs should review the *Reliability Guideline: Parameterization of the DER_A Model for Aggregate DER*[75] for relevant parameter assumptions and engineering analysis. Further, TPs and PCs should assume that there will be no headroom available for angular support on the aggregate DER model and the TPs should take the recommended outcome from the *Model Notification: Dispatching DER off of Maximum Power During Study Case Creation,*[76] with the relevant outcomes reproduced below in **Figure A.1**.

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[72] See SPIDERWG reliability guideline that promotes adoption of 1547-2018 as to why these settings are important to have listed in distribution utility practices. Available here: https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Guideline-IEEE_1547-2018_BPS_Perspectives_PostPubs.pdf

[73] The NERC SPIDERWG reliability guideline on this is available here: https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Reliability_Guideline_DER_A_Parameterization.pdf

[74] These settings are largely available for modern smart inverters. Other parameters to consider are the inverter capacity and overload ratings as well as any ramp rate or recovery parameters from older style inverters.

[75] Available here: https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Reliability_Guideline_DER_A_Parameterization.pdf

[76] Available here: https://www.nerc.com/comm/PC/NERCModelingNotifications/Dispatching_DER_Off_of_Maximum_Power_during_Study_Case_Creation1.pdf

Powerflow	Dynamics Model P-F Controls	Outcome
$P_{gen} = P_{max}$	Enabled	No action needed.
$P_{gen} = P_{max}$	Disabled	No action needed.
$P_{gen} < P_{max}$	Enabled	Need to ensure correct dynamics model parameters selection.
$P_{gen} < P_{max}$	Disabled	No action needed.

Figure A.1: Relationship of Powerflow Dispatch to Dynamic Parameterization of Aggregate DER Model

Approach

TPs have no additional specific methods to study the angular stability of aggregate DERs. Rather, the SPIDERWG asserts that the common engineering fundamentals for angular stability at higher penetrations of DERs are maintained as it pertains to the needs of the transmission system. That is, no voltage instability should exist that collapses a portion of the system in the transient dynamic domain.

Potential Solutions

TPs should review the following additional potential solutions when developing CAPs that mitigate against violations of planning criteria from angular stability studies:

1. Synchronous Condenser in areas of the transmission system that require hardening of a voltage angle separation.
2. FACTS voltage control devices to allow for direct control in the transmission system where angular separation occurs
3. More robust DER ride-through for areas where the aggregate DER tripping creates angular instability of the local area.

Transient Voltage Studies - FIDVR

Fault-Induced Delayed Voltage Recovery (FIDVR) is a phenomenon that occurs due to stalled AC induction motors subsequent to a fault causing very slow post-contingency voltage recovery (sometimes several seconds below 0.9 p.u. until loads are tripped and/or injection of reactive power). Some inverters have superior voltage and frequency ride through capabilities, lower thresholds for momentary cessation, phase jump ride through capabilities, active power-frequency control, potential fast frequency response capabilities, reactive power-voltage control, current vs voltage limits, fault ride through, and return-to-service capabilities. These are all functionalities that DERs can deploy to possibly help mitigate FIDVR. A composite load model that accurately reflects load behavior and the aggregate DER response to the voltage profile on the distribution feeder should be used to study the phenomena.

In general, additional voltage sources that can ride-through the fault and the FIDVR conditions will improve the voltage profile of the simplified distribution system. Such support mitigates the depth of the FIDVR conditions, requiring less reactive power support to boost the local bulk system voltage, and allows for greater motor start support from the bulk system. In instances where aggregate DER provide reactive-power voltage control, this effect can be greatly improved.

Base case and Sensitivity Case Development:

In areas of high DER penetration, the study case should use dynamic composite load models and the aggregate DER dynamic model. DER dispatch should reflect conditions coinciding with a high percentage of 1-phase motor load as those motors generally cause FIDVR conditions. TPs should confirm voltage ride-through and other aggregate DER capabilities with their local distribution utility to ensure that they are reflective of installed equipment.

Assumptions:

Due to the nature of FIDVR, the TP or PC should make the following assumptions:

1. The aggregate DER will operate in P priority[77]
2. The assumed MW level of DER and percentage of motor load in the composite load model must coincide with a realistic condition.[78]
3. The transient voltage dip criteria is more important rather than the recovery criteria as the lower instantaneous dips are more prone to trip DERs that can support voltage during this time.
4. Older inverters and interconnections will trip near 0.8 to 0.9 p.u. voltage at its terminals. This assumption also holds true for newer DER interconnections where the distribution utility practice installs reclosing equipment in series with the DER facility such that the DER facility is tripped.
5. Model the DER tripping as more conservative (i.e., more trips in response) when the TP or PC is uncertain on the tripping quantity from its model verification procedure.

Approach

The reactive-current voltage control features of DER may help to speed up the voltage recovery in the area. If the percentage of motor load causing delayed voltage recovery is insignificant, it may be hard to gauge the effect of DERs during the FIDVR. The following method should be performed to determine future settings or parameters needed to reduce FIDVR.:

- Perform analysis on the base case and identify the voltage performance trajectories
- Perform sensitivity studies with variation of DER voltage trip settings to inform future settings
- Perform sensitivity studies on impact of DER P-Q priority logic
- Perform sensitivity studies on impact of DER dynamic voltage support
- Perform sensitivity studies on impact of active power-frequency control versus reactive power-voltage control
- Identify CAPs in a comparison basis with the sensitivity results compared against the base case.
- Note which particular aggregate DER control logic change has the most impact on the effectiveness of the CAP.

Potential solutions

In addition to installing voltage support devices on the transmission system, PCs and TPs should identify particular DER inverter functionalities to mitigate the FIDVR event.

Frequency Response Studies with DER

Increasing in DER penetration could displace existing synchronous machines, thereby lowering the inertia needed in the system to reduce the rate of change of frequency. Frequency Response studies are intended to assess the ability of the system to recover from a sudden imbalance in resources and load. While this most often comes in the form of a sudden loss of a large generator, it could also be due to a sudden loss of DER or increase in net load. There are three key metrics when considering the outcome of the frequency response study - the lowest frequency (the nadir) for under generation conditions, the time it takes for the frequency to stabilize within acceptable limits, and the rate of change of frequency (i.e. RoCoF). NERC has published a DER study[79] that identified that the aggregate DER impacts

[77] Alternatively, the TP can assume it will operate according to local distribution practices or regulatory requirements, if known.
[78] This is very important in order to obtain visibility of the effect of DER characteristics and its post-contingency behavior under low voltage.
[79] Study available here: https://www.nerc.com/comm/RSTC_Reliability_Guidelines/DERStudyReport.pdf

of the Interconnection's frequency response are typically alterations to the frequency nadir. In that study, the secondary frequency response impacts were not identified and did not look to increasing the capability of DERs to provide frequency response. TPs and BAs should also perform similar assessments that also include secondary frequency response impacts to fully capture the impact of aggregate DER.

The initial rate of change of system frequency depends on the total inertia of responsive resources of the entire electric power system, the magnitude of current injected by these resources, and the magnitude of the disturbance. With an increase in inverter-based resources that usually do not respond to frequency deviations, of which DER is largely comprised, along with retirement of synchronous generation, the responsive set of resources is reduced, and we may see a higher initial rate of change of frequency and correspondingly a lower frequency nadir following disturbances.

Most synchronous machines will have a speed governor which is equipped with droop characteristics. Following a large system disturbance such as loss of load or generator, the synchronous generators adjust their output through speed governors to match the system load demand. This is referred to as the primary frequency response of synchronous generators and it helps arrest the system frequency deviation. Synchronous generators that have available headroom can respond to provide primary frequency response in the up direction (for under-frequency events).

AGC (Automatic Generation Control), sometimes called secondary frequency response, is another mechanism to restore the system frequency to its nominal value after a disturbance. The inertial response and primary frequency response controls can limit the initial rate of system frequency decline and arrest the frequency deviation, but the settling frequency of the system is unlikely to be at the nominal level. To fully restore system frequency, the grid operator applies AGC to increase or decrease the output of generators or loads that provide regulation services. For high DER penetration conditions, a longer time for AGC to recover system frequency, or larger and longer frequency oscillations upon a disturbance may be seen. This can be primarily due to two reasons (i) if the same recovery time is expected, then as the set of responsive resources have decreased, each remaining resource would have to provide more magnitude of MW change (ignoring whether it is a MW increase or MW decrease) and this larger change in MW can results in an increased oscillatory behavior, (ii) if the same rate and magnitude of change is maintained, then the recovery time would be longer.

Much of these impacts are true for an increase in any non-responsive set of resources. It is generally assumed that IBRs are non-responsive resources either due to control design limitation or no available headroom. However, with proper control and coordination, IBRs may be utilized to provide frequency response to help maintain system frequency.

Base Case Development:

TPs and BAs performing frequency response studies of their areas should improve their base case development procedures by incorporating the following:

1. Base case generation dispatch should focus on the time or conditions in which the maximum amount of load is being served by inverter-based resources. For PV this is likely to be around noon and for wind this is likely to be late at night or early morning.
    a. This generation dispatch should also consider any existing loading order of resources with the insertion of DER as serving load with the highest priority in the loading order (i.e., assume DER as a "must take" resource)
    b. This generation dispatch should also first replace the frequency responsive conventional generators[80] prior to displacing any baseload generators when displacing bulk system generation with DERs.

[80] The dispatch should include and incorporate in-place operating processes or controls that ensure certain levels of frequency response.

2. The base case loading level should correspond to a minimum level of frequency responsive units. This may occur at a high gross load condition with high solar PV penetrations, such as a mild spring day in California.
    a. Under a high gross loading condition, it is possible that high penetrations of DERs (in other times of day) are not affecting the frequency response as the load responsive units counteract the effect non-responsive DERs have on the frequency performance. Absent any frequency sensitive load, high gross load conditions worsen the frequency performance with reductions of frequency responsive generation.

Assumptions:

As frequency response studies inherently are wide area studies,[81] the assumptions placed on the aggregate DER represented in the Interconnection-wide base cases (or other wide area case) are extremely important. SPIDERWG thus recommends TPs, PCs, BAs, and RCs make the following assumptions when performing a frequency response study:

1. Assume that the vintage of IEEE 1547 for legacy DER is the -2003 version of the standard unless there is known applicability of other requirements or 1547-2018 categories.
    a. TPs, PCs, BAs, DPs, and RCs will need to collaborate[82] to identify which Category of DER they should assume and the expected frequency ride-through of such equipment.
2. Assume no frequency response headroom is available from DERs,[83] even if the frequency regulation control logic is enabled.
    a. TPs, PCs, BAs, and RCs can challenge this assumption in areas where DER are controlled by a Distributed Energy Management System (DERMS) or if DERs are known to be participating in frequency response markets.
3. Assume that AGC will correct any frequency off-nominal settling point during the simulation.[84]

Approach:

TPs should review the following procedural enhancements to study the impact of increasing penetrations of DERs on frequency response studies:

1. TPs and PCs should perform a protection coordination study with their DPs (registered or not) to identify any protection limits that can reduce the primary frequency response in high DER penetration conditions.
2. TPs and PCs should study frequency response under both light loading and heavy loading conditions in their study.
3. TPs, PCs, RCs, and BAs should apply a comprehensive set of contingencies that are thorough and conservative in nature. These should include:
    a. Faults near T-D Interfaces containing large penetrations of DER of varying depths and durations,
    b. Bulk system faults requiring a distribution system configuration such that the DER push against a different T-D system, and

[81] This is because frequency is generally a shared quantity for all simulated nodes throughout an entire interconnection due to the nature of AC systems.

[82] SPIDERWG has guidance on the adoption of IEEE 1547-2018 available here: https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Guideline-IEEE_1547-2018_BPS_Perspectives_PostPubs.pdf

[83] See the model notification on this topic available here: https://www.nerc.com/comm/PC/NERCModelingNotifications/Dispatching_DER_Off_of_Maximum_Power_during_Study_Case_Creation1.pdf

[84] This is not a new assumption to these type of studies. Rather, SPIDERWG identified that this assumption is still valid in areas where AGC controlled bulk generation is still dispatched.

   c. Dependent failure modes that can affect aggregate DERs (e.g., wildfire, cyber attack, or other "extreme" event category per TPL-001)

4. TPs, PCs, RCs, and BAs should run their simulation long enough to ensure all impacts are captured (typically 20-30 seconds, but sometimes longer simulations are necessary) and results are recorded to compare against damping and recovery criteria

Potential Solutions:

Frequency response studies generally have a wide variety of potential solutions. With the growth of new technologies, new frequency response tools are available to provide frequency support. While it is noted that frequency support is not ubiquitous on every generation asset, it is the Balancing Authority's responsibility to ensure there are sufficient resources to arrest frequency declines and to regulate the frequency of the Interconnection. As such, TPs and PCs should coordinate with their BAs to determine the most appropriate frequency response tool based on the specific need. Some options the TPs, PCs, and BAs should consider are:

1. Requiring fast frequency response of transmission-connected generation or DERs
2. Increasing the frequency reserve requirement of generation facilities
3. Requiring frequency droop control on DERs
4. Installing or retuning (within mechanical limits) governors on synchronous facilities to provide additional or faster frequency response

Other Types of Study Methods

While not as common, there are a few special categories of studies that either need both steady-state and transient dynamic studies to accomplish their objective or use a different model representation than what is typically used in the steady-state and transient dynamic studies. This section outlines the recommendations that SPIDERWG has on these other study methods, including model validation or model tuning studies, that don't cleanly fall into steady-state or transient dynamic objectives.

Protection Setting Studies

Protection setting studies are performed to ensure proper (and minimized) isolation of grid elements in response to disturbances. These types of studies are generally performed with specific short circuit models of transmission equipment. Historically, these assessments do not account for the current contribution of the distribution system as the T-D transformer is typically configured as a delta-wye transformer that effectively isolates zero sequence contributions and has a relatively large impedance for the balanced (positive and negative) current contributions. Further, phase-based relationships are generally not considered in the study. With DERs being either single phase or three phase in addition to having a fault current contribution that can reach 1.2 to 2.5 times[85] normal current this paradigm can change in high DER penetrations. Further, ride-through of DERs are generally not studied in the protection timeframe as the design philosophy of DERs were to separate on detecting a fault. Moving to ride-through bulk system faults so that DERs can support the BPS may challenge the assumption that DERs provide zero fault contribution due to their offline status. Should fault contributions be lowered, however, the distribution fuse protection time to clear may lengthen, creating a situation where the DERs may trip offline and cease to provide sufficient fault current due to current protection systems, which reinforces the historical assumption. This highlights the importance for including DERs in protection coordination and protection set point studies to understand the impacts of high penetration of DERs in each TPs system. SPIDERWG identified a few specific protection conditions that TPs should include the impact of aggregate DER as shown below:

1. Potential tripping due to reverse power relay activation

[85] This depends on the technology type of the DER. Converter interfaced DERs (IBR DERs) are limited in their ability to provide fault current at around 1.1 to 1.2 p.u. Synchronous based DERs do not have this limit.

2. Relay loading underestimation resulting from DER tripping post-contingency
3. UFLS or UVLS schemes[86]
4. T-D transformer load tap, nearby FACTS device reactions, and DER ride-through impacts to T-D Interface protection requirements. In particular, the T-D transformer protection schemes.

Motor Start Studies

When starting up any induction motor, there is always an inrush of current (generally six times the rated load current) to bring the machine up to speed. This inrush of current draw is only in the transient domain and resolves very quickly assuming that the rotor is free to spin and does not stall. Motor start analysis is the process to identify the voltage sag created by the inrush of current and determine if voltages are within standard limits.[87] Criteria based on these standards fall into the general following applicable categories:

1. Allowable voltage sag of 5% for motors starting less than or equal to 4 times per day
2. Allowable voltage sag of 3% for motors starting less than or equal to 2 times per hour
3. Allowable voltage sag of 2.5% for motors starting between 2 and 10 times per hour[88]

For very large industrial motors or in instances where the coincident set of motor starts would draw significant flows on the bulk system or could potentially saturate CTs at the distribution substation (i.e., where the T-D interface exists), there is a need to identify the bulk level impacts. As the voltage sag due to motor startup is directly related to the relative short circuit strength, large penetrations of DERs can impact the depth and duration of a voltage sag. Surrounding FACTS devices (e.g., SVCs and STATCOMs) may also support voltage but may or may not affect the short circuit strength of the system. Largely, aggregate DERs will displace bulk system generation that in turn can reduce the short circuit strength of the system in addition to the reduction of local voltage support those generators provided to the BPS. Further, the technology type will affect the length and depth of the voltage sag or even prevent motor start entirely (leading to motor stall) depending on the short circuit capability of the DERs and surrounding bulk grid generators. Transmission planners conducting motor start studies should ensure that the generation dispatch of both DERs and bulk-connected generators is verified. SPIDERWG also recommends that the TPs review their planning criteria for motor start studies and identify any voltage sag thresholds outside of the standard criteria above. TPs should adopt criteria of no lower than 0.95 p.u. for normal conditions and 0.92 p.u. voltage for contingency conditions to start the process and refine depending on local planning conditions.

Transfer Capability Studies

Transfer capability studies are not generally focused on the transmission to distribution interface, but rather on inter-PC transfers and line limits. As such these studies are typically performed by the PC in consultation with other PCs, the planning departments collectively address the generation composition and limitations of delivery of that power to the Facilities as part of Transfer Capability studies under high penetrations of DERs. With more decentralized generation, the internal ability of a PC to deliver power to other areas may be limited by the transformation capacity under reverse flow conditions. SPIDERWG encourages PCs to study the aggregate impacts of DERs by performing the following:

1. Identify transformer reverse flow steady-state thermal ratings in identified areas of growing or high DER penetration

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[86] SPIDERWG has an entire guideline dedicated to UFLS available here: https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Recommended_Approaches_for_UFLS_Program_Design_with_Increasing_Penetrations_of_DERs.pdf. SPIDERWG has also identified the impact to UVLS programs in a white paper available here: https://www.nerc.com/comm/RSTC_Reliability_Guidelines/White_Paper-DER_UVLS_Impact.pdf

[87] Allowable voltage dip limits consider the flicker limits imposed by IEEE 1453 (available here: https://standards.ieee.org/ieee/1453/10459/) which in turn is based on IEC 61000-3-7 (available here https://webstore.iec.ch/publication/4156) that has more limits depending on the voltage application.

[88] This equates to motors starting once every 6 to 30 minutes. Generally expected of air conditioning loads during summer months.

2. Incorporate expected DER tripping or reduced DER generation output into contingency analysis to identify planning criteria violations and associated transfer limits
3. Compare the resulting potential reduction of bulk system generators due to DER penetration against historical generation assumptions to determine any resultant resource adequacy constraints on available transfer capability.
4. Perform stability analysis to identify where DER tripping or reduced DER generation output (due to lack of ride-through capability) may occur affecting available transfer capability.

SPIDERWG also encourages PCs to identify total transfer capability impacts; however, it is not apparent that DERs will reduce the transmission system's ability to transfer power. Rather, SPIDERWG anticipates that the generation composition's ability to serve the transfer capability will be more important in high penetrations of DERs.

Case Validation Studies

There is a need to ensure that the case representation of the transmission system, generation fleet, and load composition is grounded in actual equipment performance to large and small disturbances. Case validation studies attempt to correct modelling inaccuracies as well as tune models to represent field tests or the results of benchmark reports.

Currently, there are generic and user-defined models (UDM) for DERs and each model can have its own unique behavior. Each Transmission Service Provider (TSPs) or Distribution Service Provider (DSPs) may have local criteria or standards for integrating DERs in their footprint. DER behavior and performance is dependent on their location to distribution feeders. There is also the issue of diversity in voltage levels across the distribution footprint where the DERs are connected. This underscores the importance of standardized parametrization of voltage and frequency settings for an aggregated representation of DERs with respect to the location of individual DERs on the distribution feeders and the condition under study. Once the standard voltage and frequency tripping settings are in place, the DER control functionalities can be tuned according to engineering judgement, benchmark reports, or field data. In performing transient stability studies with high DER penetration, adequate model representation is critical, so PCs and TPs should perform regular case validation studies that look at their aggregate DER models.[89]

[89] SPIDERWG has a separate reliability guide on model verification available here: https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Reliability_Guideline_DER_Data_Collection_for_Modeling_and_Model_Verification.pdf

Appendix B: Contributors

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

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Appendix C: Guideline Information and Revision History

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

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

Appendix D: Metrics

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

Baseline Metrics

All NERC reliability guidelines include the following baseline metrics:

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

Specific Metrics

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

- Of the studies performed, how often was the following done
  - DER model populated
  - DER model altered for study
  - DER model validated from previous event
  - DER model performance tracked in simulation
  - DER model affected study results in a negative way
  - DER model affected study results in a positive way
  - DER model affected study results, but no interpretation on the study outcome was performed
- Of the studies performed, how many corrective action plans were identified that:
  - DER were directly included in the plan
  - DER models were impacted by the plan, but did not have a direct action for DER

Effectiveness Survey

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

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

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

Guideline Effectiveness Survey [insert hyperlink to survey]

SAR: Clarity of DER in OPA and RTA Definitions

Action
Review and Authorize to post for 45 day comment period per RTSC SAR development process

Background
The NERC SPIDERWG identified SAR(s) based on the approved *White Paper: NERC Reliability Standards Review*[1] and provided a development plan for the associated SARs to the RSTC Executive Committee for addition into the SPIDERWG work plan.

Inaccurate representation for aggregate DER levels with a reasonable allocation of their connection points to the BPS may affect the outcomes of the Transmission Operator's (TOP) Operational Planning Analysis (OPAs) and Real-Time Assessment (RTAs). As outcomes of the OPAs and RTAs provide the TOP proper situational awareness of the operational risk to the system, OPAs and RTAs should have clear and reasonable language to account for representation of aggregate DER levels. SPIDERWG recommends revising the OPA and RTA definitions in the NERC Glossary of Terms to explicitly include aggregate DERs as a component of both the OPA and RTA definitions. The definitions of OPA and RTA both state that the assessments must, at a minimum, include inputs of "load," "load forecast," and "generation output levels" Net load quantities, BPS generation output, and their forecast levels are affected as the penetration of DERs increases as DERs offset net loading. Consequentially, this affects the amount of on-line BPS generation to serve the remaining load and may mask ride-through considerations. Not accounting for the steady-state and dynamic behavior of DERs will likely have an increasingly adverse impact on the quality of OPAs and RTAs in the future. Thus, this project is to ensure clarity for current and future BPS operating states.

[1] https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Whitepaper_SPIDERWG_Standards_Review.pdf

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Standard Authorization Request (SAR)

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

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

Requested information			
SAR Title:	SAR Title:		
Date Submitted:	Date Submitted:		
SAR Requester			
Name:	Shayan Rizvi, NPCC (NERC SPIDERWG Chair) John Schmall , ERCOT (NERC SPIDERWG Vice-Chair)		
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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	
What is the risk to the Bulk Electric System (What Bulk Electric System (BES) reliability benefit does the proposed project provide?):			
Inaccurate representation for aggregate DER levels with a reasonable allocation of their connection points to the BPS may affect the outcomes of the Transmission Operator's (TOP) Operational Planning Analysis (OPAs) and Real-Time Assessment (RTAs). As outcomes of the OPAs and RTAs provide the TOP proper situational awareness of the operational risk to the system, OPAs and RTAs should have clear and reasonable language to account for representation of aggregate DER levels. SPIDERWG recommends revising the OPA and RTA definitions in the NERC Glossary of Terms to explicitly include aggregate DERs as a component of both the OPA and RTA definitions. The definitions of OPA and RTA both state that the assessments must, at a minimum, include inputs of "load," "load forecast," and "generation output levels" Net load quantities , BPS generation output, and their forecast levels are affected as the penetration of DERs increases as DERs offset net loading. Consequentially, this affects the amount of on-line BPS generation to serve the remaining load and may mask ride-through considerations. Not accounting for			

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Requested information
the steady-state and dynamic behavior of DERs will likely have an increasingly adverse impact on the quality of OPAs and RTAs in the future. Thus, this project is to ensure clarity for current and future BPS operating states.
Purpose or Goal (What are the reliability gap(s) or risk(s) to the Bulk Electric System being addressed, and how does this proposed project provide the reliability-related benefit described above?):
This project will add clarity to the terms and language composing the NERC Glossary of Terms for the Operational Planning Analysis and Real-Time Assessment. Further, the project will ensure that the requirement language in TOP-001, TOP-002, TOP-003, and TOP-010-1(i) is consistent with the application of the clarified terms with respect to the inclusion of DERs. Specifically, this project will ensure the accurate representation of DER capacity and bulk-system bus are explicit when performing an OPA or RTA.
Project Scope (Define the parameters of the proposed project):
As demonstrated in the August 9, 2019, grid disturbance in the United Kingdom, aggregate DERs can trip off-line during BPS fault and contingency events, impacting the overall performance of the BPS and possible operation of safety nets, such as underfrequency load shedding. The Palmdale Roost, Angeles Forest, and San Fernando BPS disturbance events in the Southern California area have all included around 100 MW of DER tripping off-line for BPS faults. Furthermore, inclusion of aggregate levels of DERs in OPAs and RTAs may impact system operating limits. As the terms "load," "load forecast," and "generation output levels" are not defined in the NERC Glossary of Terms, they are subject to interpretation (i.e., entities can decide for themselves whether to include or exclude the aggregate amounts of DERs in their assessments). This project is scoped to allow the standard drafting team to make edits to the OPA and RTA definitions to clearly identify the place where aggregate DER should be in the assessment process. While the NERC Reliability Standards TOP-001, TOP-002, TOP-003, and TOP-010 generally only refer to the OPA and RTA terms, TOP-002 refers to "Demand patterns", which are impacted by the capacity of DER within a Balancing Authority (BA). Thus, this project also requires clear representation of DER in the Transmission Operator's (TOP) Operating Plan based on their OPA as well as those Operating Plans developed for a BA.
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] of developing a new or revised Reliability Standard or definition, which includes a discussion of the risk and impact to reliability-of the BES, and (2) a technical foundation document (*e.g.,* research paper) to guide development of the Standard or definition):
As identified above, the primary scoped work details clarity edits and refinements to the OPA and RTA definition. These are reproduced below:

[1] The NERC Rules of Procedure require a technical justification for new or substantially revised Reliability Standards. Please attach pertinent information to this form before submittal to NERC.

Requested information
“Operational Planning Analysis (OPA): An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)” “Real-time Assessment (RTA): An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)” These definitions refer to the terms “load”, “load forecast”, and “generation output levels”. These terms are unclear with how DER ought to be considered as part of the OPA and RTA process as DER offsets the Demand at any given point. Using a net or gross amount to assess the pre- and post-Contingency operating conditions can be the key difference if the system needs operator action to mitigate risk identified in the OPAs or RTAs; transmission operator actions are a critical component of maintaining reliability. Furthermore, as TOP-002 Requirement R4 also identifies that a BA’s Operating plan requires “expected generation resource commitment and dispatch” and “Demand patterns”, it is unclear how DER are expected to be addressed in these operating plans. As high penetrations of DER can alter bulk-connected generation dispatch as well as reduce the Demand of a system, Requirement R4 should be altered to be clear in accounting for DER in these next-day Operating Plans. Further, FERC Order 901 directed NERC to submit “one or more new or modified Reliability Standards that require …. distribution providers to provide Bulk-Power system planners and *operators* modeling data and parameters for IBR-DERs in the aggregate in their distribution provider areas where the IBR-DERs in the aggregate materially affect the reliable operation of the Bulk-Power System.” [Emphasis added] In summary, the Standard Drafting Team should: 1) Revise the OPA definition in the NERC Glossary of Terms so that it is clearly addressing aggregate DERs. This includes referring to “gross load”, “net load”, “Load”, or other clarity enhancement to ensure the proper quantity (i.e., DER + gross load, or net load) is represented in the listed example inputs. These edits should replace the unclear terms such as “load”, “load forecast”, and “generation output levels” to be clear on including aggregate DER.

Requested information
2) Revise the RTA definition in the NERC Glossary of Terms so that it is clearly addressing aggregate DERs. This includes referring to "gross load", "net load", "Load", or other clarity enhancements to ensure the proper quantity (i.e., DER + gross load, or net load) is represented in the listed example inputs. These edits should replace the unclear terms such as "load" and "generation output levels" to be clear on including aggregate DER. 3) Revise TOP-002-4 Requirement R4 to clearly address aggregate DERs. Specifically, to address the accounting for next-day condition impacts DER have on expected generation resource commitment and dispatch as well as the Demand patterns. The SDT should ensure language edits are such that DERs are not double counted when committing generation to serve net demand (i.e., reduction of load in addition to adding to the generation commitment.) 4) Ensure that changes to the OPA and RTA definition are clear when read in-text in TOP-001, TOP-002, TOP-003, and TOP-010 where the Reliability Standard refers to OPA or RTA.
Cost Impact Assessment, if known (Provide a paragraph describing the potential cost impacts associated with the proposed project):
Total cost is unknown. The clarity edits may require modeling or procedural enhancements that can impact Transmission Operators procedures. These can alter staffing and the tools procured that accomplish parts of the OPAs and RTAs.
Please describe any unique characteristics of the BES facilities that may be impacted by this proposed standard development project (*e.g.*, Dispersed Generation Resources):
As DER are inherently non-BES (i.e., distribution-connected generation resources), there are no unique characteristics of BES facilities that are directly impacted. However, Control Room design to account for different meters or other information as deemed appropriate by the TOP, BA, or RC to include may be impacted.
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 NERC Rules of Procedure Appendix 5A:
The following entities are included in TOP-001, -002, -003, and -010: TOP, BA, DP, GOP, TO, GO However, there are only a few entities that are directly impacted by the scope of this project. Directly Impacted: TOP, BA, GOP, DP Potentially Impacted: TO, GO
Do you know of any consensus building activities[2] in connection with this SAR? If so, please provide any recommendations or findings resulting from the consensus building activity.
This SAR has been submitted through the RSTC and has been vetted by the SPIDERWG membership. The SPIDERWG membership includes BAs, RCs, TOs, TPs, TOPs, PCs, and DPs. The SAR drafting has been circulated to the Real-Time Operating Subcommittee under the RSTC and their comments included. The

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

Requested information
SPIDERWG recommended this standard be revised in *White Paper: SPIDERWG NERC Reliability Standards Review*.[3]
Are there any related standards or SARs that should be assessed for impact as a result of this proposed project? If so, which standard(s) or project number(s)?
Project 2022-02 is currently scoped to define DER in the NERC Glossary of Terms. This project may be impacted by the final wording of the definition. This SAR's scope is related to the ongoing Project 2022-02 team and addresses the operation portion of the FERC Order 901 statement above.
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 with the benefits of using them.
The SPIDERWG considered Standards revisions alongside compliance implementation guidance and reliability guidelines. Neither compliance implementation guidance nor reliability guidelines were determined to be sufficient to address clarity needs of Reliability Standard language. To be clear, the SAR is scoped not to address procedure but to require clarity edits to identified terms such that aggregate DER is clearly addressed in the OPAs and RTAs in the NERC Glossary of Terms.

Commented [A1]: Potentially link in FERC 901 if applicable/identified.

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.

[3] Paper available here: https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Whitepaper_SPIDERWG_Standards_Review.pdf e

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

Identified Existing or Potential Regional or Interconnection Variances	
Region(s)/ Interconnection	Explanation
e.g., NPCC	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
Risk Tracking.	
☐ Grid Transformation ☐ Resilience/Extreme Events	☐ Energy Policy ☐ Critical Infrastructure Interdependencies
☐ Security Risks	

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
5	August 14, 2023	Standards Development Staff	Updated template as part of Standards Process Stakeholder Engagement Group

Review Reliability Risk Framework

Action
Information

Background
The Reliability Risk Framework outlines a risk framework for the ERO and details how such a framework provides an important extension of the ERO's core activities. The ERO mission1 requires establishing a consistent framework to identify, prioritize and address known and emerging reliability and security risks. To support its mission the ERO has developed policies, procedures and programs, which are identified and briefly described in Section I. These policies, procedures and programs have been incorporated into an iterative six-step risk management framework outlined in Section II. Mitigation of risks to Bulk Electric System (BES) reliability can be classified according to the likelihood of the risk occurring and the severity of its impact. Section III addresses how the ERO's policies, procedures and programs identified in Section II map into the risk likelihood and severity space. Resilience is an important component of reliability risk management and is discussed in Section IV. Section V cover the application of ERO Policies, Procedures and Programs, within time required to apply the mitigation and the likelihood and severity.

Emerging Loads and Electric Vehicles Panel Session

Action
Request RSTC Comments

Background
Historical RSTC presentations and work products have indicated a growing impact of electric vehicle (EV) loads and large loads such as data centers and crypto mining loads. This panel session is set to gauge the industry perspectives on the modern load growth that ranges from at-home end-use customer EV charging load to fleet EV charging load needing transmission service to end-uses of large loads. These electric loads are rapidly changing how the transmission planning and operations are performed and this panel session seeks to state the learnings from various companies and to engage the RSTC members with questions and opportunities to strategize on next steps.

After the panel session, NERC staff will seek RSTC members to build subordinate group(s) and add items to the RSTC work plan to tackle the way the grid is transforming with these new loads.

Probabilistic Planning for Tail Risks| PAWG White Paper

Action
Approval

Summary
The whitepaper was prepared by the PAWG to investigate low probability / high impact risks to improve the Independent System Operator's (ISO's) and stakeholders' understanding of operational risks under future weather extremes. Improved understanding of these risks will enhance the understanding of the potential consequences of extreme weather and prompt discussions about how best to prepare for them. The white paper provided key findings and recommendations focused on improving tail risks modeling in planning studies. PAWG received review by RSTC members, PAWG incorporated feedback and returned the whitepaper to the RSTC for approval in this March 2024.

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Probabilistic Planning for Tail Risks

PAWG White Paper

March 2024

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

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

The North American BPS is made up of six Regional Entities as shown on the map and in the corresponding table below. The multicolored area denotes overlap as some load-serving entities participate in one Regional Entity while associated Transmission Owners/Operators participate in another.

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

Statement of Purpose

The purpose of this white paper, Probabilistic Planning for Tail Risk, is to investigate the operational risks from low-probability/high-impact future weather extreme conditions. Understanding the impacts of risks will prompt discussions about how best to prepare for them. As described in this white paper, operational planning responses can be in the form of increased generation and transmission capacity to bolster reserve margins, identification of resources with common-mode vulnerabilities, and energy sources that can offset deficits or provide resilience in the event of an extreme event.

Recognizing that the BPS cannot totally withstand all potential events, an adequate level of reliability[1] must be provided so that the system can be reliably operated even with degradation in the quality of service. Furthermore, the system must have the ability to rebound or recover when repairs are made, or system conditions are alleviated. The *Reliability Issues Steering Committee* (RISC) *Report on Resilience*[2] provides guidance on how resilience fits into NERC's activities and how additional activities might further support resilience of the grid. The RISC report underscores NERC's longstanding focus on aspects of resilience and emphasis on re-examining the issue in the face of a changing resource mix.

The NERC Probabilistic Analysis Working Group (PAWG) attempts to address these concerns through best practices gathered from published literature and users of the probabilistic tools in the electric power industry. The main concern for both planners and operators is to develop a system with an adequate level of reliability as spelled out in NERC's Standards. Their common objective is to maintain reliability, resilience, and security of the system at satisfactory levels and plan to avoid widespread outages during extreme high-impact, low-probability events that could occur in real-time operations.

The white paper covers the full implementation of a probabilistic study on extreme weather events and includes the following components:

- Assessment or study setup for extreme weather or events, including key assumptions.
- Development and enhancement of study models.
- Simulation or study techniques regarding extreme weather.
- Reporting of probabilistic indices on extreme weather.
- Recommended steps for the Reliability and Security Technical Committee (RSTC) or other NERC entities regarding probabilistic assessments (ProbA) and the related reporting of these extreme weather risks.

[1] https://www.nerc.com/FilingsOrders/us/NERC%20Filings%20to%20FERC%20DL/Informational_Filing_Definition_Adequate_Level_Reliability_20130510.pdf
[2] Report on Resilience, NERC, November 8, 2018

Chapter 1: Key Findings and Recommendations

With the electric industry transforming its resource mix, rapid changes are being made in the way the BPS is planned and operated. Driving this transformation is a changing resource mix, with increased penetration of renewable energy resources such as wind and solar coupled with frequent extreme weather events. Models focused on tail risks could be used to address the risks imposed on the BPS. Typically, these risks are characterized by their low probability, but potentially with high-impact disruptions. Tail risks are sometimes so difficult to quantify that they seem unlikely, although we know this is not always the case.

The white paper's key findings and recommendations focused on improving modeling of tail risks in planning studies are summarized below:

Key Findings

- Exploring best practices and modeling approaches for tail risks such as extreme weather events by industry in probabilistic resource adequacy planning processes has attracted renewed attention in power systems engineering in recent years.
- Probabilistic methods can often reflect underlying uncertainties better than deterministic methods, and they can also support and enhance more efficient BPS planning and operation.
- Uncertainty of variable energy resources (VER) is likely to be the dominant source of tail risk in the future.
- The addition of a wider range of scenarios will provide the natural framework in which to analyze the variable output from renewable sources during extreme weather events when determining system impact and resource interconnection studies.
- Scenario analysis for focused time-limited duration analysis is warranted as modeling must consider weather risk with a limited duration and the scope of the outages is not easily determined from historical data.
- Expected unserved energy (EUE) could be the most useful metric in understanding and comparing the severity of the degraded tail risk state.
- Probabilistic planning needs to continually evolve to properly account for the increasing frequency and impacts of extreme natural events deviating from historical trends, coupled with the anticipated increase of weather-dependent resources connecting to the BPS.

Recommendations

- Develop a catalogue of tail risk scenarios that can be applied to many Regional Entities that consider a wide range of risks.
- Use the catalogue as a checklist to identify potential risks and suggest the need for additional study years or advise the industry of targeted "useful" sensitivities to underscore the risk.
- Analyses should include a risk perspective across relatively wide footprints because of the uncertainty of resources and the interconnected nature of the power grid.
- Encourage commercial software vendors to adopt a front-end, pre-processing model that could translate temperatures to fuel availability and augment existing tools to allow fuel limitations to be represented.
- Modeling should consider weather risk that could have a limited duration while the scope of the outages is unclear from historical data, thereby making scenario analysis for a focused time-limited duration analysis warranted.

Chapter 2: Tail Risk Study Background

Leveraging the National Infrastructure Advisory Council (NIAC) framework and the NERC adequate level of reliability, the RISC created the model depicted in **Figure 2.1** that illustrates and enables measurement of system performance or resilience and provides an understanding of the elements needed to support the reliable operation of the BPS. Measuring the profile represented in this model provides relative characteristics of system performance, identifies areas where improvements may be desired post-event, and measures the success of system improvements. The key areas that lend themselves for measurement include robustness, amplitude, degradation, recovery, and recovery state.

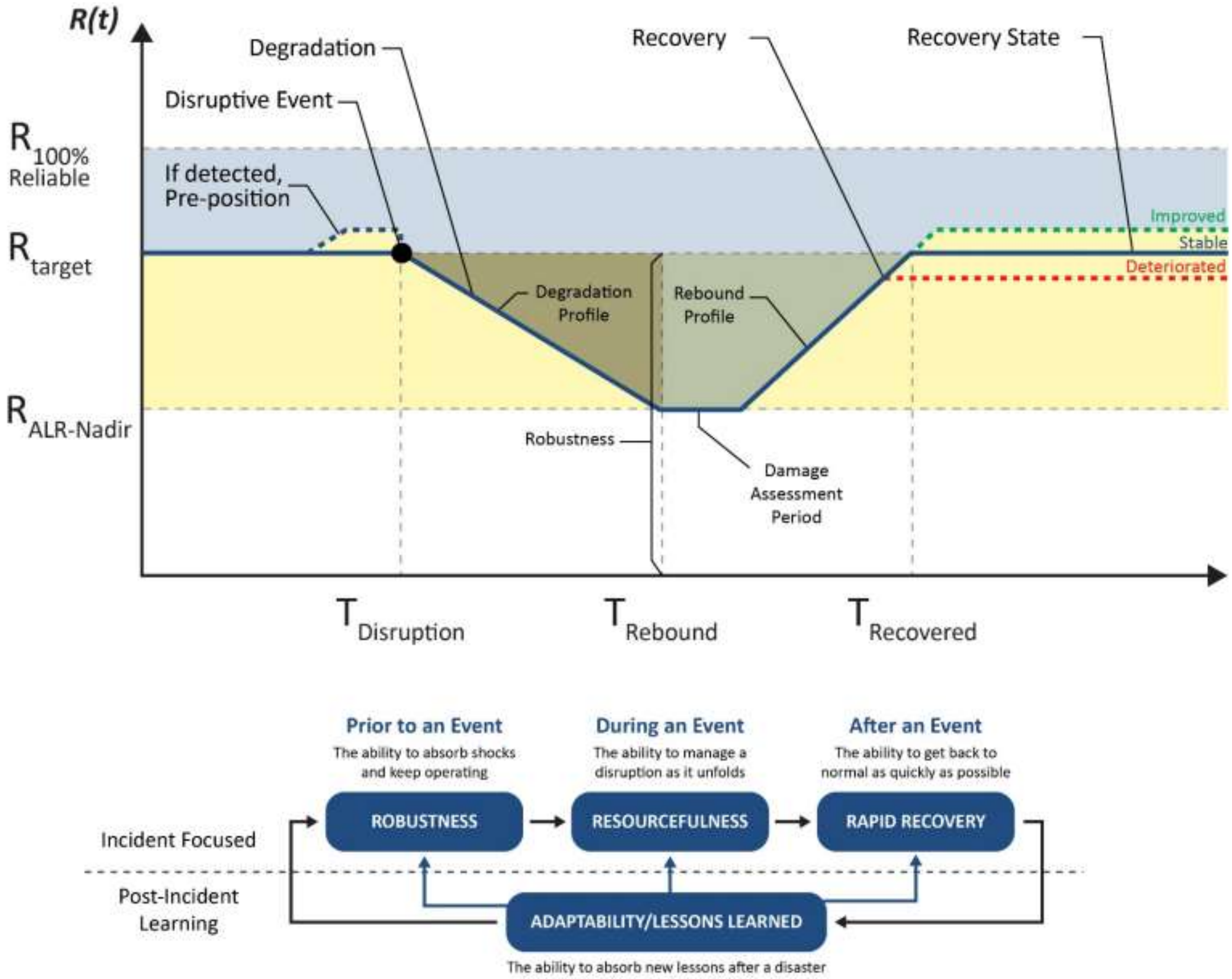


Figure 2.1: RISC Model for Reliable Operation of the BPS

Probabilistic Indices

In the electrical power industry, risk is evaluated by using a loss of load metric over a duration of time based on the probability of not meeting all customer demand, resulting in unserved energy. Probabilistic metrics describe the probability that a period will have unserved energy due to insufficient resources to meet demand during that period. This evaluation method is referred to as a loss of load probability (LOLP). The summation of the LOLP over a specific time, such as a year, will provide an expected value of the number of occurrences of loss of load events. This summation is referred to as a loss of load expectation (LOLE) over a specified period. The LOLE is typically for the most severe conditions in a day; historically, the highest contributions to LOLP and LOLE occurred during the annual peaks. A related metric that is frequently used is the expected number of hours that a deficiency will occur (e.g., loss of load hours (LOLH)) over a specific time, such as a year. Neither the LOLE nor the LOLH metrics provide information about the amount of unserved energy in the loss of load events. Because the cumulative amount[3] of this unserved energy is a useful metric, the EUE metric is frequently reported for completeness.

To develop these reliability metrics, a set of assumptions about the system to be evaluated must be developed. Using a framework that evaluates these probabilities in an organized manner quantifies if there are sufficient resources and transmission to meet system demand.[4] The results can be developed for the entire system or for portions that are constrained or bounded by transmission limitations.

While reliability models are already designed to address tail risks and investigate infrequent risks to reliable operation of the electric grid, concern is growing that some risks may become amplified by changing weather patterns that are underrepresented by assumptions used in current models. Further, these risks may not be random in nature as weather patterns cannot be assumed to be random. Additionally, supply resources are increasingly turning toward sources of energy that are a product of weather conditions (e.g., wind and solar energy) that have significant variability, common modes of production, and lulls that add to system risks. Furthermore, with increased electrification of the economy, supply disruptions due to weather conditions can be amplified.

The set of underlying assumptions for a probabilistic study can be modified to investigate specific tail risks and studied to determine the consequences of a specific conditional probability scenario. This can be done either individually or in combination with other factors. This paper proposes ways to plan the bulk system while recognizing tail risks.

Definition of Tail Risks and Extreme Weather

Tail risks are characterized by the risk imposed on a system because of their low-probability but high-impact disruptions. As the electric system becomes influenced by weather for both demand and supply, weather-related risks become critical factors that affect reliability. Furthermore, these weather-related risks are not random, and mitigating them is challenging since weather patterns may become more difficult to predict as the patterns change. Climate models may be needed to put boundaries around scenarios useful in the probabilistic analysis of future systems.

Currently, the supply uncertainty associated with solar, wind, and hydro-based VERs is reasonably well understood and accommodated in planning studies. The supply risks associated with the VERs are embedded in the historical output of solar, wind, and hydro generation. Given the availability of real and synthetic data that covers most of North America,[5] the data to evaluate some amounts of reliability impacts is available. However, a more complete range of possible weather-related risks is not available.

While the historical data provides a great deal of information about the reliability contribution of these VERs, the variability due to extreme weather is likely underrepresented. The greatest supply risk associated with these technologies is prolonged widespread hydro droughts, long periods of low wind output (e.g., "wind droughts"), high wind cut-outs, or very low ambient temperatures and solar soiling (e.g., dust, snow, smoke, smog, extreme clouds). Such reductions in VER energy would result in the drawdown of stored energy from dispatchable resources that would be needed during lulls in the production of VER energy. A drawdown in available energy may be associated with local resources but may also affect stored energy in neighboring and even more distant regions.

[3] The term "expected" here is used in the description of anticipated value of a random variable rather than a future prediction of the disruption.
[4] This is one of the roles of the Resource Planner and Transmission Planner, respectively.
[5] National Renewable Energy Laboratory (NREL) synthetic data sets in their toolkits.

Historically, the stored energy was readily available in the form of coal in coal-piles, natural gas in pipelines and geologic storage reservoirs, oil and liquefied natural gas in tanks, rods in nuclear plants, and water in hydro reservoirs. In the future, batteries will be added to the system, but the amount of energy (expressed in MWh equivalent) is expected to be much smaller than the more traditional sources of stored fossil and hydro energy. Consequently, the state of charge of batteries can be depleted relatively quickly compared to stored energy fueling legacy fossil energy resources. Depletion of stored energy resources is a key concern that makes the analysis of tail risks critical.

Recent Extreme Weather Events

Recent NERC Event Analysis reports and FERC-NERC inquiries have demonstrated the impact that some extreme weather events have had on the reliability of the bulk system. There are a few documents of note:

- Joint FERC-NERC inquiry on the December 2022 winter storm Elliott[6]
- Joint FERC-NERC inquiry on the February 2021 ERCOT events (cold weather related)[7]
- Hurricane[8] Harvey
- Hurricane Irma[9]
- Joint FERC-NERC report on the 2018 South Central Cold Weather Event[10]
- January 2014 Polar Vortex[11]

Analysis of Changing Weather Patterns

Weather, particularly changing extremes and the range of variability, is a key factor that affects resource (i.e., energy) availability, demand patterns, and related reliability concerns. Extreme weather events in Texas and California have made it apparent that multi-day or longer energy deficiencies have serious consequences for residents of the affected areas and the economy. Energy unavailability events are well documented, highlighting the importance of conducting comprehensive energy reliability assessments that cover a wide range of operating conditions, including low-probability, high-impact reliability risks (tail risks) related to extreme weather.

For instance, the Electric Power Research Institute (EPRI), in collaboration with ISO New England and other interested parties, is conducting *The Operational Impacts of Extreme Weather Events*[12] project, a probabilistic energy availability case study for the New England area under extreme weather events. The study seeks to develop a framework to assess operational energy-security risks associated with extreme weather events to enhance awareness of regional energy shortfall risk over the study horizon and prompt preparation.

Augmenting NERC PAWG Probabilistic Assessments

The PAWG has members whose companies are at work implementing the specific recommendations of the various NERC studies and reports. These companies are envisioned to modify their own planning processes in ways that are ongoing. While most of these efforts are weather related, there can be future ways and methods to probabilistically plan for extreme risks.

Time will tell if any of these efforts will emphasize tail risk over reworking the “normal” ProbAs that each organization performs as part of the NERC Long-Term Reliability Assessment and their own reports. The PAWG will continue to

[6] https://www.ferc.gov/news-events/news/ferc-nerc-release-final-report-lessons-winter-storm-elliott
[7] Joint FERC-NERC inquiry on the February 2021 ERCOT events
[8] Hurricane Harvey
[9] Hurricane Irma
[10] Joint FERC-NERC report on the 2018 South Central Cold Weather Event
[11] January 2014 Polar Vortex
[12] Operational Impacts of Extreme Weather Events Key Project

share the efforts and successes and determine if future work at the NERC PAWG is needed to provide best practice to augment the material here.

Classification of Tail Risks by Planning Response

There are three general classifications of tail risks based on the resource adequacy planning response. All three classifications can be analyzed by using simulations and are suitable for developing quantitative reliability indices. However, the type of planning response that may be appropriate to address the risk is different for each of the three classifications. Some tail risks, such as cyber security, widespread forest fires, and grid stability issues, are outside the realm of probabilistic analysis and not addressed here.

Technology-Agnostic Resource Adequacy Response

Generally, technology-agnostic resources have root causes of unavailability that are random and independent compared to the rest of the resource fleet. For this class of risk, the most appropriate planning response is to increase or decrease the number of resources available to serve demand for energy from customers. This supply is described as technology agnostic because one type of resource is reasonably interchangeable with another resource even though there may be a quantifiable capacity “equivalence rate” between different types of technologies.

The planning response to a tail risk associated with high loads driven by weather would be to install more supply resources to decrease the probability of a shortage when the high loads occur. With the rising concern that weather will encompass more extremes than observed in the past, quantifying the magnitude of the resulting additional loads is important to understanding reliability impacts and how an increase in available resources would affect reliability.

Because these conditions are driven by an identified need for additional supply, a salient feature of weather-driven extreme loads is that curtailment may have detrimental impacts on the customers. Because these episodes are not likely to be frequent, customers may not develop suitable or sufficient alternatives that would enable them to forgo essential heating or cooling services. In other words, because these events are infrequent, targeted demand reductions with market mechanisms or backup technologies (e.g., large ice-chests, gasoline-powered generators, or kerosene heaters) may not be available or sufficient.[13]

If an extreme weather event has a low probability to occur, its effect on expected load distributions would be diluted even if it had a high-impact outcome. Because the impacts are not detected, the additional supply resources indicated by the resource adequacy analysis may not be sufficient to satisfy the demands of that extreme weather event if it were to occur.

Given that the reliability criterion is non-zero, the risk of insufficient resources is an acceptable outcome. One planning response to the tail risk caused by the low probability of extreme weather is to make the desired reliability criterion more stringent and therefore to require additional resources. Because there is a risk of insufficient resources, strategic management of such a resulting loss of load occurrence must be a consideration.

During extreme weather, the effects of heating or cooling equipment running at full output may saturate demand and limit any additional increases in demand because everything is running. Alternatively, these effects may drive the aggregate demand higher based on the addition of climate-conditioning equipment—such as a spare electric space heater—operating with a high coincidence factor or the equipment’s operating characteristics themselves, such as heat pumps that switch to resistance heating at low temperatures. Care should be taken to understand the load behavior under these harsh conditions.

[13] Developing a technology solution for curtailing weather-driven loads during a once-in-a-decade extreme weather-driven event may be possible but difficult. Technology solutions, such as energy efficiency, reduce weather-driven load volatility in all hours but would not have a supplemental dispatchable component during an extreme weather event.

Technology Vulnerability Resource Adequacy Response

A secondary class of tail risk is characterized by resources that have a specific vulnerability commonly shared with other similar resources; this shared vulnerability could threaten reliability if the resource type is widespread. Examples of a technologically vulnerable resource would be wind generation during a widespread wind lull or storage resources after an extended period when stored energy is drawn down. For this class of risk, the planning response would be to recognize and limit the dependence on the resource type with the identified vulnerability. A related planning response would be to decrease the equivalence rate of the vulnerable resource type (e.g., more nameplate capacity to get the same reliability equivalent as another type of capacity). Various methods have been developed to quantify an equivalence rate between different types of capacity. This equivalence is frequently expressed as an equivalent load carrying capability (ELCC).[14]

The vulnerability is generally caused by a disruption of the primary source of energy used in electricity production or because of a common-mode condition. An example would be the decreased capability of natural gas turbine technologies associated with higher ambient temperatures. Another example of such a vulnerability is the decreasing equivalence rate of wind and solar resources as their penetration increases. This decreasing equivalence occurs because widespread wind lulls and/or widespread cloud cover reduces the primary energy source for the wind and solar resources as a class and the reductions can no longer be described as random and independent.

Another example of a technologically vulnerable resource is a fleet of natural gas resources[15] that do not have dual-fuel capability. Such resources may be subject to simultaneous primary energy source disruptions due to pipeline ruptures, fuel supply difficulties due to freeze-in of natural gas wells, competition for limited fuel supplies, or other mechanisms that preclude acquisition of sufficient fuel. These vulnerabilities could render the resources unable to provide their expected resource adequacy services. The planning response to this could include requiring or incentivizing dual-fuel capability to reduce the natural gas supply risk.

Restoration-Focused Resource Adequacy Response

The third class of tail risk is characterized as one where the most likely planning response would be to focus on resilience, enhanced restoration procedures, and equipment placement rather than implementing a resource adequacy solution where more supply resources are added. The need for this class of response is explicitly recognized because of a non-zero reliability criterion where events go beyond the capabilities of the available resources, suggesting the need for operating with a degraded system.

Examples of this class of risks could include recovery from a severe weather event, such as a hurricane, derecho, tornado, or ice storm. In these latter examples, the key problem is not the loss of supply resources, but rather an inability to move energy from where it is available to where it is needed. A planning solution that called for the installation of more resources to increase reserve margins would most likely be ineffective, as the ability of the additional resources to provide the power and move it to where it is needed depends upon the path of the storm and transmission lines that would have been taken out of service by the weather event.

A planning response for this tail risk might be to develop criteria for customer outage restoration times depending on severity. While it is quite reasonable to expect that some severe weather events could be made less impactful by the judicious location of emergency or backup generators, this is not generally referred to as a resource adequacy issue. Additional transmission to more distant areas would increase the footprint where additional support might be sought.

To address disruptive common-mode events that are not yet fully reflected in resource adequacy, the industry can build on the conceptual framework for developing resilience metrics. Resource adequacy may contribute to supply

[14] Methods to Model and Calculate Capacity Contributions of Variable Generation for Resource Adequacy Planning, March 2011

[15] BERC SPOD Document

resilience, while a broader resilience framework considers how to absorb, manage, recover, and learn from disruptive events.

Probabilistic Framework

Fundamental to the analysis of tail risks is an analysis of the underlying probabilistic distributions of loads and resources. The following figures provide a conceptual illustration of the distributions that are central to this analysis and how they interact in a resource adequacy analysis. The impact of tail risks will be discussed at a conceptual level.

The primary distribution used in resource adequacy analyses is a probabilistic representation of the loads to be served. **Figure 2.2** shows that the 8,760 hourly loads in this example have a central tendency to be between 10,000 and 16,000 MW. The highest load in the distribution is 25,868 MW corresponding to a summer peak day that is, broadly speaking, typical. A tail risk due to extreme weather would increase the peak loads in the direction shown by the red arrow. To be reliable, the probability of having insufficient resources to meet this summer peak load should be zero or a small value. In this example, a small amount of unserved load will be used for illustration.

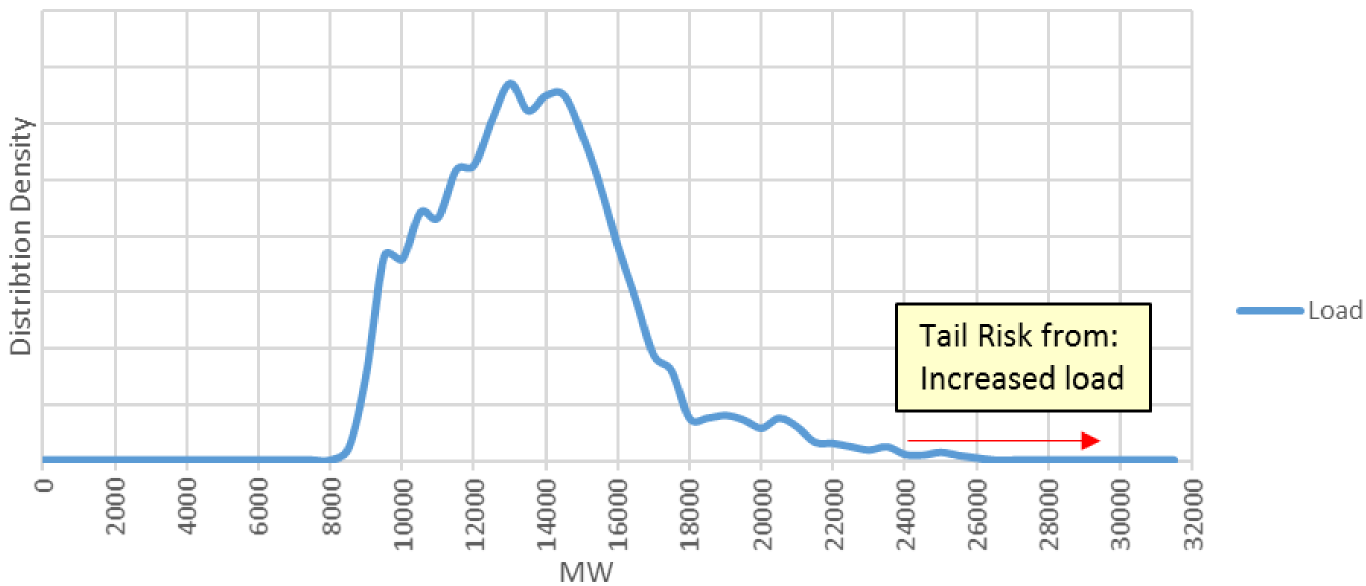


Figure 2.2: Illustrative Distribution of all 8,760 Hourly Loads

Figure 2.3 shows a conceptual distribution of available dispatchable resources. This distribution suggests that there are approximately 32,000 MW of available resources. Because of outages, the amount of capacity available to serve loads is always less than the maximum amount. In this example, the probability of having less than 25,000 MW is shown to be small. If there were common-mode vulnerabilities, the distribution would expand to the left as shown by the red arrow.

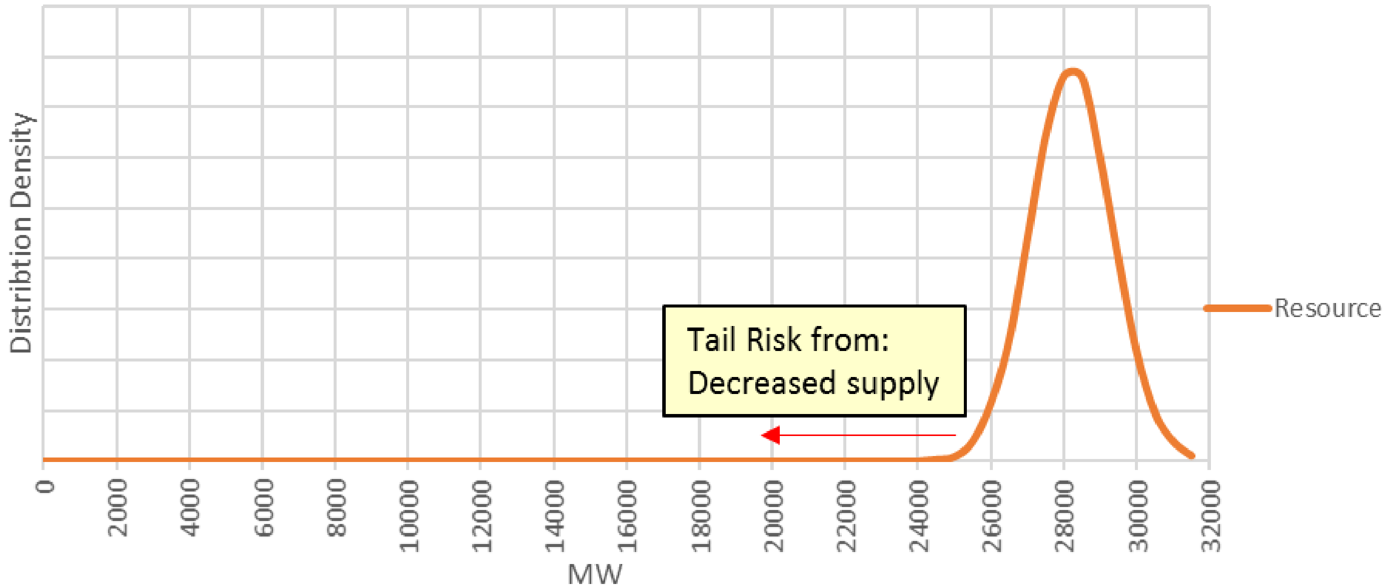


Figure 2.3: Illustrative Distribution of Available Resources

Figure 2.4 shows these two distributions superimposed on the same axes. This shows that the peak load is close to the minimum amount of capacity of the aggregate resources.

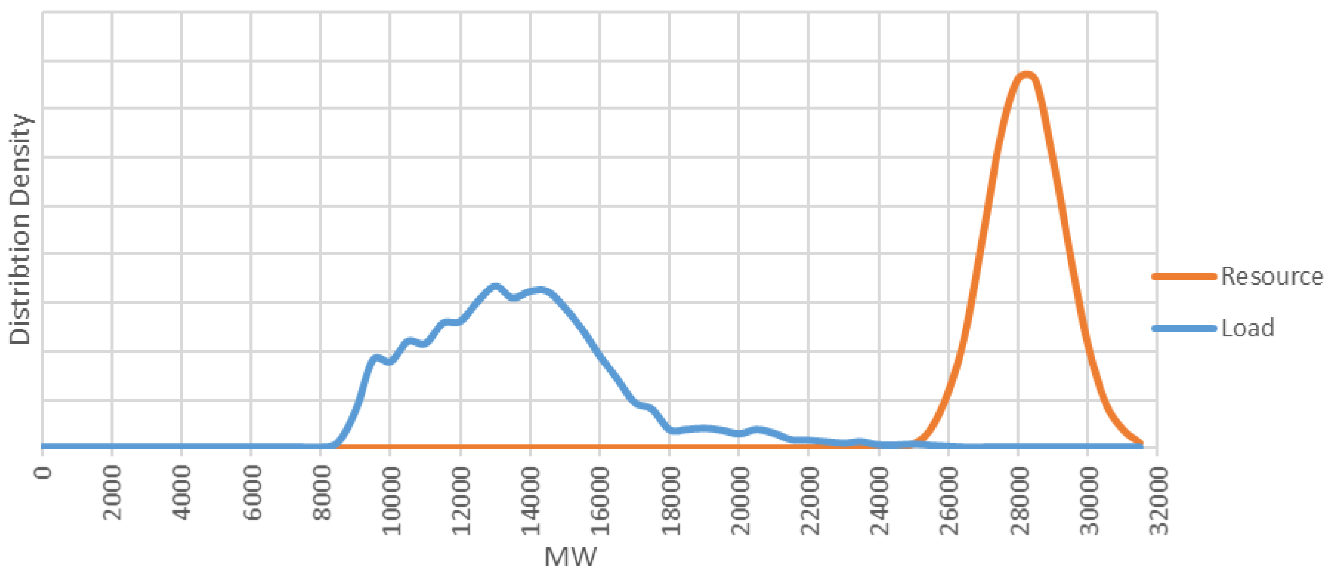


Figure 2.4: Conceptual Illustration of Loads vs. Available Resources

Figure 2.5 shows the actual margin between one Monte-Carlo replication of the resource distribution versus the load distribution.[16] Typically, the amount of available resources exceeds load by 8,000 to 20,000 MW. However, there are a few hours when the margin is close to zero or negative. In the case of a negative margin, the system had a non-zero probability of losing load.

[16] The margin was calculated by first creating a distribution representing the available capacity for all 8,760 hours. This distribution was based on a mean of 27,000 MW, a standard deviation of 1,200 MW, and a random number for each hour. The corresponding load in the associated hour was then subtracted from the available resource in order to get the margin in a specific hour. While not a rigorous probabilistic analysis, this approach is appropriate for illustrative purposes.

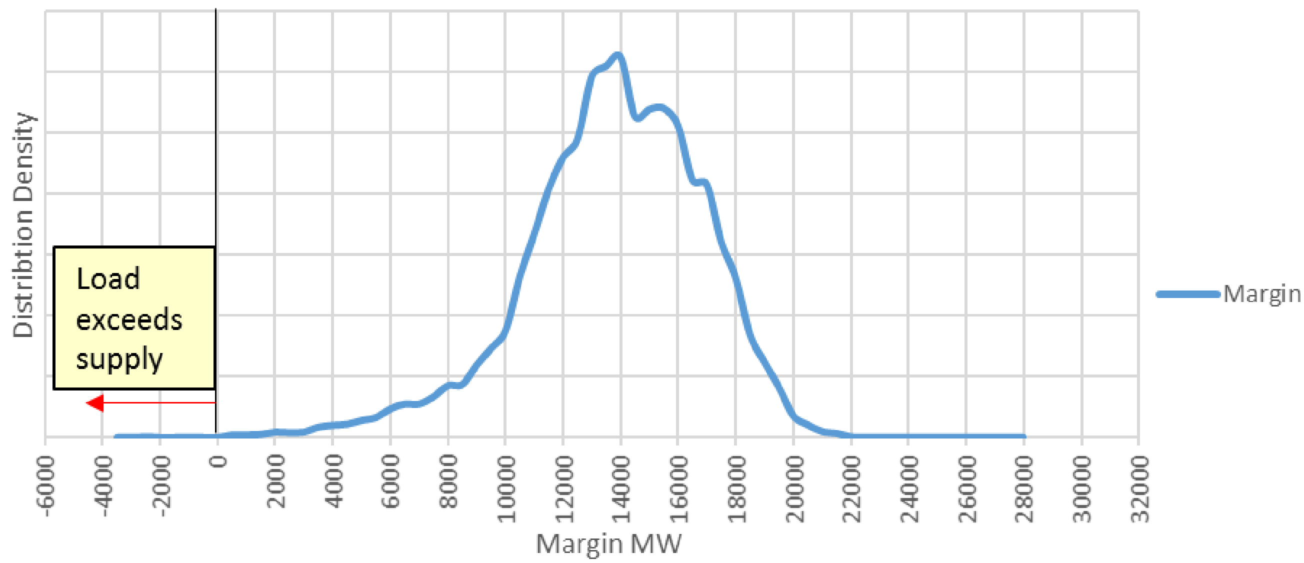


Figure 2.5: Conceptual Margin Between Loads and Resources

Figure 2.6 shows a revised margin distribution based on the addition of wind and solar resources. To illustrate a comparable loss of load magnitude, the amount of dispatchable resources was reduced.[17] Typically, the amount of available resources exceeds the load by a wider range of 4,000 to 28,000 MW, suggesting that the dispatchable resources were available but not typically needed to serve loads. Because of the assumed reduction in the amount of dispatchable resources (compared to those assumed in **Figure 2.3),** a few hours remain during which the margin is close to zero or negative, similar to **Figure 2.5**.

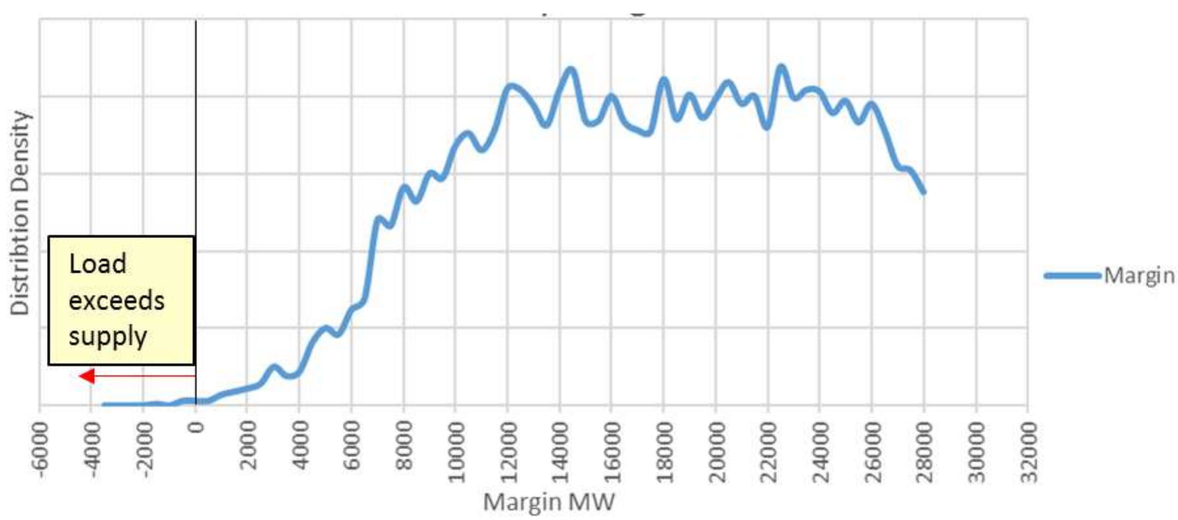


Figure 2.6: Conceptual Margin Between Loads and Mix with Wind, Solar, and Fewer Dispatchable Resources

The red arrow in **Figure 2.7** illustrates the tail risk affecting resource adequacy as discussed in this white paper; it could be due to either higher loads or resources with greater unavailability.

[17] The mean of the distribution representing the available capacity for all 8,760 hours was reduced from 27,000 MW to 18,500 with the same standard deviation of 1,200 MW.

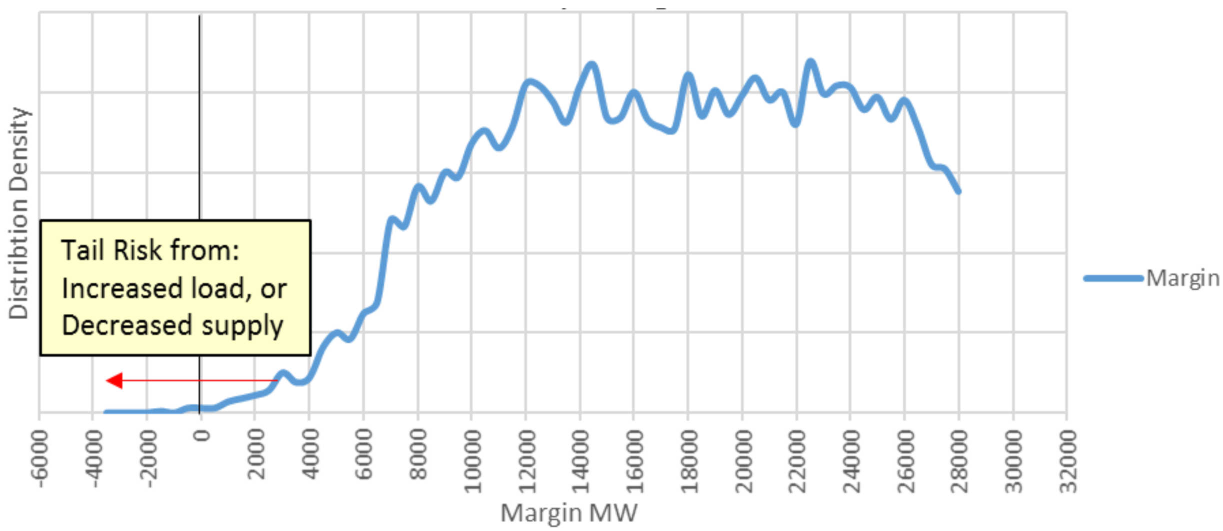


Figure 2.7: Additional Tail Risk from Increased Loads and/or Decreased Supply

Assumptions for Probabilistic Study of Tail Risks

There are several broad classes of factors that affect reliability because of tail risks. At a high level, two of these factors are the magnitude of the loads in comparison to the availability of supply and factors where supply can be a function of weather-related phenomena.

Risk of Extreme Loads

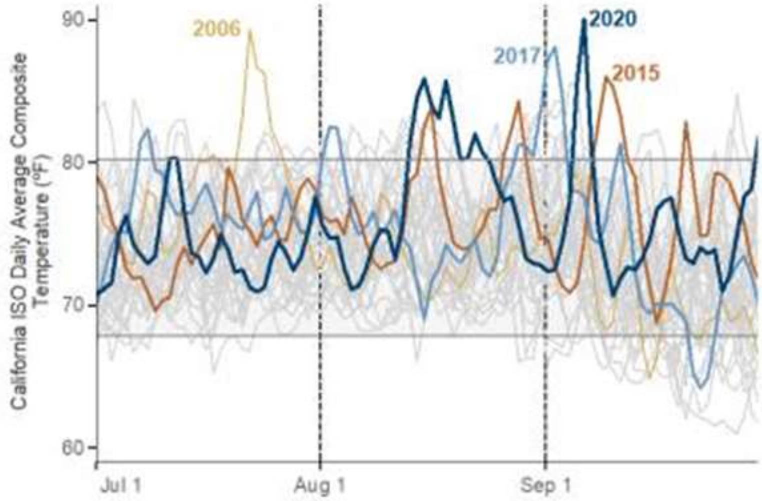
Reliability studies have methods that incorporate a range of loads based on observations developed from historical weather datasets. To some extent, forecast loads may reflect high values because the forecasting process typically incorporates normal variations based on observations spanning several decades that will surely include some hot- and cold-weather outliers. Even if the risk of extreme weather is expected to increase over time, the likelihood of that weather being far outside the outliers experienced in the historical record is low. Some climate models suggest[18] that there may be more frequent occurrences of the outlier values with only modest increases in their magnitudes. A review of 2020 California and 2021 ERCOT outages suggests that, while extreme hot or cold temperatures contributed to those reliability events, they were not outside of the historical record. Consequently, a focus on extreme temperature excursions may provide an incomplete assessment of the reliability landscape, and other factors need to be investigated.

California 2020

The August 2020 load-shedding events in California were not caused by "extreme" heat solely from temperatures in California as shown in the graph below. The rest of the western United States also experienced high temperatures at the same time, and this reduced available support from other areas throughout the Interconnection. **Figure 2.8** shows that the temperatures in both September 2020 and July 2006 were higher than mid-August 2020 when the outages occurred.[19]

[18] EPRI Report presentations with ISO New England

[19] Root Cause Analysis; Mid-August 2020 Extreme Heat Wave, California ISO, January 13, 2021



Source: CEC Weather Data/CEC Analysis

Figure 2.8: Summer California Temperatures 1985–2020

ERCOT 2021

In ERCOT, the temperature during the February 2021 cold snap was not an extreme weather event compared to past historical events. **Figure 2.9**[20] shows that the 2021 daily average temperatures tended to be the second or third coldest during the seven-day window shown. This suggests that factors other than extreme weather had a significant role in the reliability event. Specifically, resource challenges occurred due to a sensitivity to weather conditions, which did not manifest itself during previous events. In addition to the freezing of mechanical components in power plants and unavailability due to the natural gas freeze-in that will be discussed later, another significant factor was the simultaneous outage of wind resources, with a large part of those outages caused by icing.

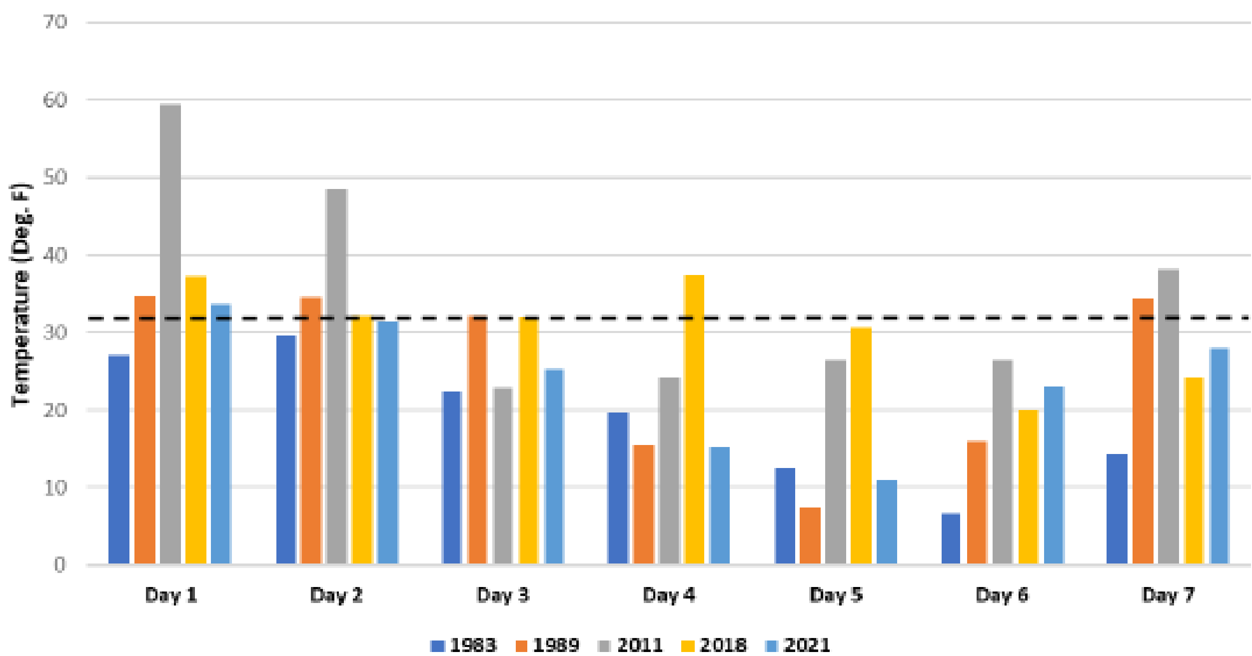


Figure 2.9: ERCOT Cold-Snap Temperatures

[20] February 2021 Cold Weather Outages in Texas and the South Central United States, pdf page 247/316

Evolving Resource Mixes Reduce Fuel Diversity

As electricity resources evolve to lower carbon-intensity portfolios, the diversity of fuels supplying generating resources is shrinking. The increased penetration of wind and solar resources is reducing the energy from fossil resources, especially coal, oil, and natural gas generators. This is a trend that affects all Regional Entities. As an example, **Figure 2.10** shows the retirement of coal-fired and other dispatchable resources projected in the next decade[21] in the NERC footprint; the non-coal resources that could retire may have had dual-fuel capability. This will decrease fuel diversity that amplifies the reliance on dependable transportation of natural gas to generators during times of system stress.

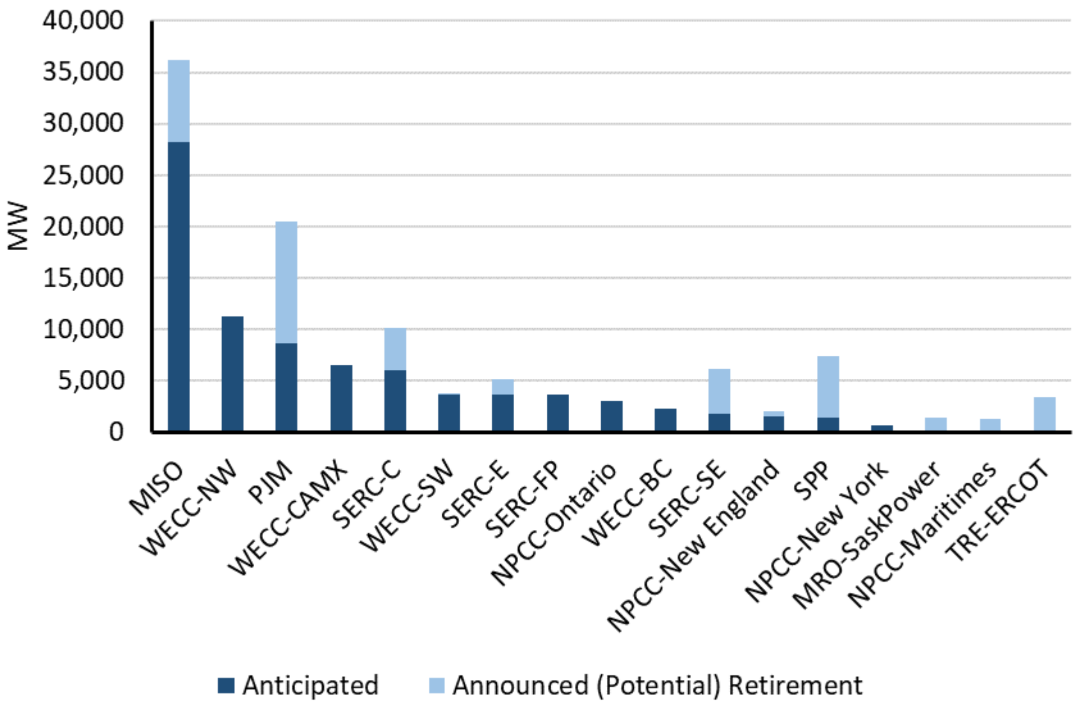


Figure 2.10: Projected Retiring Nuclear and Fossil Generation Capacity 2023–2033: NERC LTRA

Changing Weather Sensitivity of Load

The sensitivity of electricity loads to weather may be increasing as national and state policies promote electrification to increase overall energy efficiency and reduce carbon emissions from customer demand. This increased sensitivity can also be a source of increased risk. For example, increased heating electrification can result in an increased load sensitivity to cold weather that would be greater than experienced previously for a comparable temperature. The historical sensitivity to temperature would be used to develop load volatility for the forecast years. The compounded risk of both greater electrification heating loads and a potential increase in sensitivity to colder temperatures could create loads that exceed forecasts.

Load Forecast Uncertainty Multipliers

There is no standard industry practice for addressing the future load volatility in reliability models. In developing load distributions for use in reliability studies, the tail risks associated with uncertain weather are represented by load forecast uncertainty multipliers. Reliability models, such as the GE MARS Model, use a combination of load-scaling multipliers and associated probabilities to reflect higher-than-expected loads at a relatively low probability.

[21] https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2023.pdf

Increased Competition for Natural Gas

State policies are orientated toward promoting electrification to reduce carbon emissions. Because liquid fuels such as heating oil and propane are more expensive than natural gas, electrification of heating systems using these fuels would typically provide greater economic benefits. Additionally, oil has a higher carbon footprint than natural gas for heating and would be the preferred target for electrification. Consequently, the demand for natural gas heating during cold snaps is likely to remain robust. Natural gas infrastructure expansion has been lagging the increased demand from the power sector. If a lull in wind and solar energy production occurs, natural gas may not be available in sufficient quantities for the power sector, and this would place increased demand on oil and coal generation with locally stored fuels. This would also increase the use and drawdown of other forms of dispatchable stored energy such as hydroelectric and batteries.

Resource Unavailability

Typically, probabilistic reliability analyses have reflected the unavailability of generating resources as random and independent events. The statistics underlying the unavailability are typically related to mechanical problems that affect only one generator without affecting other generators. While anecdotal evidence suggests the possibility of common-mode events among dispatchable resources, it has been difficult to establish quantifiable statistical relationships to include in forward-looking reliability studies. Generally, it has been relatively straightforward to develop estimates of resource availability due to random and independent events that can then be compared to loads. However, weather-driven factors can cause common-mode failures.

Temperature Sensitivities

One of the exceptions to assumptions about random and independent generator unavailability is related to temperature dependencies. The effect of ambient temperatures on mechanical availability is typically reflected by derating generators seasonally (e.g., summer vs. winter ratings). Combustion turbines are sensitive to air density, which reduces the rating with higher temperatures because less air can be brought in to support combustion. On the other hand, the air is denser with colder temperatures and generators can ingest more air and, therefore, operate at higher outputs. Similarly, PV panels have decreased capability deratings during periods of high ambient temperatures.

Additionally, the typical seasonal profile of hydro energy limitations can also be reflected in seasonal or monthly ratings. These risk attributes have been addressed for many years in reliability analyses by using well-established protocols.

Effects of Freezing on Resource Unavailability

Mechanical unavailability due to freezing has been a recognized root cause of degraded system operations. The severity and consequences of freezing get worse with decreasing temperatures and have caused the industry to work together to address this common-mode vulnerability. However, addressing this risk vector has proven to be difficult, elaborated on here:

> *Both the 2011 and 2018 Reports identified certain equipment that more frequently contributed to generating unit outages, including frozen sensing lines, frozen transmitters, frozen valves, frozen water lines, and wind turbine icing. The Event was no different—generation freezing issues were the number one cause of the Event, and the same frequently-seen frozen components reappear. Given the repeated appearance of certain equipment in causing generating unit outages during cold weather events, NERC recommends in its Reliability Guideline that entities responsible for generating units "identify and prioritize critical components, systems and other areas of vulnerability." NERC further explains in its Reliability Guideline that "this includes critical*

instrumentation or equipment that has the potential to … initiate an automatic unit trip impact unit start-up[,] …initiate automatic unit runback schemes or cause partial outages."[22]

The effect of cold temperatures on resource unavailability affects many areas, including those located in northern climates where such conditions are expected. MISO's review of the event included these key takeaways:

Key Takeaways: … extreme weather events cause even greater negative impacts on generation performance because of issues like unexpected weather-related generator outages or fuel delivery challenges. Winterization to protect generation and fuel supplies from extreme weather can mitigate this risk but MISO and its members must assess and establish certain criteria. For instance, to what extreme temperature must generators be prepared to operate, how does MISO ensure consistency amongst similarly situated generations, and whose role it is to establish and verify such requirements? … Further, fuel availability varies over time, and how and who should ensure fuel availability must be considered in reliability planning. Furthermore, if fuel assurance is required, how do we do so in the most cost-effective manner (e.g., annual firm fuel when the generator may only be needed a few times a year)?[23]

Figure 2.11 shows the sudden rise in resource unavailability at the onset of the cold snap at about February 15. Natural gas resources showed a large increase in unavailability while coal resources showed a relatively smaller increase. Increased wind resource unavailability preceded the cold snap and remained elevated until after the cold weather dissipated.

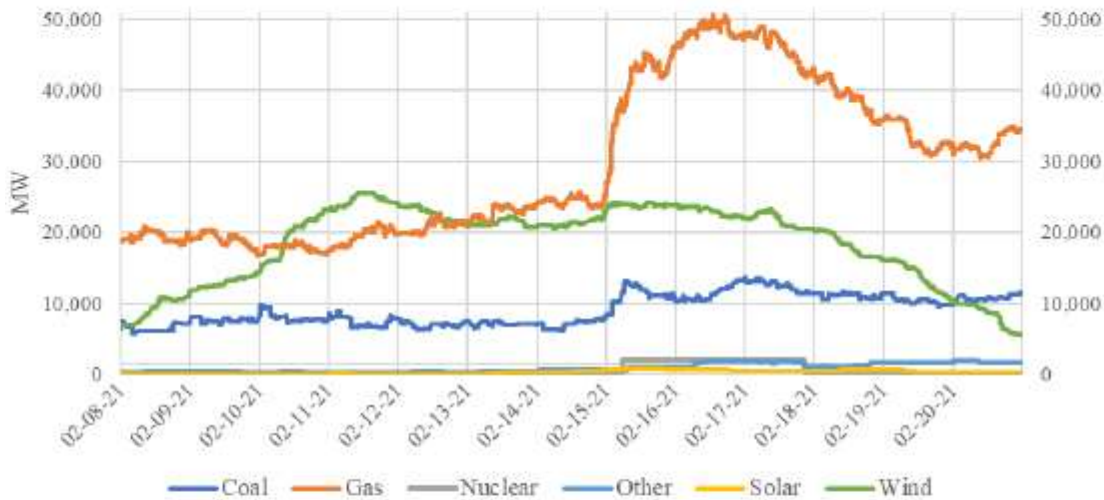


Figure 2.11: ERCOT Cold-Snap Unavailability by Energy Source

Cold Weather and Natural Gas Supply

One of the dominant risk factors that affects large footprints is the reduction in natural gas supplies during cold snaps due to lost production because of supply freeze-in. Freeze-ins are a relatively frequent and recurring problem in natural gas production and processing facilities that have caused considerable supply issues, but this is outside of the scope of current electric system reliability models.[24] The development of techniques to quantify this risk as an integral part of a reliability framework may be an appropriate next step in the evolution of probabilistic analysis.

[22] The February 2021 Cold Weather Outages in Texas and the South Central United States, https://ferc.gov/media/february-2021-cold-weather-outages-texas-and-south-central-united-states-ferc-nerc-and , p 186/316

[23] The February Arctic Event / February 14 - 18, 2021 / Event Details, Lessons Learned and Implications for MISO's Reliability Imperative, https://cdn.misoenergy.org/2021%20Arctic%20Event%20Report554429.pdf, p 7/54

[24] Natural Gas Dependence Document (see Chapter 5—Methods for Analyzing Natural Gas Demand and Infrastructure for Electric Power Needs)

It is important to account for this fuel supply aspect of resource unavailability. For example, if forced outage statistics for resources affected by cold-weather-related fuel supply were to be increased to reflect this unavailability without explicitly representing the root cause of the reduction from freeze-ins, then it is possible that a solution of adding more resources with the same vulnerability might be identified and pursued. However, because the root cause of the outage was not addressed, the reliability improvement from adding resources with the same vulnerability might prove elusive. Namely, the system condition that impacts existing resources would have the same effect on the availability of added resources. Solutions that explore other fuel types, technologies, or increased reach of transfers may have the desired impact.

ERCOT 2021

One of the key themes related to the February 2021 cold snap in the central United States was the available supply of natural gas for electricity generation.[25] This reduction in supply was mentioned in the above reports and is shown in **Figure 2.12**. The key freeze-in issues are summarized here:

> *Generating unit outages and natural gas fuel supply and delivery were inextricably linked in the Event. Fuel issues, at 31.4 percent, were the second largest cause of unplanned outages, derates and failures to start during the Event. Eighty-seven percent of the fuel issues involved natural gas fuel supply issues and 13 percent involved issues with other fuels (such as coal or fuel oil). Natural gas fuel supply issues alone caused 27.3 percent of the generating unit outages. Natural gas fuel supply issues include declines in natural gas production, the terms and conditions of natural gas commodity and transportation contracts, low pipeline pressure and other issues. During the Event, unplanned outages of natural gas wellheads due to freeze-related issues, loss of power and facility shut-ins to prevent imminent freezing issues, and unplanned outages of gathering and processing facilities decreased the natural gas available for supply and transportation to many natural gas-fired generating units in Texas and the South Central United States.*[26]

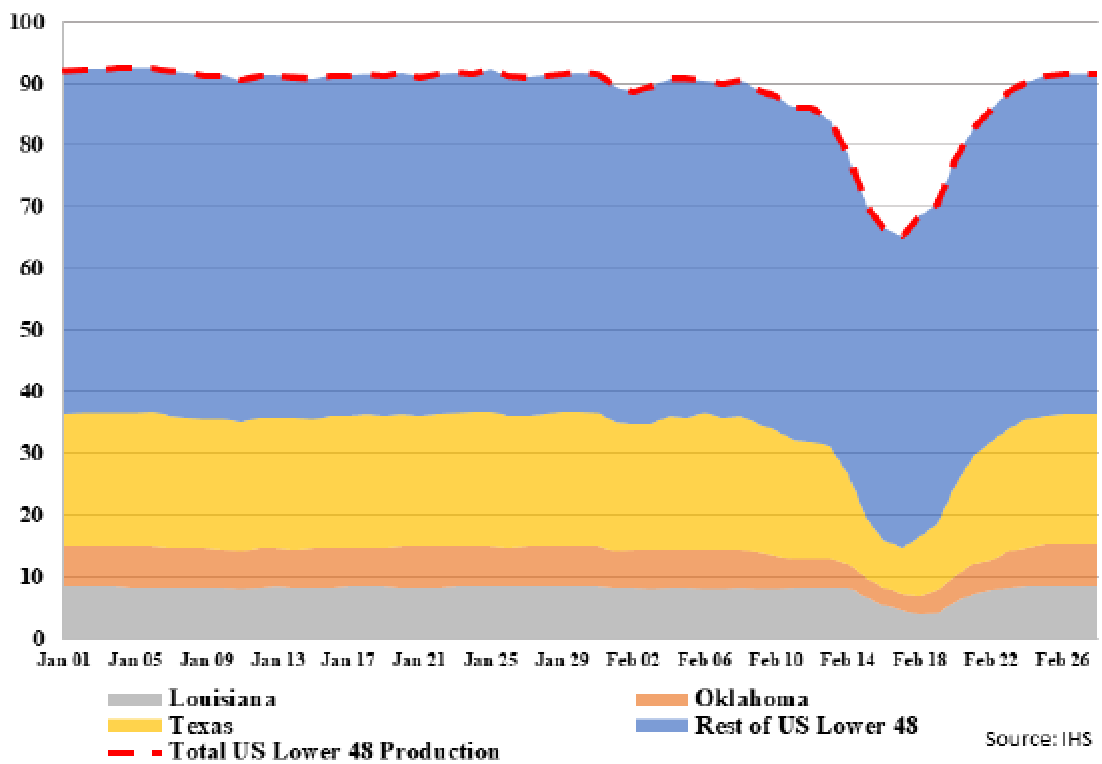


Figure 2.12: 2021 Natural Gas Freeze-In

[25] 1 Bcf of natural gas per day is sufficient to supply approximately 6,000 MW of efficient natural gas combined-cycle capacity for 24 hours.
[26] [FERC_ NERC(2021) at 163]

ERCOT 2011

A cold snap in ERCOT during February 2011 created challenging conditions for electricity generators. The reduction in available natural gas supply, shown in **Figure 2.13**, was identified as a significant root cause, as described below:

> *Both the San Juan Basin in northern New Mexico and the Permian Basin in west Texas and southeastern New Mexico tend to experience production declines with low temperatures, and the February [2011] event was no exception. The declines in these basins, together with the large increases in demand, were almost exclusively responsible for the gas curtailments in Texas, New Mexico and Arizona This weather event was so extreme that production freeze-offs were experienced not only in the San Juan and Permian Basins, but throughout Texas and as far south as the Gulf Coast.*[27]

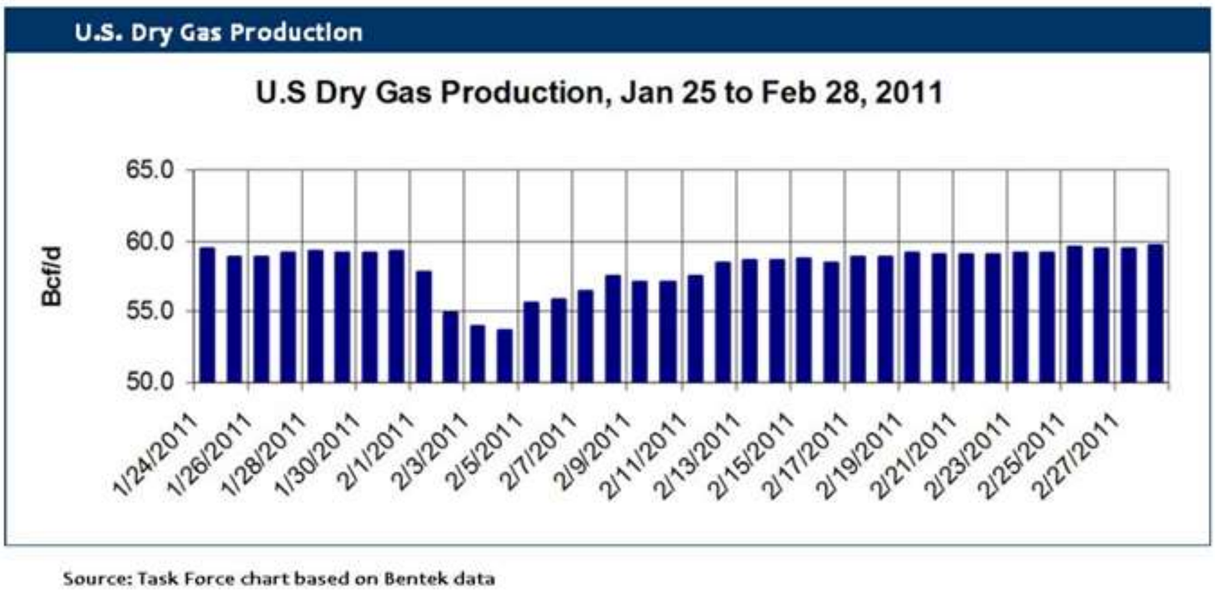


Figure 2.13: 2011 Natural Gas Freeze-In

Continuing the theme of natural gas unavailability, this tail risk was also identified as a concern in SPP, as noted below:

> *The unavailability of generation, driven mostly by lack of fuel, was the largest contributing factor to the severity of the winter weather event's impacts, which was exacerbated by record wintertime energy consumption and a rapid reduction of energy imports. (Note: Up to approximately 59,000 MW of generating name plate capacity in SPP was unavailable to meet demand during the week of the event.) When generation was most needed on Feb. 16, about 30,000 MW of generating capacity was unavailable due to forced outages. The largest single cause of these forced generation outages was attributed to fuel-supply issues, causing nearly 47% of the outages and affecting over 13,000 MW of gas generation.*[28]

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[27] Reference: Report on Outages and Curtailments During the Southwest Cold Weather Event of February 1–5, 2011: Causes and Recommendations, Staffs of the Federal Energy Regulatory Commission and the North American Electric Reliability Corporation, August 2011, p114
[FERC Outages and Curtailments Paper]

[28] A Comprehensive Review of Southwest Power Pool's Response to the February 2021 Winter Storm Analysis and Recommendations, Southwest Power Pool, July 19, 2021: [SPP Comprehensive Review]

Figure 2.13 shows the unavailability of natural gas increasing through the event with the sharpest increase beginning on February 14. Wind unavailability preceded the rise in natural gas unavailability and remained elevated throughout the event. **Figure 2.13** and **Figure 2.14** show the contribution of natural gas unavailability to the total amount of unavailable supply.

It is important to note that the electric industry does not have the ability, nor should it have the responsibility, to ensure a reliable, resilient and affordable natural gas supply. It is incumbent upon the natural gas industry to make the changes necessary to improve the supply of natural gas during extreme weather events. It is imperative that regulators understand the limitations of the electric industry in improving natural gas supply. Any new requirements to improve natural gas supply need to be imposed upon the gas industry and not the electric industry if this situation is to be improved.[29]

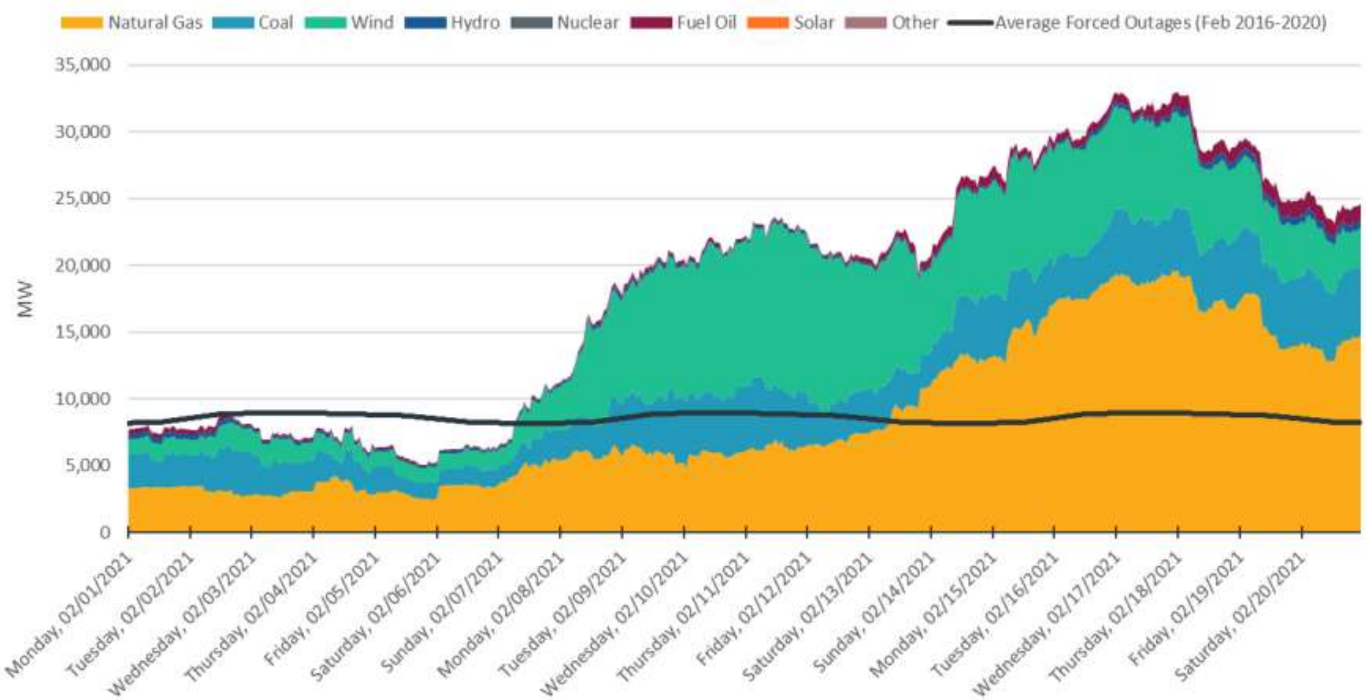

Figure 2.14: Unavailability by Source of Energy

[29] A Comprehensive Review of Southwest Power Pool's Response to the February 2021 Winter Storm Analysis and Recommendations, Southwest Power Pool, July 19, 2021: SPP Comprehensive Review

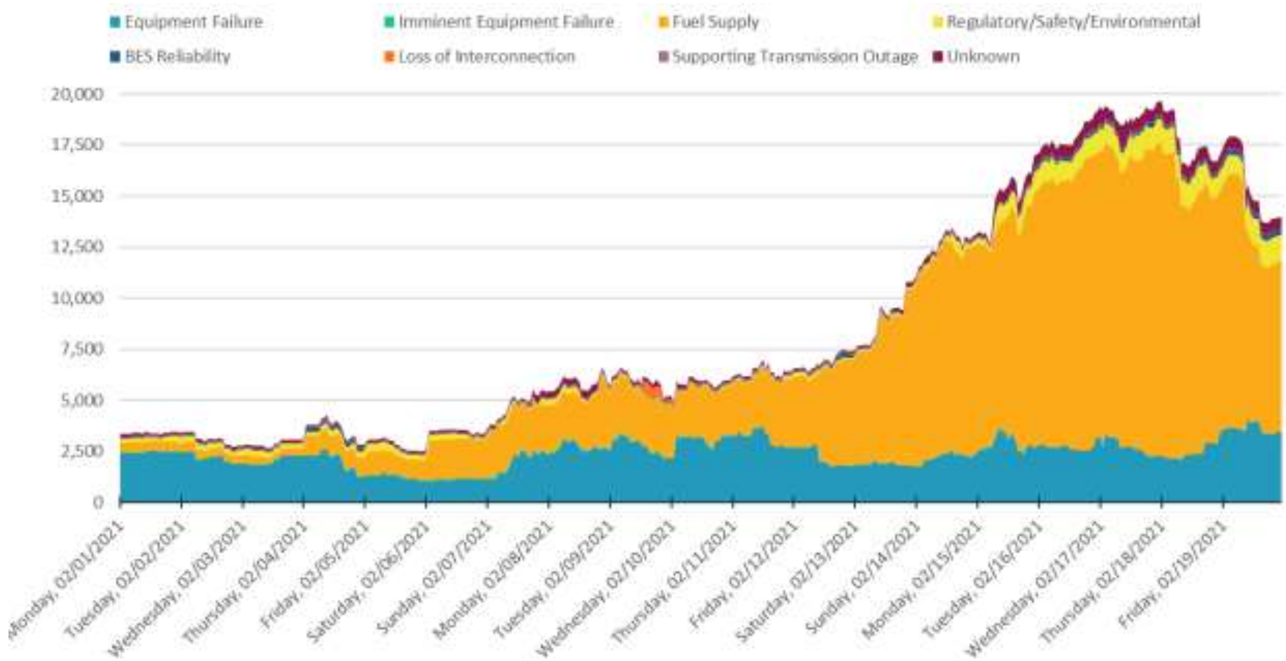

Figure 2.15: Unavailability of Natural Gas Generation Outages

Variable Energy Resources

The desire to decarbonize the power sector, coupled with declining capital costs, has resulted in the deployment of large amounts of wind and solar resources. These VERs are dependent upon weather conditions and exhibit a high degree of correlation over a relatively large footprint. Additionally, the timing and amount of energy available from wind and solar resources is not well correlated with customer demands. With increased penetration of these resources and their displacing dispatchable resources, the risk of mismatch between when the energy is available and when the energy is needed by customers increases.

In the event of wind lulls or periods of decreased solar energy production, additional sources of energy need to be dispatched to maintain a reliable system. Because of the large footprint that will be subjected to similar weather conditions, the risk of widespread lulls that lead to simultaneous decreases in output requires the amount of installed dispatchable resources to remain relatively constant or decrease only slightly. Further, transmission options should be considered that can bring in energy resources when they are needed from areas that have excess energy available. Because of the uncertainty in weather and the relatively weak correlation to load, uncertainty of VER output is likely to be the dominant source of tail risk in the future. Because of this uncertainty and the interconnected nature of the power grid, analyses should include a risk perspective across relatively wide footprints.

Interconnection Support and Tie Benefits

In reliability studies that have been dominated by dispatchable resources, the interconnection support that can be obtained from neighboring regions has frequently been included. This support has the theoretical underpinning that arises from both the load diversity across a large footprint as well as the random and independent outages of dispatchable resources. With these two assumptions, there is a significant probability that the neighboring system would have surplus resources that could be used to assist when needed.

These load diversity and independent random outage assumptions are reasonable for a weather-driven system in which weather primarily affects the loads across neighboring areas.

However, as renewable resources among all the interconnected neighboring systems increasingly become weather dominated, the assumption that a neighboring system will have surplus resources to supply may become more tenuous. Weather-dominated conditions over a large footprint can lead to wide-area wind or solar lulls that could inhibit the ability to provide mutual assistance.

Energy Storage

The lulls associated with the reduced output from VERs amplify the uncertainty associated with energy availability. Because reliability models have traditionally been focused on random independent outages of dispatchable resources, the chronological aspects of energy availability did not play a prominent role in most reliability modeling.[30] A justification for this was that many of the energy limitations could be managed through better dispatch of the relatively smaller population of energy-limited storage resources given the available dispatchable resources.

For example, low-hydro conditions could be reflected by lower seasonal ratings, reflecting decreased reservoir heads as well as limited dispatch flexibility. Low-hydro reservoir storage due to droughts or limited energy in pumped storage reservoirs or batteries could be managed by dispatching their limited energy at the hours of greatest need.

However, as the risk of wind and solar lulls materialize in a simulation and potentially transform into wind and solar droughts, the amount of energy needed to be withdrawn from storage increases. The longer the lulls continue, the more energy needs to be withdrawn. Assuming the energy storage facilities are limited in size and need to recharge, they could become depleted, possibly resulting in a deficit of available resources. Therefore, as the amount of storage increases and displaces fossil-fuel-based dispatchable resources with access to large inventories of stored energy, the energy drawdown and replenishment may create a significant risk vector. Such limitations would need to be represented better in reliability models. Energy storage is currently an active area of development by reliability model vendors.[31]

The risks associated with these energy issues are difficult to reflect because the inter-temporal aspects are typically outside the scope of reliability studies. Reliability studies evaluate the risk of loads plus a minimum amount of reserve exceeding available resources due to random and independent mechanical unavailability. In the case of energy storage, the decisions to withdraw stored energy to serve load, retain the stored energy for future contingency events, or replenish the state of charge of the stored energy have not been a core function of a reliability simulation model. Representation of the weather-driven severity, duration, and geographic footprint of stored energy drawdown needs to be based on realistic assessments of past weather and reflect possible future trends.

Location of Critical Loads

The locations of critical loads for hospitals and schools are important for managing systems in a degraded state. However, another aspect that has caused concern is the location of electricity-driven natural gas compressor station loads as noted below:

Interruption of Critical Load

During the load-shed events, there were concerns from TOPs that natural gas compressor station loads may be curtailed, exacerbating the fuel shortage issue and causing a need for additional load shed. There are additional concerns that these critical loads do not have adequate backup plans to continue operating in the event of a loss of interconnection to the grid such as gas fired compression. Reliance upon the electric grid to power compressors will lead to interruptions in service due to other forced outages not initiated by the TOP.[32]

Contingency and Robustness

Unlike wind droughts and weather-driven load excursions that can be alleviated by having more resources, some tail risks may not be avoidable. These risks can be in the form of hurricanes, tornadoes, earthquakes, and/or fires; these

[30] While reliability models have attempted to reflect chronological needs by using parameters, such as mean-time-to repair, the influence of this type of parameter over many Monte-Carlo replications was usually lost in the average's summary statistics.

[31] See NERC Battery Storage Report.

[32] SPP Winter Storm Document p 57/109

risks cannot be directly mitigated by having more installed resources. Risks like these require different remedies, such as workable restoration procedures or the positioning of restoration tools, labor, and equipment.

Other tail risks that can create unreliability, such as the loss of long lead-time replacement components (e.g., power transformers), can be addressed probabilistically but are outside the scope of a resource adequacy analysis.

Reliability Criterion

The reliability criterion that has traditionally been used for resource adequacy is 1-day-in-10 years for interruption of firm load due to insufficient resources. This criterion was developed to address unavailability due to random and independent outages of traditional dispatchable resources. In practice, this criteria risk has rarely been encountered and outages have mostly been due to other factors such as storms and fuel delivery problems that are outside the scope of traditional reliability models.

However, with an increased emphasis on VERs whose output is dominated by weather patterns that can extend over a very wide footprint, it is likely that the wind and solar lulls may become more constraining and interruption of firm load due to insufficient resources may increase. Addressing this form of resource unavailability for high penetrations of these resources is an emerging concern.

This white paper has touched on several potential reliability criteria that could be used. For example, EUE is one of the metrics that can capture the amount of energy that could not be served due to insufficient resources to serve the loads. The concept of applying a more stringent criterion to compensate for additional tail risk was also discussed. Regardless of which metric is selected as the reliability criterion of choice, they all have the same general characteristic: when the system is adequate the risks are relatively small and when the system risks increase the metrics increase rapidly. The threshold when a criterion indicates that risks have risen and actions need to be taken depends in part on what is included in the underlying risk analysis. Every additional risk factor that is considered in a resource adequacy analysis raises the resulting metric. The benefit of discussing tail risk is that it crystalizes the awareness that risks are looming in the future.

Independence of Risk Factors

Scheduled maintenance outages are not included in resource adequacy analyses even though they can have a significant impact. For example, resources could be scheduled out for maintenance and then unseasonable weather could occur. With climate change, weather patterns could emerge and very early summer weather, very late summer weather, very early winter polar vortices, or very late polar vortices could arrive and create challenging operating conditions. Tail risk could, therefore, occur when those events occur with significant amounts of resources on scheduled maintenance.

Chapter 3: Simulation-Based Approaches for Extreme Weather

This chapter will discuss the approaches to setting up a study regarding “tail” events that are typically related to extreme or unusual weather. The process used to investigate tail risks is like that used to investigate other emerging risks to the electric grid. The ProbA analyses undertaken by the PAWG embodies the current best practices and modeling approaches to analyzing risks by collectively discussing risks, sparking discussions about what might occur that is not explicitly analyzed in the base ProbA cases, and having PAWG members select issues that appear to be relevant to their system.

These results are then peer reviewed by other PAWG members. By this method, trends that begin to emerge in one area can be shared and inspire other analyses to enhance probabilistic resource adequacy planning processes.

Because tail risks are typically related to time-limited windows of varying durations, incorporating the results into an annual analysis may result in the significant masking of the effect being evaluated. Consequently, tail risks are probably best represented as scenarios of time-limited windows. However, if the tail risk occurs at a time that coincides with a critical period of need, such as hot or cold weather, and there are not any common-mode failures driving the analysis, it may be appropriate to reflect the tail risk in an annual assessment. For example, if hot summer weather is expected to be increasing in magnitude, then incorporating the risk into an annual reliability analysis that would increase installed reserves could be appropriate.

Additionally, care should be taken to understand the risk factors that are being evaluated. Causal analysis of statistics may indicate a statistical relationship between a condition and a statistic, such as EFOR. Without a clear understanding of the underlying root cause of the statistical relationship, erroneous conclusions may be inferred, and inappropriate remedies suggested. For example, in the event a statistic shows an increase in EFOR with cold temperatures, adding more resources with the same vulnerability may not produce the desired improvement because the additional resources also may not be properly insulated and winterized.

Fuel Risks Related to Severe Cold Weather

As illustrated in the previous chapter, tail risks come in many different forms and are generally correlated to weather-related events. For example, freezing conditions may inhibit fuel processing such as well-head natural gas production and extraction of fuel from storage and/or generate problems related to combustion at the burner tip.

In addition to fuel supply issues, fuel delivery systems may be inadequate for simultaneous delivery of fuel to electric power generators. Typically, this is discussed and characterized as a pipeline limitation; however, delivery of fuel oils via truck can create a significant bottleneck during a prolonged cold snap when fuel inventories at home and commercial, industrial, and electric generators are depleted and require timely refills.

Natural gas infrastructure is a common carrier that supplies natural gas energy for a wide range of customers from residential customers to electric generators. This infrastructure has traditionally been built and funded by natural gas distribution companies that consequently have priority rights to the transportation services provided by the pipelines. These priority customers generally have sufficient unused pipeline capacity to enable electric generators to use their transportation resources on an as-available basis. While some electric generators may have affiliates that provide firm supplies and transportation, this is not a widespread practice. Thus, natural gas may become unavailable due to the competing demand of other parties with higher contractual priorities. Because FERC regulations require unused natural gas pipeline capacity to be released to other customers when not needed, only firm contracts by electric generators that result in enhancements to natural gas pipeline and supply infrastructure will improve the robustness of natural gas supply to those electric generators.

Modeling Recommendations

To analyze these risks, existing tools need to be augmented to represent fuel limitations. This can be done via scenario analysis in which specific amounts of vulnerable resources are removed from service. Using a national fuel model that simulates fuel supply, demand, storage, and pipelines may be one way forward. A wide-footprint model of this complexity might be needed to predict fuel limitations because of the potential effects of temperature on natural gas availability. In addition to temperatures, winter precipitation may also inhibit adequate fuel replenishment. A front-end, pre-processing model that could translate temperatures to fuel availability would be ideal. Additionally, a scenario model that would progress through time to capture the depletion of energy reserves would be helpful.

Moderate Cold Weather-Related Risks

Severe weather is not the only cold-weather risk that may occur. Moderate cold weather-related risks in the form of ice storms are emerging due to their effects on the wind generators. Icing of wind generating resources was identified as a cause of significant unavailability in the February 2021 event in the South-Central United States. While there is a significant interest in extreme temperature events, the impacts of ice storms are much more difficult to forecast.

Modeling Recommendations

Because the effect of this type of weather risk would have a limited duration and the scope of the outages is not easily determinable from historical data, scenario analysis for a focused time-limited duration analysis would be warranted.

Severe Cold Weather-Related Non-Fuel Risks

Severe periods of cold can also result in increases in electric demands. With the emphasis on electrification of natural gas, oil, and resistance electric heating systems to energy-efficient electric heat pumps, these periods can result in significant additional loads while fuel supply issues may emerge.

Modeling Recommendations

The increase in loads can be analyzed via scenario analysis. Incorporating a cold-weather event in an annual analysis would lead to the effect being diluted. Consequently, a focused, time-limited duration analysis would be warranted.

Severe Hot Weather-Related Risks

Severe periods of hot weather can also result in increases in electricity demand. Unlike the severe cold-weather risks, natural gas demand during these hot-weather events would only be constrained during pipeline-maintenance conditions. However, hot-weather events pose risks for stored energy resources such as hydro reservoirs, pumped storage reservoirs, and other sources of energy storage such as batteries.

Modeling Recommendations

This can be analyzed via scenario analysis. A front-end, pre-processing model that could translate temperatures to a scenario model that would progress through time to capture the depletion of energy reserves would be helpful. Incorporating a hot-weather event in an annual analysis would lead to the effect being diluted. Consequently, a focused, time-limited duration analysis would be warranted.

Scheduled Maintenance of Unexpected Weather

Scheduled maintenance outages are a difficult problem for reliability analyses because of the many management decisions that affect the timing and duration of these outages. Because of the long lead times for scheduling maintenance and securing the appropriate skill sets and repair/refurbishment resources, these schedules are frequently inflexible. If either cold or hot weather occurs when a significant number of resources are out of service for maintenance, reliability could be at risk.

Modeling Recommendations

This can be analyzed via scenario analysis. A front-end, pre-processing model that could estimate known or expected scheduled maintenance would be able to provide insights. Consequently, a focused, time-limited duration analysis would be warranted.

Chapter 4: Interpretation of Probabilistic Indices for Extreme Weather

The NERC PAWG performs a ProbA[33] to supplement the annual deterministic NERC Long-Term Reliability Assessment (LTRA) analysis. The ProbA calculates monthly EUE and LOLH indices for 2 years of the 10-year LTRA outlook. Complete details and underlying assumptions of the ProbA Base Case analysis are included in the published LTRA reports. The ProbA analysis contains two studies that consist of a Base Case and a Sensitivity Case. The two differ in that the Base Case contains assumptions under normal operating conditions while the Sensitivity Case characterizes "what-if" probabilistic analysis terms.

Tail risks, such as those discussed in this white paper, are similar in construction and interpretation to the Sensitivity Cases, but a tail risk analysis studies something different. Tail risk analysis is intended to include additional risk factors to reveal the reliability implications across all hours with probabilistic methods. In many cases, time-limited windows focus on specific periods of a year where a risk or vulnerability might occur. The PAWG believes this approach to be of higher value than standardizing a Sensitivity Case study to capture the varied and complex reliability risks across Reliability Coordinators. Planning engineers use both expected outcomes as well as scenario cases.

While extreme weather scenarios represent an analysis into potential reliability risk factors, there is no guarantee or indication that these scenarios are indicative of future occurrences. However, these results are used to inform system planners and operators about potential emerging reliability risks. The PAWG recommends considering these tail risks in future probabilistic resource adequacy studies to develop further guidance for future work activities, when key points and takeaways are called out.

Reliability Metrics for Tail Risks

With the growing penetration of VERs in comparison to traditional base-load resources, either as load reducers or as supply, hourly variations in load and supply will become less predictable. Time series models that more accurately reflect the behavior of stochastic processes, such as the variations in wind speed and solar variations as well as assessment of the contributions and limitations of energy storage, may become more prevalent in probabilistic assessments. This change in modeling may, in turn, result in metrics like LOLH and EUE, which capture hourly variations in system conditions, becoming increasingly meaningful for measuring the reliability of the system. LOLH and EUE provide insight to the impact of energy-limited resources on a system's reliability, particularly in systems with growing penetration of such resources.

EUE, along with the value of load loss, can be used to perform the following actions:

- Monetize the cost of load loss to justify, prioritize, or rank transmission or other capital projects.
- Form the basis of a reference reserve margin to determine capacity credits for VERs.
- Quantify the impacts of extreme weather, common-mode failures, etc.

The focus of this section is three-fold: it surveys the electric sector's existing and future use of probabilistic studies to investigate BPS risks to reliability, it tracks evolving emerging trends, and it identifies applications for the electric sector to use known reliability metrics to assess emerging issues.

While many of the traditional probabilistic reliability metrics are useful for analyzing tail risks,[34] EUE may be the most relevant metric for understanding and comparing the severity of degraded-state tail risk events. Simulations should proceed until the system is restored at the end of the extreme weather event, so load can be lost, recovered, and

[33] Probabilistic Adequacy and Measures Technical Reference Report Final, July, 2018
[34] EPRI RA for a Decarbonized Future 2022 white paper

lost again depending on if the chosen extreme weather is expected to last significantly long (e.g., heat wave, downing of power lines over water like in the New Orleans event).

Description of Output

While the output of studies using methods in **Chapter 2:** will produce probabilistic indices, it may not be appropriate to compare the observed risk sensitivity to the ProbA base cases or another annualized metric.

Because these are tail risks, the metrics are conditional probabilities associated with a low relative probability. This conditional probability can be interpreted as the assumption that an extreme weather event is coming. Therefore, the resulting reliability indices do not reflect the actual expected probability that "extreme weather could occur and result in the risk of operating in a degraded state." Rather, it is the impact given the extreme weather occurred.

Operating in a Degraded State

Normal long-term resource adequacy plans include allowances for load and capacity relief via "emergency operating procedures." Because tail risks manifest themselves as reliability events when compounding events become so severe or pervasive that they overwhelm the reserve and contingency plans embodied in "traditional" resource adequacy plans, it may become appropriate to develop quantifiable "long-term emergency recovery procedures." Including such recovery procedures and reporting on their potential implementation can quantify a system's resilience against the identified tail risk.

Due to the infrequent and uncertain nature of whether an extreme event will occur, the appropriate planning may not be to install additional supply resources; it could be to react with a methodical and planned response while operating in a degraded state that minimizes the impact across the affected area without unnecessarily inflicting undue hardship on a limited subset of customers. This would depend on the type of load not served and the length of time that the load would not be served.

The addition of weather-related risks might necessitate the formal recognition of responses and development of emergency operating procedures to address these additional risks. For example, consider a customer with an electric heat pump for heating in the winter: they are concerned about a widespread ice storm outage that would be coupled with "normal" cold and result in days or weeks of outages such that their heat pump could not warm their home. Greater penetrations of heat pumps in the Northeast could lead to an auxiliary "emergency electrical distribution system recovery arm of fire-departments," or something similar, being added to the emergency operations. NERC encourages resource planners to develop such strategies in discussions with Transmission Planners and Planning Coordinators to plan for future-year operators to operate the system in potential emergency conditions.

Interpretation of Probabilistic Studies to Assess Tail Risk

Previous NERC assessments showed the need to support probability-based resource adequacy assessment due to a changing resource mix with significant increases in energy-limited resources, changes in off-peak demand, and other factors that can influence resource adequacy. As a result, NERC is incorporating more probabilistic approaches into its assessments, including the development of this report. The NERC PAWG examined the use of probabilistic studies for assessing emerging reliability issues.

NERC's goals, outlined in the operating plan,[35] include identifying, assessing, and prioritizing emerging risks to reliability by using probabilistic approaches to develop resource adequacy measures that reflect variability and overall reliability characteristics of the resources and composite loads, including non-peak system conditions. NERC's intent is to perform the following actions:

[35] https://www.nerc.com/comm/RISC/Related%20Files%20DL/ERO-Reliability-_Risk_Priorities-Report_Board_Accepted_February_2018.pdf

- Educate policymakers, regulators, and industry on the relationship of on-peak deterministic reliability indicators (e.g., reserve margin) to 8,760 hourly probabilistic reliability indicators (e.g., LOLH).
- Develop a catalogue of tail risk scenarios that can be applied to many areas that consider a wide range of risks.
- Create a catalogue of scenarios that builds in regional, and climate-model driven extreme events.
- Develop a screening tool to identify potential risks and suggest the need for additional study years or ad-hoc regional assessments.
- Work in tandem with LTRA annual results.
- Develop a collective understanding of existing applications of probabilistic techniques used for reliability assessments and planning studies.
- Identify commonalities to inform industry on the applications of probabilistic reliability metrics.
- Provide guidance on the development of probabilistic methods for ensuring resource adequacy and reliability to allow better risk-informed decisions for planners and policymakers in the face of increasing uncertainty of supply and demands on the BPS.

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Probabilistic Planning for Tail Risks

PAWG White Paper

March 2024

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

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

The North American BPS is made up of six Regional Entities as shown on the map and in the corresponding table below. The multicolored area denotes overlap as some load-serving entities participate in one Regional Entity while associated Transmission Owners/Operators participate in another.

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

Statement of Purpose

The purpose of this white paper, Probabilistic Planning for Tail Risk, is to investigate ~~low~~ the operational risks from low-probability~~ /~~ /high~~-~~-impact ~~risks to improve the Independent System Operator's (ISO's) and stakeholders' understanding of operational risks under~~ future weather ~~extremes. Improved understanding of these~~ extreme conditions. Understanding the impacts of risks will ~~enhance the understanding of the potential consequences of extreme weather and~~ prompt discussions about how best to prepare for them. As described in this white paper, operational planning responses can be in the form of increased generation and transmission capacity to bolster reserve margins, identification of resources with common~~-~~-mode vulnerabilities, and energy sources that can offset deficits or provide ~~resiliency~~resilience in the event of an extreme event.

Recognizing that the BPS cannot totally withstand all potential events, an adequate level of reliability[1] must be provided so that the system can be reliably operated even with degradation in the quality of service~~ due to an event.~~. Furthermore, the system must have the ability to rebound or recover when repairs are made, or system conditions are alleviated. The *Reliability Issues Steering Committee* (RISC) *Report on Resilience*[2] provides guidance on how resilience fits into NERC's activities and how additional activities might further support resilience of the grid. The RISC report underscores NERC's longstanding focus on aspects of resilience and emphasis on re-examining the issue in the face of ~~the~~a changing resource mix.

The NERC Probabilistic Analysis Working Group (PAWG) attempts to address these concerns through best practices gathered from published literature and users of the probabilistic tools in the electric power industry. The main ~~concerns~~concern for both planners and operators ~~are~~is to develop a system with an adequate level of reliability as spelled out in NERC's Standards. Their common objective is to maintain reliability, resilience, and security of the system at satisfactory levels~~,~~ and plan to avoid widespread outages during extreme high-impact, low-probability events that could occur in real-time operations.

The white paper covers the full implementation of a probabilistic study on extreme weather events and includes the following components:

- Assessment or study setup for extreme weather or events, including key assumptions.
- Development and enhancement of study models.
- Simulation or study techniques regarding extreme weather.
- Reporting of probabilistic indices on extreme weather.
- Recommended steps for the Reliability and Security Technical Committee (RSTC) or other NERC entities regarding probabilistic assessments (ProbA) and the related reporting of these extreme weather risks.

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[1] https://www.nerc.com/FilingsOrders/us/NERC%20Filings%20to%20FERC%20DL/Informational_Filing_Definition_Adequate_Level_Reliability_20130510.pdf

[2] Report on Resilience, NERC, November 8, 2018

Chapter 1: Key Findings and Recommendations

With the electric industry ~~undergoing a~~ transforming its resource mix, rapid ~~change~~changes are being made in the way the BPS is planned and operated~~, predominantly driven by~~. Driving this transformation is a changing resource mix, ~~and increasing~~with increased penetration of renewable energy resources such as wind~~,~~ and solar ~~and then combined~~coupled with frequent extreme weather events~~, models~~. Models focused on tail risks could be ~~an appropriate approach~~used to address the risks imposed on ~~a system~~the BPS. Typically, these risks are characterized by their low probability, but potentially with high~~-~~-impact disruptions. Tail risks are sometimes so difficult to ~~quantity~~quantify that they seem unlikely, although we know this is not always the case.

The white ~~paper~~paper's key findings and recommendations focused on improving modeling of tail risks ~~modeling~~ in planning studies are summarized below:

Key Findings

- Exploring ~~tail risk~~ best practices and modeling approaches ~~to~~for tail risks such as extreme weather ~~or~~ events by industry in probabilistic resource adequacy planning processes has attracted renewed attention in power systems engineering in recent years.
- Probabilistic methods can often reflect underlying uncertainties better than deterministic methods, and they can also support and enhance more efficient BPS planning and operation.
- ~~Intermittency~~Uncertainty of variable energy resources (VER) is likely to be the dominant source of tail risk in the future.
- The addition of a wider range of scenarios will provide the natural framework in which to analyze the variable output from renewable sources during extreme weather events when determining system impact and resource interconnection studies.
- Scenario analysis for focused time-limited duration analysis is warranted as modeling must consider weather risk with a limited duration and the scope of the outages is not easily determined from historical data.
- Expected unserved energy (EUE) could be the most useful metric in understanding and comparing the severity of the degraded ~~state of the~~ tail risk~~.~~ state.
- Probabilistic planning needs to continually evolve to properly account for the increasing frequency and impacts of extreme natural events deviating from historical trends, coupled with the anticipated increase of weather-dependent resources connecting to the BPS.

Recommendations

- Develop a catalogue of tail risk scenarios that can be applied to many Regional Entities that consider a wide range of risks.
- Use the catalogue as a ~~check list~~checklist to identify potential risks and suggest the need for additional study years or advise the industry of targeted "useful" sensitivities to underscore the risk.
- Analyses should include a risk perspective across relatively wide footprints because of the ~~intermittency~~uncertainty of resources and the interconnected nature of the power grid~~,~~.
- Encourage commercial software vendors to adopt a front-end, pre-processing model that could translate temperatures to fuel availability and augment existing tools to allow fuel limitations to be represented.

- Modeling should consider weather risk that could have a limited duration while the scope of the outages is ~~not easily determinable~~unclear from historical data, ~~therefore~~thereby making scenario analysis for a focused time-limited duration analysis ~~would be~~ warranted.

- ~~Uncertainty from Variable Energy Resource (VER) output is likely to be the dominant source of tail risk in the future. Because of this uncertainty and the interconnected nature of the power grid, analyses should include a risk perspective across relatively wide footprints.~~

Chapter 2: Tail Risk Study Background

Leveraging the National Infrastructure Advisory Council (NIAC) framework and the NERC adequate level of reliability, the RISC created the model depicted in **Figure 2.1** that illustrates and enables measurement of system performance or resilience and provides an understanding of the elements needed to support the reliable operation of the BPS. Measuring the profile represented in this model provides relative characteristics of system performance, identifies areas where improvements may be desired~~,~~ post~~-events-~~event, and measures the success ~~from~~of system improvements. ~~Some of the~~The key areas that lend themselves for measurement ~~are~~include robustness, amplitude, degradation, recovery, and recovery state.

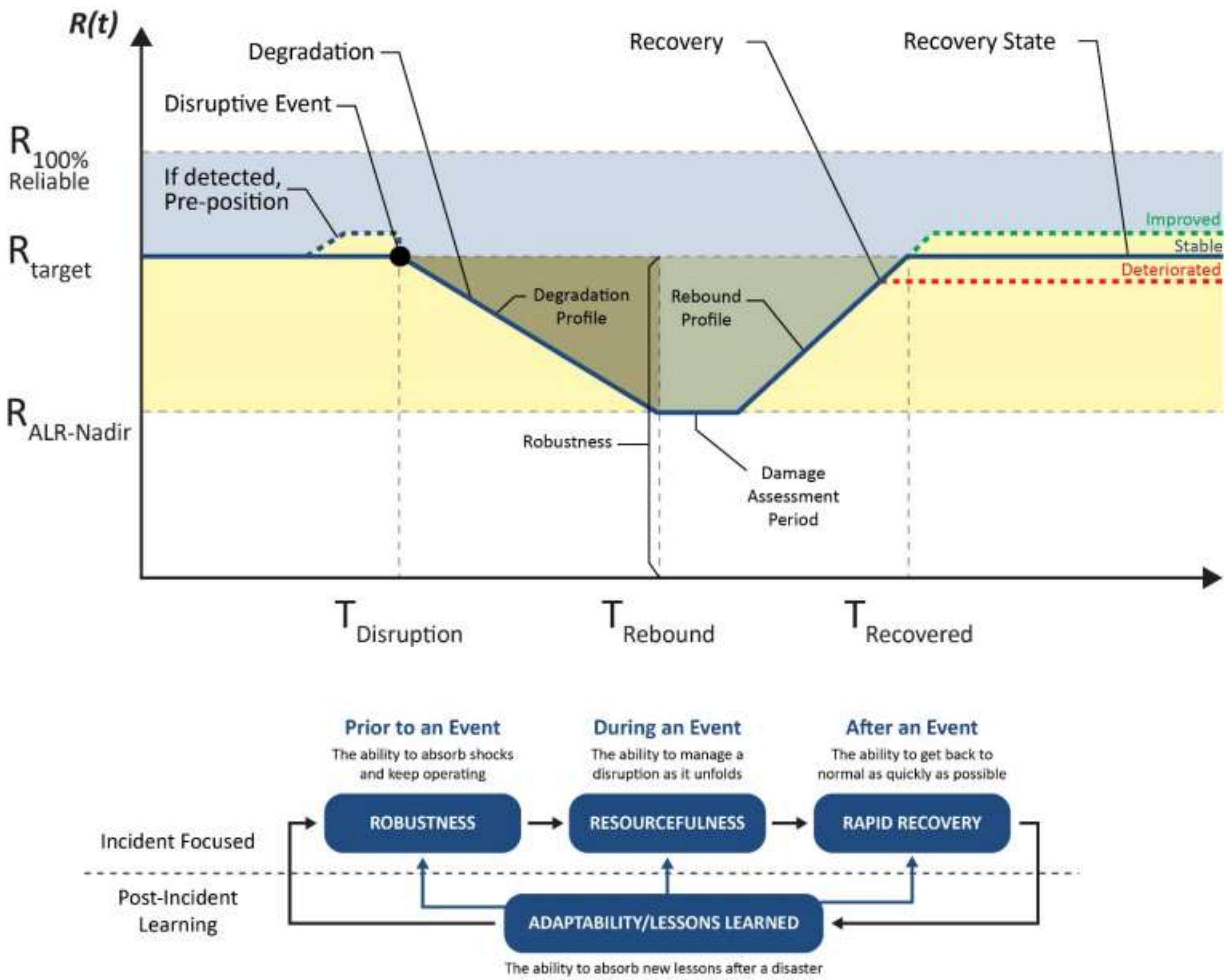


Figure 2.1: RISC Model for Reliable Operation of the BPS

Probabilistic Indices

In the electrical power industry, risk is evaluated by using a loss of load metric over a duration of time based on the probability of not meeting all customer demand, resulting in unserved energy. Probabilistic metrics describe the probability that a period will have unserved energy ~~because there would be~~due to insufficient resources to meet demand during that period. This evaluation method is referred to as a loss of load probability~~.~~ (LOLP). The summation of the ~~loss of load probability~~LOLP over a specific time, such as a year, will provide an expected value of the number of occurrences of loss of load events. This summation is referred to as a loss of load expectation (~~e.g.,~~ LOLE) over a specified period. The LOLE is typically ~~is~~ for the most severe conditions in a day; historically, the highest contributions to LOLP and LOLE occurred during the annual peaks. A related metric that is frequently used is the expected number of hours that a deficiency will occur (e.g., loss of load hours (LOLH)) over a specific time, such as a year. Neither the LOLE nor the LOLH metrics provide information about the amount of unserved energy in the loss of load events. Because the cumulative amount[3] of this unserved energy is a useful metric, the ~~expected unserved energy (e.g., EUE)~~EUE metric is frequently reported for completeness.

To develop these reliability metrics, a set of assumptions about the system to be evaluated must be developed. Using a framework that evaluates these probabilities in an organized manner quantifies if there are sufficient resources and transmission to meet system demand.[4] The results can be developed for the entire system or for portions that are constrained or bounded by transmission limitations.

While reliability models are already designed to address tail risks and investigate infrequent risks to reliable operation of the electric grid, ~~there~~concern is ~~a~~ growing ~~concern~~ that some risks may become amplified by changing weather patterns that are underrepresented by assumptions used in current models. Further, these risks may not be random in nature as weather patterns cannot ~~to~~be assumed to be random. Additionally, supply resources are increasingly turning toward sources of energy that are a product of weather conditions (e.g., wind and solar energy) that have significant variability, common modes of production, and lulls that add to system risks. Furthermore, with increased electrification of the economy, supply disruptions due to weather conditions can be amplified.

~~To investigate specific tail risks, the~~The set of underlying assumptions for a probabilistic study can be modified ~~for those~~to investigate specific tail risks and ~~are then~~ studied to determine ~~a~~the consequences of a specific conditional probability ~~associated with a~~ scenario. This can be done either individually or in combination with other factors. This paper ~~seeks to propose~~proposes ways to plan the bulk system while recognizing tail risks.

Definition of Tail Risks and Extreme Weather

Tail risks are characterized by the risk imposed on a system because of their low~~-~~-probability~~,~~ but high~~-~~-impact disruptions. As the electric system becomes influenced by weather for both demand and supply, weather-related risks become critical factors that affect reliability. Furthermore, these weather-related risks are not random, and mitigating them is challenging since weather patterns may become more difficult to predict ~~due to changing weather~~as the patterns change. Climate models may be needed to put boundaries around scenarios useful in the probabilistic analysis of future systems.

Currently, the supply uncertainty associated with solar, wind, and hydro-based VERs ~~are~~is reasonably well understood and accommodated in planning studies. The supply risks associated with the VERs are embedded in the historical output of solar, wind, and hydro generation. Given the availability of real and synthetic data that covers most of North America,[5] the data to evaluate some amounts of reliability impacts ~~are~~is available. However, a more complete range of possible weather-related risks is not available.

While ~~there is~~the historical data provides a great deal of information about the reliability contribution of these VERs ~~in the historical data~~, the variability due to extreme weather is likely underrepresented. The greatest supply risk associated with these technologies is prolonged widespread hydro droughts, long periods of low wind output (e.g., “wind droughts”), high wind cut-outs, or very low ambient temperatures and solar soiling (e.g., dust, snow, smoke, smog, extreme clouds). Such reductions in VER energy would result in the drawdown of stored energy from

[3] ~~Note that the~~ The term “expected” here is used in the description of anticipated value of a random variable rather than a future prediction of the disruption.

[4] This is one of the roles of the Resource Planner and Transmission Planner, respectively.

[5] National Renewable Energy Laboratory (NREL) synthetic data sets in their toolkits.

dispatchable resources that would be needed during lulls in the production of VER energy. A drawdown in available energy may be associated with local resources but may also affect stored energy in neighboring and even more distant regions.

Historically, the stored energy was readily available in the form of coal in coal-piles, natural gas in pipelines and geologic storage reservoirs, oil and ~~liquified~~liquefied natural gas in tanks, rods in nuclear plants, and water in hydro reservoirs. In the future, batteries will be added to the system, but the amount of energy (expressed in MWh equivalent) is expected to be much smaller than the more traditional sources of stored fossil and hydro energy. Consequently, the state~~-~~ of~~-~~ charge of batteries can be depleted relatively quickly compared to stored energy fueling legacy fossil energy resources. Depletion of stored energy resources is a key concern that makes the analysis of tail risks critical.

Recent Extreme Weather Events

Recent NERC Event Analysis reports and FERC-NERC inquiries have demonstrated the impact ~~and extent~~ that some extreme weather events have had on the reliability of the bulk system. There are a few documents of note:

- Joint FERC-NERC inquiry on the December 2022 winter storm Elliott[6]
- Joint FERC-NERC inquiry on the February 2021 ERCOT events (cold weather related)[7]
- Hurricane[8] Harvey
- Hurricane Irma[9]
- Joint FERC-NERC report on the 2018 South Central Cold Weather Event[10]
- January 2014 Polar Vortex[11]

Analysis of Changing Weather Patterns

Weather, particularly changing extremes and ~~-~~the range of variability, is a key factor that affects resource (i.e., energy) availability, demand patterns, and related reliability concerns. Extreme weather events in Texas and California have made it apparent that multi-day or longer energy deficiencies have serious consequences for residents of the affected areas and the economy. Energy unavailability ~~risks~~events are well documented, highlighting the importance of conducting comprehensive energy reliability assessments that cover a wide range of operating conditions, including low-probability, high-impact reliability risks (tail risks) related to extreme weather.

~~The~~For instance, the Electric Power Research Institute (EPRI), in collaboration with ISO New England and other interested parties, is conducting *The Operational Impacts of Extreme Weather Events*[12] project~~. This is~~, a probabilistic energy availability case study for the New England area under extreme weather events. The ~~goal of the~~ study ~~is~~seeks to ~~illustrate~~develop a framework to assess operational energy-security risks associated with extreme weather events~~.~~ ~~This opportunity is intended for industry leaders and~~ to enhance awareness of regional ~~stakeholders to illustrate how extreme weather events in the future may affect the evolving power system and to~~energy shortfall risk over the study horizon and prompt preparation.

[6] https://www.ferc.gov/news-events/news/ferc-nerc-release-final-report-lessons-winter-storm-elliott
[7] Joint FERC-NERC inquiry on the February 2021 ERCOT events
[8] Hurricane Harvey
[9] Hurricane Irma
[10] Joint FERC-NERC report on the 2018 South Central Cold Weather Event
[11] January 2014 Polar Vortex
[12] Operational Impacts of Extreme Weather Events Key Project

Augmenting NERC PAWG Probabilistic Assessments

The PAWG has members whose companies are ~~currently~~ at work implementing the specific recommendations of the various NERC studies and reports. These companies are envisioned to modify their own planning processes in ways that are ongoing. While most of these efforts are weather related, there can be future ways and methods to probabilistically plan for extreme risks.

Time will tell if any of these efforts will emphasize tail risk over reworking the “normal” ~~probabilistic assessments~~ProbAs that each organization performs as part of the NERC Long~~-~~-Term Reliability Assessment and their own reports. The PAWG will continue to share the efforts and successes and determine if future work at the NERC PAWG is needed to provide ~~a~~ best practice to augment the material ~~that is reported in the Long Term Reliability Assessment (LTRA) .~~here.

Classification of Tail Risks by Planning Response

There are three general classifications of tail risks based on the resource adequacy planning response. All three classifications can be analyzed by using simulations and are suitable for developing quantitative reliability indices. However, the type of planning response that may be appropriate to address the risk is different for each of the three classifications. Some tail risks, such as cyber~~-~~ security, widespread forest fires, and grid stability issues, are outside the realm of probabilistic analysis and not addressed here.

Technology~~-~~-Agnostic Resource Adequacy Response

Generally,~~ it is assumed that~~ technology-agnostic resources have root causes of unavailability that are random and independent compared to the rest of the resource fleet~~..~~. For this class of risk, the most appropriate planning response is to increase or decrease the number of resources available to serve demand for energy from customers. This supply is described as technology agnostic because one type of resource is reasonably interchangeable with another resource even though there may be a quantifiable capacity “equivalence rate” between different types of technologies.

The planning response to a tail risk associated with high loads driven by weather would be to install more supply resources to decrease the probability of a shortage when the high loads occur. With the rising concern that weather will encompass more extremes than observed in the past, quantifying the magnitude of the resulting additional loads is important to understanding reliability impacts and how an increase in available resources would affect reliability.

Because these conditions are driven by an identified need for additional supply, a salient feature of weather-driven extreme loads is that curtailment may have detrimental impacts on the customers. Because these episodes are not likely to be frequent, customers may not develop suitable or sufficient alternatives that would ~~allow~~enable them to ~~forego~~forgo essential heating or cooling services. In other words, because these events are infrequent, targeted demand reductions with market mechanisms or backup technologies (e.g., large ice-chests, gasoline-powered generators, or kerosene heaters) may not be available or sufficient.[13]

If an extreme weather event has a low probability to occur, its effect on expected load distributions would be diluted even if it had a high~~-~~-impact outcome. Because ~~of~~ the ~~dilution~~impacts are not detected, the additional supply resources indicated by the resource adequacy analysis may not be sufficient to satisfy the demands of that extreme weather event if it were to occur.

Given that the reliability criterion is non-zero, the risk of insufficient resources is an acceptable outcome. One planning response to the tail risk caused by the low probability of extreme weather is to make the desired reliability

[13] Developing a technology solution for curtailing weather-driven loads during a once~~-~~-in~~-~~-a~~-~~-decade extreme weather~~-~~-driven event may be possible but difficult. Technology solutions, such as energy efficiency, reduce weather-driven load volatility in all hours but would not have a supplemental dispatchable component during an extreme weather event.

criterion more stringent and therefore to require additional resources. Because there is a risk of insufficient resources, strategic management of such a resulting loss~~-~~ of~~-~~ load occurrence must be a consideration.

During extreme weather, the effects of heating or cooling equipment running at full output may ~~either~~ saturate ~~the~~ demand and limit any additional increases in demand because everything is running~~ or potentially~~. Alternatively, these effects may drive the aggregate demand higher based on the addition of climate~~-~~-conditioning equipment~~-~~—such as a spare electric space heater—operating with a high coincidence factor ~~such as when there is always another electric space heater in~~or the ~~closet~~equipment's operating characteristics themselves, such as heat pumps that ~~can be used.~~switch to resistance heating at low temperatures. Care should be taken to understand the load ~~dynamics~~behavior under these harsh conditions.

Technology Vulnerability Resource Adequacy Response

A secondary class of tail risk is characterized by resources that have a specific vulnerability commonly shared with other similar resources; this shared vulnerability could threaten reliability if the resource type is widespread. Examples of a ~~technology~~technologically vulnerable resource would be wind generation during a widespread wind lull or storage resources after an extended period when stored energy is drawn~~-~~ down. For this class of risk, the planning response would be to recognize and limit the dependence on the resource type with the identified vulnerability. A related planning response would be to decrease the equivalence rate of the vulnerable resource type (e.g., more ~~-~~nameplate capacity to get the same reliability equivalent as another type of capacity). Various methods have been developed to quantify an equivalence rate between different types of capacity. This equivalence is frequently expressed as an equivalent load carrying capability (ELCC).[14]

The vulnerability is generally caused by a disruption of the primary source of energy used in electricity production or because of a common~~-~~-mode condition. An example would be the decreased capability of natural gas turbine technologies associated with higher ambient temperatures. Another example of such a vulnerability is the decreasing equivalence rate of wind and solar resources as their penetration increases. This decreasing equivalence occurs because widespread wind lulls and/or widespread cloud cover reduces the primary energy source for the wind and solar resources as a class and the reductions can no longer be described as random and independent.

Another example of a ~~technology~~technologically vulnerable resource is a fleet of natural gas resources[15] that do not have dual~~-~~-fuel capability. Such resources may be subject to simultaneous primary energy source disruptions due to pipeline ruptures, fuel supply difficulties due to freeze-in of natural gas wells, competition for limited fuel supplies, or other mechanisms that preclude acquisition of sufficient fuel. ~~Resources with these~~These vulnerabilities could render ~~them~~the resources unable to provide their expected resource adequacy services. The planning response to this could include requiring or incentivizing dual-fuel capability to reduce the natural gas supply risk.

Restoration~~-~~-Focused Resource Adequacy Response

The third class of tail risk is characterized as one where the most likely planning response would be to focus on ~~resiliency~~resilience, enhanced restoration procedures, and equipment placement rather than implementing a resource adequacy solution where more supply resources are added. The need for this class of response is explicitly recognized because of a non-zero reliability criterion where events go beyond the capabilities of the available resources, suggesting the need for operating with a degraded system.

Examples of this class of risks could include recovery from a severe weather event, such as a hurricane, derecho, tornado, or ~~an~~ ice storm. In these latter examples, the key problem is not the loss of supply resources, but rather an inability to move energy from where it is available to where it is needed. A planning solution that called for the installation of more resources to increase reserve margins would most likely be ineffective~~. This is because~~, as the

[14] Methods to Model and Calculate Capacity Contributions of Variable Generation for Resource Adequacy Planning, March 2011
[15] BERC SPOD Document

ability of the additional resources to provide the power and move it to where ~~it's~~it is needed depends upon the path of the storm and transmission lines that ~~were~~would have been taken out~~-~~ of~~-~~ service by the weather event.

A planning response for this tail risk might be to develop criteria for customer outage restoration times depending on severity. While it is quite reasonable to expect that some severe weather events could be made less impactful by the judicious location of emergency or ~~back-up~~backup generators, this is not generally referred to as a resource adequacy issue. Additional transmission to more distant areas would increase the footprint where additional support might be sought.

To address disruptive common-mode events that are not yet fully reflected in resource adequacy, the industry can build on the conceptual framework for developing resilience metrics. Resource adequacy may contribute to supply resilience, while a broader resilience framework considers how to absorb, manage, recover, and learn from disruptive events.

Probabilistic Framework

Fundamental to the analysis of tail risks is an analysis of the underlying probabilistic distributions of loads and resources. The following figures provide a conceptual illustration of the distributions that are central to this analysis and how they interact in a resource adequacy analysis. The impact of tail risks will be discussed at a conceptual level. The primary distribution used in resource adequacy analyses is a probabilistic representation of the loads to be served. **Figure 2.2** shows that the 8,760 hourly loads in this example have a central tendency to be between 10,000 ~~MW~~ and 16,000 MW. The highest load in the distribution is 25,868 MW corresponding to a summer peak day that is, broadly speaking, typical. A tail risk due to extreme weather would increase the peak loads in the direction shown by the red arrow. To be reliable, the probability of having insufficient resources to meet this summer peak load should be zero or a small value. In this example, a small amount of unserved load will be used for illustration.

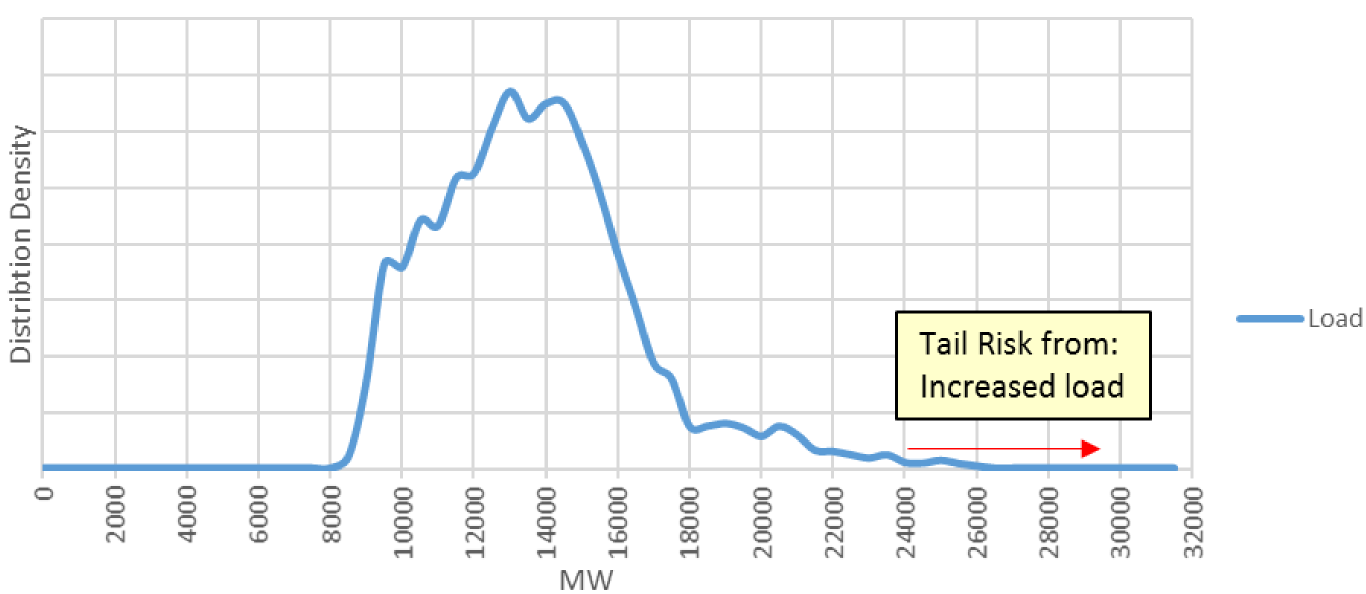


Figure 2.2: Illustrative Distribution of all 8,760 Hourly Loads

Figure 2.3 shows a conceptual distribution of available dispatchable resources. This distribution suggests that there are approximately 32,000 MW of available resources. Because of outages, the amount of capacity available to serve loads is always less than the maximum amount. In this example, the probability of having less than 25,000 MW is shown to be small. If there were common-mode vulnerabilities, the distribution would expand to the left as shown by the red arrow.

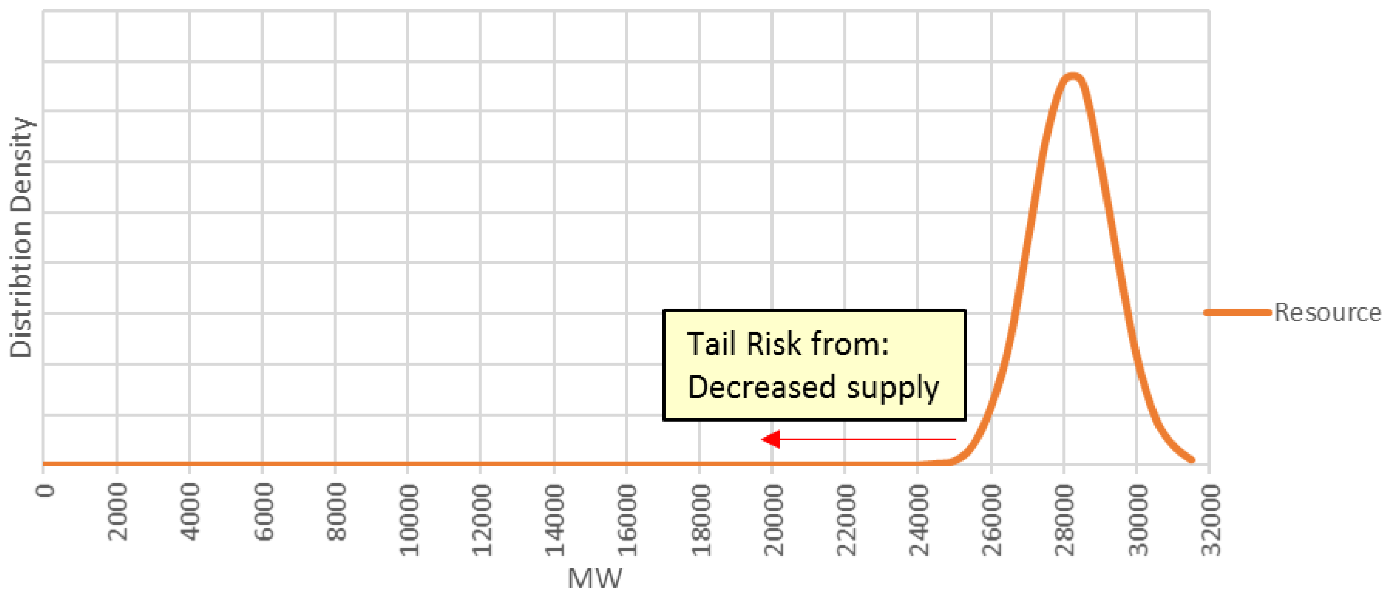


Figure 2.3: Illustrative Distribution of Available Resources

Figure 2.4 shows these two distributions superimposed on the same axes. This shows that the peak load is close to the minimum amount of capacity of the aggregate resources.

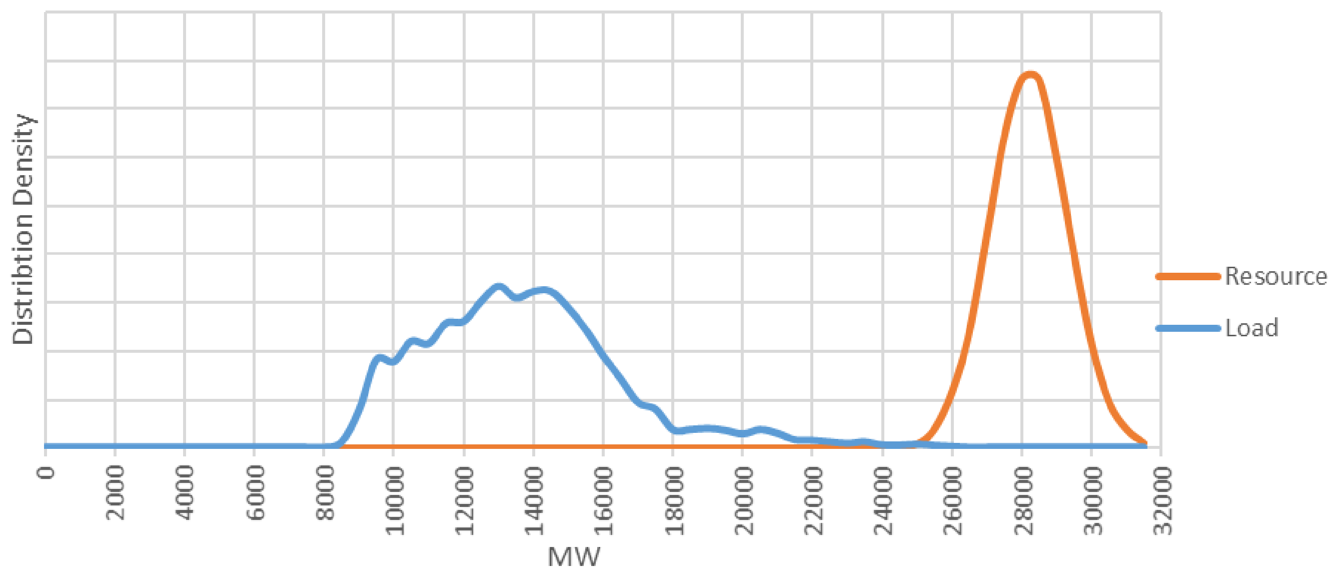


Figure 2.4: Conceptual Illustration of Loads vs. Available Resources

Figure 2.5 shows the actual margin between one Monte-Carlo replication of the resource distribution versus the load distribution.[16] Typically, the amount of available resources exceeds load by 8,000 to 20,000 MW. However, there are a few hours when the margin is close to zero or negative. In the case of a negative margin, the system had a non-zero probability of losing load.

[16] The margin was calculated by first creating a distribution representing the available capacity for all 8,760 hours. This distribution was based on a mean of 27,000 MW, a standard deviation of 1,200 MW, and a random number for each hour. The corresponding load in the associated hour was then subtracted from the available resource in order to get the margin in a specific hour. While not a rigorous probabilistic analysis, this approach is appropriate for illustrative purposes.

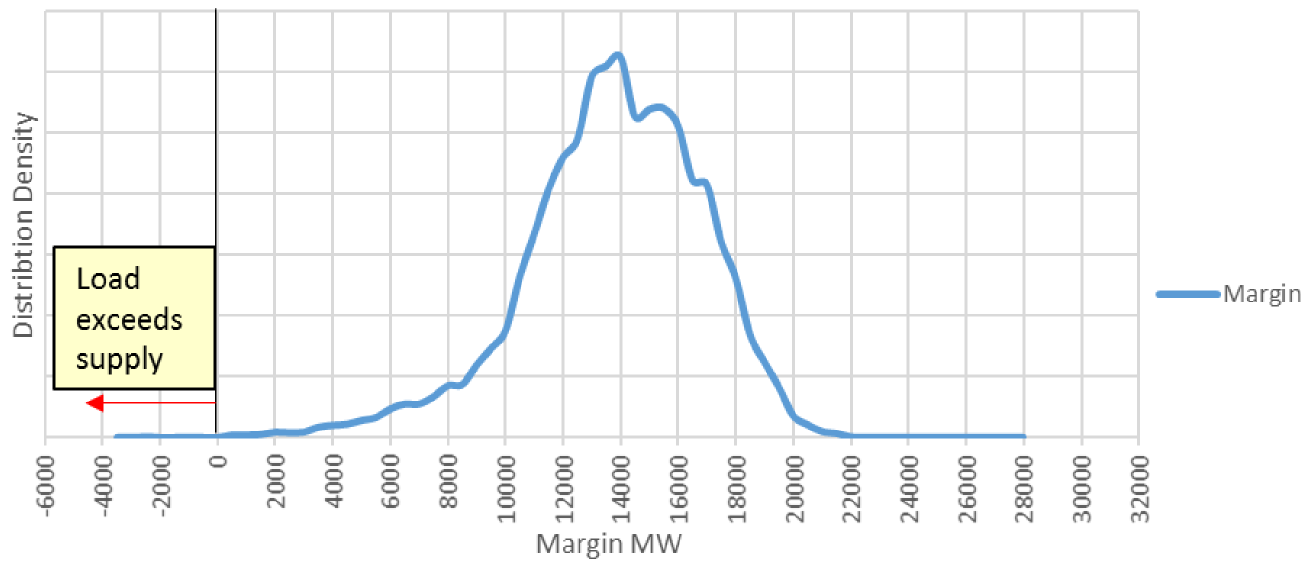


Figure 2.5: Conceptual Margin Between ~~loads~~Loads and Resources

Figure 2.6 shows a revised margin distribution based on the addition of wind and solar resources. To illustrate a comparable loss-of-load magnitude, the amount of dispatchable resources was reduced.[17] Typically, the amount of available resources exceeds the load by a wider range of 4,000 to 28,000 MW, suggesting that the dispatchable resources were available but not typically needed to serve loads. Because of the assumed reduction in the amount of dispatchable resources (compared to those assumed in **Figure 2.3),** a few hours remain during which the margin is close to zero or negative, similar to **Figure 2.5**.

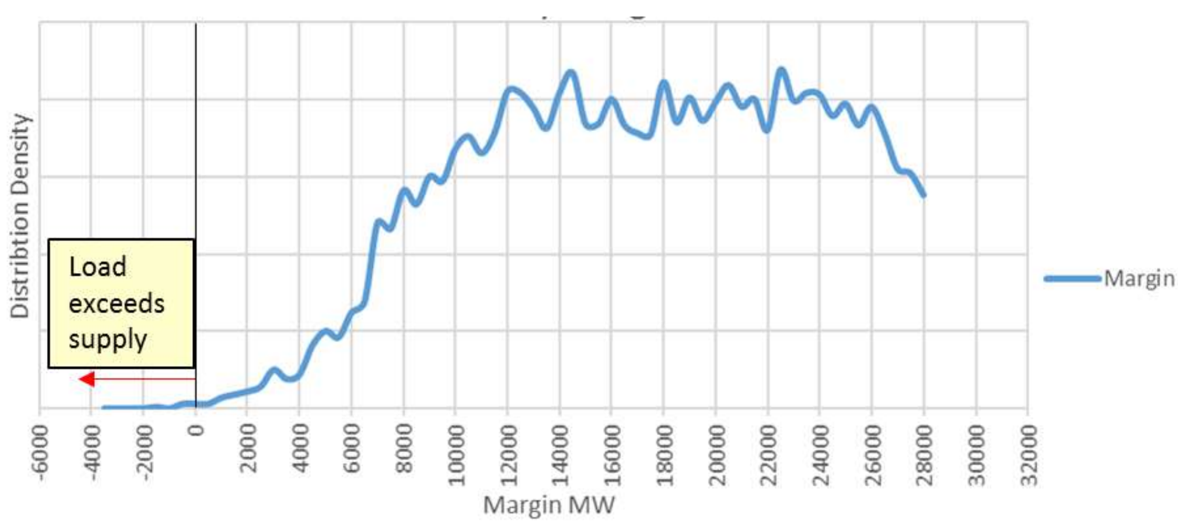


Figure 2.6: Conceptual Margin Between Loads and Mix with Wind, Solar, and Fewer Dispatchable Resources

The red arrow in **Figure 2.7** illustrates the tail risk affecting resource adequacy as discussed in this white paper; it ~~which~~ could be due to either higher loads or resources with greater unavailability.

[17] The mean of the distribution representing the available capacity for all 8,760 hours was reduced from 27,000 MW to 18,500 with the same standard deviation of 1,200 MW.

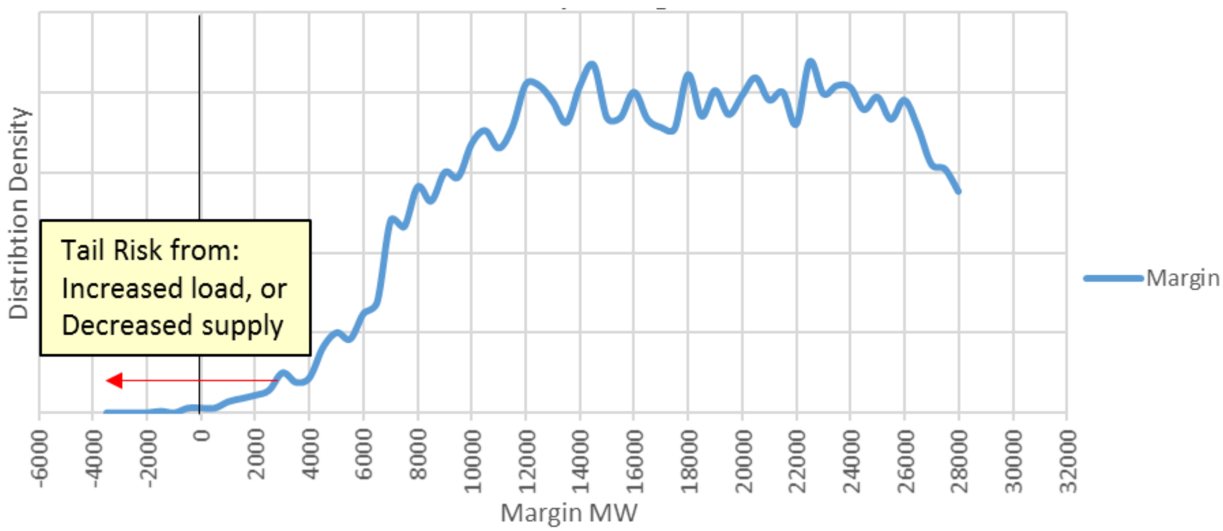


Figure 2.7: Additional Tail Risk from Increased Loads and/or Decreased Supply

Assumptions for Probabilistic Study of Tail Risks

There are several broad classes of factors that affect reliability because of tail risks. At a high level, two of these factors are the magnitude of the loads in comparison to the availability of supply and factors where supply can be a function of weather-related ~~phenomenon~~phenomena.

Risk of Extreme Loads

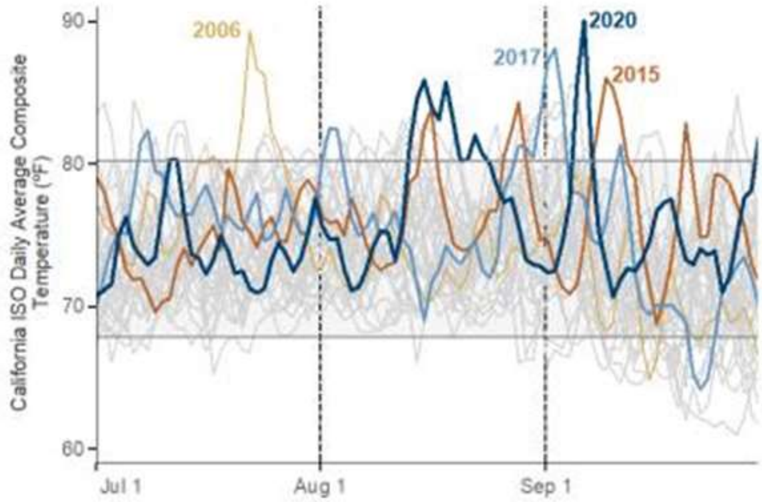
Reliability studies have methods that incorporate a range of loads based on observations developed from historical weather datasets. To some extent, forecast loads may reflect high values because the forecasting process typically incorporates normal variations based on observations spanning several decades that will surely include some hot-and cold~~-~~-weather outliers. Even if the risk of extreme weather is expected to increase over time, the likelihood of that weather being far outside the outliers experienced in the historical record is low. Some climate models suggest[18] that there may be more frequent occurrences of the outlier values with only modest increases in their magnitudes. A review of 2020 California and 2021 ERCOT outages suggests that, while extreme hot or ~~extreme~~ cold temperatures contributed to those reliability events, they were not outside of the historical record. Consequently, a focus on extreme temperature excursions may provide an incomplete assessment of the reliability landscape, and other factors need to be investigated.

California 2020

The August 2020 load~~-~~-shedding events in California ~~did~~were not ~~seem to be~~ caused by "extreme" heat solely from ~~the perspective of~~temperatures in California as shown in the graph below. The rest of the western United States also experienced high temperatures at the same ~~times~~time, and this reduced available support from ~~those~~ other areas ~~through interconnections.~~throughout the Interconnection. **Figure 2.8** shows that the ~~temperature~~temperatures in both September 2020 and July 2006 ~~had a temperature~~were higher than mid-August 2020 when the outages occurred.[19]~~.~~

[18] EPRI Report presentations with ISO New England

[19] Root Cause Analysis; Mid-August 2020 Extreme Heat Wave, California ISO, January 13, 2021



Source: CEC Weather Data/CEC Analysis

Figure 2.8: Summer California Temperatures 1985–2020

ERCOT 2021

In ERCOT, the temperature during the February 2021 cold snap was not an extreme weather event compared to past historical events. ~~Compared to five previous cold snaps,~~ **Figure 2.9**[20] shows that the 2021 daily average temperatures tended to be the second or third coldest during the seven-day window shown. This suggests that factors other than extreme weather had a significant role in the reliability event. Specifically, resource challenges occurred due to a sensitivity to weather conditions, which did not manifest itself during previous events. In addition to the freezing of mechanical components in power plants and unavailability due to the natural gas freeze-in that will be discussed later, another significant factor was the simultaneous outage of wind resources, with a large part of those outages caused by icing.

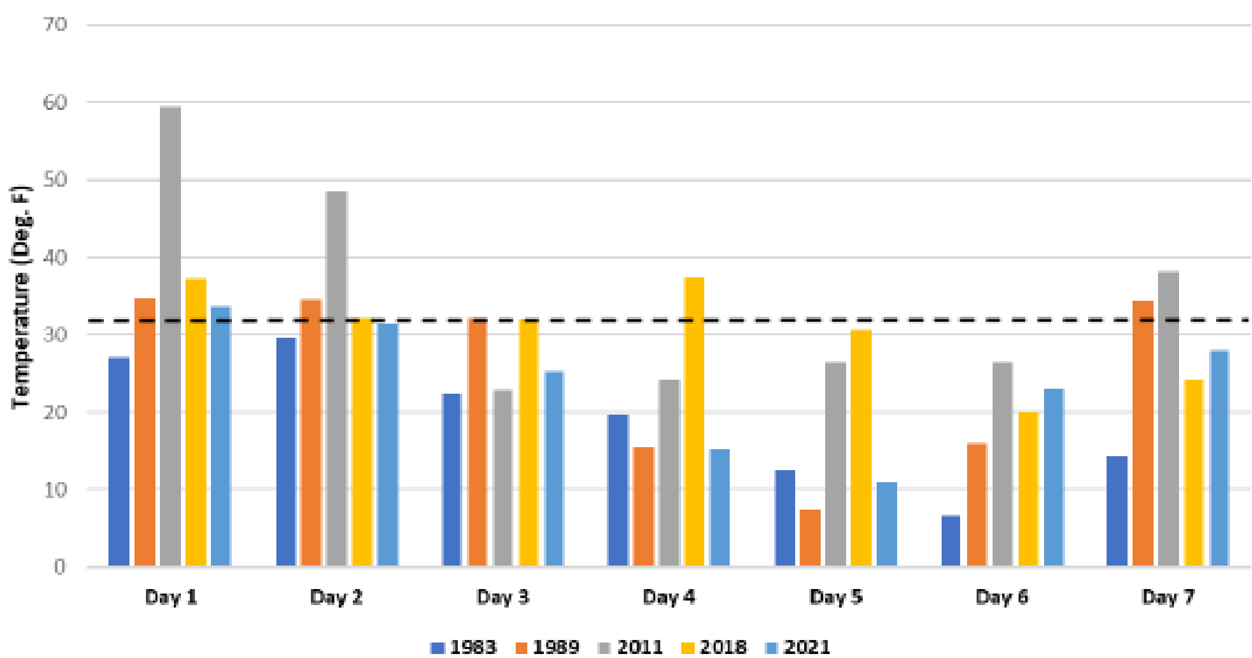


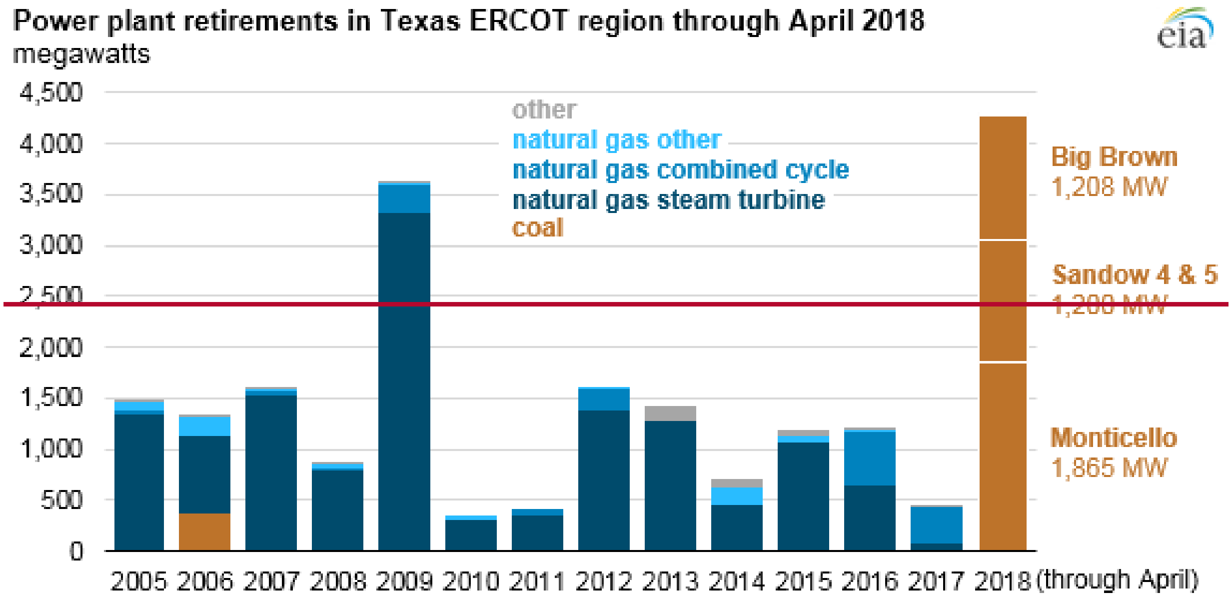
Figure 2.9: ERCOT Cold~~-~~-Snap Temperatures

[20] February 2021 Cold Weather Outages in Texas and the South Central United States, pdf page 247/316

Evolving Resource Mixes Reduce Fuel Diversity

As electricity resources evolve to lower carbon-intensity portfolios, the diversity of fuels ~~to drive~~supplying generating resources is shrinking. The increased penetration of wind and solar resources ~~are~~is reducing the ~~use of~~energy from fossil resources, especially coal, oil, and natural gas generators. This is a trend that affects all Regional Entities. As an example, **Figure 2.10** shows the retirement of coal-fired and other dispatchable resources projected in the ~~previous~~next decade[21] in ~~ERCOT~~the NERC footprint; the non-coal resources that ~~were retired~~could retire may have had dual--fuel capability. This ~~decreased~~will decrease fuel diversity that amplifies the reliance on dependable transportation of natural gas to generators during times of system stress.

[21] https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2023.pdf



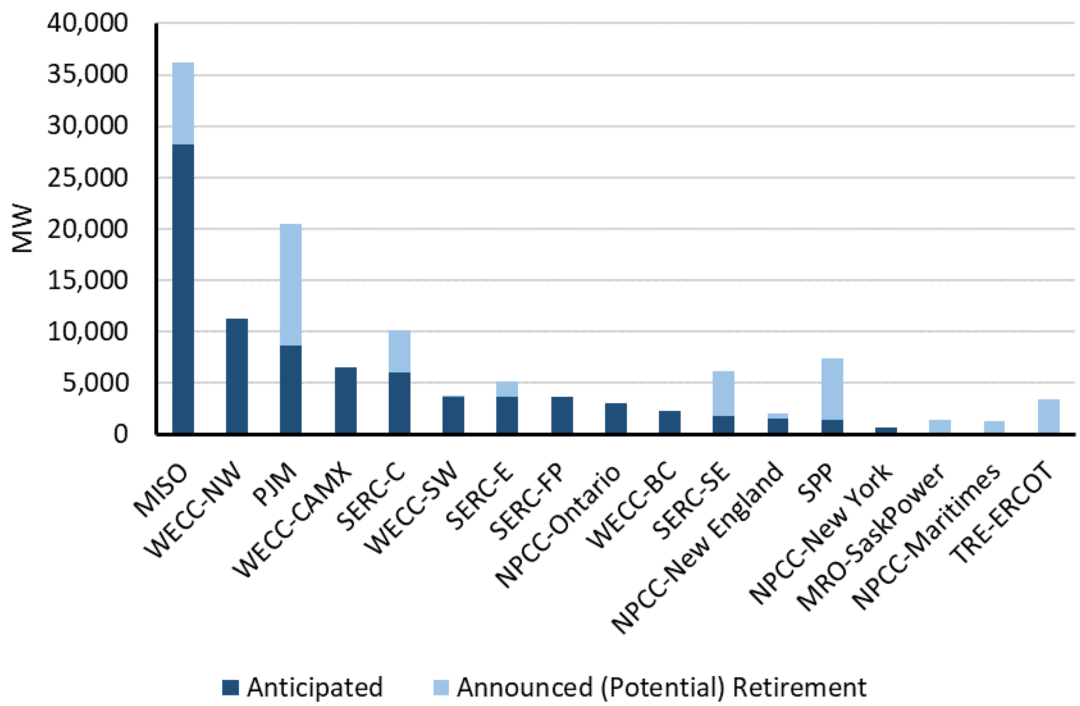


Figure 2.10: ~~Retirements in ERCOT Source: EIA~~\Projected Retiring Nuclear and Fossil Generation Capacity 2023–2033: NERC LTRA

Changing Weather Sensitivity of Load

The sensitivity of electricity loads to weather may be increasing as national and state policies promote electrification to increase overall energy efficiency and ~~consequently~~ reduce carbon emissions~~.~~ from customer demand. This increased sensitivity can also be a source of increased risk. For example, increased heating electrification can result in an increased load sensitivity to cold weather that would be greater than experienced previously for a comparable temperature~~ in the past~~. The historical sensitivity to temperature would be used to develop load volatility for the forecast years. The compounded risk of both greater electrification heating loads and a potential increase in sensitivity to colder temperatures could create loads that exceed forecasts.

Load Forecast Uncertainty Multipliers

There is no standard industry practice for addressing the future load volatility in reliability models. In developing load distributions for use in reliability studies, the tail risks associated with uncertain weather are represented by load forecast uncertainty multipliers. Reliability models, such as the GE MARS Model, use a combination of load-scaling multipliers and associated probabilities to reflect higher-than-expected loads at a relatively low probability.

Increased Competition for Natural Gas

State policies are orientated toward promoting electrification to reduce carbon emissions. Because liquid fuels such as heating oil and propane are more expensive than natural gas, electrification of heating systems using these fuels would typically provide greater economic benefits. Additionally, oil has a higher carbon footprint than natural gas for heating and would be the preferred target for electrification. Consequently, the demand for natural gas heating during cold snaps is likely to remain robust. Natural gas infrastructure expansion has been lagging the increased demand from the power sector. If a lull in wind and solar energy production occurs, natural gas may not be available in sufficient quantities for the power sector, and this would place increased demand on oil and coal generation with locally stored fuels. This would also increase the use and drawdown of other forms of dispatchable stored energy such as hydroelectric and batteries.

Resource Unavailability

Typically, probabilistic reliability analyses have reflected the unavailability of generating resources as random and independent events. The statistics underlying the unavailability are typically related to mechanical problems that affect only one generator without affecting other generators. While anecdotal evidence suggests the possibility of common-mode events among dispatchable resources, it has been difficult to establish quantifiable statistical relationships to include in forward-looking reliability studies. Generally, it has been relatively straightforward to develop estimates of resource availability due to random and independent events that can then be compared to loads. However, weather-driven factors can cause common-mode failures.

Temperature Sensitivities

One of the exceptions to assumptions about random and independent generator unavailability is related to temperature dependencies. The effect of ambient temperatures on mechanical availability is typically reflected by derating generators seasonally (e.g., summer vs. winter ratings). Combustion turbines are sensitive to air density, which reduces the rating with higher temperatures because less air can be brought in to support combustion. On the other hand, the air is denser with colder temperatures and generators can ingest more air and ~~they can~~, therefore, operate at higher outputs. Similarly, PV panels have decreased capability deratings during periods of high ambient temperatures.

Additionally, the typical seasonal profile of hydro energy limitations can also be reflected in seasonal or monthly ratings. These risk attributes have been addressed for many years in reliability analyses by using well-established protocols.

Effects of Freezing on Resource Unavailability

Mechanical unavailability due to freezing has been a recognized root cause of degraded system operations. The severity and consequences of freezing get worse with decreasing temperatures and have caused the industry to work together to address this common-mode vulnerability. However, addressing this risk vector has proven to be difficult, elaborated on here:

> *Both the 2011 and 2018 Reports identified certain equipment that more frequently contributed to generating unit outages, including frozen sensing lines, frozen transmitters, frozen valves, frozen water lines, and wind turbine icing. The Event was no different—generation freezing issues were the number one cause of the Event, and the same frequently-seen frozen components reappear. Given the repeated appearance of certain equipment in causing generating unit outages during cold weather events, NERC recommends in its Reliability*

Guideline that entities responsible for generating units "identify and prioritize critical components, systems and other areas of vulnerability." NERC further explains in its Reliability Guideline that "this includes critical instrumentation or equipment that has the potential to … initiate an automatic unit trip impact unit start-up[,] …initiate automatic unit runback schemes or cause partial outages."[22]

The effect of cold temperatures on resource unavailability affects many areas, including those located in northern climates where such conditions are expected. MISO's review of the event included these key takeaways~~.~~:

Key Takeaways: … extreme weather events cause even greater negative impacts on generation performance because of issues like unexpected weather-related generator outages or fuel delivery challenges. Winterization to protect generation and fuel supplies from extreme weather can mitigate this risk but MISO and its members must assess and establish certain criteria. For instance, to what extreme temperature must generators be prepared to operate, how does MISO ensure consistency amongst similarly situated generations, and whose role it is to establish and verify such requirements? … Further, fuel availability varies over time, and how and who should ensure fuel availability must be considered in reliability planning. Furthermore, if fuel assurance is required, how do we do so in the most cost-effective manner (e.g., annual firm fuel when the generator may only be needed a few times a year~~)~~)?[23]~~?~~

Figure 2.11 shows the sudden rise in resource unavailability at the onset of the cold snap at about February 15. Natural gas resources showed a large increase in unavailability while coal resources showed a relatively smaller increase. Increased wind resource unavailability preceded the cold snap and remained elevated until after the cold weather dissipated.

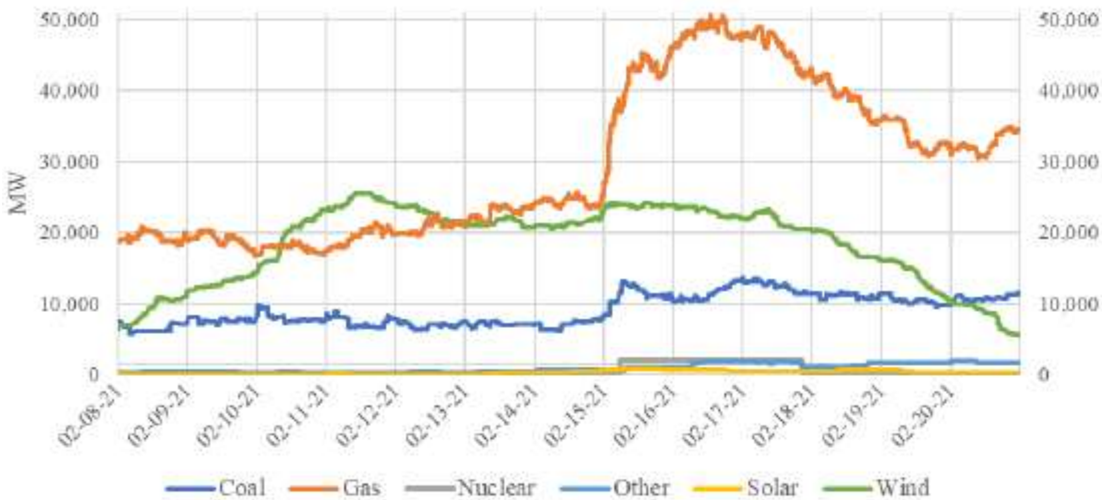


Figure 2.11: ERCOT Cold~~-~~-Snap Unavailability by Energy Source

Cold Weather and Natural Gas Supply

One of the dominant risk factors that affects large footprints is the reduction in natural gas supplies during cold snaps due to lost production because of supply freeze-in. Freeze-ins are a relatively frequent and recurring problem in natural gas production and processing facilities that ~~has~~have caused considerable supply issues, but this is outside of

[22]~~–~~ The February 2021 Cold Weather Outages in Texas and the South Central United States, https://ferc.gov/media/february-2021-cold-weather-outages-texas-and-south-central-united-states-ferc-nerc-and , p 186/316

[23] The February Arctic Event / February 14 - 18, 2021 / Event Details, Lessons Learned and Implications for MISO's Reliability Imperative, https://cdn.misoenergy.org/2021%20Arctic%20Event%20Report554429.pdf
~~https://cdn.misoenergy.org/2021%20Arctic%20Event%20Report554429.pdf, p 7/54~~, p 7/54

the scope of current electric system reliability models.[24] The development of techniques to quantify this risk as an integral part of a reliability framework may be an appropriate next step in the evolution of probabilistic analysis.

It is important to account for this fuel supply aspect of resource unavailability. For example, if forced outage statistics for resources affected by cold-weather-related fuel supply were to be increased to reflect this unavailability without explicitly representing the root cause of the reduction from freeze-ins, then ~~it's~~it is possible that a solution of adding more resources with the same vulnerability might be identified and pursued. However, because the root cause of the outage was not addressed, the reliability improvement from adding resources with the same vulnerability might prove elusive. Namely, the system condition that impacts existing resources would have the same effect on the availability of added resources. Solutions that explore other fuel types, technologies, or increased reach of transfers may have the desired impact.

ERCOT 2021

One of the key themes related to the February 2021 cold snap in the central United States was the available supply of natural gas for electricity generation.[25] This reduction in supply was mentioned in the above reports and is shown in **Figure 2~~-~~.12**. The key freeze-in issues are summarized here:

> *Generating unit outages and natural gas fuel supply and delivery were inextricably linked in the Event. Fuel issues, at 31.4 percent, were the second largest cause of unplanned outages, derates and failures to start during the Event. Eighty-seven percent of the fuel issues involved natural gas fuel supply issues and 13 percent involved issues with other fuels (such as coal or fuel oil). Natural gas fuel supply issues alone caused 27.3 percent of the generating unit outages. Natural gas fuel supply issues include declines in natural gas production, the terms and conditions of natural gas commodity and transportation contracts, low pipeline pressure and other issues. During the Event, unplanned outages of natural gas wellheads due to freeze-related issues, loss of power and facility shut-ins to prevent imminent freezing issues, and unplanned outages of gathering and processing facilities decreased the natural gas available for supply and transportation to many natural gas-fired generating units in Texas and the South Central United States.*[26]

[24] Natural Gas Dependence Document (see Chapter 5—Methods for Analyzing Natural Gas Demand and Infrastructure for Electric Power Needs)
[25] 1 Bcf of natural gas per day is sufficient to supply approximately 6,000 MW of efficient natural gas combined-cycle capacity for 24 hours.
[26] [FERC_ NERC(2021) at 163]

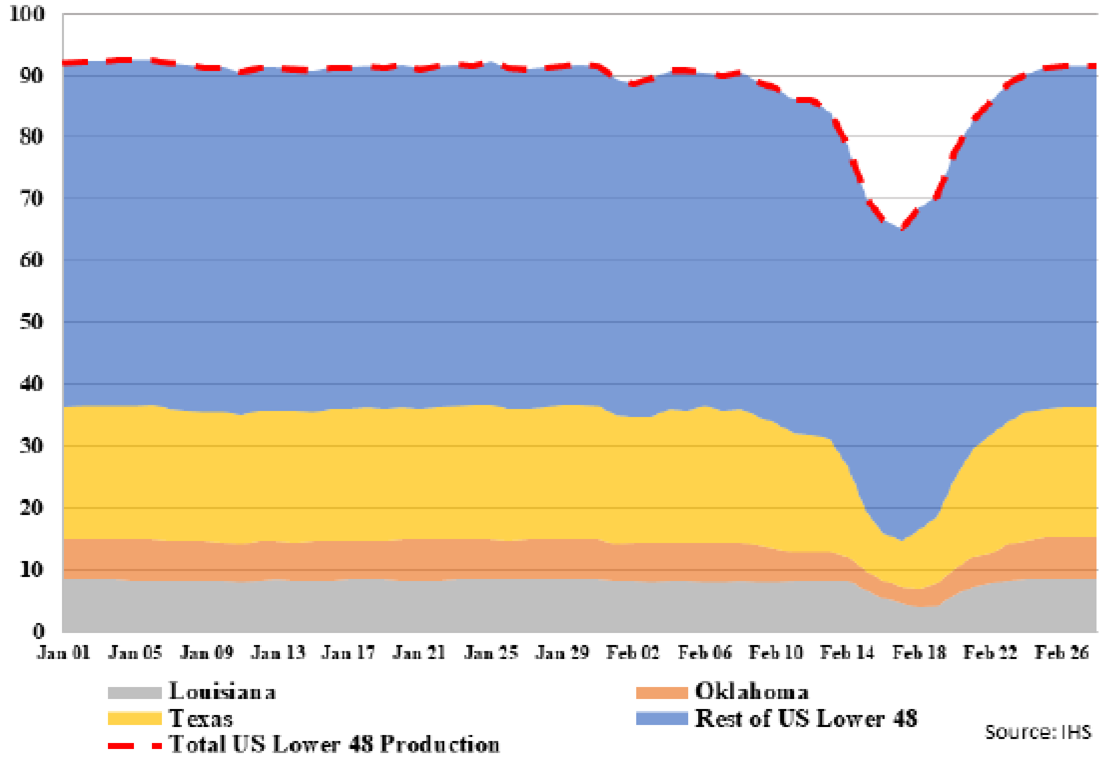


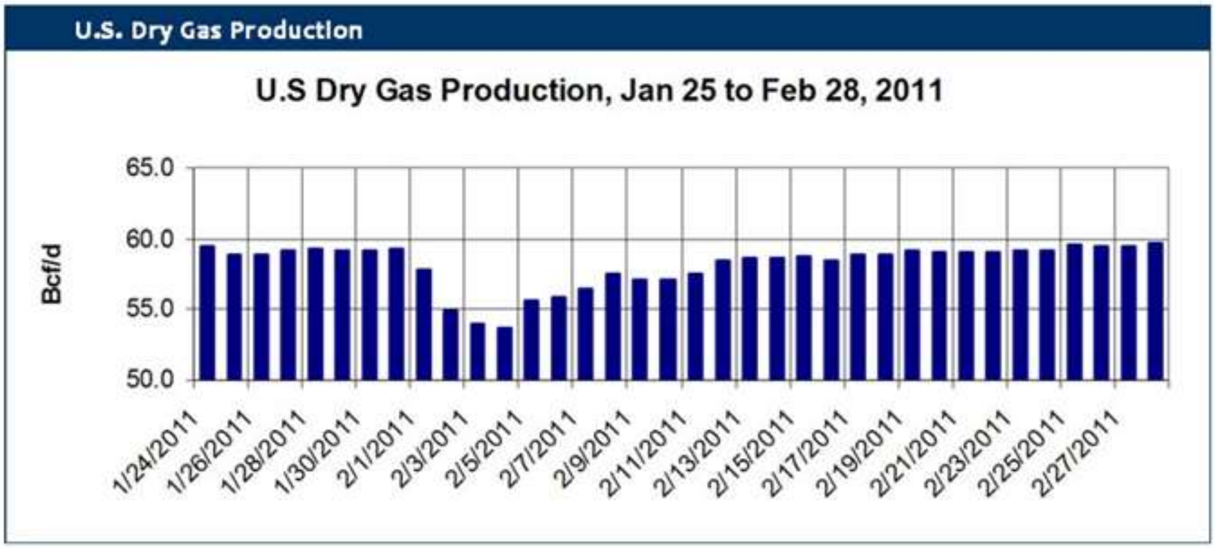
Figure 2.12: 2021 Natural Gas Freeze-~~in~~In

ERCOT 2011

A cold snap in ERCOT during February 2011 created challenging conditions for electricity generators. The reduction in available natural gas supply, shown in **Figure 2.13**, was identified as a significant root cause, as described below:

> *Both the San Juan Basin in northern New Mexico and the Permian Basin in west Texas and southeastern New Mexico tend to experience production declines with low temperatures, and the February [2011] event was no exception. The declines in these basins, together with the large increases in demand, were almost exclusively responsible for the gas curtailments in Texas, New Mexico and Arizona This weather event was so extreme that production freeze-offs were experienced not only in the San Juan and Permian Basins, but throughout Texas and as far south as the Gulf Coast.*[27]

[27] Reference: Report on Outages and Curtailments During the Southwest Cold Weather Event of February 1–5, 2011: Causes and Recommendations, Staffs of the Federal Energy Regulatory Commission and the North American Electric Reliability Corporation, August 2011, p114
FERC Outages and Curtailments Paper



Source: Task Force chart based on Bentek data

Figure 2~~-~~.13: 2011 Natural Gas Freeze-~~in~~In

Continuing the theme of natural gas unavailability, this tail risk was also identified as a concern in SPP, as noted below:

> *The unavailability of generation, driven mostly by lack of fuel, was the largest contributing factor to the severity of the winter weather event's impacts, which was exacerbated by record wintertime energy consumption and a rapid reduction of energy imports. (Note: Up to approximately 59,000 MW of generating name plate capacity in SPP was unavailable to meet demand during the week of the event.) When generation was most needed on Feb. 16, about 30,000 MW of generating capacity was unavailable due to forced outages. The largest single cause of these forced generation outages was attributed to fuel-supply issues, causing nearly 47% of the outages and affecting over 13,000 MW of gas generation~~.~~).*[28]

Figure 2.13 shows the unavailability of natural gas increasing through the event with the sharpest increase beginning on February 14. Wind unavailability preceded the rise in natural gas unavailability and remained elevated throughout the event. **Figure 2.13** ~~-~~and **Figure 2.14** ~~shows~~show the contribution of natural gas unavailability to the total amount of unavailable supply.

It is important to note that the electric industry does not have the ability, nor should it have the responsibility, to ensure a reliable, resilient and affordable natural gas supply. It is incumbent upon the natural gas industry to make the changes necessary to improve the supply of natural gas during extreme weather events. It is imperative that regulators understand the limitations of the electric industry in improving natural gas supply. Any new requirements to improve natural gas supply need to be imposed upon the gas industry and not the electric industry if this situation is to be improved.[29]

[28] A Comprehensive Review of Southwest Power Pool's Response to the February 2021 Winter Storm Analysis and Recommendations, Southwest Power Pool, July 19, 2021: SPP Comprehensive Review

[29]~~–~~ A Comprehensive Review of Southwest Power Pool's Response to the February 2021 Winter Storm Analysis and Recommendations, Southwest Power Pool, July 19, 2021: SPP Comprehensive Review

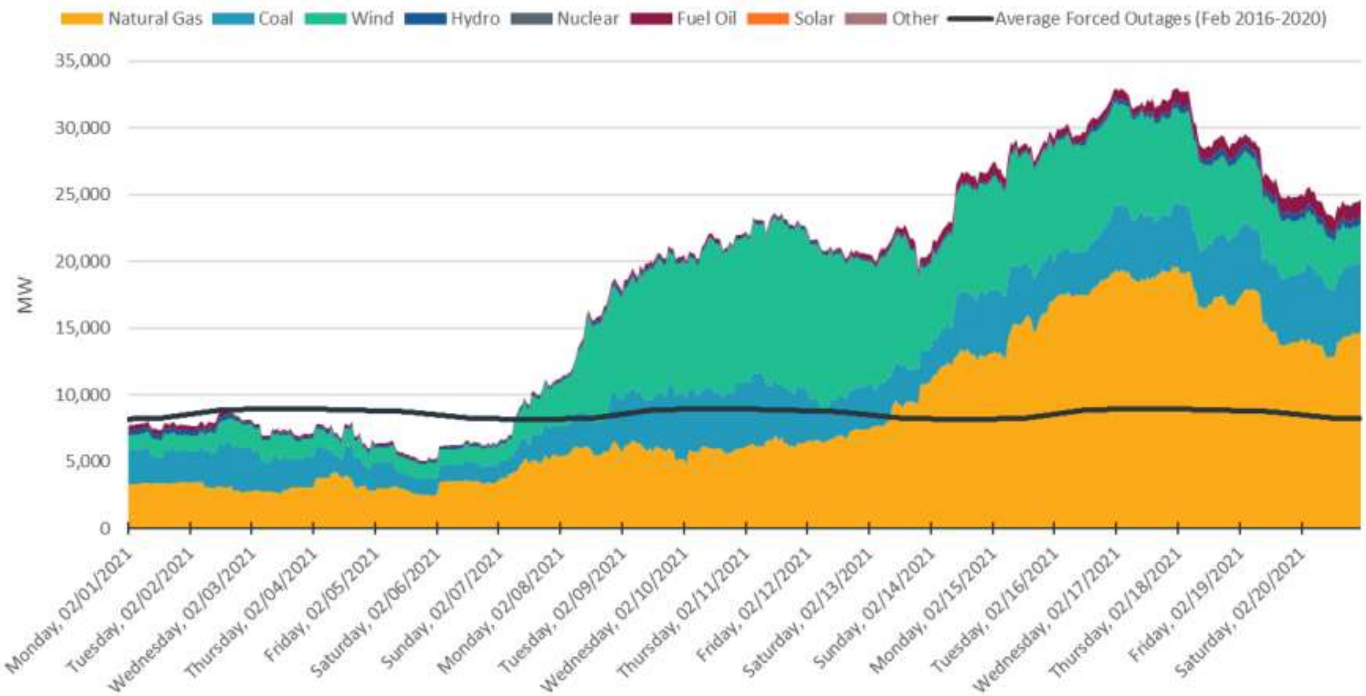


Figure 2.~~13~~14: Unavailability by Source of Energy

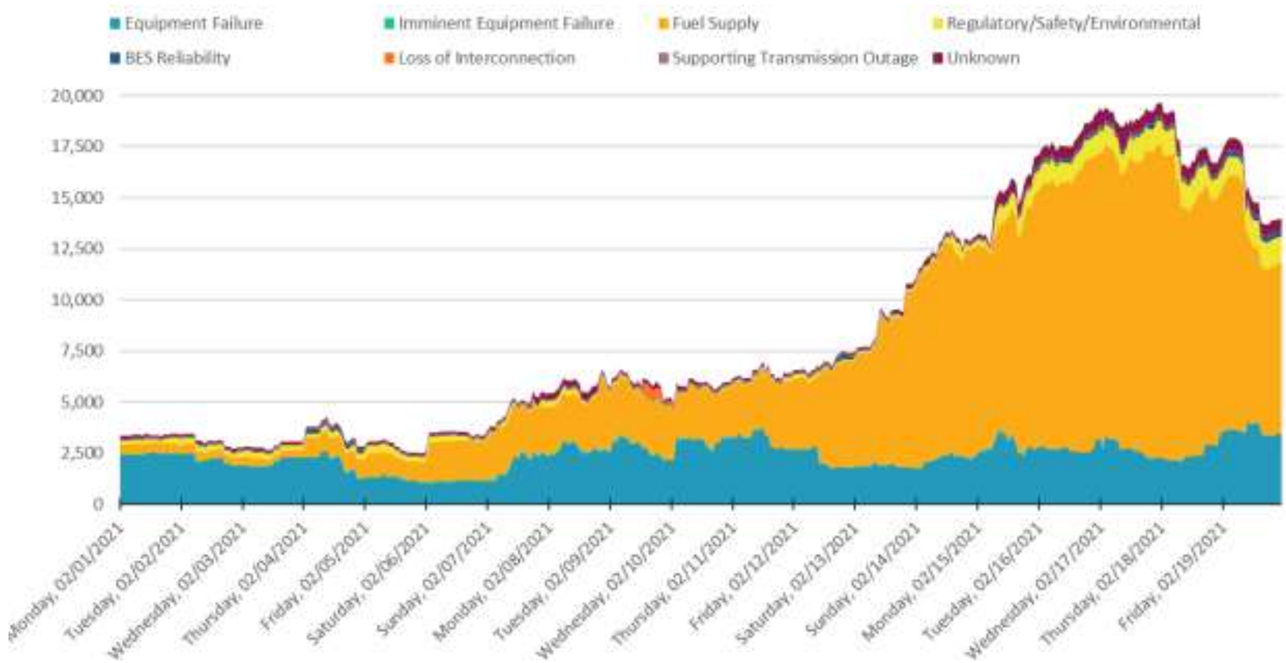


Figure 2.1~~:~~5: Unavailability of Natural Gas Generation Outages

Variable Energy Resources

~~Concerns about global extreme or unusual weather have spurred~~The desire to decarbonize the power sector, coupled with declining capital costs, has resulted in the deployment of large amounts of wind and solar resources~~ that is intended to displace carbon-emitting fuels~~. These VERs are dependent upon weather conditions and exhibit a high degree of correlation over a relatively large footprint. Additionally, the timing and amount of energy available from wind and solar resources is not well correlated with customer demands. With increased penetration of these resources and their displacing dispatchable resources, the risk of mismatch between when the energy is available and when the energy is needed by customers increases.

In the event of wind lulls or periods of decreased solar energy production, additional sources of energy need to be dispatched to maintain a reliable system. Because of the large footprint that will be subjected to similar weather conditions, the risk of widespread lulls that lead to simultaneous decreases in output requires the amount of installed dispatchable resources to remain relatively constant or decrease only slightly. Further, transmission options should be considered that can bring in energy resources when they are needed from areas that have excess energy available. Because of the uncertainty in weather and the relatively weak correlation to load, ~~intermittency~~uncertainty of ~~VERs~~VER output is likely to be the dominant source of tail risk in the future. Because of this ~~intermittency~~uncertainty and the interconnected nature of the power grid, analyses should include a risk perspective across relatively wide footprints.

Interconnection Support and Tie Benefits

In reliability studies that have been dominated by dispatchable resources, the interconnection support that can be obtained from neighboring regions has frequently been included. This support has the theoretical underpinning that arises from both the load diversity across a large footprint as well as the random and independent outages of dispatchable resources. With these two assumptions, there is a significant probability that the neighboring system would have surplus resources that could be used to assist when needed.

These load diversity and independent random outage assumptions are reasonable for a weather-driven system in which weather primarily affects the loads across neighboring areas.

However, as renewable resources among all the interconnected neighboring systems increasingly become weather dominated, the assumption that a neighboring system will have surplus resources to supply may become more tenuous. Weather~~-~~-dominated conditions over a large footprint can lead to wide-area wind or solar lulls that could inhibit the ability to provide mutual assistance.

Energy Storage

The lulls associated with the ~~intermittency of~~reduced output from VERs ~~amplifies~~amplify the uncertainty associated with energy availability. Because reliability models have traditionally been focused on random independent outages of dispatchable resources, the chronological aspects of energy availability did not play a prominent role in most reliability modeling.[30] A justification for this was that many of the energy limitations could be managed through better dispatch of the relatively smaller population of energy-limited storage resources given the available dispatchable resources.

For example, low-hydro conditions could be reflected by lower seasonal ratings, reflecting decreased reservoir heads as well as limited dispatch flexibility. Low-hydro reservoir storage due to droughts or limited energy in pumped storage reservoirs or batteries could be managed by dispatching their limited energy at the hours of greatest need.

However, as the risk of wind and solar lulls materialize in a simulation and potentially transform into wind and solar droughts, the amount of energy needed to be withdrawn from storage increases. The longer the lulls continue, the more energy ~~that~~ needs to be withdrawn. Assuming the energy storage facilities are limited in size and need to recharge, they could become depleted, possibly resulting in a deficit of available resources. Therefore, as the amount of storage increases and displaces fossil-fuel-based dispatchable resources with access to large inventories of stored energy, the energy drawdown and replenishment may create a significant risk vector. Such limitations would need to be represented better in reliability models. ~~Currently, energy~~Energy storage is currently an active area of development by reliability model vendors.[31]

[30] While reliability models have attempted to reflect chronological needs by using parameters, such as mean-time-to repair, the influence of this type of parameter over many Monte-Carlo replications was usually lost in the average's summary statistics.

[31] See NERC Battery Storage Report.

The risks associated with these energy issues are difficult to reflect because the inter-temporal aspects are typically outside the scope of reliability studies. Reliability studies evaluate the risk of loads plus a minimum amount of reserve exceeding available resources due to random and independent mechanical unavailability. In the case of energy storage, the decisions to withdraw stored energy to serve load, retain the stored energy for future contingency events, or ~~to~~ replenish the state~~-~~ of~~-~~ charge of the stored energy ~~has~~have not been a core function of a reliability simulation model. Representation of the weather~~–~~-driven severity, duration, and geographic footprint of stored energy drawdown needs to be based on realistic assessments of past weather and reflect possible future trends.

Location of Critical Loads

The locations of critical loads for hospitals and schools are important for managing systems in a degraded state. However, another aspect that has caused concern is the location of electricity-driven natural gas compressor station loads as noted below:

Interruption of Critical Load~~:~~

During the load-shed events, there were concerns from TOPs that natural gas compressor station loads may be curtailed, exacerbating the fuel shortage issue and causing a need for additional load shed. There are additional concerns that these critical loads do not have adequate backup plans to continue operating in the event of a loss of interconnection to the grid such as gas fired compression. Reliance upon the electric grid to power compressors will lead to interruptions in service due to other forced outages not initiated by the TOP.[32]~~.~~

Contingency and Robustness

Unlike wind droughts and weather-driven load excursions that can be alleviated by having more resources, some tail risks may not be ~~able to be avoided.~~avoidable. These risks can be in the form of hurricanes, tornadoes, earthquakes, and/or fires; these risks cannot be directly mitigated by having more installed resources. Risks like these require different remedies, such as workable restoration procedures or the positioning of restoration tools, labor, and equipment.

~~There are other~~Other tail risks that can create unreliability, such as the loss of long lead-time replacement components (e.g., power transformers~~) that~~), can be addressed probabilistically but are outside the scope of a resource adequacy analysis.

Reliability Criterion

The reliability criterion that has traditionally been used for resource adequacy is 1-day-in-10 years for interruption of firm load due to insufficient resources. This criterion was developed to address unavailability due to random and independent outages of traditional dispatchable resources. In practice, this criteria risk has rarely been encountered and outages have mostly been due to other factors such as storms and fuel delivery problems that are outside the scope of traditional reliability models.

However, with an increased emphasis on VERs whose output is dominated by weather patterns that can extend over a very wide footprint, it is likely that the wind and solar lulls may become more constraining and ~~that~~ interruption of firm load due to insufficient resources may ~~become more likely~~increase. Addressing this form of resource unavailability for high penetrations of these resources is an emerging concern.

This ~~whitepaper~~white paper has touched on several potential reliability criteria that could be used. For example, ~~Expected Unserved Energy (~~EUE~~)~~ is one of the metrics that can capture the amount of energy that could not be served due to insufficient resources to serve the loads. The concept of applying a more stringent criterion to compensate for additional tail risk was also discussed. Regardless of which metric is selected as the reliability criterion of choice, they all have the same general characteristic: when the system is adequate the risks are relatively small and when

[32] SPP Winter Storm Document p 57/109

the system risks increase the metrics increase rapidly. ~~-~~The threshold when a criterion indicates that risks have risen and actions need to be taken depends in part on what is included in the underlying risk analysis. ~~-~~Every additional risk factor that is considered in a resource adequacy analysis raises the resulting metric. ~~-~~The benefit of discussing tail risk is that it ~~brings into focus~~crystalizes the awareness that ~~there are~~ risks are looming in the future.

Independence of Risk Factors

Scheduled maintenance outages are not included in resource adequacy~~-~~ analyses even though they can have a significant impact. For example, resources could be scheduled out for maintenance and then unseasonable weather could occur. ~~-~~With climate change, weather patterns could emerge and very early summer weather, very late summer weather, very early winter polar vortices, or very late polar vortices ~~weather~~ could arrive and create challenging operating conditions. Tail risk could, therefore, occur when those events occur with significant amounts of resources on scheduled maintenance.

Chapter 3: Simulation-Based Approaches for Extreme Weather

This chapter will discuss the approaches to setting up a study regarding "tail" events that are typically related to extreme or unusual weather. The process used to investigate tail risks is ~~similar to~~like that used to investigate other emerging risks to the electric grid. The ProbA analyses undertaken by the PAWG embodies the current best practices and modeling approaches to analyzing risks by collectively discussing risks, sparking discussions about what might occur that is not explicitly analyzed in the base ProbA cases, and having PAWG members select issues that appear to be relevant to their system.

These results are then peer reviewed by other PAWG members. By this method, trends that begin to emerge in one area can be shared and inspire other analyses to enhance probabilistic resource adequacy planning processes.

Because tail risks are typically related to time-limited windows of varying durations, incorporating the results into an annual analysis may result in the significant ~~dilution~~masking of the effect being evaluated. Consequently, tail risks are probably best represented as scenarios of time-limited windows. However, if the tail risk occurs at a time that coincides with a critical period of need, such as hot or cold weather, and there are not any common-mode failures driving the analysis, it may be appropriate to reflect the tail risk in an annual assessment. For example, if hot summer weather is expected to be increasing in magnitude, then incorporating the risk into an annual reliability analysis that would increase installed reserves could be appropriate.

Additionally, care should be taken to understand the risk factors that are being evaluated. Causal analysis of statistics may indicate a statistical relationship between a condition and a statistic, such as EFOR. Without a clear understanding of the underlying root cause of the statistical relationship, erroneous conclusions may be inferred, and inappropriate remedies suggested. For example, in the event a statistic shows an increase in EFOR with cold temperatures, adding more resources with the same vulnerability may not produce the desired improvement because the additional resources also may not be properly insulated and winterized.

Fuel Risks Related to Severe Cold Weather

As illustrated in the previous chapter, tail risks come in many different forms and are generally correlated to weather-related events. For example, freezing conditions may inhibit fuel processing such as well-head natural gas production~~,~~ and extraction of fuel from storage~~,~~ and/or generate problems related to combustion at the burner tip.

In addition to fuel supply issues, fuel delivery systems may be inadequate for simultaneous delivery of fuel to electric power generators. Typically, this is discussed and characterized as a pipeline limitation; however, delivery of fuel oils via truck can ~~be~~create a significant bottleneck during a prolonged cold snap when fuel inventories at home~~,~~ and commercial, industrial, and electric generators are depleted ~~that~~and require timely refills.

Natural gas infrastructure is a common carrier that supplies natural gas energy for a wide range of customers from residential customers to electric generators. This infrastructure has traditionally been built and funded by natural gas distribution companies that consequently have priority rights to the transportation services provided by the pipelines. These priority customers generally have sufficient unused pipeline capacity to ~~allow~~enable electric generators to use their transportation resources on an as-available basis. While some electric generators may have affiliates that provide firm supplies and transportation, this is not a widespread practice. Thus, natural gas may become unavailable due to the competing demand of other parties with higher contractual priorities. Because FERC regulations require unused natural gas pipeline capacity to be released to other customers when not needed, only firm contracts by electric generators that result in enhancements to natural gas pipeline and supply infrastructure will improve the robustness of natural gas supply to those electric generators.

Modeling Recommendations

To analyze these risks, existing tools need to be augmented to ~~allow~~represent fuel limitations ~~to be represented~~. This can be done via scenario analysis in which specific amounts of vulnerable resources are removed from service. ~~This could be done by~~Using a national fuel model that simulates fuel supply, demand, storage, and pipelines~~.~~ may be one way forward. A wide-footprint model of this complexity might be needed to predict fuel limitations because of the potential effects of temperature on natural gas availability. In addition to temperatures, winter precipitation may also inhibit adequate fuel replenishment. A front-end, pre-processing model that could translate temperatures to fuel availability would be ideal. Additionally, a scenario model that would progress through time to capture the depletion of energy reserves would be helpful.

Moderate Cold Weather-Related Risks

Severe weather is not the only cold-weather risk that may occur. Moderate cold~~-~~ weather-related risks in the form of ice storms are emerging due to their effects on the wind generators. Icing of wind generating resources was identified as a cause of significant unavailability in the February 2021 event in the South-Central United States. While there is a significant interest in extreme temperature events, the impacts of ice storms are much more difficult to forecast.

Modeling Recommendations

Because the effect of this type of weather risk would have a limited duration and the scope of the outages is not easily determinable from historical data, scenario analysis for a focused time-limited duration analysis would be warranted.

Severe Cold Weather-Related Non-Fuel Risks

Severe periods of cold can also result in increases in electric demands. With the emphasis on electrification of natural gas, oil, and resistance electric heating systems to energy~~-~~-efficient electric heat pumps, these periods can result in significant additional loads while fuel supply issues may emerge.

Modeling Recommendations

The increase in loads can be analyzed via scenario analysis. Incorporating a cold~~-~~-weather event in an annual analysis would lead to the effect being diluted. Consequently, a focused, time-limited duration analysis would be warranted.

Severe Hot Weather-Related Risks

Severe periods of hot weather can also result in increases in electricity demand. Unlike the severe cold~~-~~-weather risks, natural gas demand during these hot~~-~~-weather events would only be constrained ~~duringpipeline~~during pipeline-maintenance conditions. However, hot~~-~~-weather events pose risks for stored energy resources such as hydro reservoirs, pumped storage reservoirs, and other sources of energy storage such as batteries.

Modeling Recommendations

This can be analyzed via scenario analysis. A front-end, pre-processing model that could translate temperatures to a scenario model that would progress through time to capture the depletion of energy reserves would be helpful. Incorporating a hot~~-~~-weather event in an annual analysis would lead to the effect being diluted. Consequently, a focused, time-limited duration analysis would be warranted.

Scheduled Maintenance of Unexpected Weather

Scheduled maintenance outages are a difficult problem for reliability analyses because of the many management decisions that affect the timing and duration of these outages. Because of the long lead times for scheduling maintenance and securing the appropriate skill sets and repair/refurbishment resources, these schedules are frequently inflexible. If either cold or hot weather occurs when a significant ~~amount~~number of resources are out of service for maintenance, reliability could be at risk.

Modeling Recommendations

This can be analyzed via scenario analysis. A front-end, pre-processing model that could estimate known or expected scheduled maintenance would be able to provide insights. Consequently, a focused, time-limited duration analysis would be warranted.

Chapter 4: Interpretation of Probabilistic Indices for Extreme Weather

The NERC PAWG performs a ~~Probabilistic Assessment (~~ProbA[33]~~)~~ to supplement the annual deterministic NERC Long-Term Reliability Assessment (LTRA) analysis. The ProbA calculates monthly ~~expected unserved energy (~~EUE~~)~~ and ~~loss of load hours (~~LOLH~~)~~ indices for 2 years of the 10-year LTRA outlook. Complete details and underlying assumptions of the ProbA Base Case analysis are included in the published LTRA reports. The ProbA analysis contains two studies that consist of a Base Case and a Sensitivity Case. The two differ in that the Base Case contains assumptions under normal operating conditions while the Sensitivity Case characterizes ~~a~~ "what-if" probabilistic analysis terms.

Tail risks, such as those discussed in this white paper, are similar in construction and interpretation to the Sensitivity Cases, but a tail risk analysis studies something different. Tail risk analysis is intended to include additional risk factors to reveal the reliability implications across all hours with probabilistic methods. In many cases, time-limited windows focus on specific periods of a year where a risk or vulnerability might occur. The PAWG believes this approach to be of higher value than standardizing a Sensitivity Case study to capture the varied and complex reliability risks across Reliability Coordinators. Planning engineers use both expected outcomes as well as scenario cases.

While extreme weather scenarios represent an analysis into potential reliability risk factors, there is no guarantee or indication that these scenarios are indicative of future occurrences. However, these results are used to inform system planners and operators about potential emerging reliability risks. The PAWG recommends considering these tail risks in future probabilistic resource adequacy studies to develop further guidance for future work activities, when key points and takeaways are called out.

Reliability Metrics for Tail Risks

With the growing penetration of VERs in comparison to traditional base-load resources, either as load reducers or as supply, hourly variations in load and supply will become less predictable. Time series models that more accurately reflect the behavior of stochastic processes, such as the variations in wind speed and solar variations as well as assessment of the contributions and limitations of energy storage, may become more prevalent in probabilistic assessments. This change in modeling may, in turn, result in metrics like LOLH and EUE, which capture hourly variations in system conditions, becoming increasingly meaningful for measuring the reliability of the system. LOLH and EUE ~~provides~~provide insight to the impact of energy-limited resources on a system's reliability, particularly in systems with growing penetration of such resources.

EUE, along with the value of load loss, can be used to perform the following actions:

- Monetize the cost of load loss to justify, prioritize, or rank transmission or other capital projects.
- Form the basis of a reference reserve margin to determine capacity credits for VERs.
- Quantify the impacts of extreme weather, common-mode failures, etc.

The focus of this section is three-fold: it surveys the electric sector's existing and future use of probabilistic studies to investigate BPS risks to reliability, it tracks evolving emerging trends, and it identifies applications for the electric sector to use known reliability metrics to assess emerging issues.

While many of the traditional probabilistic reliability metrics are useful for analyzing tail risks,[34] EUE may be the most relevant metric for understanding and comparing the severity of degraded-state tail risk events. Simulations should proceed until the system is restored at the end of the extreme weather event, so load can be lost, recovered, and

[33] Probabilistic Adequacy and Measures Technical Reference Report Final, July, 2018
[34] EPRI RA for a Decarbonized Future 2022 white paper

lost again depending on if the chosen extreme weather is expected to last significantly long (e.g., heat wave, downing of power lines over water like in the New Orleans event).

Description of Output

While the output of studies using methods in **Chapter 2:** will produce probabilistic indices, it may not be appropriate to compare the observed risk sensitivity to the ProbA base cases or ~~other~~another annualized metric.

Because these are tail risks, the metrics are conditional probabilities associated with a low relative probability. This conditional probability can be interpreted as the assumption that ~~the~~an extreme weather event is coming. Therefore, the resulting reliability indices do not reflect the actual expected probability that “extreme weather could occur and result in the risk of operating in a degraded state.” Rather, it is the impact given the extreme weather occurred.

Operating in a Degraded State

Normal long-term resource adequacy plans include allowances for load and capacity relief via “emergency operating procedures.” Because tail risks manifest themselves as reliability events when compounding events become so severe or pervasive that they overwhelm the reserve and contingency plans embodied in “traditional” resource adequacy plans, it may become appropriate to develop quantifiable “long~~-~~-term ~~emergence~~emergency recovery procedures.” Including such recovery procedures and reporting on their potential implementation can quantify a system’s ~~resiliency~~resilience against the identified tail risk.

Due to the infrequent and uncertain nature of whether an extreme event will occur, the appropriate planning may not be to install additional supply resources; it could be to react with a methodical and planned response while operating in a degraded state that minimizes the impact across the affected area without unnecessarily inflicting undue hardship on a limited subset of customers. This would depend on the type of load not served and the length of time that the load would not be served.

The addition of weather-related risks might necessitate the formal recognition of responses and development of emergency operating procedures to address these additional risks. For example, consider a customer with an electric heat pump for heating in the winter: they are concerned about a widespread ice storm outage that would be coupled with “normal” cold and result in days or weeks of outages such that their heat pump could not warm their home. ~~As the northeast area envisions greater~~Greater penetrations of heat pumps~~, the consequences of this heating policy initiative leading~~ in the Northeast could lead to~~ the creation of~~ an auxiliary “emergency electrical distribution system recovery arm of fire-departments,” or something similar~~ to be~~, being added to the emergency operations. NERC encourages resource planners to develop such strategies in ~~discussing~~discussions with Transmission Planners and Planning Coordinators to plan for future~~-~~-year operators to operate the system in potential emergency conditions.

Interpretation of Probabilistic Studies to Assess Tail Risk

Previous NERC assessments showed the need to support probability-based resource adequacy assessment due to a changing resource mix with significant increases in energy-limited resources, changes in off-peak demand, and other factors that can influence resource adequacy. As a result, NERC is incorporating more probabilistic approaches into its assessments, including the development of this report. The NERC PAWG examined the use of probabilistic studies for assessing emerging reliability issues.

NERC’s goals, outlined in the operating plan,[35]~~,~~ include identifying, assessing, and prioritizing emerging risks to reliability by using probabilistic approaches to develop resource adequacy measures that reflect variability and overall reliability characteristics of the resources and composite loads, including non-peak system conditions. NERC’s intent is to perform the following actions:

[35] https://www.nerc.com/comm/RISC/Related%20Files%20DL/ERO-Reliability-_Risk_Priorities-Report_Board_Accepted_February_2018.pdf

- Educate ~~policy makers~~policymakers, regulators, and industry on the relationship of on-peak deterministic reliability indicators (e.g., reserve margin) to 8,760 hourly probabilistic reliability indicators (e.g., LOLH~~)~~).
- Develop a catalogue of tail risk scenarios that can be applied to many areas that ~~considers~~consider a wide range of risks.
- Create a catalogue of scenarios that builds in regional, and climate-model driven extreme events.
- Develop a screening tool to identify potential risks and suggest the need for additional study years or ad-hoc regional assessments.
- Work in tandem with LTRA annual results.
- Develop a collective understanding of existing applications of probabilistic techniques used for reliability assessments and planning studies.
- Identify commonalities to inform industry on the applications of probabilistic reliability metrics.
- Provide guidance on the development of probabilistic methods for ensuring resource adequacy and reliability to allow better risk-informed decisions for planners and ~~policy makers~~policymakers in the face of increasing uncertainty of supply and demands on the ~~bulk power system~~BPS.

RSTC Reviewer	Page #	Comment
David Jacobson (Manitoba Hydro)	General	The message I took away from reading this document is that resource planners should be considering more diversity when planning new resource options so that they are not vulnerable to extreme events that have a common mode impact. In the extreme cases where an area has 100% wind, for example, they are vulnerable to wind drought. Adding more wind won't help and if neighbouring regions also have wind and are affected at the same time then they can't help either. The same goes for pretty much every technology – you don't want 100% reliance on a single energy source vulnerable to common mode failures. By considering tail risks, it is assumed that a more resilient energy supply mix can be planned

David Jacobson (Manitoba Hydro)	18	On page 18, the role of interconnection support is downplayed too much I believe: “In reliability studies that have been dominated by dispatchable resources, the interconnection support that can be obtained from neighboring regions has frequently been included. This support has the theoretical underpinning that arises from both the load diversity across a large footprint as well as the random and independent outages of dispatchable resources. With these two assumptions, there is a significant probability that the neighboring system would have surplus resources that could be used to assist when needed. These load diversity and independent random outage assumptions are reasonable for a weather-driven system in which weather primarily affects the loads across neighboring areas. However, as renewable resources among all the interconnected neighboring systems increasingly become weather dominated, the assumption that a neighboring system will have surplus resources to supply may become more tenuous. Weather dominated conditions over a large footprint can lead to wide-area wind or solar lulls that could inhibit the ability to provide mutual assistance.”

David Jacobson (Manitoba Hydro)	1	The addition of a wider range of scenarios will provide the natural framework in which to analyze the variable output from renewable sources during extreme weather events when determining system impact and resource interconnection studies." During the resource interconnection process, NERC standard TPL-001 currently applies. The range of extreme weather scenarios is limited. There is a NERC project (2023-07) to assess extreme weather impacts. This project will likely result in a new NERC standard that requires periodic review of the system. The addition of a wide range of scenarios would more naturally fit into that project
David Jacobson (Manitoba Hydro)	14	but this is outside of the scope of electric system reliability models
David Jacobson (Manitoba Hydro)	17	Figure numbers on this page are out of sync
David Jacobson (Manitoba Hydro)	19	"In the case of energy storage, the decisions to withdraw stored energy to serve load, retain the stored energy for future contingency events or to replenish the state-of-charge of the stored energy has not been a core function of a reliability simulation model." I agree with the statement but my question is does it need to be? There are other tools available to investigate energy adequacy such as hourly production cost models. Are there gaps in these other approaches or do these platforms need to be merged in some way?

David Jacobson (Manitoba Hydro)	19	"There are other tail risks that can create unreliability, such as the loss of long lead-time replacement components (e.g., power transformers) that can be addressed probabilistically but are outside the scope of a resource adequacy analysis. " Resource adequacy typically assumes the transmission grid is a copper sheet. When you get into tail risk analysis, is there more of a need to consider composite reliability analysis where generation and transmission availability are considered together?
Mark Lauby (NERC)	iv	Perhaps reference NERC's definition here at Informational_Filing_Definition_Adequate_Level_Reliability_20130510.pdf (nerc.com)
Mark Lauby (NERC)	iv	Remember that not all impacts can be avoided. That is why there is a need for recovery plans. TPL spells out the design basis events to withstand (including corrective action plans) and those events that one must study and be ready to recover from.
Mark Lauby (NERC)	4	What about wind-cutoff from low temperatures? Also, reduction in PV production during hot days.
Mark Lauby (NERC)	5	What about events that haven't resulted in load shed, but may be an indication of a challenge: Jun 6 with 60,000 MW nameplate wind churning out 200 MW in the mid-section of North America
Mark Lauby (NERC)	5	FERC NERC Elloitt report?

Mark Lauby (NERC)	5	I have no idea what this paragraph is saying about the PAWG members
Mark Lauby (NERC)	5	Again, not sure how this contributes to the report.
Mark Lauby (NERC)	7	Really doesn't take into account the simultaneous impact on all units....rather assume each plant is randomly failure at the new ELCC rate.
Mark Lauby (NERC)	7	Could it also be more transmission, especially for events that technology response scenarios?
Mark Lauby (NERC)	11	What about events that were not measured? Like wind lulls 100 ft above the surface? We are only now beginning to experience them, so sensitivety analysis is needed to bookend potential events.
Mark Lauby (NERC)	13	Should also reference NERC's LTRAs
Mark Lauby (NERC)	25	Low wind....or too much wind?

Mark Lauby (NERC)		I think we are getting way into the weeds here. Namely, the desire to model operational actions to minimize the impact. The goal should be to not get to a point that operators need to use into their operating procedures. Else we end of with many more situations that consumers demand is higher than demand and we need to take emergency actions. This appears to be where we are today...and we want to move aware from the annual winter emergencies!
George Stephen (ISO-NE)	2	This appears to be the same as the third recommendation "Uncertainty from Variable Energy Resource (VER) output is likely to be the dominant source of tail risk in the future. Because of this uncertainty and the interconnected nature of the power grid, analyses should include a risk perspective across relatively wide footprints"
George Stephen (ISO-NE)	4	Is "extreme clouds" meant to convey long-duration clouds? I think so, just confirming.
George Stephen (ISO-NE)	5	And/or increased draw/reliance on the natural gas pipelines in some areas. Also perhaps increased reliance on imports from neighboring areas.
George Stephen (ISO-NE)	5	I think a key takeaway here is that the definition of extreme weather is changing a bit. What was historically thought of as extreme (hurricanes, blizzards, etc.) is still extreme but other weather events (long duration cloudiness or lack of wind) not traditionally thought of as extreme are now becoming an extreme event in terms of its impact on the power system.
George Stephen (ISO-NE)	5	Agreed, but does nuclear really belong in the first sentence of this paragraph?

George Stephen (ISO-NE)	5	As an FYI (not sure if it belongs here or not), our next step in New England is to work with stakeholders to develop a regional energy shortfall threshold which reflects the region's risk tolerance for energy shortfall during extreme weather events. More to come on that in 2024.
George Stephen (ISO-NE)	6	Does this need to be specific to market mechanisms? What about out of market activities that reduce peak demands?
George Stephen (ISO-NE)	6	In New England one thing we've considered is that we could implement (in market, or out of market is TBD) some curtailment ahead of an extreme event that is forecasted. This would have the effect of conserving some stored fuels for use during the extreme event. So, the actual demand reduction is available and may be sufficient to head off any problems. Just a thought for consideration.
George Stephen (ISO-NE)		As an FYI, for the study NE did with EPRI, a temperature-dependent forced outage model was developed and has shown promising results

Proposed Change	PAWG Response
	Thank you for your comment. No change made

I agree with the above observation but it sends the message to stop looking at interconnections and focus more on local resource planning. NERC has kicked off the Interregional Transfer Capability Study (ITCS) and will be trying to identify prudent transmission line additions to resolve future reliability issues focusing on extreme conditions similar to what was outlined in this paper (e.g., heatwave, cold snap, natural-gas availability, low-output Variable Energy Resource). I believe that by following the recommendations of this white paper, some additional guidance could be provided to the NERC ITCS. For example, if the risk identified was a wind drought then ideally the prudent transmission line additions shouldn't be towards a neighbouring region that is very likely to also be experiencing a common mode wind drought. Alternative paths to a diverse set of resource would be more prudent. The underlying assumption is that the interconnections could be more cost effective compared with adding local resource additions to address tail risks.	Thank you for your comment. Regarding: "to wide-area wind or solar lulls that could inhibit the ability to provide mutual assistance." This is a tail risk that needs to be considered. Potential solutions may be to consider support from even more distant "neighbors" and their resources. No change made

	Thank you for your comment. the comment applies to interconnections … which is not the topic of this whitepaper. Because interconnections affect one resource we don't think this affects the topic covered by the whitepaper. No change made
but this is outside of the scope of *current* electric system reliability models	Thank you for your comment. Change made
	Thank you for your comment. Change made
	Thank you for your comments. While energy storage is an active area of development by reliability model vendors, there are models that could be used

	Thank you for your comment. that can and should be addressed probabilistically. No change made
Informational_Filing_Definition_Adequate_Level_Reliability_20130510.pdf (nerc.com)	Thank you for your comment. Change made
The following have been added to key findings section "The definition of extreme weather is changing and what was historically thought of as extreme (hurricanes, blizzards, etc.) is still extreme but other weather events (long duration cloudiness or lack of wind) not traditionally thought of as extreme are now becoming an extreme event in terms of its impact on the power system."	Thank you for your comment. Change made
add "or very low ambient temperatures…"	Thank you for your comment. Change made
The following have been added to key findings section "The definition of extreme weather is changing and what was historically thought of as extreme (hurricanes, blizzards, etc.) is still extreme but other weather events (long duration cloudiness or lack of wind) not traditionally thought of as extreme are now becoming an extreme event in terms of its impact on the power system."	Thank you for your comment. Change made
reference to Elliott report was added	Thank you for your comment. Change made

The senetence "The PAWG will continue to share the efforts and successes and determine if future work at the NERC PAWG is needed to provide a best practice to augment the material that is reported in the Long-Term Reliability Assessment (LTRA)" was updated to "The PAWG will continue to share the efforts and successes and determine if future work at the NERC PAWG is needed to provide a best practice to augment the material here."	Thank you for your comment. Change made
The senetence "The PAWG will continue to share the efforts and successes and determine if future work at the NERC PAWG is needed to provide a best practice to augment the material that is reported in the Long-Term Reliability Assessment (LTRA)" was updated to "The PAWG will continue to share the efforts and successes and determine if future work at the NERC PAWG is needed to provide a best practice to augment the material here."	Thank you for your comment. Change made
	Thank you for your comment. Actually, ELCC does take into account correlated outages among a class of resources vs. customer demands. No change made
add the following ". Additional transmission to more distant areas would increase the footprint where additional support might be sought."	Thank you for your comment. Change made
	Thank you for your comment. No change made
The graph from 2023 LTRA was used	Thank you for your comment. Change made
	Thank you for your comment. Too much wind results in curtailment .. which is not a resource adequacy problem. No change made

	Thank you for your comment. Due to increased supply variability, we think we will be heading into a world of even more emergencies … and resiliency will be the response. No change made
delete recommendation bullet "Uncertainty from Variable Energy Resource (VER) output is likely to be the dominant source of tail risk in the future. Because of this uncertainty and the interconnected nature of the power grid, analyses should include a risk perspective across relatively wide footprints"	Thank you for your comment. Change made
	Thank you for your comment. Yes, weather is variable so non specific. No change made
add to the end of the paragraph "A drawdown in available energy may be associated with local resources, but may also affect stored energy in neighboring and even more distant regions."	Thank you for your comment. Change made
The following have been added to key findings section "The definition of extreme weather is changing and what was historically thought of as extreme (hurricanes, blizzards, etc.) is still extreme but other weather events (long duration cloudiness or lack of wind) not traditionally thought of as extreme are now becoming an extreme event in terms of its impact on the power system."	Thank you for your comment. Change made
	Thank you for your comment. We think nuclear belongs here … it is stored fuel that needs to be replenished for the electric-energy conversion device to continue making electricity. No change made

	Thank you for your comment. It is do not belong to the section. No change made
the sentence was updated "with market mechanisms or back-up technologies (e.g., large ice-chests, gasoline-powered generators or kerosene heaters) may not be available or sufficient."	Thank you for your comment. Change made
	Thank you for your comment. No change made
	Thank you for your comment. No change made

NERC
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Probabilistic Planning for Tail Risks

PAWG White Paper

Bryon Domgaard, PAWG Chair
NERC Reliability and Security Technical Committee
March 12-13, 2024

RELIABILITY | RESILIENCE | SECURITY




Overview

- NERC Probabilistic Assessment Working Group (PAWG) has developed a work plan item called "Probabilistic Planning for Tail Risks"
- Objective to understand the probabilistic modeling practices and approaches that are currently used for extreme weather or events.
- Addressing (and not conflict with) ongoing and evolving technical procedures, policy changes or other industry extreme weather initiatives

Whitepaper Highlights

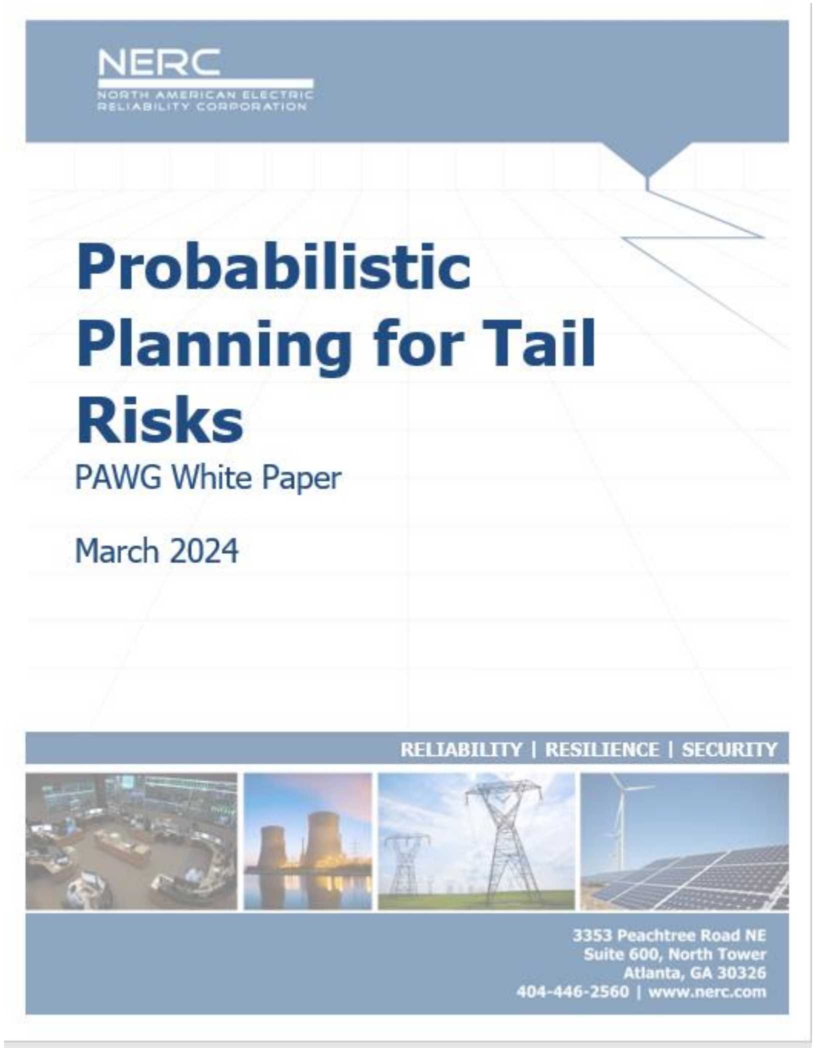
- Assessment or study setup for extreme weather or events, including key assumptions
- Development and enhancement of study models
- Addition of a wider range of scenarios will provide the natural framework in which to analyze the variable output from renewable sources during extreme weather events when determining system impact and resource interconnection studies.

2023-2024 Review Timeline

- December RSTC Presentation and request for reviewers
  - Four reviewers from RSTC (PAWG received actual comments from three reviewers)
- PAWG met to address the comments received
  - Most comments were positive and added suggestions and links to work going on in the industry
  - Updated paper to add more clarity for questions that were asked
  - The PAWG is planning on keeping this paper current and adding a pilot study

Request

- Seeking RSTC approval to post and complete this Work Plan item



Questions and Answers

Motion

Motion to approve the Probabilistic Planning for Tail Risks- PAWG White Paper

Determination of Practical Relaying Loadability Setting Paper

Action Requested:
The SPCWG is requesting that the RSTC accept the Determination of Practical Transmission Relaying Loadability Settings document

Background:
Originally published in December 2017 for PRC-023-4, this version has been updated for PRC-023-5 and has been placed into the current NERC format and template. This document was provided for review by the RSTC at their December meeting and the SPCWG has accepted those comments and revisions.

Summary:
The SPCWG requests that the RSTC accept the Determination of Practical Transmission Relaying Loadability document.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Determination of Practical Transmission Relaying Loadability Settings V1.1

Implementation Guidance for PRC-023-5
System Protection and Control Working Group

March 2024

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, is a highly reliable and secure North American bulk power system (BPS). Our mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid.

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

The North American BPS is made up of six Regional Entities as shown on the map and in the corresponding table below. The multicolored area denotes overlap as some load-serving entities participate in one Regional Entity while associated Transmission Owners/Operators participate in another.

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

Disclaimer

This supporting document may explain or facilitate implementation of Reliability Standard PRC-023-5—Transmission Relay Loadability but it does not contain mandatory requirements subject to compliance review.

Statement of Purpose

This document is intended to provide additional information and guidance for complying with the requirements of Reliability Standard PRC-023—Transmission Relay Loadability.

The function of transmission protection systems included in the referenced reliability standard is to protect the transmission system when subjected to faults. System conditions, particularly during emergency operations, may make it necessary for transmission lines and transformers to become overloaded for short periods of time. During such instances, it is important that protective relays do not prematurely trip the transmission elements, preventing the system operators from taking controlled actions to alleviate the overload. Therefore, protection systems should not interfere with the system operators' ability to consciously take remedial action to protect system reliability. The relay loadability Reliability Standard has been specifically developed to not interfere with system operator actions while allowing for short-term overloads with sufficient margin to allow for inaccuracies in the relays and instrument transformers.

While protection systems are required to comply with the relay loadability requirements of Reliability Standard PRC-023-5[1]; it is imperative that the protective relays be set to reliably detect all fault conditions and protect the electrical network from these faults.

[1] Refer to Attachment A of PRC-023-5 for inclusions and exclusions.

Chapter 1: Examples For R1

R1—Phase Relay Setting

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. [Risk Factor: High]

Criteria

1.1 Transmission Line Thermal Rating

Set transmission line relays so they do not operate at or below 150% of the highest seasonal facility rating of a circuit for the available defined loading duration nearest four hours (expressed in amperes).

$$Z_{\text{relay30}} = \frac{.85\ x\ V_{L-L}}{\sqrt{3}\ x\ 1.5\ x\ I_{Rating}}$$

Where:

$Z_{relay30}$ = Relay reach in primary Ohms at a power factor angle of 30 degrees

V_{L-L} = Rated line-to-line voltage

I_{rating} = Facility Rating

Set the relay so it does not operate at or below 150% of the highest seasonal facility rating (I_{rating}) of the line for the available defined loading duration nearest four hours. When evaluating a distance relay, assume a 0.85 per unit relay voltage and a line phase (power factor) angle of 30 degrees.

$$Z_{\text{relay30}} = \frac{.85\ x\ V_{L-L}}{\sqrt{3}\ x\ 1.5\ x\ I_{Rating}}$$

1.2 Transmission Line Established 15-Minute Rating

When the study to establish the original loadability parameters was performed, it was based on the four-hour facility rating. The intent of the 150% factor applied to the facility rating in the loadability requirement was to approximate the 15-minute rating of the transmission line and add some additional margin. Although the original study performed to establish the 150% factor did not segregate the portion of the 150% factor that approximates the 15-minute capability from that portion that was to be a safety margin, it has been determined that a 115% margin is appropriate. In situations where detailed studies have been performed to establish 15-minute ratings on a transmission line, the 15-minute highest seasonal facility rating can be used to establish the loadability requirement for the protective relays.

Set the tripping relay so it does not operate at or below 115% of the 15-minute highest seasonal facility rating (I_{rating}) of the line. When evaluating a distance relay, assume a 0.85 per unit relay voltage and a line phase (power factor) angle of 30 degrees.

$$Z_{\text{relay30}} = \frac{.85\ x\ V_{L-L}}{\sqrt{3}\ x\ 1.15\ x\ I_{Rating}}$$

1.3 Maximum Theoretical Power Transfer Limit Across a Transmission Line

Set transmission line relays so they do not operate at or below 115% of the maximum power transfer capability of the circuit (expressed in amperes) by using one of the following to perform the power transfer calculation:

1.3.1 Maximum Power Transfer with Infinite Source

An infinite source (zero source impedance) with a 1.00 per unit bus voltage at each end of the line. See **Figure 1.1**.

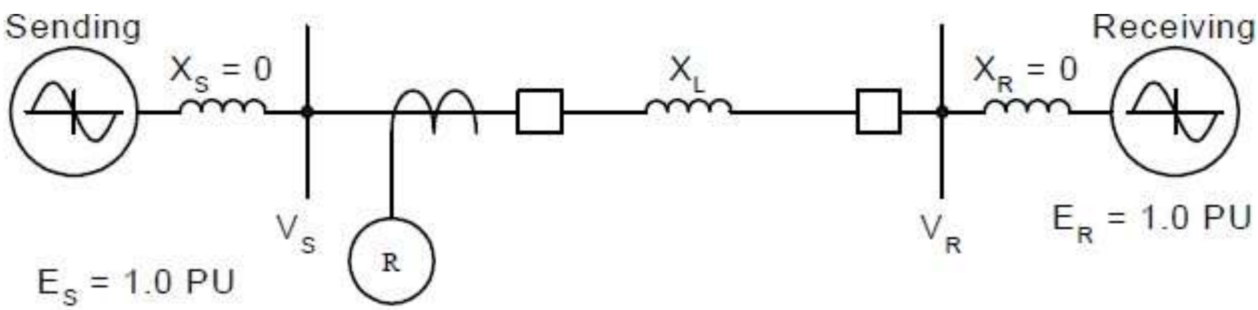

Figure 1.1: Maximum Power Transfer

The power transfer across a transmission line is defined by the equation:[2]

$$P = \frac{(V_S x\ V_R\ x\ \sin\delta)}{X_L}$$

Where:

P = the power flow across the transmission line

V_S = Line-to-Line voltage at the sending bus

V_R = Line-to-Line voltage at the receiving bus

δ = Voltage angle between V_S and V_R

X_L = Reactance of the transmission line in ohms

The theoretical maximum power transfer occurs when δ is 90 degrees. The maximum power transfer will be less than the theoretical maximum power transfer and will occur at some angle less than 90 degrees since the source impedance of the system is not zero. The following conservative assumptions are made:

- δ is 90 degrees
- Voltage at each bus is 1.0 per unit
- An infinite source is assumed behind each bus (i.e., no source impedance is assumed)

The equation for maximum power becomes the following:

$$P_{max} = V^2/XL$$
$$I_{real} = P_{max}/(\sqrt{3}\ x\ V)$$
$$I_{real} = V/(\sqrt{3}\ x\ X_L)$$

[2] More explicit equations that may be beneficial for long transmission lines (typically 80 miles or more) are contained in **Appendix A**

Where:

P_{max} = Maximum power that can be transferred across a system

I_{real} = Real component of current

V = Nominal line-to-line bus voltage

At maximum power transfer, the real component of current and the reactive component of current are equal:

$$I_{total} = \sqrt{2}\ x\ I_{real}$$

$$I_{total} = \frac{\sqrt{2}\ x\ V}{\sqrt{3}\ x\ X_L}$$

$$I_{total} = \frac{0.816\ x\ V}{X_L}$$

Where:

I_{total} is the total current at maximum power transfer.

Set the tripping relay so it does not operate at or below 115% of I_{total} (where $I_{total} = \frac{0.816\ x\ V}{X_L}$)

When evaluating a distance relay, assume a 0.85 per unit relay voltage and a line phase (power factor) angle of 30 degrees.

$$Z_{\text{relay30}} = \frac{.85\ x\ V_{L-L}}{\sqrt{3}\ x\ 1.15\ x\ I_{total}}$$

1.3.2 Maximum Power Transfer with System Source Impedance

Actual source and receiving end impedances are determined by using a short-circuit program and choosing the classical or flat start option to calculate the fault parameters. The impedances required for this calculation are the generator subtransient impedances. See Figure 1.2.

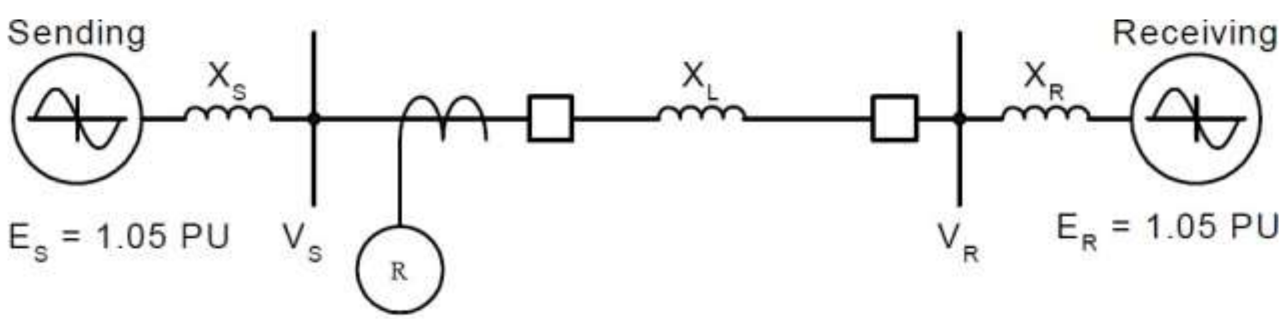

Figure 1.2: Site-Specific Maximum Power Transfer Limit

The recommended procedure for determining X_S and X_R is as follows:

- Remove the line or lines under study (parallel lines need to be removed prior to doing the fault study).
- Apply a three-phase short circuit to the sending and receiving end buses.

- The program will calculate a number of fault parameters, including the equivalent Thévenin source impedances.
- The real component of the Thévenin impedance is ignored.

The voltage angle across the system is fixed at 90 degrees, and the current magnitude (I_{real}) for the maximum power transfer across the system is determined as follows:[3]

$$P_{max} = \frac{(1.05\ x\ V)^2}{X_s + X_R + X_L}$$

Where:

P_{max} = Maximum power that can be transferred across a system

E_S = the line-to-line internal voltage for the generator modeled behind the equivalent sending end reactance X_S

E_R = the line-to-line internal voltage for the generator modeled behind the equivalent receiving end reactance X_R

δ = Voltage angle between E_S and E_R

X_S = Thévenin equivalent reactance in ohms of the sending bus

X_R = Thévenin equivalent reactance in ohms of the receiving bus

X_L = Reactance of the transmission line in ohms

V = Line-to-Line bus voltage

$$I_{real} = \frac{(1.05\ x\ V)}{\sqrt{3}\ (X_s + X_R + X_L)}$$

$$I_{real} = \frac{(0.606\ x\ V)}{(X_s + X_R + X_L)}$$

The theoretical maximum power transfer occurs when δ is 90 degrees. All stable maximum power transfers will be less than the theoretical maximum power transfer and will occur at some angle less than 90 degrees since the source impedance of the system is not zero. The following conservative assumptions are made:

- δ is 90 degrees
- Voltage at each bus is 1.05 per unit
- The source impedances are calculated using the sub-transient generator reactances.

At maximum power transfer, the real component of current and the reactive component of current are equal; therefore:

$$I_{total} = \sqrt{2}x\ I_{real}$$

$$I_{total} = \frac{\sqrt{2}\ x\ 0.606\ x\ V}{(X_S + X_R + X_L)}$$

$$I_{total} = \frac{0.857\ x\ V}{(X_S + X_R + X_L)}$$

[3] More explicit equations that may be beneficial for long transmission lines (typically 80 miles or more) are contained in **Appendix A:**.

Where:

I_{total} = Total current at maximum power transfer

Set the tripping relay so it does not operate at or below 115% of I_{total}. When evaluating a distance relay, assume a 0.85 per unit relay voltage and a line phase (power factor) angle of 30 degrees.

$$Z_{\text{relay30}} = \frac{.85\ x\ V_{L-L}}{\sqrt{3}\ x\ 1.15\ x\ I_{total}}$$

This should be reverified whenever major system changes are made.

1.4 Special Considerations for Series-Compensated Lines

Series capacitors are used on long transmission lines to allow increased power transfer. Special consideration must be made in computing the maximum power flow that protective relays must accommodate on series-compensated transmission lines. Series capacitor emergency ratings, typically 30-minute, are frequently specified during design.

The capacitor banks are protected from overload conditions by triggered gaps and/or metal oxide varistors (MOVs) and can also be protected or bypassed by breakers or motor operated disconnects. Triggered gaps and/or MOVs (**Figure 1.3**) operate on the voltage across the capacitor ($V_{protective}$) whichever may be present in a given installation.

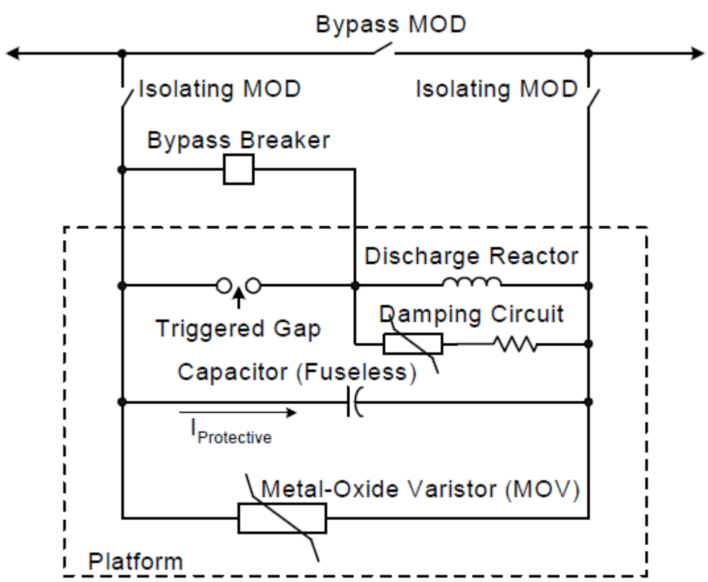

Figure 1.3: Series Capacitor Components

This voltage can be converted to a current by this equation:

$$I_{protective} = \frac{V_{protective}}{X_c}$$

Where:

$V_{protective}$ = Protective level of voltage across the capacitor spark gaps and/or MOVs

X_C = Capacitive reactance

The protection limits the theoretical maximum power flow because I_{total}, assuming the line inductive reactance is reduced by the capacitive reactance, will typically exceed $I_{protective}$. A current of $I_{protective}$ or greater will result in a capacitor bypass. This reduces the theoretical maximum power transfer to that of only the line inductive reactance as described in section 1.3.

The relay settings must be evaluated against 115% of the highest series capacitor emergency current rating and the maximum power transfer calculated in R1 Part 1.3 by using the full-line inductive reactance (uncompensated line reactance). This must be done to accommodate situations where the capacitor is bypassed for reasons other than $I_{protective}$. The relay must be set to accommodate the greater of these two currents.

Set the tripping relay so it does not operate at or below the greater of the following:

- 115% of the highest emergency rating of the series capacitor. When evaluating a distance relay, assume a 0.85 per unit relay voltage and a line phase (power factor) angle of 30 degrees.
- I_{total} (where I_{total} is calculated under R1 Part 1.3 using the full line inductive reactance). When evaluating a distance relay, assume a 0.85 per unit relay voltage and a line phase (power factor) angle of 30 degrees.

$$Z_{\text{relay30}} = \frac{.85\ x\ V_{L-L}}{\sqrt{3}\ x\ 1.15\ x\ I_{total}}$$

1.5 Weak Source Systems

In some cases, the maximum line end three-phase fault current is small relative to the thermal loadability of the conductor. Such cases exist due to some combination of weak sources, long lines, and the topology of the transmission system (Figure 1.4).

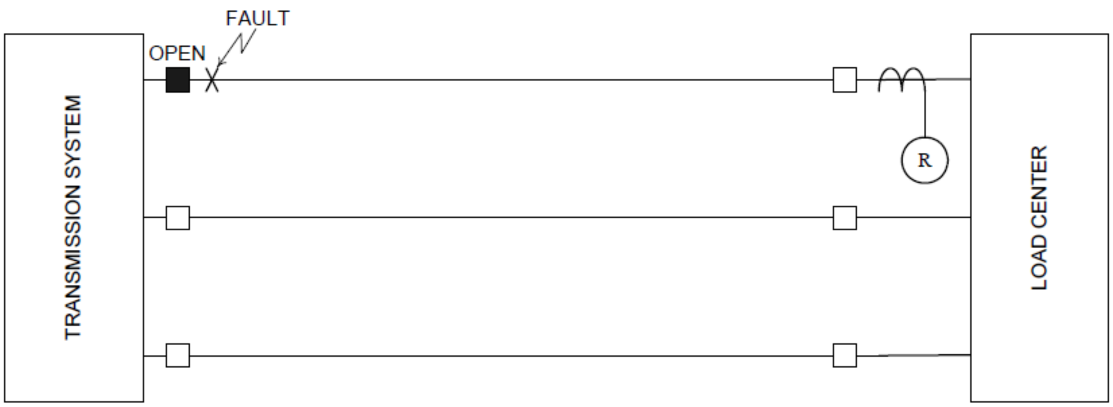

Figure 1.4: Weak Source Systems

Since the line end fault is the maximum current at one per unit phase to ground voltage, and it is possible to have a voltage of 90 degrees across the line for maximum power transfer across the line, the voltage across the line is equal to this equation:

$$V_{S-R} = \sqrt{V_S^2 + V_R^2} = \sqrt{2}\ x\ V_{LN}$$

It is necessary to increase the line end fault current I_{fault} by $\sqrt{2}$ to reflect the maximum current that the terminal could see for maximum power transfer and by 115% to provide margin for device errors. An additional factor of 105% is also included due to the assumption that the voltage on each bus is 1.05 per unit. Refer to the following equation:

$$I_{max} = 1.15\ x\ \sqrt{2}\ x\ 1.05\ x\ I_{fault}$$
$$I_{max} = 1.71 x I_{fault}$$

Where:
I_{fault} is the line-end three-phase fault current magnitude obtained from a short circuit study, reflecting sub-transient generator reactances.

Set the tripping relay on weak-source systems, so it does not operate at or below 1.70 times I_{fault}, where I_{fault} is the maximum end of line three-phase fault current magnitude. When evaluating a distance relay, assume a 0.85 per unit relay voltage and a line phase (power factor) angle of 30 degrees.

$$Z_{\text{relay30}} = \frac{.85 \ x \ V_{L-L}}{\sqrt{3} \ x \ 1.70 \ x \ I_{fault}}$$

1.6 Not Used

1.7 Load Remote to Generation

Some system configurations have load centers (no appreciable generation) remote from the generation center where no appreciable current would flow from the load centers to the generation center (**Figure 1.5**).

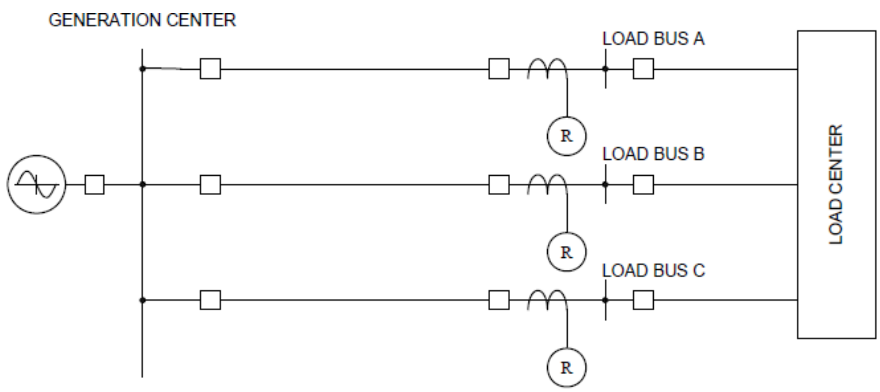

Figure 1.5: Load Remote to Generation Center

Although only minimal current can flow from the load center to the generation center under normal conditions, the forward-reaching relay element on the load center breakers must provide sufficient loadability margin for unusual system conditions. To qualify, one must determine the maximum current flow (I_{max}) from the load center to the generation center under any system configuration.

Set the tripping relay at the load center so it does not operate at or below 115% of the maximum current flow. When evaluating a distance relay, assume a 0.85 per unit relay voltage and a line phase (power factor) angle of 30 degrees.

$$Z_{\text{relay30}} = \frac{.85 \ x \ V_{L-L}}{\sqrt{3} \ x \ 1.15 \ x \ I_{max}}$$

1.8 Remote Load Center

Some system configurations have one or more transmission lines connecting a remote, net importing load center to the rest of the system.

For the system shown in **Figure 1.6**, the total maximum load at the load center defines the maximum load that a single line must carry.

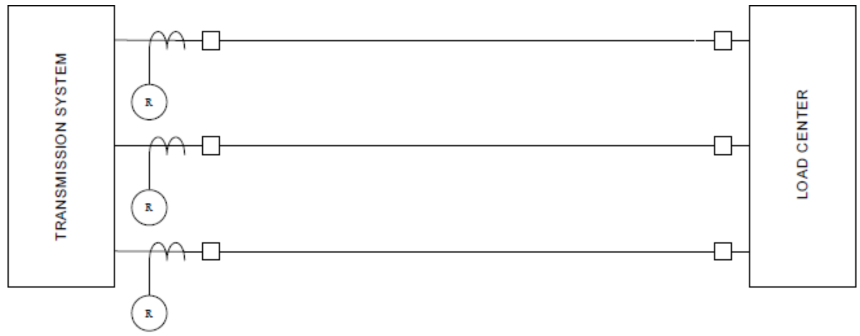

Figure 1.6: Remote Load Center

Also, one must determine the maximum power flow on an individual line to the area (I_{max}) under all system configurations, reflecting any higher currents resulting from reduced voltages, and ensure that under no condition will loop current in excess of I_{max} flow in the transmission lines.

Set the tripping relay so it does not operate at or below 115% of the maximum current flow. When evaluating a distance relay, assume a 0.85 per unit relay voltage and a line phase (power factor) angle of 30 degrees.

$$Z_{\text{relay30}} = \frac{.85\ x\ V_{L-L}}{\sqrt{3}\ x\ 1.15\ x\ I_{max}}$$

1.9 Load Center Remote to Transmission System

Some system configurations have one or more transmission lines connecting a cohesive, remote, net importing load center to the rest of the system. For the system shown in **Figure 1.7**, the total maximum load at the load center defines the maximum load that a single line must carry. This applies to the relays at the load center ends of lines addressed in R1 Part 1.8.

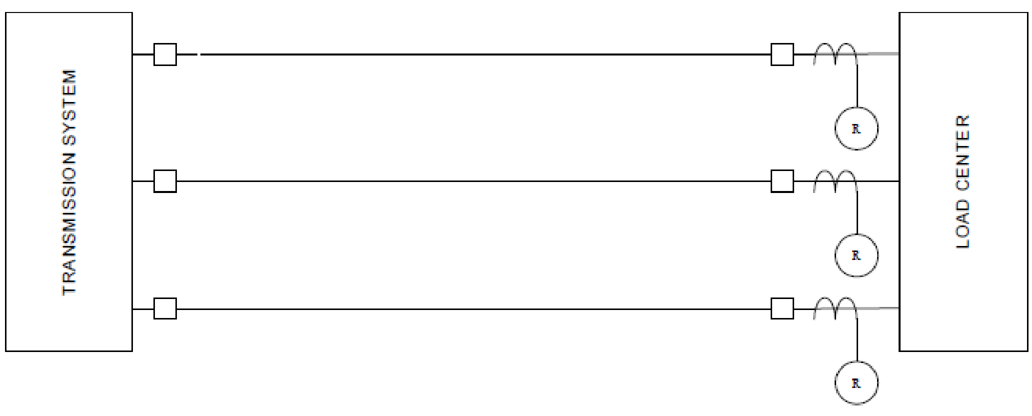

Figure 1.7: Load Center Remote to Transmission System

However, under normal conditions, only minimal current can flow from the load center to the transmission system. The forward-reaching relay element on the load center breakers must provide sufficient loadability margin for unusual system conditions, including all potential loop flows. To qualify, one must determine the maximum current flow (I_{max}) from the load center to the transmission system under any system configuration.

Set the tripping relay so it does not operate at or below 115% of the maximum current flow. When evaluating a distance relay, assume a 0.85 per unit relay voltage and a line phase (power factor) angle of 30 degrees.

$$Z_{\text{relay30}} = \frac{.85\ x\ V_{L-L}}{\sqrt{3}\ x\ 1.15\ x\ I_{max}}$$

1.10 Transformer Overcurrent Protection

The transformer fault protective relaying settings are set to protect for fault conditions, not excessive load conditions. These fault protection relays are designed to operate relatively quickly. Loading conditions on the order of magnitude of 150% (50% overload) of the maximum applicable nameplate rating of the transformer can normally be sustained for several minutes without damage or appreciable loss of life to the transformer.

For transformers with operator established emergency ratings, the minimum overcurrent setting must be the greater of 115% of the highest established emergency rating, or 150% of the maximum nameplate rating.

This criterion is also applicable for transmission line relays on transmission lines terminated only with a transformer.

1.10.1 Coordination with IEEE Damage Curve

If load-responsive transformer fault protection relays are present, ensure that their protection settings do not expose the transformer to a fault level and duration that exceeds the transformer's mechanical withstand capability as illustrated by the "dotted line" in IEEE C57.109-2018 - *IEEE Guide for Liquid-Immersed Transformers Through-Fault-Current Duration, Clause 4.4, Figure 4.* An example showing coordination between an overcurrent relay protecting a transformer with transformer's mechanical and thermal withstand capability is shown in **Figure 1.8**.

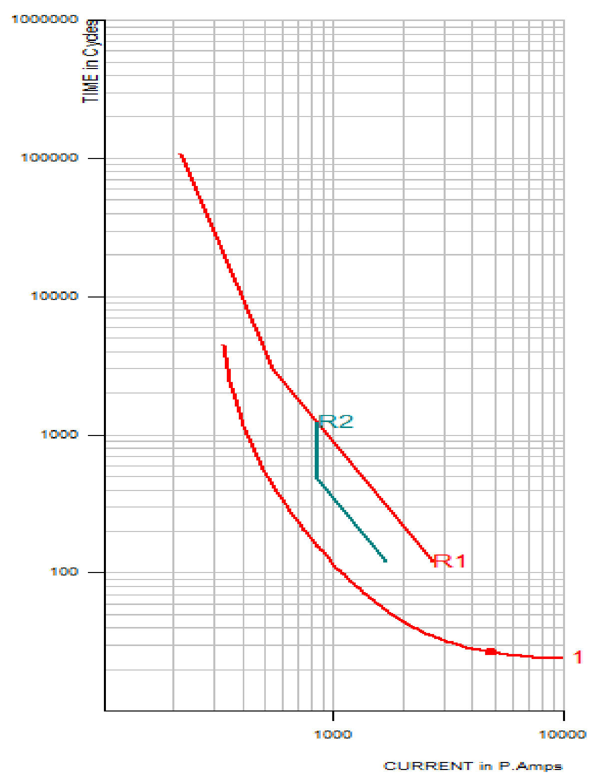

Figure 1.8: Overcurrent Relay Coordinated With Transformer's Mechanical and Thermal Withstand Capability

1.11 Transformer Overload Protection

If the pickup of overcurrent relays is less than what criterion 1.10 specifies, then the relays must be set to allow the transformer to be operated at an overload level of at least 150% of the maximum applicable nameplate rating, or 115% of the highest operator established emergency transformer rating (whichever is greater) for at least 15 minutes to provide time for the operator to take controlled action to relieve the overload.

Alternatively, the relays may be set below the requirements of criterion 1.10 if tripping is supervised using either a top oil or simulated winding hot spot temperature element set no less than 100° C for the top oil temperature or no less than 140° C for the winding hot spot temperature.

1.12 Long Line Relay Loadability—Two Terminal Lines

This description applies only to classical two-terminal lines. For lines with other configurations, see R1 Part 1.12.2, *Three (or more) Terminal Lines, and Lines with One or More Radial Taps*. A large number of transmission lines in North America are protected with distance-based relays that use an mho characteristic. Although other relay characteristics are now available that offer the same fault protection with more immunity to load encroachment, generally they are not required based on the following:

- The original loadability concern from the Northeast blackout (and other blackouts) was overly sensitive distance relays (usually Zone 3 relays).
- Distance relays with mho characteristics that are set at 125% of the line length are clearly not "overly sensitive" and were not responsible for any of the documented cascading outages under steady-state conditions.
- It is unlikely that distance relays with mho characteristics set at 125% of line length will misoperate due to recoverable loading during major events.
- Even though unintentional relay operation due to load could clearly be mitigated with blinders or other load encroachment techniques, in the vast majority of cases, it may not be necessary if the relays with mho characteristics are set at 125% of the line length **Figure 1.9**. For available techniques, see reference 14.

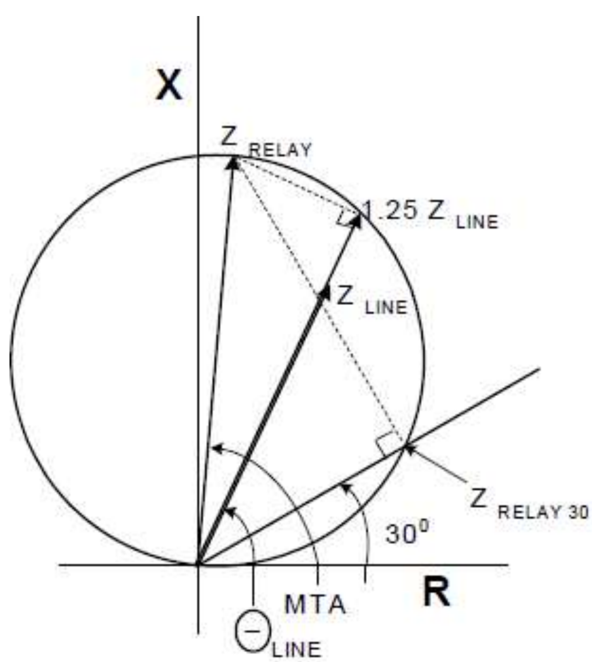

Figure 1.9: Long Line Relay Loadability

It is prudent that the relays be adjusted to as close to the 90-degree MTA setting as the relay can be set to achieve the highest level of loadability without compromising the ability of the relay to reliably detect faults.

The basis for the current loading is as follows:

V_{relay} = Line-to-Line voltage at the relay location

Z_{line} = Line impedance

Θ_{line} = Line impedance angle

Z_{relay} = Relay setting in ohms at the maximum torque angle

MTA = Maximum torque angle, the angle of maximum relay reach

$Z_{relay30}$ = Relay trip point at a 30-degree phase angle between the voltage and current

I_{trip} = Relay operating current at 30 degrees with normal voltage

$I_{relay30}$ = Current (including a 15% margin) that the circuit can carry at 0.85 per unit voltage at a 30-degree phase angle between the voltage and current before reaching the relay trip point

Use the following for applying a mho-characteristic relay at any maximum torque angle to any line impedance angle:

$$Z_{relay} = \frac{1.25\ x\ Z_{line}}{\cos(MTA - \theta_{line})}$$

The relay reach at the load power factor angle of 30° is determined from the following:

$$Z_{relay\ 30} = \left[\frac{1.25\ x\ Z_{Line}}{\cos(MTA - \theta_{line})}\right] x \cos(MTA - 30°)$$

The relay operating current at the load power factor angle of 30° is as follows:

$$I_{trip} = \frac{V_{relay}}{\sqrt{3}\ x\ Z_{relay\ 30}}$$

$$I_{trip} = \frac{V_{relay}\ x\ cos(MTA - \theta_{line})}{\sqrt{3}\ x\ 1.25\ x\ Z_{line}\ x\ \cos\ (MTA - 30°)}$$

The load current with a 15% margin factor and the 0.85 per unit voltage requirement is calculated by the following:

$$I_{relay\ 30} = \frac{0.85\ x\ I_{trip}}{1.15}$$

$$I_{relay\ 30} = \frac{0.85\ x\ V_{Relay}\ x\ \cos\ (MTA - \theta_{line})}{1.15\ x\ \sqrt{3}\ x\ 1.25\ x\ Z_{line}\ x\ \cos\ (MTA - 30°)}$$

$$I_{relay\ 30} = \left(\frac{0.341\ x\ V_{relay}}{Z_{line}}\right)\ x\ \left(\frac{\cos(MTA - \theta_{line})}{\cos(MTA - 30°)}\right)$$

1.12.2 Long Line Relay Loadability—Three (or more) Terminal Lines and Lines with One or More Radial Taps

Three (or more) terminal lines present protective relaying challenges from a loadability standpoint due to the apparent impedance as seen by the different terminals. This includes lines with radial taps. The loadability of the line may be different for each terminal of the line so the loadability must be done on a per terminal basis. See **Figure 1.10**.

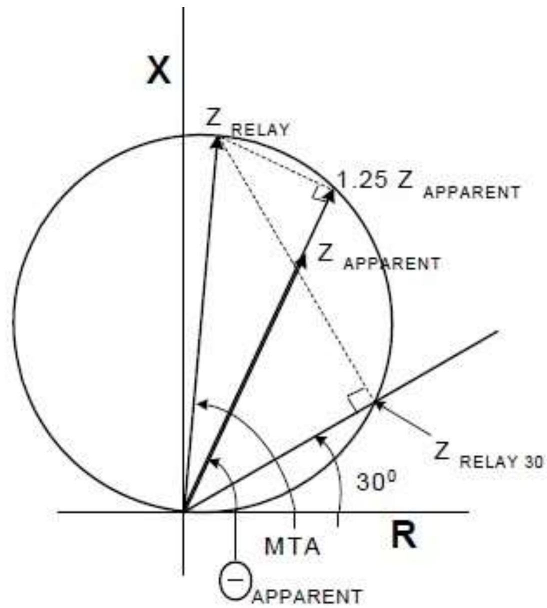

Figure 1.10: Three (or more) Terminal Lines and Lines with One or More Radial Taps

The basis for the current loading is as follows:

V_{relay} = Phase-to-phase line voltage at the relay location

$Z_{apparent}$ = Apparent line impedance as seen from the line terminal. This apparent impedance is the impedance calculated (using in-feed) for a fault at the most electrically distant line terminal for system conditions normally used in protective relaying setting practices.

$\Theta_{apparent}$ = Apparent line impedance angle as seen from the line terminal

Z_{relay} = Relay setting at the maximum torque angle

MTA = Maximum torque angle, the angle of maximum relay reach

$Z_{relay30}$ = Relay trip point at a 30 degree phase angle between the voltage and current

I_{trip} = Trip current at 30 degrees with normal voltage

$I_{relay30}$ = Current (including a 15% margin) that the circuit can carry at 0.85 voltage at a 30 degree phase angle between the voltage and current before reaching the trip point

For applying a mho-characteristic relay at any maximum torque angle to any apparent impedance angle, use the following equation:

$$Z_{relay} = \frac{1.25\ x\ Z_{apparent}}{\cos\left(MTA - \theta_{apparent}\right)}$$

The relay reach at the load power factor angle of 30° is determined from the following:

$$Z_{relay\ 30} = \left[\frac{1.25\ x\ Z_{apparent}}{\cos\left(MTA - \theta_{apparent}\right)}\right] x \cos(MTA - 30°)$$

The relay operating current at the load power factor angle of 30° is as follows:

$$I_{trip} = \frac{V_{relay}}{\sqrt{3}\ x\ Z_{relay\ 30}}$$

$$I_{trip} = \frac{V_{relay}\ x\ cos(MTA - \theta_{apparent})}{\sqrt{3}\ x\ 1.25\ x\ Z_{apparent}\ x \cos\ (MTA - 30°)}$$

The load current with a 15% margin factor and the 0.85 per unit voltage requirement is calculated by the following equations:

$$I_{relay\ 30} = \frac{0.85\ x\ I_{trip}}{1.15}$$

$$I_{relay\ 30} = \frac{0.85\ x\ V_{Relay}\ x \cos\ (MTA - \theta_{apparent})}{1.15\ x\ \sqrt{3}\ x\ 1.25\ x\ Z_{apparent}\ x \cos\ (MTA - 30°)}$$

$$I_{relay\ 30} = \left(\frac{0.341\ x\ V_{relay}}{Z_{apparent}}\right) x\ (\frac{\cos\left(MTA - \theta_{apparent}\right)}{\cos(MTA - 30°)})$$

1.13 Other Practical Limitations

Where other situations present practical limitations on circuit capability, set the phase protection relays so they do not operate at or below 115% of such limitations.

No calculations necessary.

Appendix A: Long Line Maximum Power Transfer Equations

Lengthy transmission lines have significant series resistance, reactance, and shunt capacitance (see **Figure A.1**). The line resistance consumes real power when current flows through the line and increases the real power input during maximum power transfer. The shunt capacitance supplies reactive current, which impacts the sending end reactive power requirements of the transmission line during maximum power transfer. These line parameters should be used when calculating the maximum line power flow.

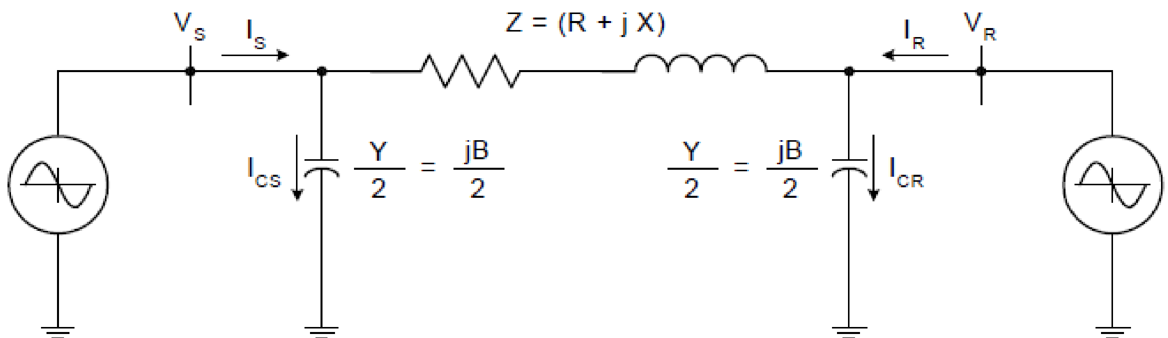

Figure A.1: Transmission Line Model for Maximum Power Transfer Calculation

The following equations may be used to compute the maximum power transfer:

$$P_{S3-\theta} = \frac{V_S^2}{|Z|}\cos(\theta°) - \frac{V_S V_R}{|Z|}\cos\,(\theta + \delta°)$$

$$Q_{S3-\theta} = \frac{V_S^2}{|Z|}\sin(\theta°) - V_S^2\frac{B}{2} - \frac{V_S V_R}{|Z|}\sin\,(\theta + \delta°)$$

The equations for computing the total line current are below. These equations assume the condition of maximum power transfer (δ = 90º) and nominal voltage at both the sending and receiving line ends:

$$I_{real} = \frac{V}{\sqrt{3}\,|Z|}\,(\cos(\theta°) + \sin(\theta°))$$

$$I_{reactive} = \frac{V}{\sqrt{3}|Z|}\left(\sin(\theta°) - |Z|\frac{B}{2} - \cos\,(\theta°)\right)$$

$$I_{total} = I_{real} + jI_{reactive}$$

$$I_{total} = \sqrt{I_{real}^2 + I_{reactive}^2}$$

Where:

P = the power flow across the transmission line

V_S = Phase-to-phase voltage at the sending bus

V_R = Phase-to-phase voltage at the receiving bus

V = Nominal phase-to-phase bus voltage

δ = Voltage angle between VS and VR

Z = Reactance, including fixed shunt reactors, of the transmission line in ohms*

Θ = Line impedance angle

B = Shunt susceptance of the transmission line in mhos*

*The use of hyperbolic functions to calculate these impedances is recommended to reflect the distributed nature of long line reactance and capacitance.

Appendix B: Impedance-Based Pilot Relaying Considerations

Some utilities employ communication-aided (pilot) relaying schemes that, when taken as a whole, may have a higher loadability than would otherwise be implied by the setting of the forward (overreaching) impedance elements. Impedance-based pilot relaying schemes may comply with PRC-023-5 Requirement R1 if all of the following conditions are satisfied:

- The overreaching impedance elements are used only as part of the pilot scheme itself (i.e., not also in conjunction with a Zone 2 timer which would allow them to trip independently of the pilot scheme).
- The scheme is of the permissive overreaching transfer trip type, requiring relays at all terminals to sense an internal fault as a condition for tripping any terminal.
- The permissive overreaching transfer trip scheme has not been modified to include weak infeed logic or other logic that could allow a terminal to trip even if the closed remote terminal does not sense an internal fault condition with its own forward-reaching elements. Unmodified directional comparison unblocking schemes are equivalent to permissive overreaching transfer trip in this context. Directional comparison blocking schemes will generally not qualify.

For purposes of this discussion, impedance-based pilot relaying schemes fall into two general classes:

- **Unmodified permissive overreaching transfer trip** (POTT) requires relays at all terminals to sense an internal fault as a condition for tripping any terminal. Unmodified directional comparison unblocking schemes are equivalent to permissive overreach in this context.
- **Directional comparison blocking** (DCB) requires relays at one terminal to sense an internal fault, and relays at all other terminals to not sense an external fault as a condition for tripping the terminal. Depending on the details of scheme operation, the criteria for determining that a fault is external may be based on current magnitude and/or on the response of directionally sensitive relays. Permissive schemes that have been modified to include “echo” or “weak source” logic fall into the DCB class.

Unmodified POTT schemes may offer a significant advantage in loadability as compared with a non-pilot scheme. Modified POTT and DCB schemes will generally offer no such advantage. Both applications are discussed below.

Unmodified Permissive Overreaching Transfer Trip

In a non-pilot application, the loadability of the tripping relay at Station “A” is determined by the reach of the impedance characteristic at an angle of 30 degrees, or the length of line AX in **Figure B.1**. In a POTT application, point “X” falls outside the tripping characteristic of the relay at Station “B”, preventing tripping at either terminal. Relay “A” becomes susceptible to tripping along its 30-degree line only when point “Y” is reached. Loadability will therefore be increased according to the ratio of AX to AY, which may be sufficient to meet the loadability requirement with no mitigating measures being necessary.

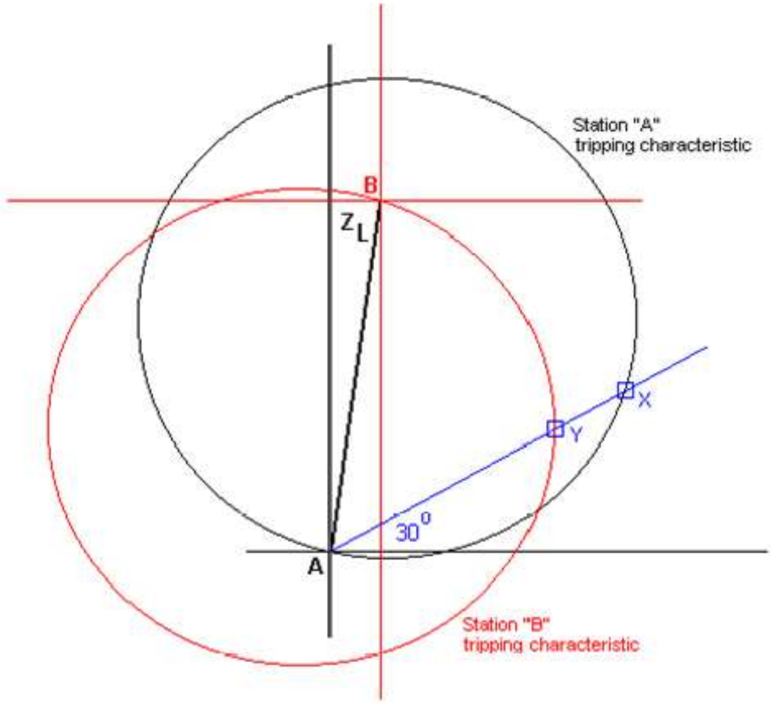

Figure B.1: Permissive Overreaching Transfer Trip (unmodified)

Directional Comparison Blocking

In **Figure B.2**, blocking at Station "B" utilizes impedance elements which may or may not have offset. The settings of the blocking elements are traditionally based on external fault conditions only. It is unlikely that the blocking characteristic at Station "B" will extend into the load region of the tripping characteristic at Station "A". The loadability of Relay "A" will therefore almost invariably be determined by the impedance AX.

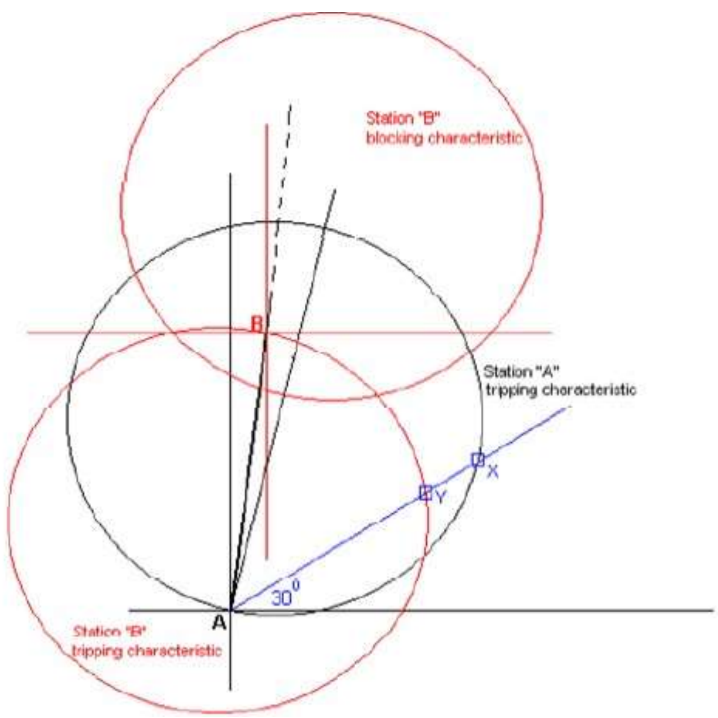

Figure B.2: Directional Comparison Blocking with Reverse-Looking Blocking Elements

Appendix C: Power Swing Blocking Relay

Power swing blocking (PSB), also known as out-of-step blocking, is sometimes applied on transmission lines and transformers to prevent tripping of the circuit element for predicted (by transient stability or other studies) or observed power system swings.

There are many methods of providing the PSB function; one common approach with distance relays one to three impedance characteristics approximately concentric with the tripping characteristic. These characteristics may be circular, quadrilateral, or other shapes.

During normal system conditions, the accelerating power (Pa) will be essentially zero. During system disturbances, Pa will be greater than zero. Pa is the difference between the mechanical power input (Pm) and the electrical power output (Pe) of the system while ignoring any losses. The machines or group of machines will accelerate uniformly at the rate of Pa/2H radians per second squared, where H is the inertia constant of the system. During a fault condition, Pa is much greater than 1, resulting in a near instantaneous change from load to fault impedance. During a stable swing condition, Pa is less than 1, resulting in a slower rate of change of impedance.

For a system swing condition, the apparent impedance will form a loci of impedance points (relative to time) that changes relatively slowly at first; for a stable swing (where no generators "slip poles" or go unstable), the impedance loci will eventually damp out to a new steady-state operating point. For an unstable swing, the impedance loci will change quickly, traversing the jx-axis of the impedance plane as the generator slips a pole as shown in Figure C.1.

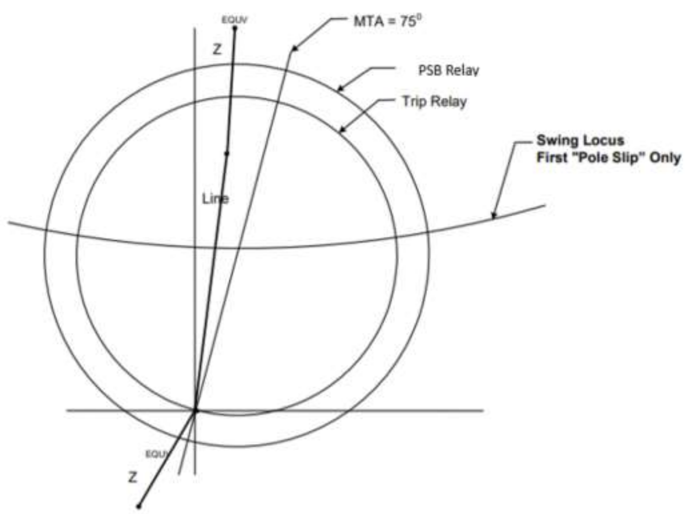

Figure C.1: Portion of an Unstable Swing

For simplicity, this appendix discusses the concentric-distance-characteristic method of PSB while considering circular mho characteristics most commonly used with electromechanical relays. As mentioned above, this approach uses a mho characteristic for the PSB relay that is larger than and approximately concentric to the related distance relay characteristic. The PSB characteristic is also equipped with a timer so that a fault will transit the PSB characteristic too quickly to operate the PSB relay, but a swing will reside between the PSB characteristic and the tripping characteristic for a sufficient period of time for the PSB relay to operate. Operation of the PSB relay (including the timer) will, in turn, inhibit the distance relay from operating. More sophisticated schemes differentiate between a swing and a heavy load condition by using a second timer that identifies that the impedance stays inside the PSB characteristic (not characteristic of a swing) and unblocks the scheme. Often, this unblocking timer is built into the scheme logic and is not user settable.

Figure C.1 illustrates the relationship between the PSB relay and the tripping relay and shows a sample of a portion of an unstable swing.

Impact of System Loading on the PSB Relaying

Figure C.1 illustrates a distance relay and PSB relay and shows the relative effects of several apparent impedances.

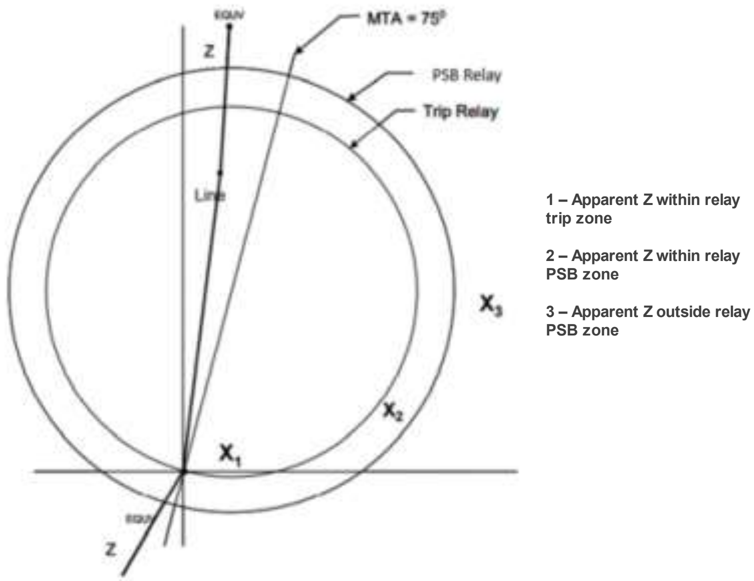

Figure C.1: Power Swing Blocking Characteristics with Load

Both the distance relay and the PSB relay have characteristics responsive to the impedance that is seen at the line terminal. The distance relays must be considered when evaluating the effect of system loads on relay characteristics (usually referred to as “relay loadability”). However, when the behavior of PSB relays is also considered, it becomes clear that they must also be included in the evaluation of system loads, as their reach must necessarily be longer than that of the distance relays, making them even more responsive to load.

Three different load impedances are shown. Load Impedance 1 shows an impedance (either load or fault) that would operate the distance relay. Load Impedance 3 shows a load impedance well outside both the tripping characteristic and the PSB characteristic and illustrates the desired result.

The primary concern relates to the fact that, if an apparent impedance, shown as Load Impedance 2, resides within the PSB characteristic (but outside the tripping characteristic) for the duration of the PSB timer, the PSB relay inhibits the operation of the distance relay. It becomes clear that such an apparent impedance can represent a system load condition as well as a system swing; if (and as long as) a system load condition operates the PSB relay, the distance relay will be prevented from operating for a subsequent fault condition.

Several techniques are commonly used by some solid state and many microprocessor relays, singly or in combination, to mitigate such “permanent” power swing blocking. Several possible (but not all) methods ensure detection and clearing of all faults will occur during any of the loading conditions of PRC-023 R1:

- One mitigation method uses a timer to detect that the measured impedance remains between the two relay characteristics for a period that is longer than the characteristic of a swing and unblocks the scheme. Often, this unblocking timer is built into the scheme logic and is not user settable. This method can also be used with electromechanical relays and some solid-state relays.

- The PSB algorithm may monitor the time that the impedance locus remains within an inner blinder region to reset the blocking using an adaptive timer based on the measured swing rate.
- The PSB algorithm may monitor negative and/or zero sequence currents and reset the PSB relay for a significant unbalance.
- Distance protection may use quadrilateral or other non-mho shapes to allow smaller resistive reach settings for both protection and PSB characteristics that do not encroach on the relay loadability characteristic.
- PSB characteristics that use quadrilateral or modified mho shapes may be set with shorter resistive reach that encroaches on the distance relay protection mho characteristics and use relay logic to only allow trips when the impedance locus is within both the protection and PSB characteristic.
- The PSB algorithm may continuously monitor parameters, such as swing center voltage, currents, or impedance, to determine whether PSB should be asserted. Continuous monitoring prevents “permanent” PSB by automatically resetting if the apparent impedance locus stops moving as is characteristic of a fault.
- Other techniques may also be used.

Appendix D: Switch-on-to-Fault Schemes

Introduction

Switch-on-to-fault (SOTF) schemes (also known as "close-into-fault schemes or line-pickup schemes) are protection functions intended to trip a transmission line breaker when closed on to a faulted line. Dedicated SOTF schemes are available in various designs, but since the fault-detecting elements tend to be more sensitive than conventional impedance-based line protection functions, they are designed to be "armed" only for a brief period following breaker closure. Depending on the details of scheme design and element settings, there may be implications for line relay loadability. This paper addresses those implications in the context of scheme design.

SOTF Scheme Applications

SOTF schemes are applied for one or more reasons:

- When an impedance-based protection scheme uses line-side voltage transformers, SOTF logic is required to detect a close-in, three-phase fault to protect against a line breaker being closed into such a fault. Phase impedance relays whose steady-state tripping characteristics pass through the origin on an R-X diagram will generally not operate if there is zero voltage applied to the relay before closing into a zero-voltage fault. This condition typically occurs when a breaker is closed into a set of three-phase grounds that operations/maintenance personnel failed to remove prior to re-energizing the line. When this occurs in the absence of SOTF protection, the breaker will not trip, and breaker failure protection will not be initiated, possibly resulting in time-delayed tripping at numerous remote terminals. Unit instability and load loss can also occur.
- Current fault detector pickup settings must be low enough to allow positive fault detection under what is considered to be the "worst case" (highest) impedance to the source bus.
- When an impedance protection scheme uses line-side voltage transformers, SOTF current fault detectors may operate significantly faster than impedance units when a breaker is closed into a fault anywhere on the line. The dynamic characteristics of typical impedance units are such that their speed of operation is impaired if polarizing voltages are not available prior to the fault.
- Current fault detector pickup settings will generally be lower in this application than in (1) above. The greater the coverage desired, and the longer the line, the lower the setting.
- Regardless of voltage transformer location, SOTF schemes may allow high-speed clearing of faults along the entire line without having to rely or wait on a communications-aided tripping scheme.
- Current or impedance-based fault detectors must be set to reach the remote line terminal to achieve that objective.

SOTF Line Loadability Considerations

This reference document is intended to provide guidance for the review of existing SOTF schemes to ensure that those schemes do not operate for non-SOTF conditions or under heavily stressed system conditions. This document also provides recommended practices for application of new SOTF schemes:

- The SOTF protection must not operate assuming that the line terminals are closed at the outset and carrying up to 1.5 times the facility rating (as specified in Reliability Standard PRC-023-5) when calculated in accordance with the methods described in this standard.
- For existing SOTF schemes, the SOTF protection must not operate when a breaker is closed into an unfaulted line that is energized from the remote terminal at a voltage exceeding 85% of nominal at the local terminal. For SOTF schemes commissioned after formal adoption of this report, the protection should not operate when a breaker is closed into an unfaulted line that is energized from the remote terminal at a voltage exceeding 75% of nominal at the local terminal.

SOTF Scheme Designs

- **Direct-tripping high-set instantaneous phase overcurrent**
  This scheme is technically not a SOTF scheme in that it is in-service at all times, but it can be effectively applied under appropriate circumstances for clearing zero-voltage faults. It uses a continuously enabled, high-set instantaneous phase overcurrent unit or units set to detect the fault under “worst case” (lowest source impedance) conditions. The main considerations in the use of such a scheme involve detecting the fault while not overreaching the remote line terminal under external fault conditions and not operating for stable load swings. Under NERC line loadability requirements, the overcurrent unit setting also must be greater than 1.5 times the facility rating (as specified in Reliability Standard PRC-023-5) when calculated in accordance with the methods described in this standard.

- **Dedicated SOTF Schemes**
  Dedicated SOTF schemes generally include logic designed to detect an open breaker and to arm instantaneous tripping by current or impedance elements only for a brief period following breaker closing. The differences in the schemes are from the method by which breaker closing is declared, whether there is a scheme requirement that the line be dead prior to breaker closing, and in the choice of tripping elements. In the case of modern relays, every manufacturer has its own design. Additionally, users have choices for scheme logic as well as element settings in some cases.

  In some SOTF schemes, the use of breaker auxiliary contacts and/or breaker “close” signaling is included, limiting scheme exposure to actual breaker closing situations. With others, the breaker-closing declaration is based solely on the status of voltage and current elements. This is regarded as marginally less secure from misoperation when the line terminals are (and have been) closed but can reduce scheme complexity when the line terminates in multiple breakers, any of which can be closed to energize the line.

SOTF and Automatic Reclosing

With appropriate consideration of dead-line reclosing voltage supervision, there are no coordination issues between SOTF and automatic reclosing into a de-energized line. If the pre-close line voltage is the primary means for preventing SOTF tripping under heavy loading conditions, it is desirable from a security standpoint that the SOTF line voltage detectors be set to pick up at a voltage level below the automatic reclosing live-line voltage detectors and below 0.8 per-unit voltage.

Where this is not possible, the SOTF fault detecting elements are susceptible to operation for closing into an energized line and should be set no higher than required to detect a close-in, three-phase fault under worst case (highest source impedance) conditions, assuming that they cannot be set above 1.5 times the facility rating (as specified in Reliability Standard PRC-023-5). Immunity to false tripping on high-speed reclosure may be enhanced by using scheme logic that delays the action of the fault detectors long enough for the line voltage detectors to pick up and instantaneously block SOTF tripping.

Appendix E: References

The listed IEEE Standards are available from the IEEE Standards Association.[4] The listed ANSI Standards are available directly from the American National Standards Institute.[5]

1. Performance of Generator Protection During Major System Disturbances, IEEE Paper No. TPWRD-00370-2003, Working Group J6 of the Rotating Machinery Protection Subcommittee, Power System Relaying Committee, 2003.
2. Transmission Line Protective Systems Loadability, Working Group D6 of the Line Protection Subcommittee, Power System Relaying Committee, March 2001.
3. Practical Concepts in Capability and Performance of Transmission Lines, H. P. St. Clair, IEEE Transactions, December 1953, pp. 1152–1157.
4. Analytical Development of Loadability Characteristics for EHV and UHV Transmission Lines, R. D. Dunlop, R. Gutman, P. P. Marchenko, IEEE transactions on Power Apparatus and Systems, Vol. PAS – 98, No. 2 March-April 1979, pp. 606–617.
5. EHV and UHV Line Loadability Dependence on var Supply Capability, T. W. Kay, P. W. Sauer, R. D. Shultz, R. A. Smith, IEEE transactions on Power Apparatus and Systems, Vol. PAS –101, No. 9 September 1982, pp. 3568–3575.
6. Application of Line Loadability Concepts to Operating Studies, R. Gutman, IEEE Transactions on Power Systems, Vol. 3, No. 4 November 1988, pp. 1426–1433.
7. IEEE Standard C37.113, IEEE Guide for Protective Relay Applications to Transmission Lines.
8. ANSI Standard C50.13, American National Standard for Cylindrical Rotor Synchronous Generators.
9. ANSI Standard C84.1, American National Standard for Electric Power Systems and Equipment – Voltage Ratings (60 Hertz), 1995.
10. IEEE Standard 1036, IEEE Guide for Application of Shunt Capacitors, 1992.
11. J. J. Grainger & W. D. Stevenson, Jr., Power System Analysis, McGraw- Hill Inc., 1994, Chapter 6 Sections 6.4 – 6.7, pp 202 – 215.
12. Final Report on the August 14, 2003, Blackout in the United States and Canada: Causes and Recommendations, U.S.-Canada Power System Outage Task Force, April 2004.
13. August 14, 2003, Blackout: NERC Actions to Prevent and Mitigate the Impacts of Future Cascading Blackouts, approved by the NERC Board of Trustees, February 10, 2004.
14. Increase Line Loadability by Enabling Load Encroachment Functions of Digital Relays, System Protection and Control Task Force, North American Electric Reliability Council, December 7, 2005.

[4] http://www.techstreet.com/ieee

[5] https://webstore.ansi.org/default.aspx

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Determination of Practical Transmission Relaying Loadability Settings V1.1

Implementation Guidance for PRC-023-5 System Protection and Control Working Group

Lynn Schroeder and Manish Patel, SPCWG

Reliability and Security Technical Committee Meeting
March 12, 2024

Determination of Practical Transmission Relaying Loadability Settings V1.1

- Implementation Guidance for PRC-023-5
  - Originally Published in 2017 for PRC-023-4
  - Revised for PRC-023-5 and re-formatted
    - PRC-023-5 retired R2
      - Changed standard as needed to address the retirement of R2 related to OOS Blocking
      - Modified “Determination of Practical Transmission Relaying Loadability Ratings Version1” to address removal of R2

Determination of Practical Transmission Relaying Loadability Settings V1.1

- Provides guidance for complying with the requirements of PRC-023 – Transmission Loadability
- 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."

Determination of Practical Transmission Relaying Loadability Settings V1.1

- IG – Chapter 1
  - Examples for meeting each Criteria
    - 1.1 Thermal Rating
    - 1.2 Established 15-Minute Rating
    - 1.3 Maximum Theoretical Power Transfer Limit
    - 1.4 Series-Compensated lines
    - 1.5 Weak Source
    - 1.6 Not used (Consistent with R2 removal in PRC-023-5)
    - 1.7 Load Remote to Generation
  - (Cont.) Examples for meeting each Criteria
    - 1.8 Remote Load Center
    - 1.9 Load Center Remote to Transmission Line
    - 1.10 Transformer Overcurrent Protection
    - 1.11 Transformer Overload Protection
    - 1.12 Long Line Relay Loadability – Two Terminal Lines
    - 1.13 Other Practical Limitations

- PRC023 Criteria (Subset)
    - "1. Set transmission line relays so they do not operate at or below 150% of the highest seasonal Facility Rating of a circuit, for the available defined loading duration nearest 4 hours (expressed in amps)."
        - Commonly used in industry

$$Z_{relay30} = \frac{.85 \; x \; V_{L-L}}{\sqrt{3} \; x \; 1.5 \; x \; I_{Rating}}$$

Where:

$Z_{relay30}$ = Relay reach in primary Ohms at a power factor angle of 30 degrees

V_{L-L} = Rated line-to-line voltage

I_{rating} = Facility Rating

Determination of Practical Transmission Relaying Loadability Settings V1.1

- PRC023 Criteria (Subset)
  - "5. Set transmission line relays on weak source systems so they do not operate at or below 170% of the maximum end-of-line three-phase fault magnitude (expressed in amps).
    - In some cases, the maximum line end 3P fault current is small relative to the thermal loadability of the conductor.
    - 170% represents the maximum line current with ~115% margin.

Since the line end fault is the maximum current at one per unit phase to ground voltage and it is possible to have a voltage of 90 degrees across the line for maximum power transfer across the line, the voltage across the line is equal to:

$$V_{S-R} = \sqrt{V_S^{\,2} + V_R^{\,2}} = \sqrt{2} \times V_{LN}$$

It is necessary to increase the line end fault current I_{fault} by $\sqrt{2}$ to reflect the maximum current that the terminal could see for maximum power transfer.

$$I_{\max} = \sqrt{2} \times 1.05 \times I_{fault}$$

$$I_{max} = 1.485 \times I_{fault}$$

Determination of Practical Transmission Relaying Loadability Settings V1.1

- PRC023 Criteria (Subset)
  - "12. When the desired transmission line capability is limited by the requirement to adequately protect the transmission line, set the transmission line distance relays to a maximum of 125% of the apparent impedance (at the angle of the transmission line) subject to the following constraints: a)…MTA to 90 deg.. b) evaluate… .85pu voltage and…. 30 deg c) …87% of R1 current"
    - *May be used (as an example) for relays with less immunity to load encroachment. – Beyond Zone 3,2005*

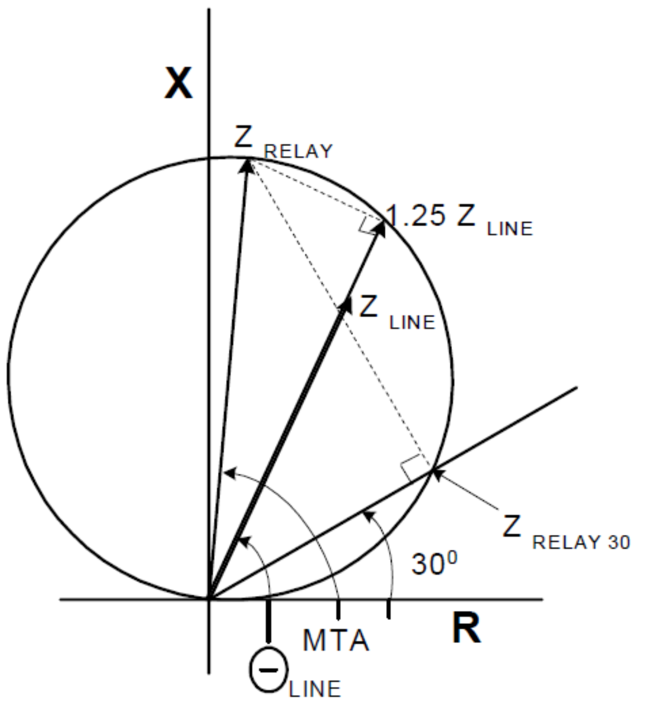

Figure 7 – Long Line relay Loadability

Determination of Practical Transmission Relaying Loadability Settings V1.1

- Appendix
  - A – Long Line Maximum Power Transfer Equations
  - B – Impedance-Based Pilot Relaying Considerations
  - C – Power Swing Blocking Relay
    - Considering retirement of R2, added guidance for PSB elements as suggested by the PRC-023-5 SDT

Determination of Practical Transmission Relaying Loadability Settings V1.1

- Summary
  - Technical information pertinent to industry for understanding Loadability Requirements
  - Reformatted to new NERC template
  - Minor revisions consistent with R2 removal
  - Incorporates -5 SDT comments
  - Incorporates RSTC review comments

Determination of Practical Transmission Relaying Loadability Settings V1.1

- Action Requested
  - SPCWG is requesting that the RSTC accept the “Determination of Practical Transmission Relaying Loadability Settings V1.1”.

Questions and Answers

Transmission System Phase Backup Protection

Action Requested:

The SPCWG is requesting that the RSTC form a group to review and provide feedback on the Transmission System Phase Backup Protection document that reviews the importance of backup protection schemes.

Background:

In 2011, the System Protection and Control Subcommittee published a version of this document as a Reliability Guideline. After review, this document is a Technical Reference Document. This document has been revised to place it in the new format style and reviewed by the SPCWG and determined that it is still a valid and relevant reference for industry.

Summary:

The SPCWG requests that the RSTC review and provide feedback on this document in anticipation of being submitted to the RSTC for approval at the June meeting.

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NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Transmission System Phase Backup Protection

Technical Reference Document

June 2024

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

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

The North American BPS is made up of six Regional Entities as shown on the map and in the corresponding table below. The multicolored area denotes overlap as some load-serving entities participate in one Regional Entity while associated Transmission Owners/Operators participate in another.

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

Statement of Purpose

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

Each entity registered in the NERC compliance registry is responsible and accountable for maintaining reliability and compliance with applicable mandatory Reliability Standards. Reliability guidelines are not binding norms or parameters nor are they Reliability Standards; however, NERC encourages entities to review, validate, adjust, and/or develop a program with the practices set forth in this guideline. Entities should review this guideline in detail and in conjunction with evaluations of their internal processes and procedures; these reviews could highlight that appropriate changes are needed, and these changes should be done with consideration of system design, configuration, and business practices.

This document was originally approved by the NERC Planning Committee in June 2011. This document was originally published as a Reliability Guideline. It has been reclassified as a technical reference document and placed into the current NERC report format as it still contains useful information.

Chapter 1: Introduction and Need to Discuss Backup Protection

Backup protection can, and in many cases does, play a significant role in providing adequate system performance or aiding in containing the spread of disturbances due to faults accompanied by Protection System failures or failures of circuit breakers to interrupt current. However, NERC protection standards affect and may limit the use of backup protection to ensure that backup protection does not play a role in increasing the extent of outages during system disturbances. A number of significant system disturbance reports since the 2003 Northeast Blackout have recommended evaluating specific applications of adding backup and/or redundant protection to enhance system performance or contain the extent of a disturbance. The most significant of these is the Florida Reliability Coordinating Council (FRCC) report from the February 26, 2008 system disturbance titled "*FRCC System Disturbance and Underfrequency Load Shedding Event Report February 26th, 2008 at 1:09 pm*". This report states that "NERC should assign the System Protection and Control Task Force to produce a technical paper describing the issue and application of backup protection for autotransformers". As a result, the NERC Planning Committee (PC) has assigned the NERC System Protection and Control Subcommittee (SPCS) the task of developing a document on backup protection applications.

The goal of this reliability guideline[1] is to discuss the pros, cons, and limitations of backup protection, and include recommendations, where deemed appropriate, for a balanced approach to the use of backup relaying as a means to ensure adequate system performance and/or to provide a system safety net to limit the spread of a system disturbance for events that exceed design criteria, such as those involving multiple protection system or equipment failures. The document provides a discussion of fundamental concepts related to phase backup protection for the most common equipment on the power system: transmission lines and autotransformers. The document is not intended to provide a comprehensive discussion of all methods used for providing backup protection.

[1] Reliability Guidelines are documents that suggest approaches or behavior in a given technical area for the purpose of improving reliability. Reliability guidelines are not standards, binding norms, or mandatory requirements. Reliability guidelines may be adopted by a responsible entity in accordance with its own facts and circumstances.

Chapter 2: Background on NERC SPCWG Activities Related to Backup Protection

The use of backup protection and the implications of its use on the power system is a subject that has been discussed many times by the NERC SPCS since its formation as a NERC Task Force[2] after the 2003 Northeast Blackout. Overreaching or backup phase distance relays providing primary and/or backup functions played a role in the cascading portion of the 2003 Northeast Blackout and have played similar roles in other previous and subsequent blackouts.

The SPCS has done much work with respect to backup protection or issues that affect the use of backup protection. One of the first SPCTF reports was on the “Rationale for the Use of Local and Remote (Zone 3) Protective Relaying Backup Systems.”[3] This paper discussed the pros and cons of the use of Zone 3 type backup protection in a general sense. The Protection System Reliability Standard developed as a result of the 2003 Northeast Blackout, PRC-023-1 “Transmission Relay Loadability,” codified requirements for loadability of phase responsive transmission relays which in some cases significantly limited the ability of some relays to provide backup protection. This led to other SPCTF papers illustrating ways to use legacy and modern protective relays to increase relay loadability while meeting protection requirements.

The SPCTF reference paper “Protection System Reliability”[4] was created to accompany the Standard Authorization Request (SAR) for a new standard to set the acceptable level of redundancy required in Protection System designs to meet system performance requirements. A new standard is currently being considered under a SAR submitted by the SPCS. The Protection System Reliability paper discusses the potential use of local and remote backup Protection Systems to provide redundancy, but purposely does not go into detail regarding all the complexities involved in the use of remote backup protection.

The “Power Plant and Transmission System Protection Coordination”[5] Technical Reference Document describes a number of backup protection elements that may be applied on generators and how to ensure adequate coordination and loadability of these elements. These SPCS efforts, other SPCS efforts, and experiences from other events since the 2003 Northeast Blackout point to a need to address the technical details behind the pros and cons of applying backup protection in greater detail in this technical paper.

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[2] The System Protection and Control Task Force (SPCTF), formed in 2004, was the predecessor to the System Protection and Control Subcommittee (SPCS). Since then, the SPCS was recategorized as a working group and renamed the SPCWG

[3] Rationale for the Use of Local and Remote (Zone 3) Protective Relaying Backup Systems – A Report on the Implications and Uses of Zone 3 Relays, February 2, 2005.

[4] Protection System Reliability – Redundancy of Protection System Elements, December 4, 2008.

[5] Power Plant and Transmission System Protection Coordination – Revision 1, July 30, 2010.

Chapter 3: Terminology Used in This Document

Redundancy
In the context of this paper, redundancy is the existence of separate Protection System components, as discussed in the NERC SPCS Technical Reference Document "Protection System Reliability," installed specifically for the purpose of meeting the NERC system performance requirements during a single Protection System failure.

It is not the goal of this paper to specify detailed methods to design redundancy into a Protection System. Other papers, including the NERC document cited above and the IEEE Power System Relaying Committee (PSRC) Working Group I19 document "Redundancy Considerations for Protective Relay Systems,"[6] provide detailed discussion of methods to design redundancy into a Protection System.

Backup Protection
In the context of this paper, backup protection consists of any Protection System elements that clear a fault when the fault is accompanied by a failure of a Protection System component or a failure of a breaker to interrupt current. Backup protection may operate because it is intentionally set to meet specific performance requirements, or it may operate for conditions when multiple contingencies have occurred that bring the event into the backup zone of protection. Backup protection may be provided locally, remotely, or both locally and remotely.

Local Backup
The local backup method provides backup protection by adding redundant Protection Systems locally at a substation such that any Protection System component failure is backed up by another device at the substation. For local backup to provide redundancy, the local backup Protection System must sense every fault and consist of separate Protection System components, as discussed in the NERC SPCS Technical Reference Document "Protection System Reliability." To back up the failure of a circuit breaker to interrupt current, breaker failure circuitry is commonly used to initiate a trip signal to all circuit breakers that are adjacent to the failed breaker. On some bus arrangements, this may require transfer tripping to one or more remote stations.

Remote Backup
The remote backup method provides backup by using the Protection Systems at a remote substation to initiate clearing of faults on equipment terminated at the local substation. Figure 3.1 depicts use of the terms "local" and "remote" in the context of this discussion.

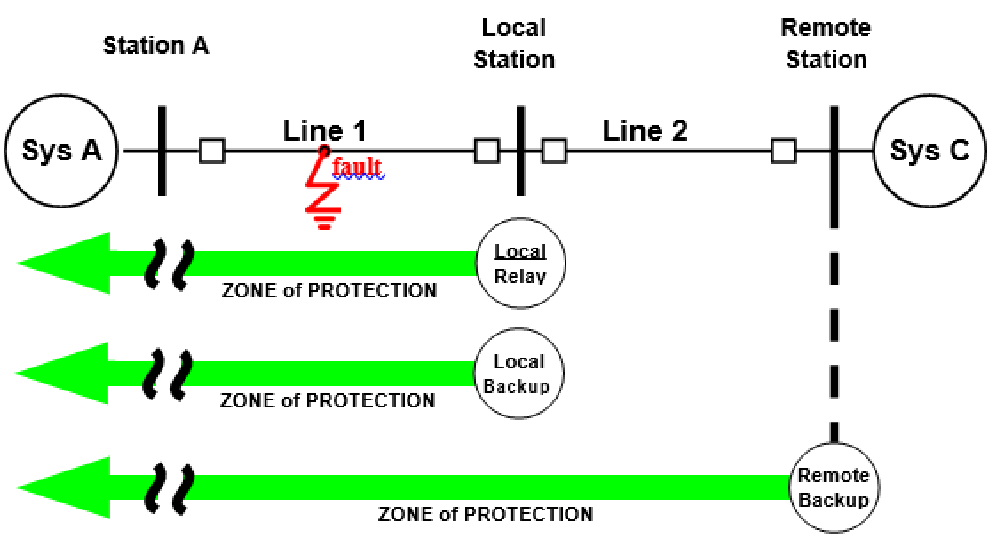

Figure 3.1: Definition of Local and Remote Backup as Applied to Transmission Lines

Remote backup may be used to provide protection for single or multiple Protection System failures or failures of circuit breakers to interrupt current at the local substation. When remote backup is used to provide backup protection for a single Protection System failure or a failure of a circuit breaker to interrupt current, the relays at the remote station are set sensitive enough that they can detect all faults that should be cleared from the adjacent (local) substation for which backup protection is being provided. Remote backup may provide an additional benefit of protecting for multiple Protection System failures, but the relays at the remote station may not be set sensitive enough that they can detect all faults that should be cleared from the local substation.

When remote backup can be set to meet system performance requirements it can provide complete Protection System redundancy since it shares no common components with the local relay system. The remote backup protection is intentionally set with time delay to allow the local relaying enough time to isolate the faulted Elements from the power system prior to the remote terminals operating. The remote backup protection covers the failure of a Protection System and/or the failure of a circuit breaker to interrupt current.

Chapter 4: Advantages and Disadvantages of Local and Remote Backup Protection

Advantages of Local Backup Protection Systems

System disruption - For the failure of the local Protection System or the circuit breaker, local backup protection usually isolates a smaller portion of the transmission grid as compared to remote backup protection.

Relay loadability – Local backup protection generally has no effect on relay loadability because it is set similarly to the primary system. Local backup does not require as sensitive a setting as remote backup and therefore is less susceptible to loadability concerns.

Tripping on Stable System Swings – Local backup protection is less susceptible to operation for stable power swings for the same reasons it is less susceptible to loadability concerns.

Speed of operation – Generally, local backup Protection Systems can be set to operate more quickly than remote backup Protection Systems.

Disadvantage of Local Backup Protection Systems

Multiple Local Protection System Failures – Providing redundant Protection Systems does not eliminate the possibility of all common mode failures. A well designed fully redundant local Protection System can fall short when multiple local Protection System failures occur.

Advantages of Remote Backup Protection Systems

Common Mode Failures – Use of remote backup systems, because of their physical separation, minimizes the probability of delayed clearing or failure to clear a fault due to a common mode failure.

Multiple Protection System Failures – Remote backup can, in some cases, provide a safety net to limit the extent of an outage due to multiple local Protection System failures. This is especially significant for low-probability scenarios that exceed design criteria.

Reduced Reliance on Telecommunication – Remote backup protection generally does not rely on telecommunication between substations.

Disadvantages of Remote Backup Protection Systems

Slow Clearing – Remote backup generally requires longer fault clearing times than local backup to allow the local Protection System to operate first.

Wider-Area Outage for Single Failures – For a single Protection System failure, remote backup generally requires that additional Elements be removed from the power system to clear the fault versus local backup. Depending on the scenario, this can have the added impact of de-energizing the local substation and interrupting all tapped load on the lines that are connected to the substation where the relay or breaker fails to operate.

Relay loadability – The desired setting of remote backup is more likely to conflict with the relay loadability requirements than local backup.

Tripping on Stable System Swings – Remote backup is more susceptible to tripping during stable system swings because this application typically requires relay settings with longer reach or greater sensitivity than local backup.

Difficult to Detect Remote Faults – It is more difficult and more complicated to set remote backup protection to detect all faults in the protected zone for all possible system configurations prior to a fault.

Difficult to Study – It is generally more difficult to study power system and Protection System performance for a remote backup actuation. This is because more power system Elements may trip. Tripping may be sequential and reclosing may occur at different locations at different times. For example, tapped loads may be automatically reconfigured and prolonged voltage dips that may occur due to the slow clearing may cause tripping due to control system actuations at generating plants or loads. It is very difficult to predict the behavior of all control schemes that may be affected by such a voltage dip, thus it is very difficult to exactly predict the outcome of a remote backup clearing scenario.

Chapter 5: System Performance Requirements

The Bulk Electric System must meet the performance requirements specified in the Transmission Planning (TPL) standards when a single Protection System failure or a failure of a circuit breaker to interrupt current occurs. When a single Protection System failure or failure of a circuit breaker to interrupt current prevents meeting the system performance requirements specified in the TPL standards, either the Protection System or the power system design must be modified.

When time delayed clearing of faults is sufficient to meet reliability performance requirements, owners have the option to deploy either two local systems or one local system and a remote backup system to meet reliability levels. In either case, the Protection Systems must operate and clear faults within the required clearance time to satisfy the system performance requirements in the TPL standards.

Backup protection may also function as a safety net to provide protection for some conditions that are beyond the system performance requirements specified in the TPL standards. When used as a safety net, backup protection may be designed to protect against a specific multiple Protection System failure or failures of circuit breakers to interrupt current. Backup protection may also be designed to limit the extent of disturbances due to unanticipated multiple Protection System failures or failures of circuit breakers to interrupt current. When backup is applied as a safety net it must meet the requirements of current NERC standards related to relay loadability, Protection System coordination, and system performance requirements during a single Protection System failure or failure of a circuit breaker to interrupt current. Future standards related to Protection System performance during stable system swings may also affect the use of backup protection and provide further guidance on assessing relay response during stable swings. When remote backup is applied as a safety net it may be appropriate to place a greater emphasis on security over dependability.

Function of Local Backup

The main function of local backup is to address a single local Protection System failure or failure of a circuit breaker to interrupt current. The redundancy provided by local backup inherently addresses single Protection System failures while minimizing the impact to the system. Local backup may address some failures of multiple Protection Systems, but generally will not address these failures to the extent of a remote backup scheme.

Breaker failure is a form of local backup that must be studied per NERC Planning Standards. The effects of a breaker failure operation must be studied to determine that system performance requirements are met. It is common throughout the industry to apply local breaker failure protection for transmission level circuit breakers.

Function of Remote Backup:

Remote backup can play a role in addressing single or multiple Protection System failures or failures of circuit breakers to interrupt current.

For addressing a single Protection System failure or failure of a circuit breaker to interrupt current, local backup is generally preferred to remote backup for many of the reasons stated above. However, certain configurations lend themselves to the use of remote backup while minimizing the disadvantages of using remote backup. Examples are discussed later in this document.

Multiple Protection System failures may not be anticipated or studied. The degree to which protection designs can detect faults under the condition of multiple Protection System failures varies based on a company's design practices, system topology, and a number of other factors.

Remote backup protection can provide a safety net minimizing the impact of unanticipated conditions caused by multiple Protection System failures to a greater degree than that afforded by local backup protection only.

Multiple failures due to more common combinations of single Protection System failures and/or failures of circuit breakers to interrupt current occurred in a number of the examples of post-2003 events discussed below.

Chapter 6: Post-2003 Events Involving Backup Protection

2008 Florida Event

Description of the 2008 Florida Event

On February 26, 2008, a system disturbance occurred within the FRCC Region that was initiated by delayed clearing of a three-phase fault on a 138 kV switch at a substation in Miami, Florida. According to the report "FRCC System Disturbance and Underfrequency Load Shedding Event Report February 26th, 2008 at 1:09 pm" it resulted in the loss of 22 transmission lines, approximately 4300 MW of generation and approximately 3650 MW of customer load. The local primary protection and local backup breaker failure protection associated with a 138 kV switch had been manually disabled during troubleshooting. The fault had to be isolated by remote clearing because the local relay protection had been manually disabled.

Backup Protection and the Florida Event:

The report states "The 230 kV/138 kV autotransformers at Flagami do not utilize phase overcurrent or impedance backup protection. Although there are no current industry requirements for this type of protection, the autotransformers offer a position to install additional local relaying that could be used to isolate the 230 kV system from faults on the 138 kV system." Furthermore the investigation recommends "NERC should assign the System Protection and Control Task Force to produce a technical paper describing the issue and application of backup protection of autotransformers." The lack of autotransformer backup protection that contributed to this event was addressed by the installation of new protection equipment after this event.

2004 West Wing Substation Event

Description of the 2004 West Wing Substation Event:

Another significant event where fault clearing times and the extent of outages could have been improved by the use of local backup or planned remote backup protection was the West Wing event on June 14th, 2004. In this event, a 230 kV line faulted to ground. The relay system for the faulted 230 kV line was designed with a single auxiliary tripping relay. This relay was used for tripping of the 230 kV line breakers and breaker failure initiation. The single auxiliary relay failed. Remote backup clearing with clearing times of 20 to 40 seconds was required to clear the fault. The remote clearing required in this case resulted in the loss of ten 500 kV lines, six 230 kV lines, and over 4500 MW of generation (including three nuclear units) per the initial WECC communication on the event. A couple of weeks after the event, several of the single-phase 500/230 kV autotransformers involved in the event failed catastrophically.

Backup Protection and the West Wing Event:

The first recommendation from the Arizona Public Service (APS) report "June 14, 2004 230 kV Fault Event and Restoration" was to add backup protection to the 500/230 kV autotransformers involved in the event. The report states that had backup protection been installed on the 500/230 kV autotransformers that the fault would have been cleared significantly faster and damage would have been prevented, and this remote backup "would have prevented the disturbance from being cleared within the 500 kV system".

Additionally, if the local protection scheme at West Wing included fully redundant systems with redundant auxiliary tripping relays, this event could have been mitigated.

Both the lack of remote backup protection and the lack of redundant local protection that contributed to this event were addressed by the installation of new protection equipment after this event.

2007 Broad River Event

Description of the 2007 Broad River Event:

Another event where remote backup protection played a key role was the August 25, 2007 Broad River Energy Center Event. In this event, a 230 kV generator step-up transformer bushing failed and faulted to ground. The relay system for the faulted 230 kV transformer was designed with a single auxiliary tripping relay. The single auxiliary relay failed. Remote backup protection cleared the fault in about 0.5 seconds. The remote clearing in this case resulted in the loss of four 230 kV transmission lines and three Broad River Energy Center Units. In addition one 230 kV transmission line tripped due to a failed relay, two generating units tripped due to incorrectly coordinated backup protection settings, and two generating units tripped due to low station auxiliary bus voltage during the fault.

Backup Protection and the Broad River Event:

Recommendations from the NERC investigation report for this event included installing redundant relaying for the generator step-up transformer that sustained the fault. This recommendation has been implemented.

The overall effects of this event to the power system were minor compared to the Florida or West Wing events. However, this event does illustrate that when remote backup is applied to meet system performance requirements during single Protection System failures, the highest degree of coordination of Protection Systems and knowledge of system reactions to sustained low transmission level voltage is needed.

2006 Upper New York State Event

Description of the 2006 Upper New York State Event:

The last event is a near miss event that occurred in New York State on March, 29, 2006 in the switchyard for a hydro plant. In this event, a ground fault occurred on the 13.8 kV side of a 115/13.8/13.8 kV transformer due to raccoon contact. The fault quickly evolved into a 3-phase to ground fault on the 115 kV side of the transformer. One of the 115 kV circuit breakers required to clear the 13.8 kV and 115 kV faults failed. Breaker failure was initiated to clear the fault via the surrounding circuit breakers; however one of these breakers failed to clear for about 5 seconds resulting in a double breaker failure for 5 seconds. During this time, all 14 in-service hydro units at the connected plant tripped on backup phase distance relays. The switchyard at this location also included a number of 230/115 kV autotransformers and 230 kV lines. The 230/115 kV autotransformer relay schemes in this area were not designed with phase backup protection that could detect this 115 kV fault. The delayed clearing in this event resulted in the loss of the 14 units at the hydro plant, numerous smaller hydro-generating facilities throughout northern New York, and one unit in Ontario, totaling 1200 MW, as well as various equipment in the connected switchyard.

Backup Protection and the Upper New York State Event:

Recommendations from the New York Power Authority (NYPA) investigation report for this event included considering whether to apply overcurrent backup protection on autotransformers. A decision whether to add backup overcurrent protection has not been made at this time.

The overall effects of this event to the power system were minor compared to the Florida or West Wing events. However, this event is a good illustration of the type of unanticipated failure event where remote backup protection can provide a safety net that may limit the extent of an outage.

Chapter 7: Examples

The following sections provide a number of examples of backup protection applied to transmission lines and transformers. It is important to note that these examples were selected to illustrate concepts discussed in the paper and are not intended to be prescriptive or to suggest a preferred method of transformer protection, nor are they inclusive of all possible methods for providing backup protection. The protection system design (e.g., CT and PT primary connections) and settings derived in these examples are only for illustrative purposes.

Remote Backup Protection on Transmission Lines

Protection Systems applied to transmission lines commonly include elements which provide remote backup protection. The most common type of remote backup protection for phase faults on transmission lines is phase distance relaying with fixed time delay. The most common methods to provide remote backup for ground faults are by using ground distance relays with fixed time delay, ground time overcurrent relays with inverse time-current curves, or a combination of both. Phase faults generally affect the system to a higher degree than ground faults and phase relays are more susceptible to tripping than ground relays for severe system conditions.

The following series of examples focus on phase faults and illustrate some of the complexities of using remote backup protection as outlined above. Examples 1, 2, and 3 illustrate the complexity of applying remote backup protection to meet NERC system performance requirements during a single Protection System failure. In these examples the line terminals do not have local backup protection. **Figure 7.1** is used to illustrate application of remote backup protection for breaker failure protection. In this example the line terminals have local backup protection.

Example 1

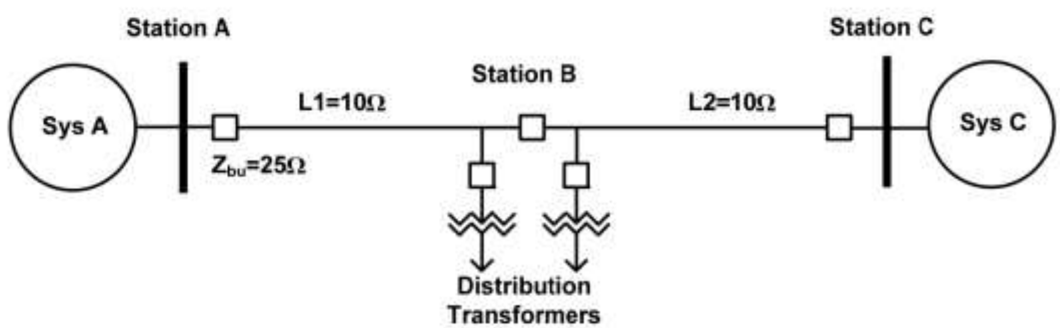

Figure 7.1: Simple Three-Station, Two-Line System Used in Example 1

The simple system of two lines in **Figure 7.1** shows the configuration under consideration in this example. In this case, the backup zone at the Station A line terminal can be set to cover phase and ground faults on the transmission line between Stations B and C and provide remote backup for any single transmission line Protection System related component failure. For this configuration, source impedances behind Stations A and C are not important.

For this example, using a 25% margin, the backup relay reach at Station A necessary to detect all faults on line L2 is Z_{bu} = 1.25 (L1 + L2) = 25 Ω

Complexities

If a time delay of 0.7 to 1.0 seconds is assumed, remote backup clearing would be slower than a local breaker failure scheme with transfer trip from Station B to Station A. A transient stability simulation may be necessary to verify that this clearing time results in a system response that meets performance requirements. In many cases similar to this example the remote backup can be set within the loadability requirements of PRC-023, will not reach through the distribution transformers, and will provide adequate backup protection for Protection System failures at Station B.

The simple system of three lines in Figure 7.2 shows the configuration under consideration in this example.

Example 1A

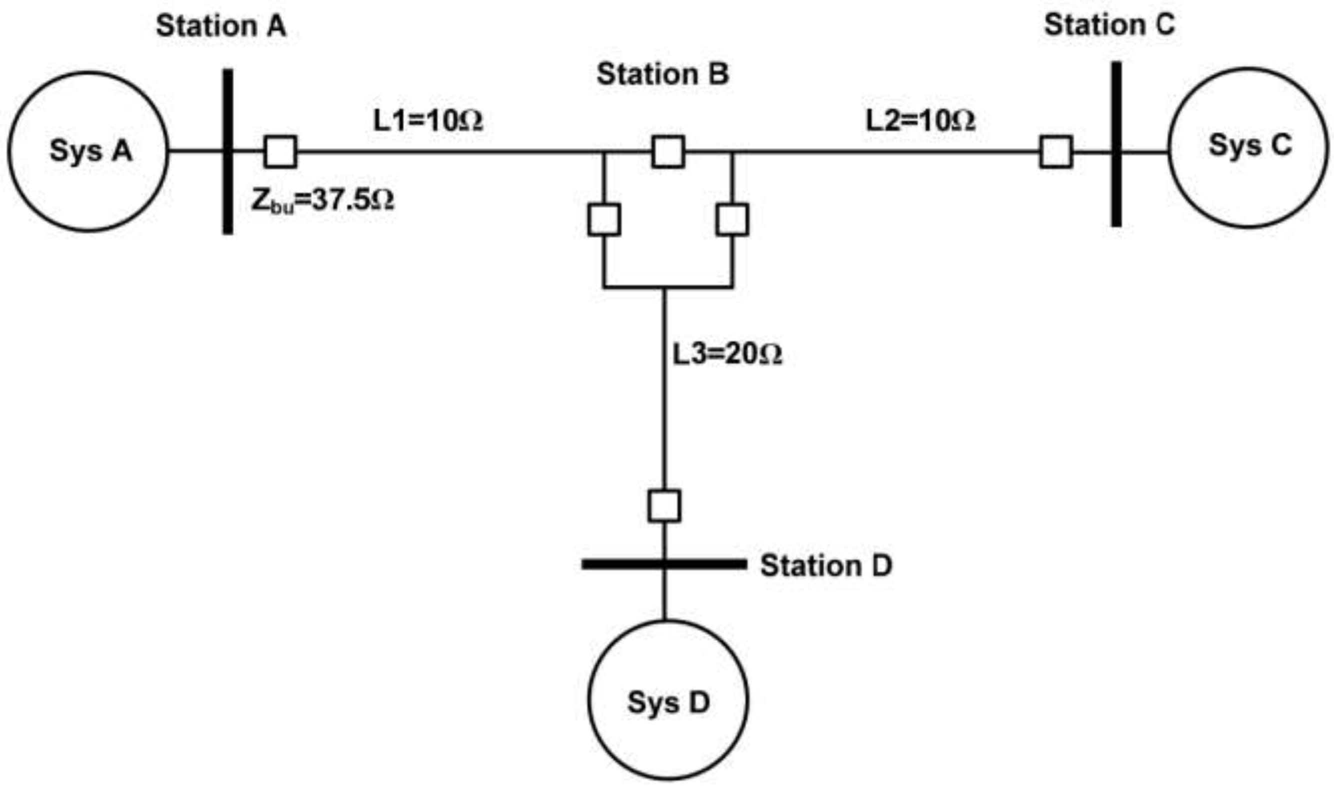

Figure 7.2: Simple Four-Station, Three-Line System Used in Example 1A

In this case, all of the line terminals have local backup protection for line faults as defined in section 3. Thus, a backup zone at the Station A line terminal may be designed to provide protection to address a couple of different situations:

1. The breaker failure protection scheme for the breakers at Station B is designed with local breaker failure but without breaker failure transfer trip communications capability from Station B to Station A. Due to the lack of transfer trip communications, the backup zone at Station A is designed to provide backup protection for faults on lines BC or BD with a breaker failure at Station B. Because the Station B breakers have local breaker failure protection, the Station A relay can be set to cover phase and ground faults on the transmission line between Stations B and C or B and D without considering apparent impedance (i.e., the local breaker failure operation at station B will open the other two breakers and remove the infeed). The owner of this scheme has decided to use backup instead of installing a transfer trip channel. This backup setting will also provide some protection for multiple Protection System failures of line BC or BD relaying. For this configuration and application, source impedances behind Stations A, C and D are not important.

2. The breaker failure protection scheme for the breakers at Station B is designed with local breaker failure and breaker failure transfer trip communications capability from Station B to Station A. The backup zone at Station A is designed to provide backup protection for faults on lines BC or BD with a breaker failure and a loss of transfer trip communications at Station B. Similar to the first situation, because the Station B breakers have local breaker failure protection, the Station A relay can be set to cover phase and ground faults on the transmission line between Stations B and C or B and D without considering apparent impedance for this application. This application protects for a situation that is beyond a single Protection System failure or failure of a circuit breaker to interrupt current and is thus not required to meet system performance requirements. The owner of this scheme has decided to apply backup as a safety net and may have decided to apply this

type of backup based on past experiences or events. This backup setting will also provide some protection for multiple Protection System failures of line BC or BD relaying. For this configuration and application, source impedances behind Stations A, C and D are not important.

For this example, using a 25% margin, the backup relay reach at Station A necessary to detect all faults on line L3 is Z_{bu} = 1.25 (L1 + L3) = 37.5 Ω.

Complexities

If a time delay of 0.7 to 1.0 seconds is assumed, remote backup clearing would be slower than a local breaker failure scheme with transfer trip from Station B to Station A. When the system is designed without transfer trip capability, a transient stability simulation may be necessary to verify that this clearing time results in a system response that meets performance requirements. In many cases similar to this example the remote backup can be set within the loadability requirements of PRC-023, will not reach through the distribution transformers, and will provide adequate backup protection for breaker failures at Station B and some line Protection System failures at Station B. Figure 7.3 illustrates the increased backup protection reach in this example compared to Example 1.

Example 2

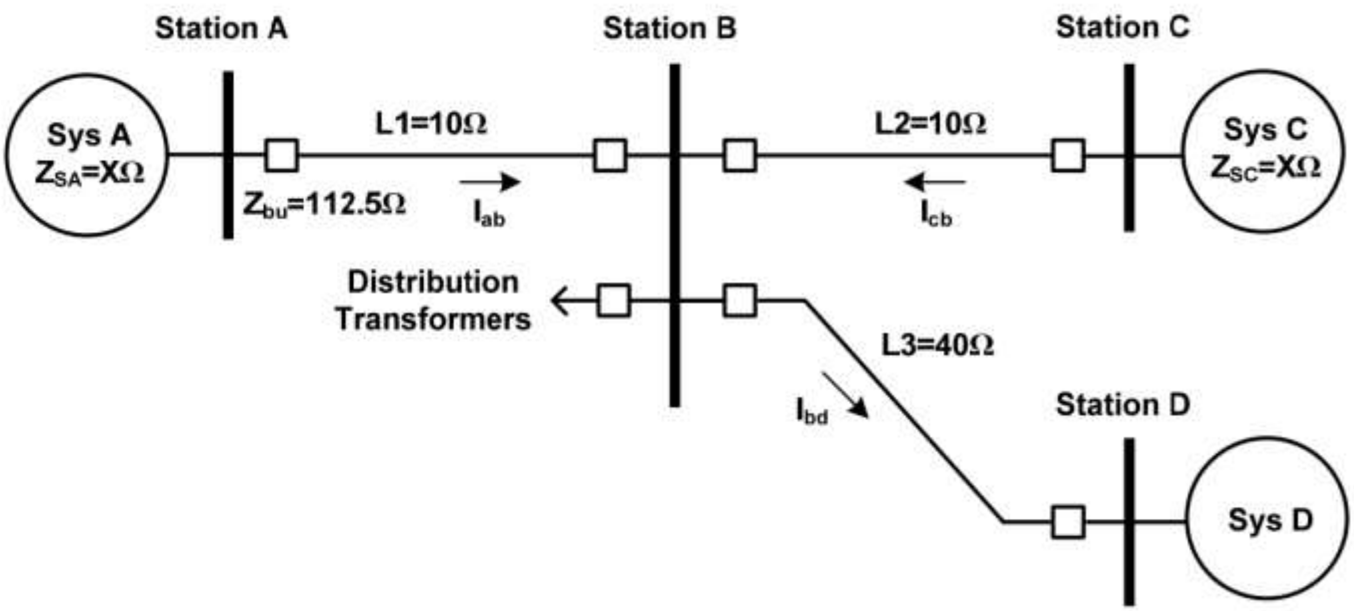

Figure 7.3: Four-Station, Three-Line System Used in Example 2

Example 2 is complicated compared to Example 1A by the presence of a longer line between Stations B and D and the distribution transformers at bus B. For this configuration, source impedances behind Stations A and C are assumed to be equal. The source impedance behind Station D is not important in this simple system. In this case, a fault on L3 near Station D would be difficult to detect from Station A without overreaching for faults beyond Station C or seeing through the distribution transformers.

The apparent impedance seen by the relay at Station A is: $Z_{bu} = V_a/I_{ab} = ((I_{ab} \times L1) + (I_{bd} \times L3))/I_{ab} = L1 + (I_{bd}/I_{ab}) \times L3$
Given the symmetry of the example system, $I_{ab} = I_{cb}$, and thus I_{bd} = 2Iab

For this example, using a 25% margin, the backup relay reach at Station A necessary to detect all faults on line L3 is Z_{bu} = 1.25 (L1 + 2L3) = 112.5 Ω.

If the source impedance of System A could be higher for certain system conditions, the setting would need to be increased accordingly.

Complexities

In this case, such a large setting at Station A may detect distribution level faults at Station B. A time delay of 0.7 to 1.0 seconds would be required to coordinate with remote relaying at Stations B and C given that the Station A backup zone will likely detect all faults on L2 and may look far past Station C, especially when L3 is out of service. The longer time to clear may also cause power quality issues for the loads at Stations A, B, or C that in the worst case may result in local loss of load. In many cases similar to this example it may not be possible to set the remote backup within the loadability requirements of PRC-023 without the use of some form of load encroachment. The larger setting might also be more susceptible to tripping on stable system swings. A transient stability simulation may be necessary to verify that this clearing time results in a system response that meets performance requirements. Figure 7.4 illustrates the increased backup protection reach in this example compared to Examples 1 and 1A.

Example 3

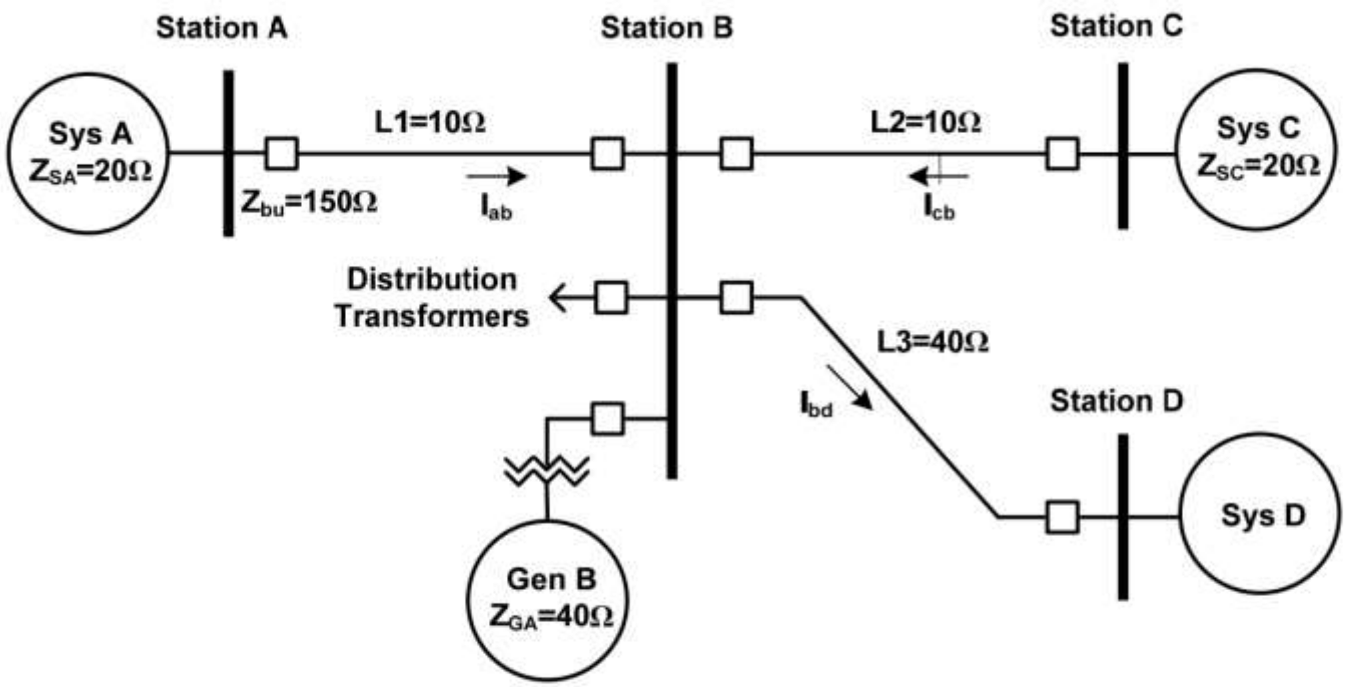

Figure 7.4: Four-Station, Three-Line System Used in Example 3

Example 3 is further complicated compared to Example 2 by the presence of a generator at Station B. For this configuration, source impedances behind Stations A and C are assumed to be equal at 20 Ω with a reasonable system contingency source outage behind Station A. The impedance of the generator at Station B (including the generator step-up transformer) is assumed to be equal to 40 Ω. The source impedance behind Station D is not important for this example and can be ignored. In this case, a fault on L3 near Station D would be more difficult to cover.

The apparent impedance seen by the relay at Station A must be calculated:

For the given fault, System A + L1 is in parallel with System C + L2, and the combination of these two systems is in parallel with Generator B, with all three systems in series with L3,

Or

The equivalent impedance of these systems is 30 Ω is in parallel with 30 Ω, in parallel with 40 Ω, + 40 Ω = 50.9 Ω

For fault near Station D on a 138 kV system, the total fault contribution from System A, System C, and Generator B is 1571 A.

The fault current contribution at Station A is 571 A and the line-to-ground voltage is 68.550 kV.

The apparent impedance at Station A for the L1 line relay is ~120 Ω

For this example, using a 25 percent margin, the backup relay reach at Station A necessary to detect all faults on line L3 is Z_{bu} = 1.25 (120) = 150 Ω
Additionally, the voltage on the Station B 138 kV bus is ~ 0.82 per unit.

Complexities

In this case, such a large setting at Station A may detect distribution level faults at Station B. A time delay of 0.7 to 1.0 seconds may be required to coordinate with remote relaying at Stations B and C given that the Station A backup zone will likely detect all faults on L2 and may look far past Station C, especially when L3 is out of service and/or Generator B is out of service. Thus, remote backup clearing would be much slower than local backup clearing. The longer time to clear may cause power quality issues for the loads at Stations A, B, or C that in the worst case may result in local loss of load. The longer time to clear and resulting lower voltage dip at the Station B bus may also cause an issue for the auxiliary equipment at Generating Station A that could result in a loss of generation. In many cases similar to this example it may not be possible to set the remote backup within the loadability requirements of PRC-023 without the use of some form of load encroachment. The larger setting might also be more susceptible to tripping on stable system swings. A transient stability simulation may be necessary to verify that this clearing time results in a system response that meets performance requirements.

In general, a system such as shown in **Figure 7.4** requires much greater care and study to ensure adequate system performance prior to implementation than a system that uses local backup to cover for faults on L3. Additionally, much greater care is required as the system changes over time to ensure that the remote backup system for Example 3 still provides adequate fault coverage while meeting system performance requirements. **Figure 7.5** illustrates the increased backup protection reach in this example compared to Examples 1, 1A, and 2. It must be noted that the line lengths in the various examples were purposely picked to illustrate the effects that apparent impedance can have on remote backup settings. The extent to which relay reach must be increased for actual configurations may be more or less than shown in these examples.

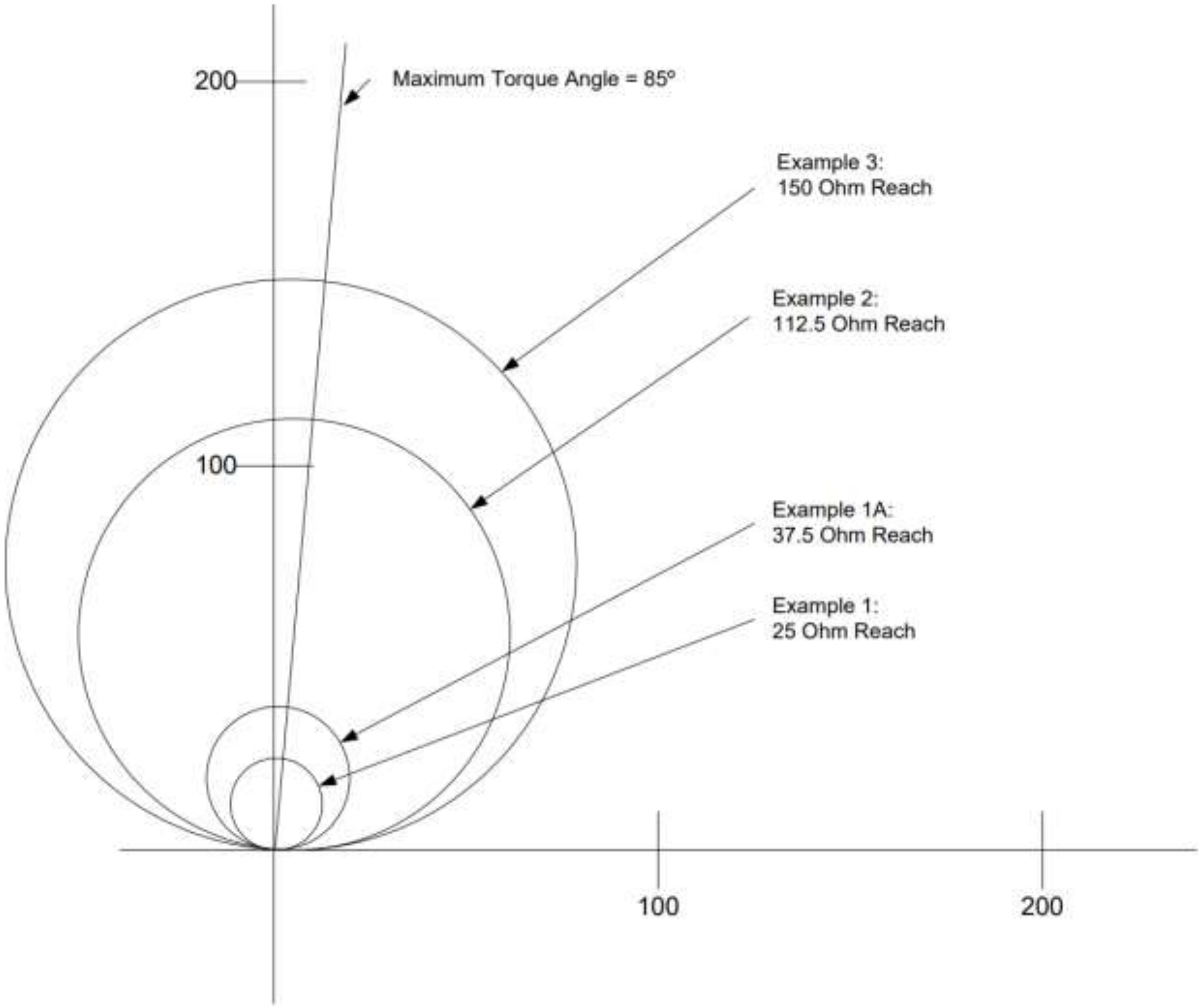

Figure 7.5: Comparison of Backup Protection System Reach for Examples 1, 1A, 2, and 3

Backup Protection on Autotransformers

Applying phase backup protection on autotransformers is not as common as applying remote backup on transmission line terminals. Backup protection on transformers can be applied as backup for faults on both the high side and low side voltage levels and is commonly applied to protect transformers for uncleared faults.

The system events involving multiple voltage levels described in Section 6 were all related to faults on equipment on lower voltage systems (115 kV or 230 kV). These events support the general observation that the level of redundancy of protection on higher voltage level circuits is usually greater than that on the lower voltage circuits connected to autotransformers. Some lower voltage lines may not have local redundancy at all and the use of backup protection on the transformers may provide additional protection for uncleared faults.

Autotransformer backup may be designed to clear faults due to single relay failures or as a safety net. **Figure 7.6** provides examples of the safety net protection coverage that may be achieved for two possible system configurations. In the second configuration, the reach of the backup protection will be reduced by roughly one-half versus the first configuration due solely to the paralleled equivalent contributions of the two transformers. When autotransformer backup protection is counted on to clear faults due to single relay failures, it is subject to meeting system performance requirements and subject to many of the same limitations as remote backup on transmission lines. When lower voltage systems are fully redundant, autotransformer backup can provide a safety net to limit damage to the low voltage system and isolate the low voltage system from the high voltage system for slow clearing faults due to multiple Protection System failures or failures of circuit breakers to interrupt current.

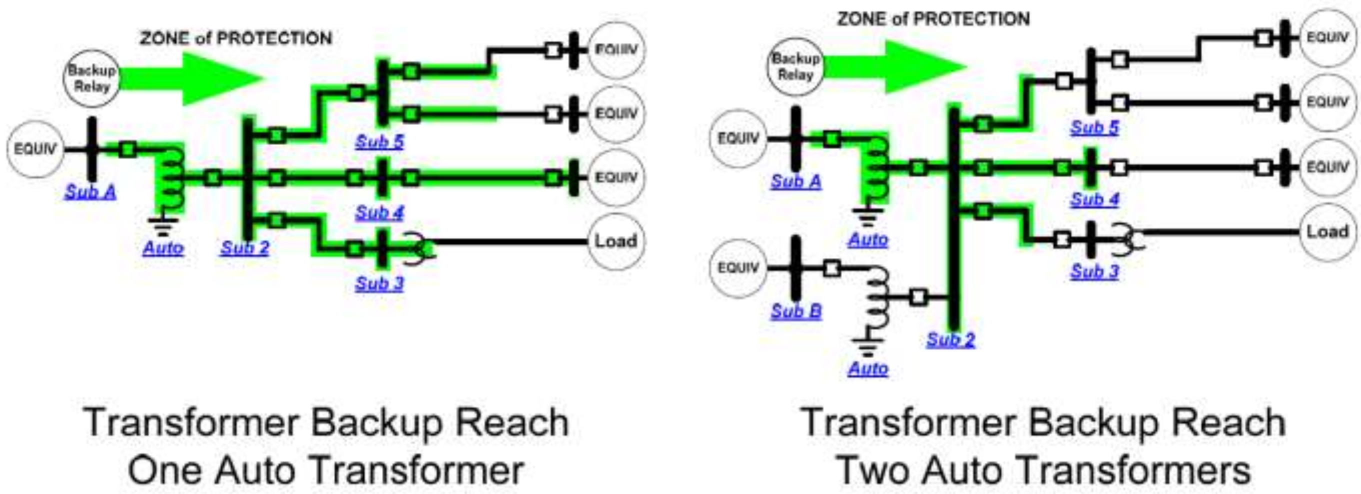

Figure 7.6: Safety Net Backup Protection Reach

Since the cited system events involving multiple voltage levels were related to faults on the lower voltage systems, the discussion on autotransformer backup will focus on backup applied to detect faults on the low voltage side of the autotransformer. The discussion will also be geared toward phase faults since phase faults generally negatively affect the system to a higher degree than ground faults and most transformer Protection Systems include ground backup protection. Additional reasons to focus on phase faults are that slow clearing ground faults can migrate into phase faults, and phase relays are more susceptible to tripping due to loadability issues than ground relays for severe system loading conditions.

Various methods may be utilized to protect and clear an autotransformer for phase faults external to an autotransformer. Three common types of phase backup protection for autotransformers to be discussed in this paper with examples are: phase time overcurrent relays; phase time overcurrent relays torque controlled by phase distance relays and phase instantaneous relays; and phase distance and phase instantaneous relays with fixed time delays. A fourth type of backup that can be applied on a transformer low side to provide backup protection for low side bus or close-in fault protection failure that has little complexity is a limited reach distance function. This application does not have relay loadability issues that may be associated with other methods. Additional discussion on transformer backup protection is provided in the IEEE Guide for Protective Relay Applications to Power Transformers (IEEE C37.91).

A very inverse time overcurrent curve will be used in the examples in this paper. Other types of curves have different advantages and disadvantages which are outside the scope of this paper and require similar considerations.

Example Autotransformer Data:

- 345(wye)/34(delta)/138(wye) kV with no delta connected load
- 300 MVA maximum nameplate for the 345/138 winding
- 1250 A nameplate at 138 kV and 500 A nameplate at 345 kV
- Maximum 138 kV 3-phase fault = 20,000 A (Z_{TR} ~ 4 Ω @ 138 kV)
- This transformer has been determined to be critical by the Planning Coordinator and
- is thus subject to PRC-023 limitations

Relay Settings Based on a Simple System

A phase protective relay could be applied on either the high or the low side of the autotransformer. For the examples that follow, the current elements of all the phase protective relays are connected to current transformers on the high side of the transformer such as in **Figure 7.7**. Thus, these relays also may provide backup protection for faults on the transformer high side and tertiary windings. In many cases, 3-phase potential devices are only available on the low side of the transformer so the phase distance relays are applied on the 138 kV side of the transformer. This also allows for a better reach of the phase distance relay into the 138 kV system as this connection does not result in the Protection System detecting the voltage drop through the transformer for 138 kV faults.

A desirable goal is to create a generic method for setting the phase protection relays that provides adequate backup protection, coordinates with other system relays, provides adequate overload protection for uncleared through-faults, will not trip on transformer inrush, and meets the loadability limitations of PRC-023-1. It may not be possible to meet all of these goals for all configurations of some systems. Two examples (a simple system and a more complex system) illustrate some of these limitations.

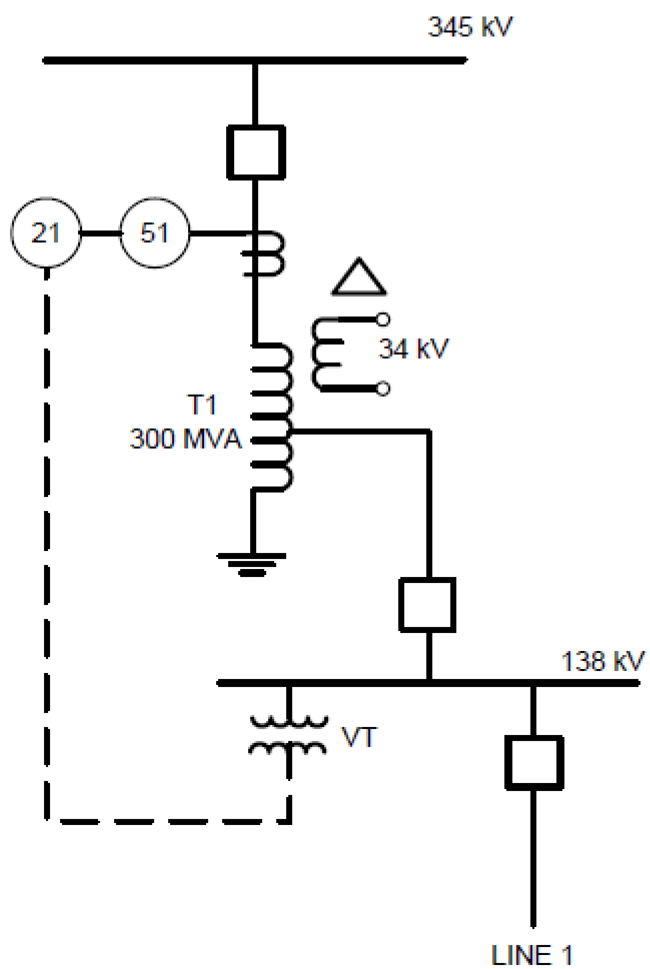

Figure 7.7: Simple System One-Line Used in Transformer Protection Example

Example 4: Phase Time Overcurrent Relay Setting

In this example PRC-023 limitations for phase responsive transformer relays will dictate the minimum pickup setting of the relay. These limitations are:

- 150% of the applicable maximum transformer nameplate rating (expressed in amperes), including the forced cooling ratings corresponding to all installed supplemental cooling equipment.
- 115% of the highest operator established emergency transformer rating.

Assuming there are no operator established emergency transformer ratings for this transformer, the minimum pickup for this relay is limited to 150% of 300 MVA. On the 345 kV side this translates to ~ 750 A. Adding a minimum of additional margin and creating a setting that could likely be used for electromechanical relays with limited tap selections, the minimum pickup will be set to 800 A (about 2000 A at 138 kV).

To coordinate with local 138 kV breaker failure for close-in faults (typical 10 cycle breaker failure relay time is assumed), the minimum time to trip must be at least 0.4 second. This tripping speed also ensures that this relay trips faster than remote backup protection on the high voltage system (1 second is assumed) that may also detect low voltage system faults (especially close-in low voltage system faults). Thus, a time lever of 3 is chosen. Using the very inverse curve, the time for the relay to initiate a trip will then be about 0.4 second for a 20,000 A 138 kV fault, 0.77 second for a 10,000 A 138 kV fault and 1.74 seconds for a 6,000 A 138 kV fault. Coordination must be verified between these fault clearing times and the 138 kV line L1 protection (see Figure 7.2.2). The clearing times in this example were selected because they will coordinate with typical transmission line protection settings, will be secure during transformer inrush conditions, and are faster than required to coordinate with the transformer through-fault damage curve shown in IEEE Standard C37.91- 2000.

Example 5: Torque Controlled Phase Time Overcurrent Settings

For the relay in **Figure 7.8**, a mho phase distance element and a phase instantaneous overcurrent element both torque control a phase time overcurrent. The phase time overcurrent element will not pickup and start timing until the mho phase distance element or the phase instantaneous overcurrent element picks up first. This allows a more sensitive phase time overcurrent setting than a pure phase time overcurrent relay since the phase time overcurrent relay is not subject to the loadability limitation. The phase instantaneous element is needed in addition to the phase distance element to cover for 138 kV bus faults and other close-in faults where the phase distance element may lose memory voltage and drop out prior to fault clearing given that the phase distance element is connected to the 138 kV potential device.

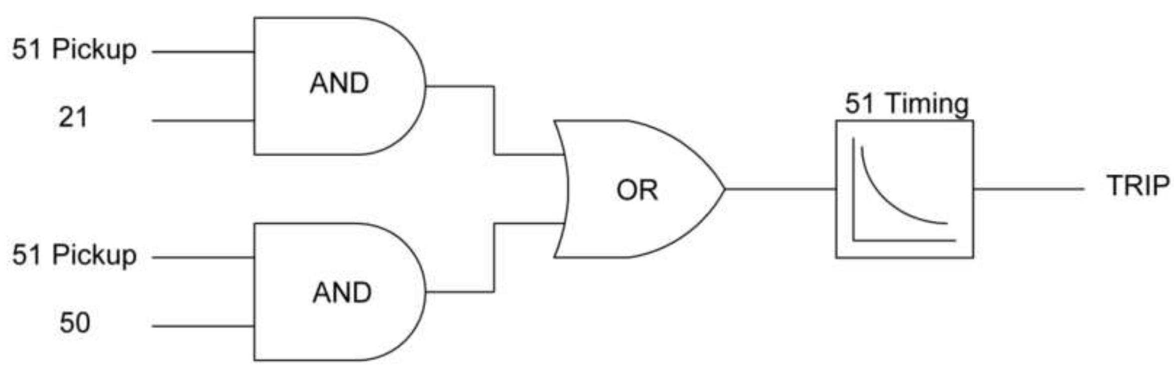

Figure 7.8: Logic Diagram for Application of Phase Time Overcurrent Elements Torque Controlled by Phase Distance and Instantaneous Phase Overcurrent Elements

Phase Distance Element Setting

Assuming there are no operator established emergency transformer ratings for this transformer, the same PRC-023 limitation (150% of maximum nameplate rating) will limit the reach of the phase distance relay. Using the NERC criteria and assuming the relay uses a mho characteristic,

Max Allowable Setting = $_{Zrelay@30}$ = $(0.85*V_{relay})/(1.732*I_{Nameplate}*1.5)$

where V_{relay} = phase-to-phase line voltage at the relay location

and $I_{Nameplate}$ = 1250 A

To make the loadability of this setting equivalent to the time overcurrent for comparison purposes, we will use 800 A at 345 kV (2000 A at 138 kV) instead of $I_{Nameplate}$*1.5 (750 A at 345k V or 1875 A at 138 kV) to determine the loadability limitation. This limits $Z_{relay@30}$ to about 34 Ω at 138 kV. Since this relay is subject to PRC-023, this relay will be set with a 90 degree torque angle to maximize loadability. Thus $Z_{relay@90}$ is set to 68 Ω ($Z_{relay@90} = Z_{relay@30}$/cos (90-30)). A typical 138 kV line impedance angle is 75 degrees. The reach at the 75 degree line angle is 68*cos(15) = 66 Ω.

Phase Instantaneous Overcurrent Element Setting

If high side potentials are available and used for the phase distance element, this element may not be required. The use of high side potentials to feed a distance relay does, however, limit the reach of the relay into the lower voltage system. The examples in this document are based on use of low side potential devices, so this element is included in this example as a method for assuring reliable operation for close-in low side faults when the phase distance relays do not have sufficient memory polarization for the duration of a zero voltage fault.

The instantaneous phase element setting is required for close-in three-phase faults where the phase distance relay may not operate because of very low voltage. Thus, sensitivity is not a great concern. Set this element to 225% of transformer nameplate to provide ample margin above emergency loading or roughly 1200 A at 345 kV (3000 A at 138 kV).

Phase Time Overcurrent Setting:

The phase time overcurrent minimum pickup is not subject to loadability limitations because the phase distance and instantaneous phase overcurrent relays that provides the torque control meets the loadability requirement; however, it may be desirable to provide additional security. For this example, the relay is set at 500 A at 345 kV (corresponding to the transformer nameplate rating) as a balance between security and sensitivity.

To coordinate with local 138 kV breaker failure for close-in faults, the minimum time to trip must be at least 0.4 second. This tripping speed also ensures that this relay trips faster than remote backup protection on the high voltage system (1 second is assumed) that may also detect low voltage system faults (especially close-in low voltage system faults). Thus, a time lever of 3.5 is chosen. Using the very inverse curve, the time to trip for selected 138 kV faults will then be about 0.39 second for a 20,000 A fault, 0.55 second for a 10,000 A fault, and 0.96 second for a 6,000 A fault. Coordination must be verified between these fault clearing times and the 138 kV line L1 protection (see Figure 7.2.2). The clearing times in this example were selected because they will coordinate with typical transmission line protection settings, will be secure during transformer inrush conditions, and are faster than required to coordinate with the transformer through-fault damage curve shown in IEEE Standard C37.91-2000.

Example 6: Phase Distance and Instantaneous Phase Overcurrent with Fixed Timers Settings

For the relay in **Figure 7.9**, a mho phase distance element tripping through a fixed timer is used. When the potential is provided from the low side of the transformer, the phase distance element is supplemented by an instantaneous phase overcurrent relay that also trips through the fixed timer.

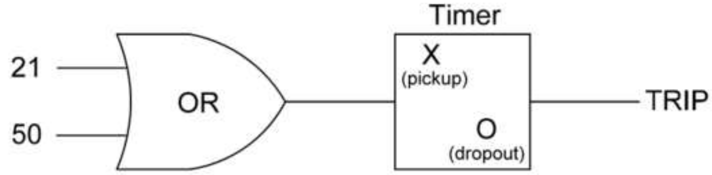

Figure 7.9: Logic Diagram for Application of Phase Distance and Instantaneous Phase Overcurrent Elemets with Fixed Timers

Phase Distance Element Setting
Assuming there are no operator established emergency transformer ratings for this transformer, the same PRC-023 limitation (150% of maximum nameplate rating) will limit the reach of the phase distance relay. Using the NERC criteria and assuming the relay uses a mho characteristic,

Max Allowable Setting = $Z_{relay@30}$ = $(0.85*V_{relay})/(1.732*I_{Nameplate}*1.5)$

where V_{relay} = Phase-to-phase line voltage at the relay location

and $I_{Nameplate}$ = 1250 A

To make the loadability of this setting equivalent to the unsupervised phase time overcurrent for comparison purposes, we will use 2000 A instead of $I_{Nameplate}*1.5$ (1875 A) to determine the loadability limitation. This limits $Z_{relay@30}$ to about 34 Ω. This relay will be set with a 90 degree torque angle to maximize reach while meeting the loadability limitation. Thus $Z_{relay@90}$ is set to 68 Ω ($Z_{relay@90} = Z_{relay@30}/\cos(90-30)$). A typical 138 kV line impedance angle is 75 degrees. This reach at the 75 degree line angle is 68*cos(15) = 66 Ω.

Instantaneous Phase Overcurrent Element Setting
If high side potentials are available, this element may not be required. The use of high side potentials to supply a distance relay does, however, limit the reach of the relay into the lower voltage system. The examples in this document are based on use of low side potential devices, so this element is included in this example.

The instantaneous phase element setting is required only for close-in three-phase faults where the phase distance relay may not operate because of very low voltage. Since for this example the main concern is with using this element to protect for close-in 138 kV faults (approximately 8000 A at 345 kV for a 138 kV bus fault) and the distance element will provide sensitivity for more remote faults sensitivity for this element is not a great concern. Set this element to 800 percent of transformer nameplate to provide security for transformer inrush or roughly 4000 A at 345 kV (10,000 A at 138 kV).

Fixed Timer Settings
Ideally, this timer is set slower than the longest 138 kV line backup protection time and faster than any 345 kV line backup protection that reaches into the 138 kV system.

In practice, 345 kV relaying may not be able to detect 138 kV faults under normal conditions. If so, the timer should be set slightly higher than the longest 138 kV line backup protection time. Assuming a maximum 138 kV line backup time of 1.0 second, this relay may be set at 1.2 seconds.

If 345 kV relays are able to detect 138 kV faults under normal conditions, coordination with 345 backup protection may not be possible. In this case, the Transmission Owner must choose a specific time based on careful consideration of the consequences of the possible tripping sequence that might occur when a 138 kV fault is cleared in backup time or re-coordinate as necessary. Examples of this are shown in **Table 7.1** and **Table 7.2**.

Table 7.1: Simple System Setting and Reach Summary

	345 kV Side Setting	138 kV Side Setting	3-phase fault Reach into simple 138 kV system
Phase Time Overcurrent Only	800	2000	36 Ω
Torque Controlled Phase Time Overcurrent	500	1250	60 Ω
Distance Element	NA	66 Ω @ 75 degrees	66 Ω

Assumptions:

- 345 kV system is an infinite source
- 300 MVA transformer is 4 Ω at 138 kV
- Overcurrent Relay Setting = 80000/(4 + Reach in ohms)

Table 7.2: Simple System Setting and Time to Trip Summary

	20,000 A 138kV Fault	10,000 A 138kV Fault	6,000 A 138kV Fault
Phase Time Overcurrent Only	0.4 seconds	0.77 seconds	1.74 seconds
Torque Controlled Phase Time Overcurrent	0.39 seconds	0.55 seconds	0.96 seconds
Distance Element with Fixed Timer	1.2 seconds	1.2 seconds	1.2 seconds

More Complex Systems

Most systems are not as simple as a single autotransformer feeding a single transmission line. Substations can have numerous transmission lines, multiple transformers in parallel, additional components such as shunt devices, and networked or looped lines. As the substation and its connected transmission system become more complex, so too does the application of backup protection.

A more complex system is shown in **Figure 7.10** consisting of two autotransformers operating in parallel each feeding its own bus. In this example the connected 138 kV transmission lines are networked with significant fault current sources. This substation has two autotransformers operating in parallel feeding four transmission lines. In this configuration, the reach of the backup protection will be reduced by roughly one-half versus the simple system example due solely to the paralleled equivalent contributions of the two 300 MVA transformers. If any of the connected lines are short and provide additional fault current source contributions, the reach will be less than one-half of the reach calculated for the simple system. This reach limitation must be factored into system performance analyses when the Protection System design relies on autotransformer backup to clear faults for single Protection System failures. **Figure 7.10** illustrates the impact on backup protection reach when multiple transformers are in parallel. In some cases it may be difficult, if not impossible, to achieve coordinated backup protection for more than close-in faults. In these cases the Transmission Owner may need to carefully consider the consequences of possible tripping sequences or re- coordinate where possible.

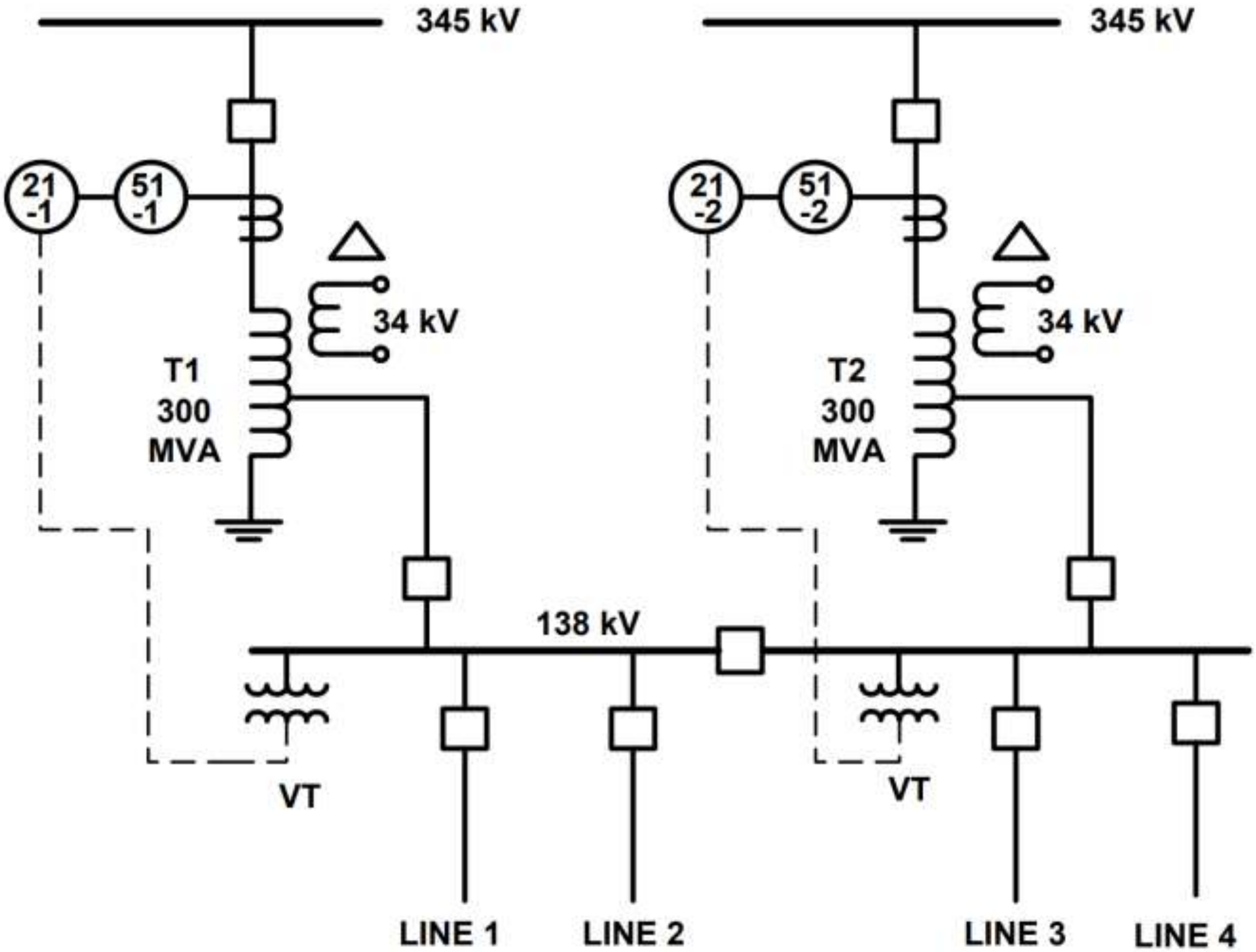

Figure 7.10: More Complex System One-Line Used in Transformer Protection Example

Another problem for autotransformer backup in more complex systems is the inability of the local backup Protection Systems on the two transformers to provide selectivity based on the location of faults. The Protection Systems on both transformers may react similarly and operate simultaneously for faults because they will have similar or identical relay settings. In some cases it may be worthwhile considering backup protection that will split the bus to limit the number of system Elements interrupted, although for some bus configurations this may be impractical or add an undesired level of Protection System complexity. The relay practitioner will need to consider the application of backup Protection Systems applied on these complex systems and incorporate the appropriate degree of dependability and security to protect the assets and prevent degradation of reliability.

Chapter 8: Conclusions

Transmission system events have shown that backup protection can play a significant role in preventing or mitigating the effects of Protection System or equipment failures.

Local backup inherently addresses single Protection System failures or failures of a circuit breaker to interrupt current while meeting NERC performance requirements and generally reduces the number of Elements that must be removed from the power system to clear the fault. Local backup may address some failures of multiple Protection Systems, but generally will not address these failures to the extent of a remote backup scheme. Remote backup may also adequately perform this function and can also act as a safety net to reduce the extent of a power system disturbance during multiple Protection System failures or failures of circuit breakers to interrupt current. Application of remote backup protection, however, may be limited by the need to meet the requirements of NERC Reliability Standards designed to assure adequate power system response during single failures or severe system events.

The design of the power system and the local protection design practices dictate whether local or remote backup protection can be securely and dependably applied to meet NERC standards for power system and Protection System performance requirements. Careful examination of the overall interaction of Protection Systems may provide insight as to where additional local or remote backup can be applied to help mitigate the spread of an outage.

Chapter 9: Recommendation

Large autotransformers are major capital investments and play a large role in the reliability and flexibility of the Bulk Electric System. Lead times for obtaining replacements are typically a minimum of six to twelve months; therefore, failures of these transformers can result in prolonged reduction in Bulk Electric System reliability and flexibility. Because of this, it is recommended that back up Protection Systems be applied to these assets to reduce the likelihood of damage due to prolonged through-fault currents caused by the failure of local or remote Protection Systems to clear the fault.

Appendix A: Contributors

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Revision History

Revision History		
Version	**Comments**	**Approval Date**
V1.0	Original Approved document	June 2011
V1.1	SPCWG review and minor revision of approved document	Pending

Review request for a PRC-024-3 IBR compliance evaluation document

Action Requested:

The SPCWG is requesting that the RSTC form a group to review and provide feedback on the Steady-State Approach for PRC-024-3 Evaluation for Inverter-Based Resources document that examines the complexities of evaluating compliance with PRC-024-3 with respect to Inverter-Based Resources.

Background:

This report illustrates how a Generator Owner (GO) of an inverter-based resource (IBR) may evaluate their compliance with Requirement R2 of the NERC Reliability Standard PRC-024-3. The example provided in this report is not exclusive as there are likely other methods for implementing a standard. This report provides an example of how NERC registered entities can project their IBR unit voltage protection settings to a corresponding main power transformer (MPT) high-side voltage or conversely project the MPT high-side voltages to the corresponding IBR unit voltage protection settings. They can then directly compare the voltage protection settings to the PRC-024-3 voltage boundary curve since both values are on the same basis.

As the examples in the paper show, there is a significant difference between the voltage setting at the IBR unit terminal and the corresponding voltage at the MPT high side in this example. This case highlights the importance of considering the voltage drop from the protection location to the MPT high side when evaluating compliance with PRC-024. The IBR-plant detailed model produces the most conservative results when used in calculations if the worst-case IBR unit for undervoltage and overvoltage settings are individually identified. Additionally, it can be observed that the difference in voltage drop between the two extreme IBR units can be significant. Only in the simplest collector system configurations, will manual calculations be adequate for showing compliance with PRC-024.

Summary:

The SPCWG requests that the RSTC form a review team to provide feedback so that this can be submitted to the RSTC for approval at their June meeting.

Steady-State Approach for PRC-024-3 Evaluation for Inverter-Based Resources

June 2024

Statement of Purpose

This report illustrates how a Generator Owner (GO) of an inverter-based resource (IBR) may evaluate their compliance with Requirement R2 of the NERC Reliability Standard PRC-024-3. The example provided in this report is not exclusive as there are likely other methods for implementing a standard. This report provides an example of how NERC registered entities can project their IBR unit voltage protection settings to a corresponding main power transformer (MPT) high-side voltage or conversely project the MPT high-side voltages to the corresponding IBR unit voltage protection settings. They can then directly compare the voltage protection settings to the PRC-024-3 voltage boundary curve since both values are on the same basis.

Scope

This report applies to GOs who are evaluating compliance with PRC-024-3 Requirement R2 copied below.

> R2. Each Generator Owner shall set its applicable voltage protection in accordance with PRC-024 Attachment 2, such that the applicable protection does not cause the generating resource to trip or cease injecting current within the "no trip zone" during a voltage excursion at the high side of the GSU or MPT, subject to the following exceptions: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*
>
> - If the Transmission Planner allows less stringent voltage protection settings than those required to meet PRC-024 Attachment 2, then the Generator Owner may set its protection within the voltage recovery characteristics of a location-specific Transmission Planner's study.
> - Applicable voltage protection may be set to trip or cease injecting current during a voltage excursion within a portion of the "no trip zone" for documented and communicated regulatory or equipment limitations in accordance with Requirement R3.

Figure 1 shows an example of a typical IBR plant. The high-side terminals of the MPT are referred to as point of measurement (POM) in this document. MPTs are also widely known as generator step-up (GSU) transformers. The individual wind turbine generators (WTG)/Inverters in the plant are referred to as IBR units and respective terminals to as point of coupling (POC).

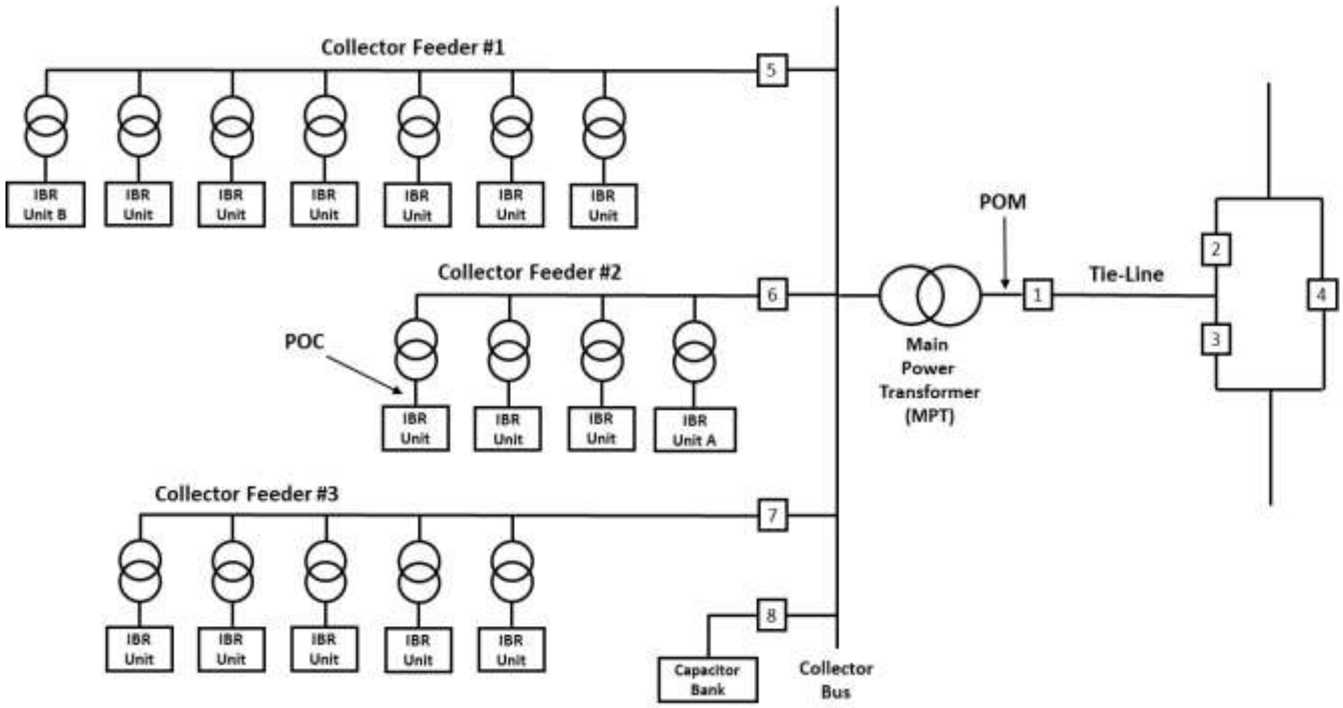

Figure 1: A Typical IBR Plant

Methodology

Attachment 2 of PRC-024-3 outlines how to evaluate protection settings.

Evaluating Protection Settings:

The voltage values in the Attachment 2 voltage boundaries are voltages at the high side of the GSU/MPT (i.e., POM). For generating resources with multiple stages of step up to reach interconnecting voltage, this is the high side of the transformer with a low side below 100 kV and a high side 100 kV or above. When evaluating protection settings, consider the voltage differences between where the protection is measuring voltage and the POM. A steady-state calculation or dynamic simulation may be used. If using a steady-state calculation or dynamic simulation, use the following conditions when evaluating protection settings:

- The most probable real and reactive power loading conditions for the IBR plant are under study.
- All installed IBR plant reactive power support (e.g., static VAR compensators, synchronous condensers, capacitors) equipment is available and operating normally.
- The actual tap settings of transformers between the IBR unit terminals and the high side of the GSU/MPT are accounted for.
- For dynamic simulations, the automatic voltage regulator[1] is in automatic voltage control mode with associated limiters in service.

The PRC-024-3 standard allows the use of either steady-state calculation or dynamic simulation to evaluate compliance. This report demonstrates a steady-state calculation method.

---

[1] In the context of IBR plant, the automatic voltage regulator is equivalent to the power plant controller.

Similar to what is provided in the *PRC-024-2 Implementation Guidance*, which gives examples for synchronous generators, this report provides an example of how NERC registered entities can project their IBR unit voltage protection settings to a corresponding MPT high-side voltage or conversely project the MPT high-side voltages to the corresponding protection system voltage. They can then directly compare the voltage protection settings to the PRC-024-3 voltage "no trip zone" boundary since both values are on the same basis.

Like an assessment for a synchronous resource, a steady-state PRC-024 assessment for IBR plant relies on steady-state voltage calculations. In addition, there are some added assessment considerations due to the nature of operation and configuration/design of IBR plants.

IBRs have two distinct characteristics compared to Synchronous resources:

- IBRs consist of multiple dispersed IBR units connected through the ac collector system.
- IBR units are dynamic devices and respond very rapidly to voltages at their ac terminals. They can change their power factor (PF) very quickly.

The steady-state calculation methodology shown in this report accounts for the dispersed nature of the IBR units and the collector system. In addition, the dynamic nature of IBR units has been partially considered in this report's calculations. Additional suggestions have been included to further account for the dynamic nature of the IBR units to be considered in steady-state calculations.

Steady State Calculations

A steady state assessment consists of the following steps:

1. Represent the plant.
2. Determine the most probable real and reactive power loading conditions.
3. Calculate voltage drops.
4. Translate voltages and determine PRC-024 compliance:
    a. IBR unit protection settings from the POC to the POM
       Compare with the PRC-024-3 voltage no-trip boundaries

       OR

    b. PRC-024-3 voltage no-trip boundaries from the POM to the POC
       Compare with the IBR unit voltage protection settings

Represent the Plant

An IBR plant typically has a number of IBR units (10's or 100's) all connected together by an ac collector system to one or more main power transformers as shown in **Figure 1**. An aggregated representation of the plant, consisting of one aggregated IBR unit and an equivalenced collector system, is often used in power flow and dynamic studies. Depending on the plant layout, it may be possible to use an aggregated representation for calculating voltage drops. However, an aggregated representation of an IBR plant is often not suitable for PRC-024 assessment as the variation in the collector system results in different total impedances and therefore different voltage drops from each IBR unit to the MPT high side, where the PRC-024 no-trip zone is defined. An aggregated representation of the collector system uses equivalent values that represent the IBR plant as a whole but do not represent the voltage drop to any actual IBR unit. Therefore, the aggregated representation does not represent the voltage drop experienced by the actual IBR unit protection levels. Analysis with the detailed IBR plant model requires a tool capable of solving a power flow.

Other IBR plant equipment should also be represented, such as the following:

- MVAR contribution from capacitor banks or other reactive support devices in their normal operating condition
- The actual tap positions of the IBR unit transformers and MPT

If the MPT uses an on-load tap changer, then the most probable tap position should be used. Another approach is to select a neutral tap position or the tap position that provides nominal voltage on the low side of the MPT for the 0.95 PF lagging on high side of the MPT.

Most Probable Real and Reactive Power Loading Conditions

The PRC-024-3 standard requires that the compliance assessment be done at the most probable real and reactive loading conditions.

For this report, the most probable loading condition for assessing both undervoltage and overvoltage was the plant producing rated real power at the POM at a power factor of 0.95 lagging (supplying vars) at the POM.

The rationale for this chosen loading condition is made up of the following:

- The undervoltage condition is most likely to occur during a system fault when the system voltage (and the voltage at the POM) is already low pre-fault due to high loading. In this case, the IBR unit will be trying to boost the voltage prior to the fault by supplying vars.
- During the undervoltage event, the IBR will continue to supply vars.
- The overvoltage condition is most likely to occur as the system voltage recovers after a fault clearance. Depending on the speed of voltage recovery, the depth of voltage dip during a fault, the voltage control characteristics of the IBR units during undervoltage events, and the dynamics of the IBR unit controllers, the IBR unit may still be supplying lagging vars as the voltage recovers and moves into the overvoltage condition upon fault clearance. Without considering the specific dynamics of a particular IBR, this report assumes that even an IBR operating at 0 PF lagging during a severe fault will be fast enough to change the PF back to pre-fault 0.95 lagging at the POM as the voltage recovers after a fault past the normal operating region into the overvoltage region.
- It is possible to further refine the above approach to evaluating overvoltage with the steady-state methodology with consideration of the dynamic nature of IBR units. For example, when evaluating overvoltage trip settings with delays of greater than 0.2 seconds, it may be appropriate to use unity or even a leading power factor at the POM. This is based on an assumption that a 0.2-second time delay offers enough time for IBR unit controls to change the power factor.

Calculate Voltage Drops

Assessment of the transferred protection levels does not need to be performed for every IBR unit within the IBR plant. For the assumptions outlined above, the voltage at the POC is always going to be higher than voltage at the POM. Only two worst-case IBR units need to be considered:

- For assessing undervoltage protection settings, the chosen IBR unit is the one with the lowest voltage difference between the POM and terminals of the IBR unit (e.g., IBR unit A on collector feeder #2 has the shortest length between collector bus and IBR unit terminals and least current.).
- For assessing overvoltage protection settings, the IBR unit chosen is the one with the highest voltage difference between the POM and the terminals of this IBR unit (e.g., IBR unit B on collector feeder #1 has the longest length between collector bus and IBR unit terminals and highest current.).

The first step is to identify the worst-case IBR unit for undervoltage and overvoltage protection assessment. To do so, the total voltage drop from each IBR unit to the MPT high side is calculated to identify the IBR unit with the lowest voltage drop, which is the worst case for undervoltage assessment, and the IBR unit with the greatest drop, which is the worst case for overvoltage assessment. The voltage drop is calculated for every segment between the POC and the POM by using a load flow model.

The voltage drop calculations are done by considering the IBR as a constant current source. This is different from the methodology in *Generator Voltage Protective Relay Settings*,[2] which outlines PRC-024-2 voltage drop calculations for a synchronous unit assessment. In the methodology used for synchronous units in the PRC-024-2 implementation guidance, the synchronous unit is considered a constant MVA source. The output current of the unit is adjusted as the voltage drop is calculated for different GSU high side bus voltage levels. However, unlike the synchronous case, IBR units are current limited devices and are considered a constant current source for the purpose of PRC-024 compliance evaluation. This means that current at rated or most probable POM voltage is used to calculate voltage drop between the POC and the POM. Additionally, since the IBR plant impedance does not change with voltage, the same voltage drop value can be applied for all MPT high side voltage levels.

The constant current and the constant voltage drop level should be determined with the IBR plant operating as follows:

- The MPT high side bus at rated or most probable voltage
- The most probable power factor at the MPT high side, which for this report is chosen to be of 0.95 lagging power factor
- The IBR plant output at its rated MW level

[2] Generator Voltage Protective Relay Settings is implementation guidance endorsed by the Electricity Reliability Organization.

Example: Wind Plant

The example wind plant in Table 1 includes six collector feeders below a single MPT. The number of WTGs (i.e., IBR units) connected to each collector feeder varies from 3–13.

Table 1: Wind Plant Information		
Plant Data		
Power Factor at POM	0.95 lagging	
Plant MW Rating	156	
POM Voltage Rating (kV)	230	
Capacitor Bank Location and Voltage	MPT Low Side, 34.5kV bus	
Capacitor Bank MVAR Rating	10	
WTG/IBR unit Data		
MVA Rating	2.083	
MW Rating	2	
Power Factor Range	+/-0.80	
Number of WTGs/IBR units	78	
Nominal Voltage (kV)	0.63	
WTG/IBR unit Transformer Data		
MVA Rating	2.3	
Low-Side Nominal Voltage (kV)	0.63	
High-Side Nominal Voltage (kV)	34.5	
Low-Side Tap Setting	0%	0.63kV
High-Side Tap Setting	0%	34.5kV
%Impedance	8.344	@2.3MVA
Main Power Transformer Data		
Base MVA Rating	96	
Low-Side Nominal Voltage (kV)	34.5	
High-Side Nominal Voltage (kV)	230	
Low-Side Voltage Tap	0%	34.5kV
High-Side Voltage Tap	0%	230kV
% Impedance	9.8	@96MVA

The over and undervoltage protection settings at the WTG/IBR unit level are included in Table 2.

Table 2: IBR Unit-Level Protection Settings		
Protection Level	Voltage (pu)	Time Delay (s)
UV1	0.55	0.20
UV2	0.76	0.50
UV3	0.83	2.00
OV1	1.30	0.00
OV2	1.26	0.20
OV3	1.24	0.75
OV4	1.20	2.00

Calculation Using a Detailed Collector System Model of Wind Plant

A detailed collector system power flow model of the plant is used to calculate the voltage drop between IBR units and the high side of the MPT. The plant power flow model includes the capacitor bank connected to the collector bus and is in-service since this is the normal operating condition of the plant. The tap position for IBR unit transformer(s) and the MPT is also reflected in the power flow model. The voltage drop is calculated for rated or most probable voltage and a 0.95 lagging power factor at the MPT high side while operating at rated power and remaining within the P-Q capabilities of the IBR unit. The 0.95 lagging power factor at the MPT high side is achieved by setting all IBR units in the plant to provide the same real and reactive power output, which is one approach for assessing compliance with PRC-024.

As described in the methodology section, the worst-case IBR units with the highest and lowest voltage drop are identified. Typically, for assessing undervoltage protection settings, the IBR unit chosen is the one with the lowest voltage difference between the POM and terminals of the IBR unit. Whereas, for assessing overvoltage protection settings, the IBR unit chosen is the one with the highest voltage difference between the POM and the terminals of this IBR unit. **Table 3** and **Table 4** show the voltage levels calculated by using a power flow model for the worst-case IBR units at different points within the IBR plant.

Table 3: Voltage Levels at Multiple Points within the IBR Plant – Highest Drop IBR unit			
IBR unit Setting Level	IBR unit Setting (pu)	MPT Low Side (pu)	MPT High Side (pu)
UV1	0.55	0.4980	0.4266
UV2	0.76	0.7080	0.6366
UV3	0.83	0.7780	0.7066
OV1	1.30	1.2480	1.1766
OV2	1.26	1.2080	1.1366
OV3	1.24	1.1880	1.1166
OV4	1.20	1.1480	1.0766

Table 4: Voltage Levels at Multiple Points within the IBR Plant–Lowest Drop IBR unit			
IBR unit Setting Level	IBR unit Setting (pu)	MPT Low Side (pu)	MPT High Side (pu)
UV1	0.55	0.4980	0.4579
UV2	0.76	0.7080	0.6679
UV3	0.83	0.7780	0.7379
OV1	1.30	1.2480	1.2079
OV2	1.26	1.2080	1.1679
OV3	1.24	1.1880	1.1479
OV4	1.20	1.1480	1.1079

Figure 2 shows undervoltage pickup settings at IBR unit terminals reflected to the high-side of the MPT (i.e., POM) along with the PRC-024 low voltage no-trip boundary. IBR units experiencing lowest and highest voltage drop between terminals and the POM are shown. As seen in Figure 2, the undervoltage pickup settings reflected to the high side of the MPT for an IBR unit with the lowest voltage drop between the terminals and the POM are higher than the same undervoltage settings for an IBR unit with the highest voltage drop between the terminals and the POM. Given that the trip settings applied in all IBR units are same within an IBR plant, the IBR unit with lowest voltage drop between the terminals and the POM should be used when evaluating undervoltage pickup settings.

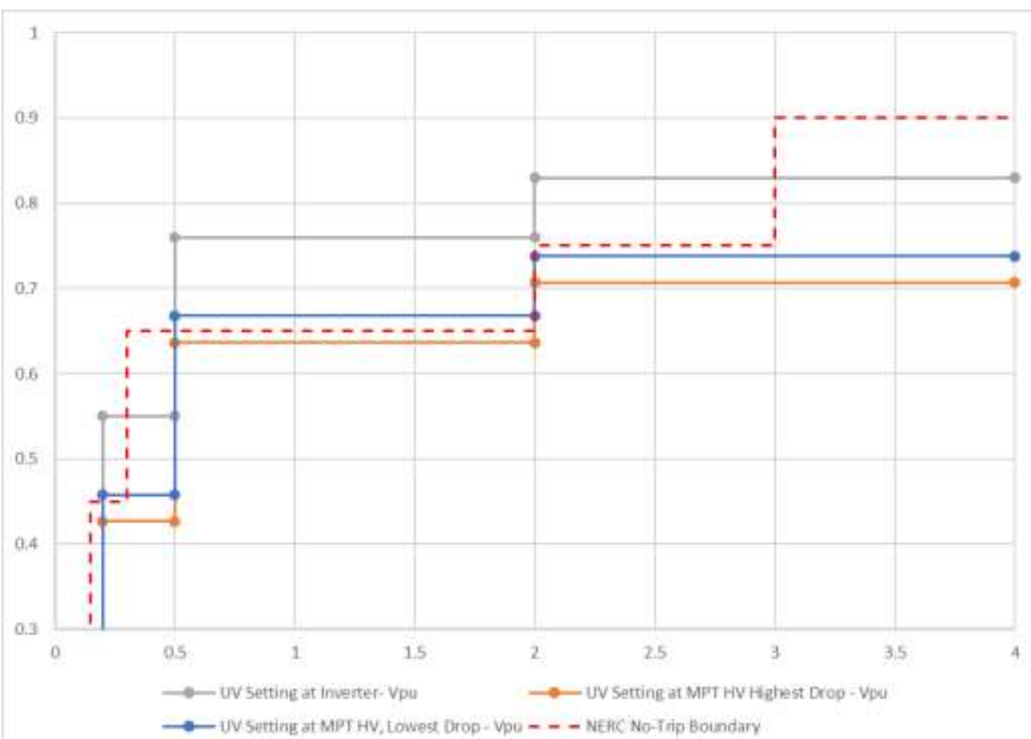

Figure 2: IBR Unit Undervoltage Settings Reflected to MPT High-Side Versus PRC-024 No-Trip Boundary

In this example, undervoltage levels UV1 and UV2 do not comply with the PRC-024 requirements. The undervoltage trip level UV3 barely meets the PRC-024 requirements. The pickup for UV1 and UV2 should be lowered so that the voltage of IBR unit (when reflected to POM) with lowest voltage drop between the terminals and the POM is below the low voltage no-trip boundary of the PRC-024. Note that, while lowering the protection level to meet this criteria will result in compliant settings, PRC-024 is not a comprehensive setting standard.

Figure 3 shows overvoltage pickup settings at IBR unit terminals reflected to the high-side of the MPT (i.e., POM) along with the PRC-024 high voltage no-trip boundary. IBR units experiencing lowest and highest voltage drop between terminals and the POM are shown. As seen in **Figure 3**, the overvoltage pickup settings reflected to the high side of the MPT for an IBR unit with the highest voltage drop between the terminals and the POM are lower than the same overvoltage pickup settings for an IBR unit with the lowest voltage drop between the terminals and the POM. Considering the IBR unit with highest voltage drop between the terminals and the POM, none of the overvoltage levels comply with the PRC-024 requirements. The pickup for all overvoltage levels should be raised so that voltage of IBR unit (when reflected to POM) with highest voltage drop between the terminals and the POM is above the high voltage no-trip boundary of the PRC-024.

Alternatively, the no-trip boundaries could be reflected from the MPT high side to the IBR unit level, as shown in **Figure 4** and **Figure 5**. Either reflection direction method will result in the same conclusions.

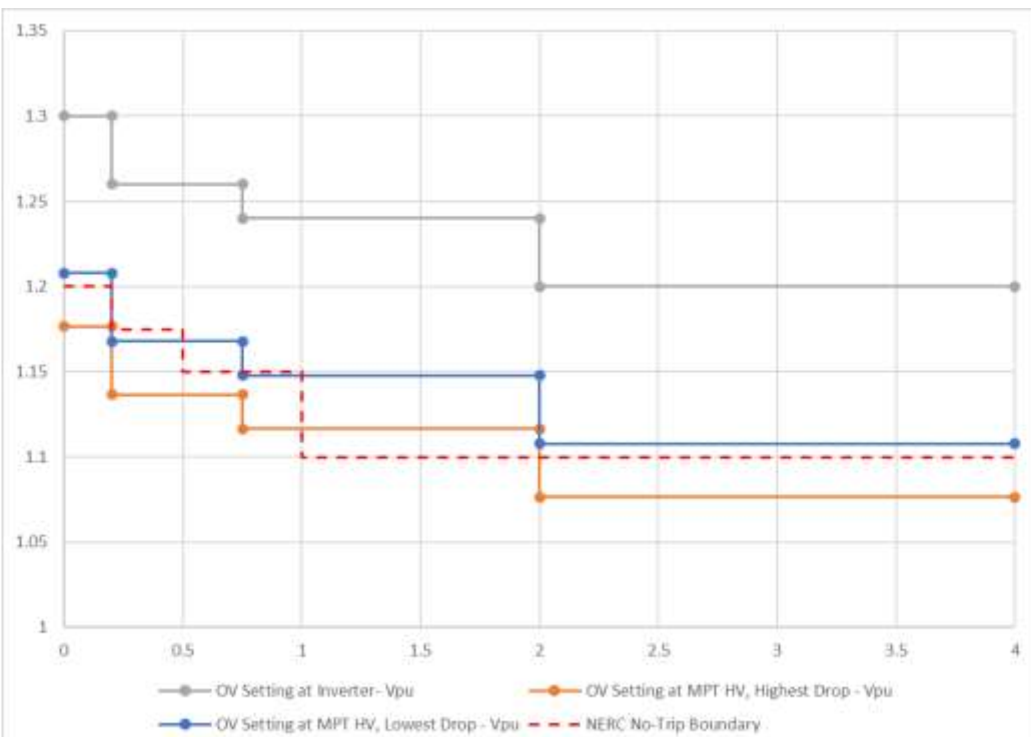

Figure 3: IBR Unit Overvoltage Settings Reflected to MPT High-Side Versus PRC-024 No-Trip Boundary

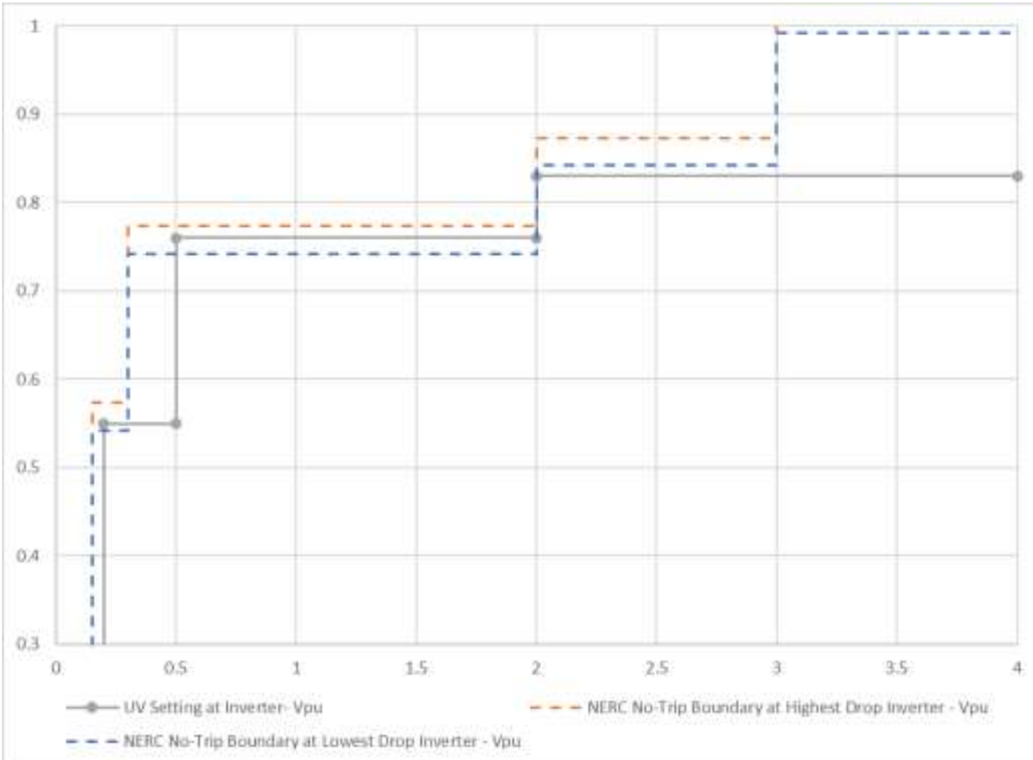

Figure 4: IBR unit Undervoltage Settings Versus PRC-024 No-Trip Boundary Reflected to IBR unit Terminal

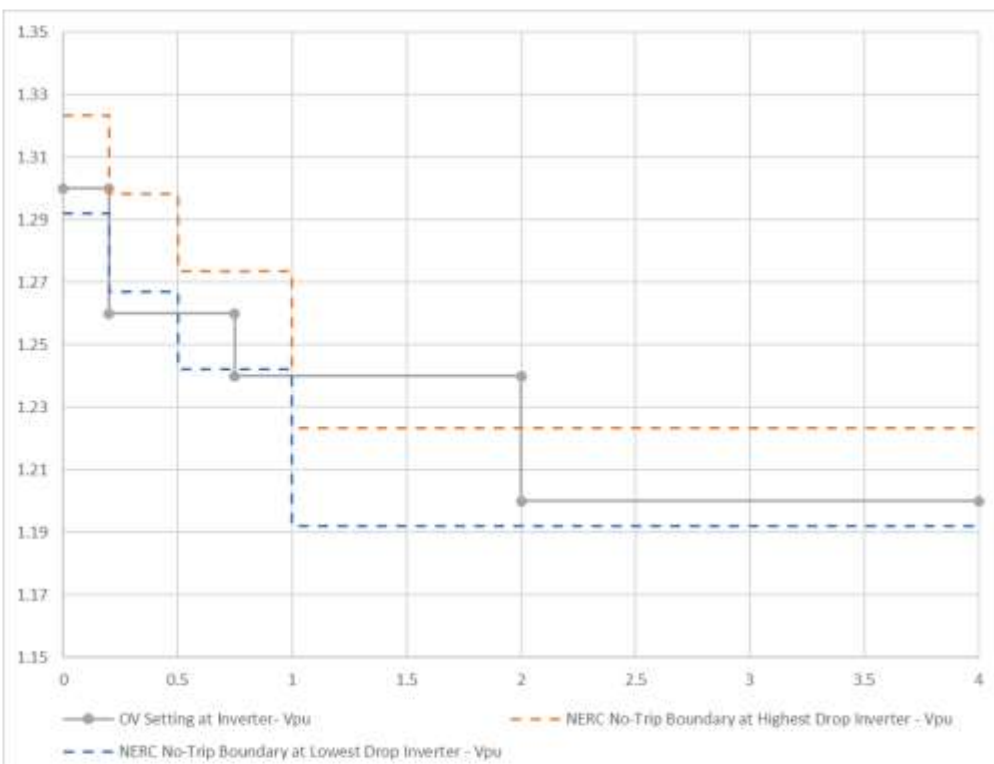

Figure 5: IBR unit Overvoltage Settings Versus PRC-024 No-Trip Boundary Reflected to IBR Unit Terminal

Calculation with Aggregated IBR Unit and Equivalenced Collector System Model

For comparison, the same voltage drop calculations were performed with an aggregated representation of the IBR plant with a single aggregated IBR unit, a single aggregated IBR unit transformer, and a single aggregated collector system below the plant's MPT.[3] Again, this aggregate representation results in an average representation of the voltage drop to IBR units in the plant and does not represent the actual voltage drop for any single actual IBR unit. Calculations with aggregated IBR unit and equivalenced collector system model are not recommended; they are only shown for comparison. As before, the voltage drop was calculated for rated or most probable voltage and 0.95 lagging power factor at the POM while producing as close to rated power as possible while remaining within the P-Q capabilities of the IBR unit. Additionally, the MPT tap was set to nominal and the MPT low-side capacitor bank was connected since this is the normal operating condition for the IBR plant. **Table 5** shows the voltage levels calculated by the simulator for the aggregated IBR unit at different points in the IBR plant.

Table 5: Voltage Levels at Multiple Points within the IBR Plant – Aggregated Plant Mode

IBR unit Setting Level	IBR unit Setting (pu)	MPT Low Side (pu)	MPT High Side (pu)
UV1	0.55	0.4984	0.4423
UV2	0.76	0.7084	0.6523
UV3	0.83	0.7784	0.7223
OV1	1.30	1.2484	1.1923
OV2	1.26	1.2084	1.1523
OV3	1.24	1.1884	1.1323
OV4	1.20	1.1484	1.0923

Figure 6 and **Figure 7** show the undervoltage and overvoltage settings, respectively, at the MPT high side for the aggregated IBR unit compared to the worst-case IBR unit settings from the previous section.

[3] E. Muljadi et al., "Equivalencing the collector system of a large wind power plant," 2006 IEEE Power Engineering Society General Meeting, Montreal, QC, Canada, 2006, pp. 9 pp.-, doi: 10.1109/PES.2006.1708945.

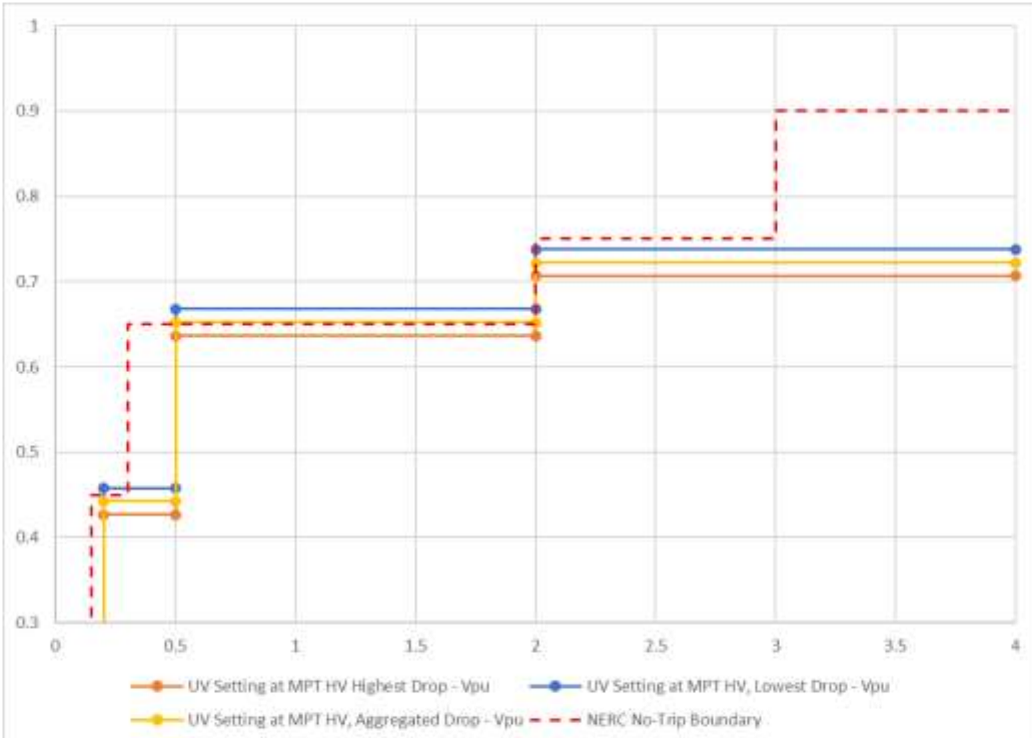

Figure 6: Undervoltage Settings Reflected to High-Side of MPT–Aggregated Versus Detailed IBR Plant

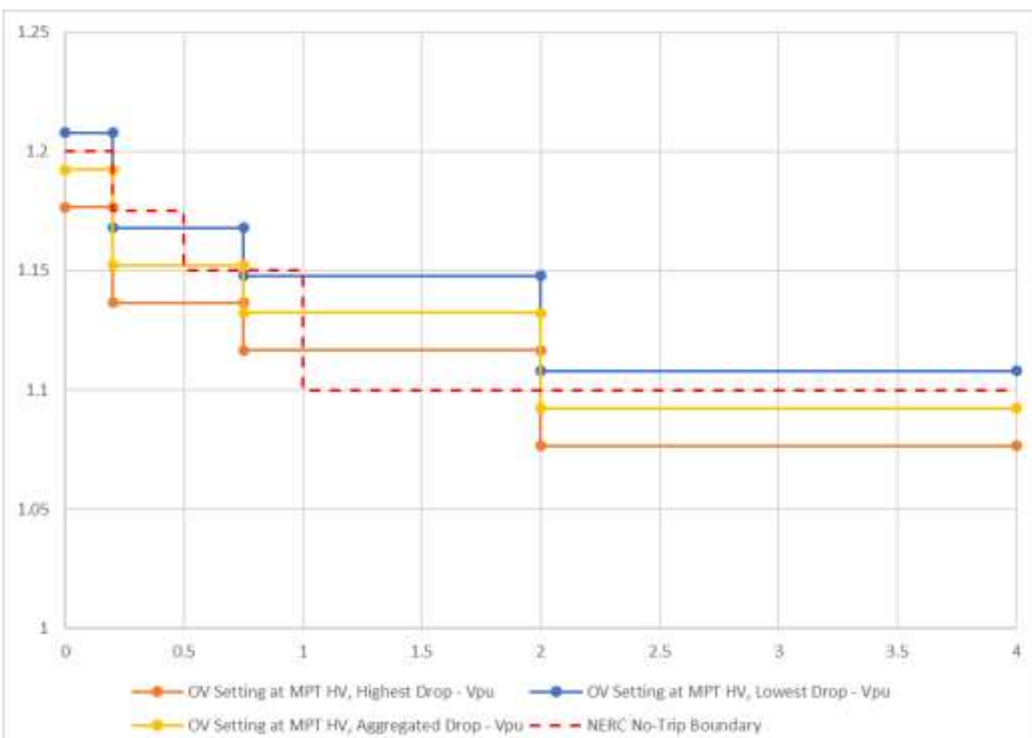

Figure 7: Overvoltage Settings Reflected to High-Side of MPT–Aggregated Versus Detailed IBR Plant

Conclusion

As shown in **Figure 2** and **Figure 3**, there is a significant difference between the voltage setting at the IBR unit terminal and the corresponding voltage at the MPT high side in this example. This case highlights the importance of considering the voltage drop from the protection location to the MPT high side when evaluating compliance with PRC-024. The IBR-plant detailed model produces the most conservative results when used in calculations if the worst-case IBR unit for undervoltage and overvoltage settings are individually identified. Additionally, it can be observed that the difference in voltage drop between the two extreme IBR units can be significant. Only in the simplest collector system configurations, will manual calculations be adequate for showing compliance with PRC-024.