Agenda
Reliability and Security Technical Committee

December 11, 2024 | 11:00 a.m. – 4:30 p.m. Eastern
Virtual

Join WebEx

Call to Order

NERC Antitrust Compliance Guidelines, Public Announcement, and Participant Conduct Policy

Introduction and Chair's Remarks

Agenda

1. **Administrative items**
    a. Arrangements
       Announcement of Quorum
    b. Reliability and Security Technical Committee (RSTC) Membership 2023-2026
    c. RSTC Newsletter
    d. RSTC Charter

Consent Agenda

2. **Consent Items* – Approve**
    a. September 11-12, 2024 RSTC Meeting Minutes

Regular Agenda

3. **Remarks and Reports**
    a. Subcommittee Reports*
    b. RSTC Work Plan
    c. Report of November 2024 Member Representatives Committee Meeting and Board of Trustees Meeting
4. **2025 RSTC Strategic Plan – Approve –** John Stephens, RSTC Vice Chair
5. **RSTC Subordinate Group Review Recommendations* – Approve –** John Stephens, RSTC Vice Chair
6. **6GHZTF Close Out – Information –** Valerie Carter-Ridley, NERC Staff Jennifer Flandermeyer, Chair FRTF | David Grubbs, Sponsor
7. **Implementation Guidance TPL-001-5 Trip Coil Interpretation – Endorse –** Rich Bauer, NERC Staff | David Mulcahy, Sponsor

8. **New Technology Enablement and Field Testing - Whitepaper – Approve** – *Larry Collier, NERC Staff | Marc Child, Sponsor*

9. **Technical Reference Document: Clarity of DERs in Operational Planning Assessments and Real-Time Assessments – Approve –** *Shayan Rizvi, SPIDERWG Chair | Wayne Guttormson, Sponsor*

10. RSTC HIGH PRIORITY **Reliability Guideline: BPS Planning under Increasing Penetration of Distributed Energy Resources – Approve –** *Shayan Rizvi, SPIDERWG Chair | Wayne Guttormson, Sponsor*

11. **White Paper: Reducing DER Variability and Uncertainty Impacts on the Bulk Power system – Approve –** *Shayan Rizvi, SPIDERWG Chair | Wayne Guttormson, Sponsor*

12. **Standard Authorization Request: EOP-005 – Endorse –** *Shayan Rizvi, SPIDERWG Chair | Wayne Guttormson, Sponsor*

13. RSTC HIGH PRIORITY **Reliability Guideline: Recommended Practices for Performing EMT System Studies for Inverter-Based Resources – EMTTF Work Plan Item #2 – Approve –** Aung Thant, NERC Staff | Jody Green, Sponsor

14. **Technical Reference Document: Considerations for Performing an Energy Reliability Assessment – Vol 2* – Approve –** Mike Knowland, ERAWG Chair | Srinivas Kappagantula, Sponsor

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

*Background materials included.

RSTC Status Report – Event Analysis Subcommittee (EAS)

Chair: Chris Moran
Vice-Chair: James Hanson
December 11-12, 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 – 2 published; 4 in development
- Development of FMM Diagrams – 3 approved; 3 in development
- Conducted Generating Unit Winter Weather Readiness Webinar
- Conducted Annual Monitoring & Situational Awareness Technical Conference

Ongoing & Upcoming Activities

- Development of Lessons Learned
- FMMWG Development of Failure Mode & Mechanism Diagrams
- 2025 RSTC Work Plan Summit

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
Electromagnetic Transient Modeling Task Force (EMTTF)

Co-Chairs: Adam Sparacino, Miguel Acosta

On Track
Schedule at risk
Milestone delayed

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

Items for RSTC Approval/Discussion:

- Seeking approval: Draft Reliability Guideline: Recommended Practices for Performing EMT System Studies for Inverter-Based Resources
- Seeking approval: Draft White Paper: Case Study on Adoption of EMT Modeling and Studies in Interconnection and Planning Studies for BPS-connected IBRs

Recent Activity

- Update on Project 2022-04 EMT Modeling: Changes to FAC-002 – Standard Drafting Team Leads
- Technical Presentations:
- Streamlining Grid Interconnection Studies for IBRs using PSCAD – Huanfeng Zhao, Om
- IBR Testing Automation in EMTP – Henry Gras Nayak

Upcoming Activity

- Upgrade to a working group
- Work Plan for 2025

Workplan Status *(6 month look-ahead)*

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

RSTC Status Report – Electric Vehicle Task Force (EVTF)

On Track
Schedule at risk
Milestone delayed

Chair: Uzma Siddiqi
Vice-Chair: Syed Qaseem Ali
December XX, 2024

Purpose: *The growth of Electric Vehicles (EVs) is expected to dramatically change the composition of the load seen by the Bulk Power System (BPS). The EVTF shall promote collaboration between electric utilities and the EV automotive representatives such that the two can build a common nomenclature and develop recommended utility interconnection requirements (e.g., ride-through), procedures, and approaches to handle the growing adoption of EVs seen by the ERO Enterprise in a manner supportive to reliability of the BPS. The EVTF shall focus on the integration challenges and develop potential solutions to the engineering challenges faced by integration of this emerging load type.*

Items for RSTC Approval/Discussion:

- None

Recent Activity

.
- Kicked off October 2024 at UMTRI facilities
- Toured research facilities to test new EVs
- Solicited volunteers for work plan item drafting
- Set 2025 meeting schedule

Upcoming Activity

- *Continue drafting of work plan documents*
- *Next meeting February 11-12, 2025. Virtual*

Workplan Status *(6 month look-ahead)*

Milestone	Status	Comments
White Paper: Risk Profiles and Prioritization on Motor Vehicle Electrification	On Track	In draft.
White Paper: Risk Mitigation Strategies to Mange Motor Vehicle Electrification	On Track	In draft.
Technical Report: EV Charging States and Type Tests	On Track	In draft.

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 24: Commissioning Best Practices for IBRs – Elevate from a white Paper to a reliability guideline

Recent Activity

- 30-day comment period for Item 16: SAR for FAC-001 and FAC-002 Enhancements

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

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

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 developing more effective modeling for the large loads, including data centers, and transitioning utilities from the older load models to the CMLD Composite Load Model.

Items for RSTC Approval/Discussion:

- **Review**: LMWG Work Plan

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 Data 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	Complete

Recent Activity

- Identified approaches to model data center load dynamic characteristics based on past event Disturbance Recorder Data, the ITIC graph, and theoretical understanding of data center equipment
- Conducted studies to show how the EV model can be used for planning studies
- Informed the industry about different large load interconnection issues to highlight the need for accurate load modeling

Upcoming Activity

- Conduct Reliability Studies with EV Unidirectional EV Charger Model and Bidirectional EV Charger Model
- Continue Review of Responses to Data Center Questionnaire
- Reviewing dynamic modeling / lab testing / disturbance monitoring for large loads
- Plan for in-person meeting with LLTF to go over modeling Large load issues
- Develop modeling guidance for Large loads

RSTC Status Report – Reliability Assessment Subcommittee (RAS)

Chair: Amanda Sargent (04/2024)
Vice-Chair: Evan Shuvo (07/2024)
December 11-12, 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:
None

Recent Activity:

- Collected information related to Winter Storm Elliott Rec. 10: *Coordinated with RTOS. Info was included 2024-2025 WRA.*
- 2024-2025 WRA was published Nov 14 | Industry Webinar Nov 19
- RAS Meeting November 13-14: topics included: Preparation of 2024 assessments, planning for 2025 ProbA/Energy Assessment, planning for the future assessments vision

Upcoming (RSTC) Activity:

- 2024 LTRA publication planned for December 14 | Industry Webinar January 29 (Tentative)

Workplan Status *(6-month look ahead)*

Milestone	Status	Comments
2024 Long-Term Reliability Assessment (LTRA)	On Track (green)	The RSTC review complete. Publication planned for December 14.
2025 Summer Reliability Assessment (SRA)	On Track (green)	In planning. Request letter expected in January.
ERO Energy Assessments	On Track (green)	Collaborating with PAWG to develop new approaches in ERO reliability assessments.

RSTC Status Report – Real Time Operating Subcommittee (RTOS)

Chair: Christopher Wakefield
Vice-Chair: Derek Hawkins
December 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

- RTOS sub-group participated in a Load Forecasting panel discussion
- RTOS sub-group participated in AI/ML ERO Whitepaper

Items for RSTC Approval/Discussion:

N/A

Upcoming Activity

- Working group established to determine next steps regarding the IROL Guideline.
- Working group established to review the RTOS Scope document.

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

Milestone	Status	Comments
Monitor development of common tools and act as point of contact for EIDSN.	🟢	On-going
Frequency Monitor Reporting (Standing RTOS agenda item to discuss).	🟢	On-going
Reliability Guideline: Methods for Establishing IROLs	🟢	In-progress
RTOS Scope: 3-year cyclical review	🟢	In-progress

RSTC Status Report – Supply Chain Working Group (SCWG)

Chair: Roy Adams
Vice-Chair: Dr. Tom Duffey
December 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:
- Petition for promotion from a working group to a subcommittee

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 Q3-2024.
- SCWG formed a single project team for both gap assessment and NERC CIP 013-2 SAR response. A detailed update was provided to RSTC under separate cover.

Upcoming Activity
- SCWG is discussing the potential for additional guidelines based on industry feedback and supply chain security issues.
- SCWG members participate as requested in projects and outreach events pertaining to cloud computing security risk topics.
- SCWG is reconvening subgroups on Vendor Incident Response and Procurement Language guidelines to finalize response to public comments.

Workplan Status *(6 month look-ahead)*

Milestone	Status	Comments
Respond to FERC SCRM NOPR: liaise with the NERC-designated drafting team to address NOPR goals	On Track	Not Started
Revisions to Security Guideline Procurement Language.	On Track	In-progress
Revisions to Security Guideline Vendor Incident Response	On Track	In-progress
Petition for promotion from working group to a subcommittee	On Track	In-progress

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

Chair: Karl Perman
Vice Chair: Thomas Peterson
December 2024

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

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

Items for RSTC Approval/Discussion:
- Seeking approval on final draft of Whitepaper: New Technology Enablement & Field Testing

Recent Work Plan Activity
- Final Draft Complete - Whitepaper: New Technology Enablement & Field Testing
- Subteam launched, and outline under way for Security Guideline for Inverter-Based Resources
- Subteam launched, and outline under way for Security Guideline for Inverter-Based Resources
- Subteam kickoff for AI/ML in November. Work Item to be determined after research.

Upcoming Activity
- Collaborate with other industry groups on IBR/DER/AI
- No other planned work item initiation at this time.

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

Milestone	Status	Comments
Whitepaper: New Tech Enablement	On Track (green)	Requesting RSTC Approval
Security Guideline for Inverter-Based Resources	On Track (green)	In Progress
Security Guideline for Distributed Energy Resource Aggregators	On Track (green)	In Progress
AI/ML Work item to be identified	On Track (green)	Subteam Kickoff

RSTC Status Report – Synchronized Measurement Working Group (SMWG)

Chair: Clifton Black
Vice-Chair: Open
December 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 July SMWG Virtual Meeting (7/30).
- Held October SMWG Hybrid Meeting (10/17).
- Grid Oscillation Events Reporting (Standing RTOS agenda item to discuss).

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.
- Collaborate with NASPI and develop a series of role-based training courses focusing on synchrophasor technology.

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

Milestone	Status	Comments
Add Oscillation as a Category in RCIS	On Track	In-progress
Role-based Training Courses	On Track	In-progress
Synchrophasor Data Accuracy Maintenance Manual (with EMSWG)	On Track	In-progress
Whitepaper Roadmap for Operationalizing Synchrophasor Technology	On Track	In-progress
CIP Implementation Guidance for Synchrophasors	On Track	In-progress
Consolidate Forced oscillation guideline and Oscillation analysis white paper	On Track	In-progress

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

Chair: Lynn Schroeder
Vice-Chair: Manish Patel
As of November 7. 2024

On Track
Schedule at risk
Milestone delayed

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

Items for RSTC Approval/Discussion:

Accept: TPL-001-5 Footnote 13 Implementation Guidance document

Workplan Status *(6 month look-ahead)*

Milestone	Status	Comments
Ethernet P&C TRD	On Track	The outline is complete, and the writing portion continues
Misoperations Analysis Report	On Track	Team is working on developing a template that will be used to guide the report structure
TPL-001-5.1 footnote 13	On Track	Requesting Acceptance

Recent Activity

- Develop Technical Reference document for Ethernet based P&C.
- Develop implementation guidance for TPL-001-5.1 addressing footnote 13
- Submitted a request to RSTC EC to develop an annual report that analyzes Misoperations over a 1-year time period

Upcoming Activity

- Work on Ethernet based Protection and Control document
- Create a template for the structure on the Misoperations analysis report

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)
December XX, 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**: *Technical Reference Document: Clarity of DERs in Operational Planning Assessments and Real-Time Assessments*
- **Approve**: *Reliability Guideline: Bulk Power System Planning Under Increasing Penetration of Distributed Energy Resources*
- **Approve**: *White Paper: Reducing DER Variability and Uncertainty Impacts on the Bulk Power System*
- **Endorse**: *SAR EOP-005*

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 October 2024 to update work products.
- Drafting comments from past RSTC and industry reviews
- Set 2025 meeting schedule. Planned to meet once jointly with EVTF in 2025.

Upcoming Activity
- *Continue drafting of Reliability Guidelines from Standards Review White Paper*
- *Continue collaboration among the RSTC groups for SARs*
- *Respond to comment for DER forecasting reliability guideline*
- *Continue drafting response to RSTC on PRC-006 SAR*

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	● (green)	On RSTC December Agenda
C11 – White Paper: Variability, Uncertainty, and Data Collection for the BPS with DER Aggregators	● (green)	On RSTC December Agenda
A3 – White Paper: Modeling of DER Aggregator and DERMS Functional Impacts	● (red)	In draft. Rescoped. Anticipated Q1 2025
Reliability Guideline: Detection of Aggregate DER Response during Grid Disturbances	● (green)	In scoping and draft. Anticipated Q2 2025
Reliability Guideline: DER Forecasting	● (green)	Responding to industry comment. Anticipated Q1 2025
Reliability Guideline: Aggregate DER in Emergency Operations	● (green)	In draft. Anticipated Q3 2025
Technical Reference Document: DERs and OPA-RTAs	● (green)	On RSTC December Agenda

Work Look Ahead - SAR

- On Track
- Schedule at risk
- Milestone delayed

Workplan Status (6 month look-ahead)

Milestone	Status	Comments
C16 – SAR PRC-006	On Track	In draft. Expected Q1 or Q2 of 2025

RSTC Status Report – Security Working Group (SWG)

Co-Chair: Brent Sessions
Co-Chair: John Tracy
December 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.

Recent Activity

- Completed
  - BCSI TTX
  - OLIR mapping CIP to CSF
  - FERC LL CIP-002
  - Cloud Encryption Implementation Guidance
    - ERO Endorsed / Approved
- Work Plan Updates
  - Looking at retiring or rewriting *Security Guideline: Primer for Cloud Solutions and Encrypting BCSI*
- Recent Activity
  - Physical Security Sub-team Security Guideline

Items for RSTC Approval/Discussion:

- N / A

On-going Activity

- Continuation of Physical Security sub-team
  - Physical Security Guideline
- Continuation of sub-team CIP Implementation Guidance for Synchrophasors
  - Entity presentations continue for Synchrophasor use-cases
  - Both CIP and non-CIP approaches
- OLIR Mapping NIST800-53 to NERC CIP
  - Continue working through NIST control families
  - Work progressing towards the finish line
- Evidence Request Tool
  - Sub-team continues working revisions / updates to the ERT as needed

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

Milestone	Status	Comments
CIP IG for Incorporating Synchrophasor Data into Real-time Operations	On Track (green)	
Physical Security Guideline	On Track (green)	
NIST 800-53 to NERC CIP Standards mapping	On Track (green)	
CIP Evidence Request Tool	On Track (green)	

Agenda Item 4
RSTC Meeting
December 11, 2024

2025 RSTC Strategic Plan

Action
Approve

Background
In June 2024, the RSTC established a review team to review and update the RSTC Strategic Plan. The review team updated the RSTC Strategic Plan based on its review of the plan document for updates based on risks identified in 2024 by industry and the RSTC. This included work being undertaken by the Large Loads Task Force as well as the Electric Vehicle Task Force. Enhancements were added to the Grid Transformation risk priority area and mode specific information was added to the tables contained in Chapters two and three.

The review team is seeking RSTC approval of the RSTC Strategic Plan.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Reliability and Security Technical Committee

2025-2026 Strategic Plan

January 2025

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	Reliability First
SERC	SERC Reliability Corporation
Texas RE	Texas Reliability Entity
WECC	WECC

Introduction and Objectives

The NERC Reliability and Security Technical Committee (RSTC) is a stakeholder committee chartered by the NERC Board of Trustees (Board) to proactively support the NERC ERO Enterprise's mission. The RSTC, in accordance with its charter, will develop and maintain a two-year strategic plan and an associated work plan to carry out the functions of the committee:

- Ensure alignment of the strategic work plan with ERO reports and analyses, including the NERC Business Plan and Budget, ERO Enterprise Long-Term Strategy, biennial Reliability Issues Steering Committee (RISC) ERO Reliability Risk Priorities report, State of Reliability report recommendations, Long Term, Seasonal and Special Reliability Assessment recommendations, and ongoing event analysis trends.
- Leverage industry technical expertise to provide insights, considerations and educational materials regarding reliability impacts of policy and regulatory decisions.
- Coordinate the objectives in the strategic work plan with the Standing Committees Coordinating Group.
- Support response to mandates related to BPS reliability (e.g. FERC Order 901[1], ITCS[2]).

This strategic plan guides the functions and core mission of the RSTC, providing a sustainable set of expectations and deliverables for the RSTC to assess and enhance reliability, resilience, and security of the BPS. The RSTC engages in the identification and communication of reliability risks along with potential mitigation strategies. These activities will include close coordination with the RISC as well as taking steps to create industry-wide awareness. This strategic plan will not remain static throughout a two-year timeframe. Rather, it is crucial that the plan retains the flexibility to address emerging issues.

This two-year plan, along with its goals and measures, is typically reviewed during the December RSTC meeting, and enhancements to the plan will be made and presented to the NERC Board each year in accordance with the Charter as required to achieve the goal of promoting reliability, resilience, and security.

[1] https://www.ferc.gov/media/e-1-rm22-12-000
[2] https://www.nerc.com/pa/RAPA/Pages/ITCS.aspx

Executive Summary

The 2025 update to the RSTC strategic plan was conducted by a small group of RSTC members per the two-year Strategic Planning Process, which is detailed in Appendix A. The group identified four strategic priorities, with the recognition of the need to increase awareness of reliability implications, and closer collaboration and coordination with policy makers on emerging energy policy issues:

1. Grid Transformation,
2. Inverter Based Resources (IBR),
3. Resilience and Extreme Events, and
4. Security.

Trends in several areas of the electric industry are the primary drivers of these priorities. Policy and economic drivers are shifting the resource mix from large, centralized fossil-fired power stations towards variable energy resources (VER) spread over large geographic areas. Concurrent with this shift, the capacity to provide essential reliability attributes that are inherent in large synchronous generators and critical to managing the reliability of the BPS are decreasing. The inverter-based devices that are expected to mimic and replace these Essential Reliability Services are still being evaluated for their applicability and functionality. Amid this transition, natural gas use for electric generation appears to increase in peak periods but for fewer hours. This is testing both the physical and regulatory interfaces between the electric and gas industries in novel ways. In addition, electric demand is growing in extraordinary ways and with uncertain load profiles such as data centers, crypto mining and electric vehicle loads. Compounding the risks, the impact of extreme weather events during this transition is challenging system operators in unprecedented ways. Finally, security risks appear to be increasing, and all industry stakeholders must remain vigilant to physical and cyber-attacks and vulnerabilities of globally interconnected supply chains.

With respect to the four emerging strategic risks, the RSTC identified specific focus areas and desired outcomes. Potential risk mitigation steps are left for further investigation by the subcommittees, working groups, and task forces (collectively "subgroups"). A complete list of the focus areas follows:

Grid Transformation

1. Energy Assurance: As the grid relies on more just-in-time fueled resources – i.e., natural-gas fired generators and VERs – and traditional, slower starting resources have become less economic to operate, ensuring energy is available and delivered at the right time to serve load is essential.
2. Gas-Electric Coordination: The gas infrastructure and regulatory framework were not originally designed to support the needs of the electric industry. As the generation fleet transitions to less carbon-intense resources, the use of gas fired resources for base load and peaking needs is increasing especially during critical times and under certain conditions, and the limitations of this historical framework are becoming more apparent.
3. Demand Growth: Electrification policies are adding to traditional macroeconomic-driven load growth. Moreover, the characteristics of newly connected loads are not well understood and may present unique reliability challenges. These demands compound the challenges of an evolving generation mix and manifestly increase reliability risk. To address specific reliability risks, the RSTC formed two task forces in 2024. The Large Loads Task Force (LLTF) was formed to better understand the reliability impact(s) of emerging large loads such as Data Centers (including crypto and AI), Hydrogen Fuel Plants, etc. and their impact on the BPS. The Electric Vehicle Task Force (EVTF) was also formed to promote collaboration between electric utilities and the EV automotive representatives such that the two can build a common language and develop recommended utility interconnection requirements (e.g., ride-through), procedures, and approaches to handle the growing adoption of EVs in a manner supportive to the reliability of the BPS.

4. Distributed Energy Resources (DER): As more decentralized, distribution-connected generation come on to the grid, the reliability attributes also shift to where the generation is connected. This step towards major decentralization could be accompanied with unintended risks. Current Reliability Standard requirements are centrally focused to require performance on the generation side to serve load. There are no existing requirements that distribution-connected resources perform to maintain the reliability of the bulk power system.
5. Demand and DER Aggregators: For many years, utilities have implemented demand side programs to manage demand on their systems in an aggregated manner. Policy decisions, such as FERC Order 2222 along with technology advances, have increasingly opened the door to market participation by aggregators of distribution-connected resources and for "third party" aggregators to manage and control their operation. The current and forecasted state of aggregation needs to be fully assessed to ensure appropriately prioritized and coordinated efforts regarding aggregators of distribution-connected resources and performance, modeling, and visibility of these resources.

Inverter-Based Resources

1. IBR Performance: As the first generations of IBRs were deployed and reached a critical mass, issues with their ability to ride through system faults and disturbances became apparent. This has resulted in concerns for grid operators, and there are efforts underway to address the performance of in-service IBRs.
2. IBR Modeling versus Performance: In addition to the operating concerns, the nascent industry has lacked standard models used for power flow and grid stability analysis. Additionally, interconnecting utilities have found many device settings of installed IBRs deviate from the models provided.
3. IBR Interconnection Requirements and Evaluation: IBR numbers are expected to grow over the next decade and exceed the megawatts of synchronous generation in many regions. RSTC and its subgroups are examining the viability of codifying interconnection requirements to address the concerns with ride-through and actual versus modelled performance, plus potentially adding certain reliability services, on a prospective basis.

Resilience and Extreme Events

1. Planning for High-Impact Events: Generation performance is correlated with weather, and demand may exhibit nonlinear behaviors under extreme conditions. This necessitates an assessment of risk in planning models including low frequency but highly impactful conditions.
2. Wide-area Energy Assessments: Short- and long-duration low-frequency, high-impact weather events sometimes extend beyond the boundaries of individual balancing authority areas and can lead to an increase in risks across a wide area. Resource planning and reliability assessments would benefit from joint-regional coordinated action.

Security

1. Physical and Cyber Security: External threats have caused damage and disruption to the Bulk Electric System (BES). Unfortunately, threats from lone wolf actors to state-sponsored hackers are expected to increase. DERs and Distribution-Side Aggregators are expanding the current attack surface. Raising awareness of these threat vectors and the extent to which DER aggregators may be following cybersecurity protocols encourages protective actions that mitigate the risk and strengthen the grid.
2. Supply Chain Assurance and Protection: Today's supply chain is highly globalized to the extent the BPS may not be able to function if supply of certain components is disrupted or weaponized. The risks from globalization are coming into sharp focus with recent geopolitical events. Attention is required to ensure the grid continues to function in the event global supply chains are disrupted.

While the small group of RSTC members developing this plan debated and identified the strategic risks, it became apparent that the full RSTC should undertake a thorough examination of the indicators and metrics used to measure risk. The consensus among the group is that existing metrics sufficiently measure the current state of reliability and may be used to extrapolate trajectories with historical data, but these indicators do not sufficiently measure emerging, novel risks. Early each calendar year the RSTC will discuss action to:

- Review current reliability metrics,
- Identify the risks that those metrics are attempting to address,
- Identify risks areas that could materialize in the future and are unique or peculiar to the strategic risks,
- Define leading indicators that may better forecast future risk areas and allow the ERO and stakeholders to proactively mitigate those risks, and
- Identify appropriate pathways to communicate risks and new leading indicators to energy policymakers.

Following Board approval, the RSTC will communicate these strategic risks and focus areas to the subgroup leads. Through an iterative process, these groups will propose to the RSTC specific work plan items intended to address these identified risks. The RSTC will review the work plan items against this strategic plan for alignment and prioritization and approve the work plan items as appropriate. The rest of this document describes the details of the processes used to develop the strategic plan and describes those risks in more detail.

Chapter 1: Mission, Vision, and Guiding Principles

Mission

Ensure the reliability and security of the bulk-power system by identifying critical risks and deploying effective and efficient risk mitigations.

Vision

The RSTC is the premier technical authority on BPS reliability, resilience, and security, and its effectiveness stems from the stakeholder members who command deep technical knowledge, broad industry experience, and a collective duty to ensure the reliability of the bulk-power system.

Guiding Principles

The following principles serve to guide our practices:

- Coordinate with the RISC on priorities to align the RSTC strategic plan with the ERO's strategic plan.
- Maintain a focus on identification, analyses, and mitigation of existing and emerging reliability, resilience, and security risks.
- Continually strive for the development and dissemination of high-quality lessons learned through event analysis (EA), emerging cause code trending, and information sharing.
- Maintain relationships with other NERC standing committees (e.g. support the Standing Committee Coordinating Group), NERC Forums, and industry trade groups (e.g. NATF, IEEE).
- Maintain and enhance reliability, resilience, and security through the pursuit of clear NERC Reliability Standard Authorization Requests, Reliability Standards, Reliability Guidelines, Security Guidelines, Technical Reference Documents, NERC Alerts, Interpretations, lessons learned, and compliance clarifications.
- Incorporate a planning, operations and security perspective into NERC reports issued to industry.
- Deliver technically sound and accurate analyses, assessments, and recommendations.
- Identify critical emerging issues and trends that could potentially have reliability impacts in the near term and long term.
- Ensure the facts are unbiased and not providing an advocacy of policy matters.
- Promote coordination effectiveness across the NERC ERO Enterprise.
- Ensure continued provision of high levels of expertise, technically sound conclusions, and timely results/deliverables.
- Ensure the RSTC structure, processes and procedures, its working relationships with other technical standing committees, its subcommittees, working groups and task forces are focused on the highest priorities for reliability, resilience, and security within the ERO enterprise.

Chapter 2: Strategic Objectives and Priorities

The RSTC's strategic objectives provide a bridge between the RSTC's mission and vision and the annual goals and work plan deliverables needed to achieve them. The strategic objectives of the RSTC provide clear expectations of the goals and deliverables of the committee and its subgroups and are not expected to change often. However, the strategic priorities and the expected work products may change, as needed. The strategic objectives of the RSTC are:

1. Drive effective mitigation actions against emerging and established reliability and security risks, specifically targeting the strategic priorities.
2. Promote and increase stakeholder and regulator engagement and awareness.
3. Learn from events and past performance trends and deploy mitigation.
4. Identify and assess long-term planning and emerging reliability and security risks.
5. Make recommendations and develop solutions that support technology and security integration into BPS planning and operations.
6. Provide general information to a wide audience that highlights reliability and security risks on the bulk power system from significant changes to energy resources and electric loads.

To achieve these objectives, the RSTC uses its subgroups to develop its work products. The subgroups are organized under three categories: Performance Monitoring, Risk Mitigation, and Reliability and Security Assessment.

There are two types of key projects included in the RSTC work plan to support the strategic objectives:

1. **Programmatic:** Periodic, cyclical or continuous actions, deliverables, and processes that support the identification, prioritization, and monitoring of reliability risks. The RSTC's **Performance Monitoring** and **Reliability and Security Assessment** subgroups primarily serve to support programmatic strategic objectives.
2. **Prioritized Risk:** Targeted and focused actions to identify and develop specific reliability risk mitigations. The RSTC's **Risk Mitigation** subgroups primarily serve to support the strategic risk mitigation objectives. This also includes emerging risks identified between strategic planning periods (from assessments, disturbance reports, etc.).

Programmatic

1. **Identify key areas of concern, trends, and emerging reliability issues by periodically assessing system reliability and performance.**

   The RSTC will focus on developing reliability assessments, evaluations, and studies, and extracting insights to identify reliability, resilience, and security risks. By identifying and quantifying emerging risks, the RSTC can craft risk-informed recommendations, provide the basis for actionable risk mitigations, and provide education to industry stakeholders and policymakers. The RSTC supports this process primarily through the Reliability Assessment Subcommittee (RAS), Performance Analysis Subcommittee (PAS), and Resources Subcommittee (RS). Primary deliverables include:

   a. **Long-Term Reliability Assessment (annually):** 10-year outlook of resource adequacy and transmission projections. Emerging reliability and security integration issues are identified.

   b. **Seasonal Reliability Assessments (annually):** Summer and winter season operational outlook, projection, and leading indicators.

c. **Special Reliability Assessments (ad-hoc):** topical technical evaluation of a specified reliability risk.

d. **State of Reliability Report (annually):** Historical performance, evaluating 5-year (or longer) trends, indicators, and lagging metrics.

e. **Frequency Response Annual Analysis (annually):** Historical performance of frequency response per a Federal Energy Regulatory Commission (FERC) directive.

2. **Identify lessons learned and trends based on system events and make recommendations for improvement.**
The RSTC will focus on event prevention or mitigation by supporting and continually enhancing the ERO's EA program to ensure a comprehensive process, as well as rapidly developing and disseminating lessons learned. Through the Event Analysis Subcommittee (EAS), the RSTC approves any changes to the EA Process and reviews periodic event reports and lessons learned. Any mitigation actions for the ERO to pursue or recommendations for industry can result in additions to the RSTC work plan and, depending on the outcomes of the risk assessment, may be added to the strategic objectives. Primary deliverables include:

a. **Event and Disturbance Reports (*ad-hoc*):** Event reports detail specific details and root causes of BPS events. The EA Process is approved by EAS, and individual reports are published by the ERO and serve as input to the RSTC.

b. **Lessons Learned (*ad-hoc*):** Identified best practice or revealing reliability risk based on an event or group of events. Lessons Learned documents are published by the ERO and serve as input to the RSTC.

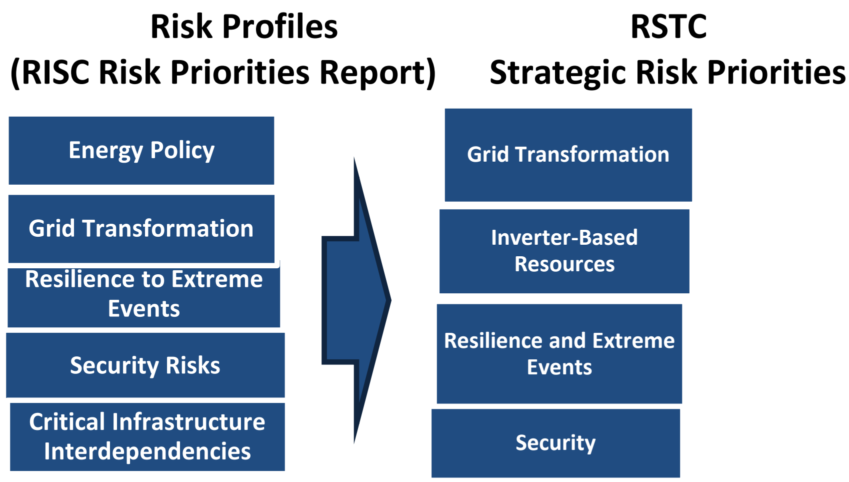
3. **Promote and increase stakeholder engagement and awareness of reliability risks.**
The RSTC will continue to promote outreach to stakeholder and policymaking organizations on reliability, resilience, and security matters through webinars and in-person conferences, workshops, and other mediums to deliver content and reliability messages. The RSTC will leverage strong relationships with industry groups such as NATF, NAGF, IEEE, EPRI etc. as well as regulatory and governmental authorities to target specific technical areas of concern and work together on industry outreach. Primary engagements include:

a. **Reliability Conferences and Workshops (*ad-hoc*):** Convene industry to share and exchange ideas and practices that promote reliability in a variety of technical areas. Conferences can support the RSTC's mission by "creating a forum for aggregating ideas and interests, drawing from diverse industry stakeholder expertise, to support the ERO Enterprise's mission."

b. **Webinars (*ad-hoc*):** Virtual information sharing and exchange provides opportunities to quickly engage industry and achieve our collaboration goals. Webinars serve an integral function of providing insight and guidance by disseminating valuable reliability information to owners, operators, and users of the BPS.

Priority Risks

Based on the Risk Profiles identified by the RISC, the RSTC has identified four strategic priorities: 1) Grid Transformation, 2) Inverter-Based Resources, 3) Resilience and Extreme Events, and 4) Security.



Future actions by the RSTC on its Strategic Risk Priorities are focused on the risk mitigation and deployment parts of the Framework for Risk Mitigation as explained in Appendix A. Through this strategic plan, subgroups are identified and tasked with identifying risk mitigation solutions (e.g., Reliability Standard, Reliability/Security Guideline) and working with the RSTC Executive Committee (EC) and subgroup sponsors to add the risk mitigation projects to the RSTC Work Plan. The RSTC EC authorizes projects to be added to the RSTC Work Plan (which could include collaboration with other groups), rejects proposed tasks that are not aligned with the prioritized risks, or refers matter(s) to the RSTC for further discussion. For each RSTC Strategic Risk Priority, a 2-Year plan is detailed below indicating specific risks, desired outcome and measures of success.

1. **Grid Transformation**
   Unassured fuel supplies, including the timing and inconsistent output from VERs, pipeline deliveries, and uncertainty in forecasted load can result in insufficient amounts of energy on the system to serve electrical demand and ensure the reliable operation of the BPS throughout the year.[3] The RSTC and its subgroups will develop methods, processes, tools, and/or SARs that are needed to address energy security – factoring in modelling requirements, extreme events and critical infrastructure interdependencies.

   A part of the grid transformation creates a higher reliance on natural gas resources as a prime flexible resource to ensure reliable operation of the Grid. Coordination between the gas and electric systems will become even more important over the transition. Differences in scheduling requirements, physical capacity constraints, and adequate ramping capability must be addressed to ensure a reliable transition.

   Public policy and economics continue to drive the retirement of traditional resources at a time when load growth is beginning to quickly increase in portions of NERC. Technologies, such as electric vehicles, as well as new computing techniques, are driving substantial portions of this load growth. Some of the loads may have unique characteristics or interactions with other grid loads and resources that need to be fully understood to maintain reliability.

[3] https://www.nerc.com/comm/RSTC/ERATF/ERATF%20Energy%20Adequacy%20White%20Paper.pdf

In addition, across the industry there has been significant discussion regarding the impact of Distributed Energy Resources and aggregation of demand-side resources. The potential BES reliability impacts need to be assessed to ensure appropriate prioritization of industry resources around this topic.

Identified Specific Risks	Technical Areas of Focus	Desired Outcome	Measure of Success
Energy Assurance: Insufficient assessment of energy supplies to ensure operational awareness and energy availability.	• Modeling and data sharing requirements • System Operations • Resource planning	• SAR for Reliability Standards (submitted in 2022) • Supplemental materials developed and disseminated for industry use in performing energy assessments	• Standards Committee approval of new Reliability Standards • RSTC approval / endorsement of Considerations for Performing an Energy Reliability Assessment, Volume 2 • EEA3 trends • Performance during extreme weather conditions • CPS1 trends
Energy Assurance: Insufficient assessment of energy supplies to evaluate resource requirements in the long-term planning horizon.	• Modeling and data sharing requirements • Resource planning	• SAR for Reliability Standards (submitted in 2022) • Work on Long-Term Planning Horizon Standards expected to begin in 2024 • Supplemental materials developed & disseminated for industry use in performing energy assessments	• Standards Committee approval of new Reliability Standards (separate effort and SAR from Operations Planning Standards) • RSTC approval / endorsement of Considerations for Performing an Energy Reliability Assessment, Volume 2 • EEA3 trends • CPS1 trends
Gas-Electric Coordination: Increased dependence on natural gas as fuel for flexible and dispatchable resources	• Resource Planning • Modeling and data sharing requirements • System Operations	• Support WSE Joint Inquiry Report recommendations • Support DOE/NERC balancing study • Proactively identify regions and scenarios of elevated risk	• Reduce risk and actual occurrences of fuel-related generation outages due to lack of pipeline gas
Demand Growth: Accelerated demand growth	• Reliability Assessment • Resource Planning	• Methods to educate Policy Makers are effectively communicating reliability risks associated with the evolving resource mix • Methods / standards in	• SRA/WRA • LTRA • State of Reliability

Identified Specific Risks	Technical Areas of Focus	Desired Outcome	Measure of Success
		place to ensure an adequate level of essential reliability services are maintained throughout the transition	
Demand Growth: New loads may have unique characteristics which could present reliability concerns	• Load Modeling • System Operations • Transmission Planning	• Unique characteristics of new loads are identified & understood. • Viable solutions to address reliability concerns of new load characteristics are identified and documented. • Models of the new load facilities are developed for power system studies that sufficiently captures their unique characteristics.	• State of Reliability • Event Analysis
Distributed Energy Resources: High penetration of DER may pose a reliability risk	• Identify specific reliability risks • Load forecasts • Ride-through • Data sharing protocol	• Complete assessment of existing and expected penetration of Distributed Energy Resources and identification of associated reliability risks	• LTRA • Event Analysis
Demand and DER Aggregation: Increasing aggregation of demand side resources may pose reliability and security risks	• Identify specific aggregation operating modes • Data sharing protocol	• Complete assessment of existing and expected activity of demand side aggregation of distribution-connected resources and identification of associated reliability risks • Evaluate cybersecurity, back-up control, essential reliability service, dispatchability, and reliable integration of DER aggregators. • Identify performance, modeling and data sharing requirements for planning and operating the BES	• LTRA • Event Analysis

2. **Inverter-Based Resources**

The BPS in North America is undergoing a significant transformation in technology, design, control, planning, and operation. These changes are occurring more rapidly than ever before. Particularly, technological advances in IBRs are having a major impact on generation, transmission, and distribution systems. The speed of this change continues to challenge grid planners, operators, and protection engineers. Implemented correctly, inverter-based technology can provide significant benefits for the BPS; however, events have shown that the new technology can introduce significant risks if not integrated properly.

The ERO has established a strategy that outlines steps NERC and the Regional Entities will take to mitigate risks associated with the integration of large amounts of IBR.[4] The RSTC will drive improvements in the performance of IBRs by focusing on the improvement of IBR interconnection, planning studies, and operations, as well as staying abreast of new inverter technologies and risks. Communicating risk and mitigation measures across the industry will be a critical component of this strategy to enhance IBR performance.

Identified Specific Risks	Technical Areas of Focus	Desired Outcome	Measure of Success
IBR Performance	• System Operations • Event Analysis	• IBR ride-through of faults • IBR performance standard	• Event Analysis Process • State of Reliability Report • Summer and Winter Reliability Assessments • Long-Term Reliability Assessment
IBR Performance: Monitoring	• Event analysis	• Identify and study Events involving IBR performance	• Event Analysis Process • State of Reliability Report • Summer and Winter Reliability Assessments • Long-Term Reliability Assessment
IBR Modelling versus Performance	• Modeling and Data Sharing • Long-term planning studies • Event Analysis	• IBRs perform as modeled, or actual IBR performance is modeled in planning. • Modelling standards are approved that ensure IBRs perform as modelled.	• Event Analysis Process • State of Reliability Report • Summer and Winter Reliability Assessments • Long-Term Reliability Assessment

[4] https://www.nerc.com/comm/Documents/NERC_IBR_Strategy.pdf

Identified Specific Risks	Technical Areas of Focus	Desired Outcome	Measure of Success
IBR Interconnection Requirement and Evaluation	• Modeling and Data Sharing	• Impact of IBR Interconnection is fully understood and modelled before operating • Standards are approved that specify what assessments and model validation must be carried out as part of the interconnection process.	• Event Analysis Process • State of Reliability Report • Summer and Winter Reliability Assessments • Long-Term Reliability Assessment

3. Resilience and Extreme Events

Recent cold weather events (e.g. Polar Vortices, Winter Storms Elliot, and Uri), heat events (e.g. 2020 California event and British Columbia's heat dome), and localized natural events (e.g. hurricanes, derechos and ice storms) represent an increase in extreme natural events that have an impact on the resilience and reliability of the BPS. The RSTC and its subgroups will ensure modeling requirements include new approaches to adequately assess risks from low-frequency, high-impact events, including wide-area impacts to enable reliable operations of the BPS, and improve resource and energy planning.

The RSTC will develop methods, processes, tools, and/or SARs that are needed to address system resiliency and reliability during extreme events.

Identified Specific Risks	Technical Areas of Focus	Desired Outcome	Measure of Success
Planning for High-Impact Events: Assess expected performance of the bulk power system during extreme events	• Load Forecasting • Probabilistic Assessment • Energy Assessment • Model Verification • Transmission Planning	• Develop new approaches in ERO reliability assessments to adequately assess impacts of extreme events. • Leverage existing GridEx events to assess readiness from a confluence of extreme weather and cyber events.	• Event Analysis Process • State of Reliability Report • Summer and Winter Reliability Assessments • Long-Term Reliability Assessment • Special Assessment

Identified Specific Risks	Technical Areas of Focus	Desired Outcome	Measure of Success
Wide-Area Energy Assessment: Assess expected performance of the bulk power system during extreme events involving neighboring regions	• Energy Assessment • Probabilistic Assessment • Model Verification • Transmission Planning	• Enhancement to Reliability Assessment Process to include Wide-Area Energy Assessment Capabilities • Develop new approaches in ERO reliability assessments to adequately assess wide-area energy risks. • Conduct special assessments of wide-area extreme event impacts. • Sponsor joint regional reliability assessments that could occur from extreme weather events.	• Summer and Winter Reliability Assessments • Long-Term Reliability Assessment • Special Assessment

4. Security

Exploitation of security risks could arise from a variety of external and/or internal sources. Additionally, the operational and technological environment of the electrical grid is evolving significantly and rapidly and increasing the potential cyberattack surface. Sources of potential exploitation include increasingly sophisticated attacks by nation-state, terrorist, and criminal organizations. Vulnerability to such exploits is exacerbated by insider threats, poor cyber hygiene, supply-chain considerations, and dramatic transformation of the grid's operational and technological environment. Supply chains, specifically, are a targeted opportunity for nation-state, terrorists, and criminals to penetrate organizations without regard to whether the purchase is for information technology, operational technology, software, firmware, hardware, equipment, components, and/or services.

Supply chain risk management and the threats from components and sub-components developed by potential foreign adversaries should continue to be addressed by NERC and industry with evaluation of CIP-013 standard for any needed improvements. Over the next two years, the RSTC will be focused on determining the risk mitigations.

Identified Specific Risks	Technical Areas of Focus	Desired Outcome	Measure of Success
Physical & Cyber Security:	• Distributed Energy Resources • Demand Side Aggregators • Integration of new technology	• Improved awareness of and resistance to potential attacks	▪ State of Reliability ▪ Event Analysis
Supply Chain Assurance & Protection: Inadequate supply chain security can disrupt, infiltrate, and expose OT systems to unauthorized control.	• Open-Source Software • Provenance • Risk Management Lifecycle • Secure Equipment Delivery • Vendor Risk Management • Cloud Computing • Vendor Incident Response • Supply Chain Procurement	• Whitepaper: NERC Standards Gap Assessment • Coordinate with NATF and NAGF for supply chain evaluation activities	▪ SAR for Supply Chain Standards ▪ Evaluation of the security of the global supply chain and identification of critical components with limited availability

Chapter 3: Primary Subgroup Strategic Direction

In the table below, the RSTC's primary subgroups (those directly under the RSTC) each play a role in meeting the objectives and priorities of the RSTC. To provide additional clarity and direction, strategic direction that aligns with the RSTC's strategic priorities, in addition to what is identified in the scope of the subgroup, is provided below:

Subgroup	Focus	Related Strategic Prioritized Risk
Event Analysis Subcommittee (EAS)	Identification Monitoring	• Grid Transformation • Inverter-Based Resources • Resilience and Extreme Events
Performance Analysis Subcommittee (PAS)	Identification Monitoring	• Grid Transformation • Inverter-Based Resources • Resilience and Extreme Events
Real Time Operating Subcommittee (RTOS)	Identification Monitoring	• Grid Transformation • Inverter-Based Resources • Resilience and Extreme Events
Synchronized Measurement Working Group (SMWG)	Monitoring	• Grid Transformation • Inverter-Based Resources
Resources Subcommittee (RS)	Identification Monitoring	• Grid Transformation • Inverter-Based Resources
Energy Reliability Assessment Working Group (ERAWG)	Determining Deploying Measuring	• Grid Transformation • Inverter-Based Resources • Resilience and Extreme Events
Reliability Assessment Subcommittee (RAS)	Identification Monitoring	• Grid Transformation • Inverter-Based Resources • Resilience and Extreme Events
Security Integration and Technology Enablement Subcommittee (SITES)	Determining Deploying Measuring	• Grid Transformation • Security
6 GHz Task Force (6GTF)	Determining Deploying Measuring	• Grid Transformation
Electric-Gas Working Group (EGWG)	Determining Deploying Measuring	• Grid Transformation • Resilience and Extreme Events

Subgroup	Focus	Related Strategic Prioritized Risk
Electric Vehicle Task Force	Determining Deploying	• Grid Transformation • Security
Facility Ratings Task Force (FRTF)	Determining Deploying Measuring	• Resilience and Extreme Events
Inverter-Based Resource Performance Subcommittee (IRPS)	Determining Deploying Measuring	• Inverter-Based Resources
Large Loads Task Force	Determining Deploying	• Grid Transformation • Security
Load Modeling Working Group (LMWG)	Determining Deploying Measuring	• Grid Transformation
Security Working Group (SWG)	Determining Deploying Measuring	• Security
Supply Chain Working Group (SCWG)	Determining Deploying Measuring	• Security
System Planning Impacts from Distributed Energy Resources Working Group (SPIDERWG)	Determining Deploying Measuring	• Grid Transformation • DER
System Protection and Control Working Group (SPCWG)	Determining Deploying Measuring	• Inverter-Based Resources

Appendix A: RSTC Strategic Planning Process

The RSTC Strategic Planning Process ensures high priority risks are systematically addressed by the RSTC using a common framework for decision-making with broad concurrence, as well as ensuring all committee members and stakeholders have clear expectations on how the RSTC plans to meet its objectives.

Following the issuance of the RISC report, a Strategic Planning group convenes to conduct the 2-year Strategic Planning Process

The Strategic Planning Process begins with the latest version of the RISC Risk Priorities report, which presents the results of strategically defined and prioritized risks, as well as specific recommendations for mitigation. The RSTC provides input into the development of this report and the RISC's risk assessment through a variety of mechanisms, including reliability assessments and event reports.

The RSTC Strategic Plan (this document) then aligns the highest-priority risks and recommendations from the Risk Priorities Report and with the priorities outlined for the RSTC over the next two years. Additional priorities based on high-priority emerging risks identified by the RSTC may be included within the 2-year Strategic Plan (as determined by the RSTC's Executive Committee).

Once all priorities are identified for the RSTC, specific risks are identified and RSTC subgroups determine the recommended mitigation steps. These risk mitigation projects, along with programmatic actions, then comprise the detailed RSTC Work Plan. Many of the identified risks share interdependencies that will be considered in the development of the work plan.

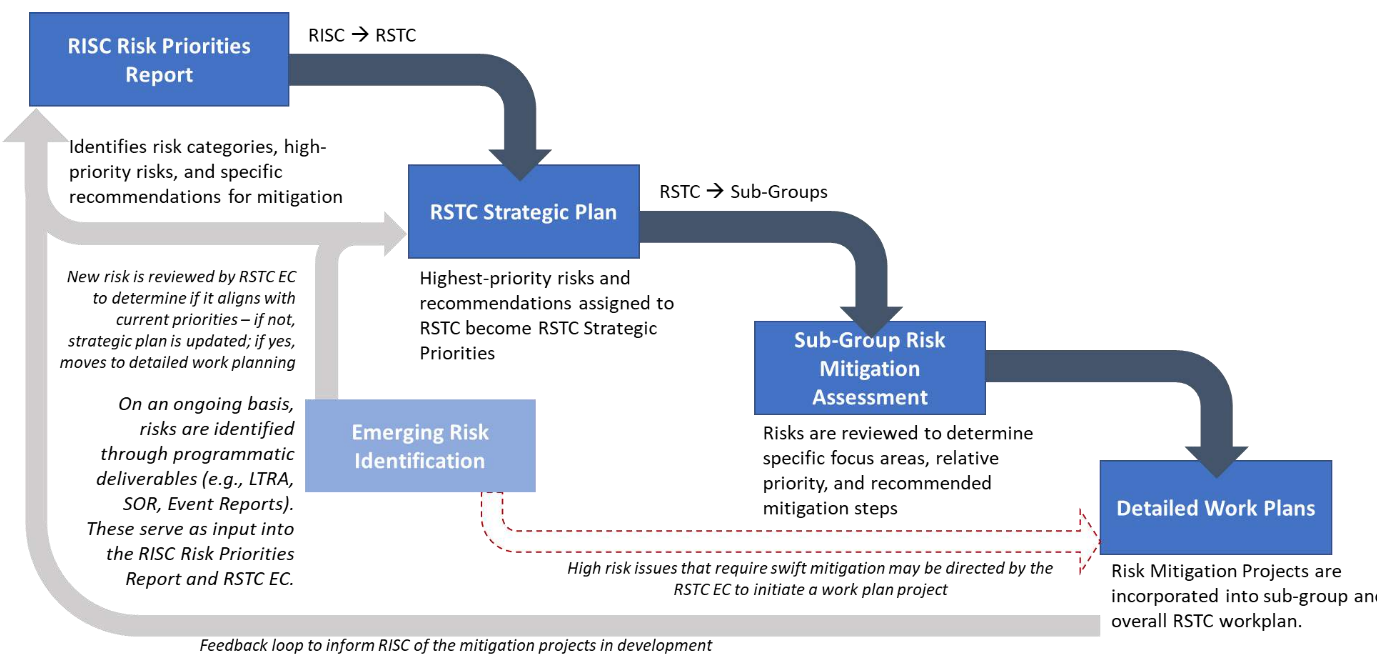


Figure 1: RSTC Strategic Planning Process Flow Chart

RSTC Strategic Plan Role in Risk Mitigation

The RSTC provides expertise in reliability, resilience, and security, and plays a key role in the mitigation of reliability, resilience, and security risks. As identified in the RISC's Framework[5] for Risk Mitigation, the RSTC is responsible for all steps of the framework, including: Risk Identification and Validation, Risk Prioritization, Determination of Risk Remediation/Mitigation, Deploying Risk Remediation/Mitigation, Measure Success, and Monitor Residual Risk. Therefore, the strategic plan includes key activities to support each of these steps.

The Risk Mitigation Framework guides the ERO in the prioritization of risks and provides guidance on the application of ERO policies, procedures, and programs to inform resource allocation and project prioritization in the mitigation of those risks. Additionally, the framework accommodates measuring residual risk after mitigation that enables the ERO to evaluate the success of its efforts in mitigating risk and provides a necessary feedback mechanism for future prioritization, mitigation efforts, and program improvements.

The successful reduction of risk is a collaborative process between the ERO, industry, and the technical committees including the RSTC and the RISC. The framework provides a transparent process using industry experts in parallel with ERO experts throughout the process—from risk identification and deployment of mitigation strategies to monitoring the success of these mitigations.

Figure 2: ERO Mitigation Framework for Known and Emerging Reliability Risks

The RSTC's Notional Work Plan Process[6] provides a detailed review of each step and how the RSTC supports and actively contributes to the risk mitigation framework. The following table summarizes how the RSTC performs each step and the expected deliverables that support the Risk Mitigation Framework:

[5] https://www.nerc.com/comm/RISC/Related%20Files%20DL/Framework-Address%20Known-Emerging%20Reliabilit-Securit%20%20Risks_ERRATTA_V1.pdf
[6] https://www.nerc.com/comm/RSTC/Documents/RSTC%20Work%20Plan%20Notional%20Process_Approved_Sept_2020.pdf

Risk Mitigation Framework Steps	RSTC Role	RSTC Deliverable Type
1. Risk Identification and Validation	RSTC identifies and validates risks through its performance, event, and future technical analysis and assessments	• Identification and Monitoring ▪ Long-Term and Seasonal Reliability Assessments ▪ Special Assessments ▪ Event and Disturbance Reports ▪ State of Reliability Report ▪ Other reliability/security indicators, whitepapers, gap assessments
2. Risk Prioritization	RSTC provides support and consulting to the RISC prioritization and risk ranking actions.	
3. Determination of Risk Remediation/Mitigation	RSTC proposes remediation/mitigation	• RSTC Biennial Strategic Plan
4. Deploying Risk Remediation/Mitigation	RSTC develops and deploys remediation/mitigation	• RSTC Work Plan ▪ Standard Authorization Requests – SAR ▪ Reliability/Security Guidelines ▪ Compliance Guidance ▪ Reliability and Security Assessments ▪ Stakeholder Outreach ▪ Technical Reference Document ▪ NERC Alert
5. Measure Success	RSTC ensures an approach to measure the effectiveness of the risk remediation/mitigation and deploys it. Measurement approach should be included in the approval of the deployed remediation/mitigation.	• Identification and Monitoring ▪ State of Reliability Report ▪ Event and Disturbance Reports ▪ Special/Specific Reliability and Security Indicators
6. Monitor Residual Risk	RSTC monitors residual risk through established programs.	• Identification and Monitoring ▪ Long-Term, Seasonal, and Special Reliability and Security Assessments ▪ Event and Disturbance Reports ▪ State of Reliability Report ▪ Other reliability and security indicators and whitepapers

Determination of Risk Remediation/Mitigation

Technical group, RSTC EC, and Sponsors discuss the reliability/resilience issues, technical justification, and consider possible solutions. Potential outcomes or solutions include deliverables in the RSTC Charter such as white papers, reference documents, technical reports, reliability guidelines, SARs, and compliance implementation guidance. Other potential solutions are contained in NERC Rules of Procedure (ROP), ERO Event Analysis Process, NERC Alerts, and other risk management measures. Finally, the RSTC EC authorizes tasks to be added to the RSTC Work Plan (which could include collaboration with other groups), rejects proposed tasks, or refers matter(s) to the RSTC for further discussion.

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Reliability and Security Technical Committee

20254-2026~~5~~ Strategic Plan

January 20254

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	Reliability First
SERC	SERC Reliability Corporation
Texas RE	Texas Reliability Entity
WECC	WECC

Introduction and Objectives

The NERC Reliability and Security Technical Committee (RSTC) is a stakeholder committee chartered by the NERC Board of Trustees (Board) to proactively support the NERC ERO Enterprise's mission. The RSTC, in accordance with its charter, will develop and maintain a two-year strategic plan and an associated work plan to carry out the functions of the committee:

- Ensure alignment of the strategic work plan with ERO reports and analyses, including the NERC Business Plan and Budget, ERO Enterprise Long-Term Strategy, biennial Reliability Issues Steering Committee (RISC) ERO Reliability Risk Priorities report, State of Reliability report recommendations, Long Term, Seasonal and Special Reliability Assessment recommendations, and ongoing event analysis trends.
- Leverage industry technical expertise to provide insights, considerations and educational materials regarding reliability impacts of policy and regulatory decisions.
- Coordinate the objectives in the strategic work plan with the Standing Committees Coordinating Group.
- Support response to mandates related to BPS reliability (e.g. FERC Order 901[1], ITCS[2]).

This strategic plan guides the functions and core mission of the RSTC, providing a sustainable set of expectations and deliverables for the RSTC to assess and enhance reliability, resilience, and security of the BPS. The RSTC engages in the identification and communication of reliability risks along with potential mitigation strategies. These activities will include close coordination with the RISC as well as taking steps to create industry-wide awareness. This strategic plan will not remain static throughout a two-year timeframe. Rather, it is crucial that the plan retains the flexibility to address emerging issues.

This two-year plan, along with its goals and measures, is typically reviewed during the December RSTC meeting, and enhancements to the plan will be made and presented to the NERC Board each year in accordance with the Charter as required to achieve the goal of promoting reliability, resilience, and security.

[1] https://www.ferc.gov/media/e-1-rm22-12-000
[2] https://www.nerc.com/pa/RAPA/Pages/ITCS.aspx

Executive Summary

The 2025 update to the RSTC strategic plan ~~Shortly after the Board approved the 2023 ERO Reliability Risk Priorities Report ("2023 ERO Risk Report") the RSTC convened a small group to~~was ~~conduct~~conducted by a small group of RSTC members per the two-year Strategic Planning Process, which is detailed in Appendix A. The group identified four strategic priorities, with the recognition of the need to increase awareness of reliability implications, and closer collaboration and coordination with policy makers on emerging energy policy issues:

1. Grid Transformation,
2. Inverter Based Resources (IBR),
3. Resilience and Extreme Events, and
4. Security.

Trends in several areas of the electric industry are the primary drivers of these priorities. Policy and economic drivers are shifting the resource mix from large, centralized fossil-fired power stations towards variable energy resources (VER) spread over large geographic areas. Concurrent with this shift, the capacity to provide essential reliability attributes that are inherent in large synchronous generators and critical to managing the reliability of the BPS are decreasing. The inverter-based devices that are expected to mimic and replace these Essential Reliability Services are still being evaluated for their applicability and functionality. Amid this transition, natural gas use for electric generation appears to increase in peak periods but for fewer hours. This is testing both the physical and regulatory interfaces between the electric and gas industries in novel ways. In addition, electric demand is growing in extraordinary ways and with uncertain load profiles such as data centers, crypto mining and electric vehicle loads. Compounding the risks, the impact of extreme weather events during this transition is challenging system operators in unprecedented ways. Finally, security risks appear to be increasing, and all industry stakeholders must remain vigilant to physical and cyber-attacks and ~~disruption~~ vulnerabilities of globally interconnected supply chains.

With respect to the four emerging strategic risks, the RSTC identified specific focus areas and desired outcomes. Potential risk mitigation steps are left for further investigation by the subcommittees, working groups, and task forces (collectively "subgroups"). A complete list of the focus areas follows:

Grid Transformation

1. Energy Assurance: As the grid relies on more just-in-time fueled resources – i.e., natural-gas fired generators and VERs – and traditional, slower starting resources have become less economic to operate, ensuring energy is available and delivered at the right time to serve load is essential.
2. Gas-Electric Coordination: The gas infrastructure and regulatory framework were not originally designed to support the needs of the electric industry. As the generation fleet transitions to less carbon-intense resources, the use of gas fired resources for base load and peaking needs is increasing especially during critical times and under certain conditions, and the limitations of this historical framework are becoming more apparent.
3. Demand Growth: Electrification policies are adding to traditional macroeconomic-driven load growth. Moreover, the characteristics of newly connected loads are not well understood and may present unique reliability challenges. These demands compound the challenges of an evolving generation mix and manifestly increase reliability risk. To address specific reliability risks, the RSTC formed two task forces in 2024. The Large Loads Task Force (LLTF) was formed to better understand the reliability impact(s) of emerging large loads such as Data Centers (including crypto and AI), Hydrogen Fuel Plants, etc. and their impact on the bulk power system (BPS). The Electric Vehicle Task Force (EVTF) was also formed to promote collaboration between electric utilities and the EV automotive representatives such that the two can build a common language and develop recommended utility interconnection requirements (e.g., ride-through),

procedures, and approaches to handle the growing adoption of EVs ~~seen by the ERO Enterprise~~ in a manner supportive to the reliability of the BPS.

4. Distributed Energy Resources (DER): As ~~the grid shifts toward~~ more decentralized, distribution-connected generation come on to the grid, the reliability attributes also shift to where the generation is connected. This step towards major decentralization could be accompanied with unintended risks. Current Reliability Standard requirements are centrally focused to require performance on the generation side to serve load. There are no existing requirements that distribution-connected resources perform to maintain the reliability of the bulk power system.

5. Demand and DER Aggregators: For many years, utilities have implemented demand side programs to manage demand on their systems in an aggregated manner. Policy decisions, such as FERC Order 2222 along with technology advances, have ~~also~~ increasingly opened the door to market participation by aggregators of distribution-connected resources and for "third party" aggregators to manage and control their operation. The current and forecasted state of aggregation needs to be fully assessed to ensure ~~we~~ appropriately prioritized and coordinated efforts regarding aggregators of distribution-connected resources and performance, modeling, and visibility of these resources.

Inverter-Based Resources

1. IBR Performance: As the first generations of IBRs were deployed and reached a critical mass, issues with their ability to ride through system faults and disturbances became apparent. This has resulted in concerns for grid operators, and there are efforts underway to address the performance of in-service IBRs.

2. IBR Modeling versus Performance: In addition to the aforementioned operating concerns, the nascent industry has lacked standard models used for power flow and grid stability analysis. Additionally, interconnecting utilities have found many device settings of installed IBRs deviate from the models provided.

3. IBR Interconnection Requirements and Evaluation: IBR numbers are expected to grow over the next decade and exceed the megawatts of synchronous generation in many regions. RSTC and its subgroups are examining the viability of codifying interconnection requirements to address the concerns with ride-through and actual versus modelled performance, plus potentially adding certain reliability services, on a prospective basis.

Resilience and Extreme Events

1. Planning for High-Impact Events: Generation performance is correlated with weather, and demand may exhibit nonlinear behaviors under extreme conditions. This necessitates an assessment of risk in planning models including low frequency but highly impactful conditions.

2. Wide-area Energy Assessments: Short- and long-duration low-frequency, high-impact weather events sometimes extend beyond the boundaries of individual balancing authority areas and can lead to an increase in ~~propagating~~ risks across a wide area. Resource planning and reliability assessments would benefit from joint-regional coordinated action.

Security

1. Physical and Cyber Security: External threats have caused damage and disruption to the Bulk Electric System (BES). Unfortunately, threats from lone wolf actors to state-sponsored hackers are expected to increase. DERs and Distribution-Side Aggregators are expanding the current attack surface. Raising awareness of these threat vectors and the extent to which DER aggregators may be following cybersecurity protocols encourages protective actions that mitigate the risk and strengthen the grid.

2. <u>Supply Chain Assurance and Protection</u>: Today's supply chain is highly globalized to the extent the BPS may not be able to function if supply of certain components is disrupted or weaponized. The risks from globalization are coming into sharp focus with recent geopolitical events. Attention is required to ensure the grid continues to function in the event global supply chains are disrupted.

While the small group of RSTC members developing this plan debated and identified the strategic risks, it became apparent that the full RSTC should undertake a thorough examination of the indicators and metrics used to measure risk. The consensus among the group is that existing metrics sufficiently measure the current state of reliability and may be used to extrapolate trajectories with historical data, but these indicators do not sufficiently measure emerging, novel risks. Early each calendar year~~In early 2024~~ 2025 the RSTC will discuss action to:

- Review current reliability metrics,
- Identify the risks that those metrics are attempting to address,
- Identify risks areas that could materialize in the future and are unique or peculiar to the strategic risks,
- Define leading indicators that may better forecast future risk areas and allow the ERO and stakeholders to proactively mitigate those risks, and
- Identify appropriate pathways to communicate risks and new leading indicators to energy policymakers.

Following Board approval, the RSTC will communicate these strategic risks and focus areas to the subgroup leads. Through an iterative process, these groups will propose to the RSTC specific work plan items intended to address~~mitigate~~ these identified risks. The RSTC will review the work plan items against this strategic plan for alignment and prioritization and approve the work plan items as appropriate. The rest of this document describes the details of the processes used to develop the strategic plan and describes those risks in more detail.

Chapter 1: Mission, Vision, and Guiding Principles

Mission

Ensure the reliability and security of the bulk-power system by identifying critical risks and deploying effective and efficient risk mitigations.

Vision

The RSTC is the premier technical authority on BPS reliability, resilience, and security, and its effectiveness stems from the stakeholder members who command deep technical knowledge, broad industry experience, and a collective duty to ensure the reliability of the bulk-power system.

Guiding Principles

The following principles serve to guide our practices:

- Coordinate with the RISC on priorities to align the RSTC strategic plan with the ERO's strategic plan.
- Maintain a focus on identification, analyses, and mitigation of existing and emerging reliability, resilience, and security risks.
- Continually strive for the development and dissemination of high-quality lessons learned through event analysis (EA), emerging cause code trending, and information sharing.
- Maintain relationships with other NERC standing committees (e.g. support the Standing Committee Coordinating Group), NERC Forums, and industry trade groups (e.g. NATF, IEEE).
- Maintain and enhance reliability, resilience, and security through the pursuit of clear NERC Reliability Standard Authorization Requests, Reliability Standards, Reliability Guidelines, Security Guidelines, Technical Reference Documents, NERC Alerts, Interpretations, lessons learned, and compliance clarifications.
- Incorporate a planning, operations and security perspective into NERC reports issued to industry.
- Deliver technically sound and accurate analyses, assessments, and recommendations.
- Identify critical emerging issues and trends that could potentially have reliability impacts in the near term and long term.
- Ensure the facts are unbiased and not providing an advocacy of policy matters.
- Promote coordination effectiveness across the NERC ERO Enterprise.
- Ensure continued provision of high levels of expertise, technically sound conclusions, and timely results/deliverables.
- Ensure the RSTC structure, processes and procedures, its working relationships with other technical standing committees, its subcommittees, working groups and task forces are focused on the highest priorities for reliability, resilience, and security within the ERO enterprise.

Chapter 2: Strategic Objectives and Priorities

The RSTC's strategic objectives provide a bridge between the RSTC's mission and vision and the annual goals and work plan deliverables needed to achieve them. The strategic objectives of the RSTC provide clear expectations of the goals and deliverables of the committee and its subgroups and are not expected to change often. However, the strategic priorities and the expected work products may change, as needed. The strategic objectives of the RSTC are:

1. Drive effective mitigation actions against emerging and established reliability and security risks, specifically targeting the strategic priorities.
2. Promote and increase stakeholder and regulator engagement and awareness.
3. Learn from events and past performance trends and deploy mitigation.
4. Identify and assess long-term planning and emerging reliability and security risks.
5. Make recommendations and develop solutions that support technology and security integration into BPS planning and operations.
6. Provide general information to a wide audience that highlights reliability and security risks on the bulk power system from significant changes to energy resources and electric loads.

To achieve these objectives, the RSTC uses its subgroups to develop its work products. The subgroups are organized under three categories: Performance Monitoring, Risk Mitigation, and Reliability and Security Assessment.

There are two types of key projects included in the RSTC work plan to support the strategic objectives:

1. **Programmatic:** Periodic, cyclical or continuous actions, deliverables, and processes that support the identification, prioritization, and monitoring of reliability risks. The RSTC's **Performance Monitoring** and **Reliability and Security Assessment** subgroups primarily serve to support programmatic strategic objectives.
2. **Prioritized Risk:** Targeted and focused actions to identify and develop specific reliability risk mitigations. The RSTC's **Risk Mitigation** subgroups primarily serve to support the strategic risk mitigation objectives. This also includes emerging risks identified between strategic planning periods (from assessments, disturbance reports, etc.).

Programmatic

1. **Identify key areas of concern, trends, and emerging reliability issues by periodically assessing system reliability and performance.**

   The RSTC will focus on developing reliability assessments, evaluations, and studies, and extracting insights to identify reliability, resilience, and security risks. By identifying and quantifying emerging risks, the RSTC is able to craft risk-informed recommendations, provide the basis for actionable risk mitigations, and provide education to industry stakeholders and policymakers. The RSTC supports this process primarily through the Reliability Assessment Subcommittee (RAS), Performance Analysis Subcommittee (PAS), and Resources Subcommittee (RS). Primary deliverables include:

   a. **Long-Term Reliability Assessment (annually):** 10-year outlook of resource adequacy and transmission projections. Emerging reliability and security integration issues are identified.

   b. **Seasonal Reliability Assessments (annually):** Summer and winter season operational outlook, projection, and leading indicators.

c. **Special Reliability Assessments (ad-hoc):** topical technical evaluation of a specified reliability risk.

d. **State of Reliability Report (annually):** Historical performance, evaluating 5-year (or longer) trends, indicators, and lagging metrics.

e. **Frequency Response Annual Analysis (annually):** Historical performance of frequency response per a Federal Energy Regulatory Commission (FERC) directive.

2. Identify lessons learned and trends based on system events and make recommendations for improvement.

The RSTC will focus on event prevention or mitigation by supporting and continually enhancing the ERO's EA program to ensure a comprehensive process, as well as rapidly developing and disseminating lessons learned. Through the Event Analysis Subcommittee (EAS), the RSTC approves any changes to the EA Process and reviews periodic event reports and lessons learned. Any mitigation actions for the ERO to pursue or recommendations for industry can result in additions to the RSTC work plan and, depending on the outcomes of the risk assessment, may be added to the strategic objectives. Primary deliverables include:

a. **Event and Disturbance Reports (*ad-hoc*):** Event reports detail specific details and root causes of BPS events. The EA Process is approved by EAS, and individual reports are published by the ERO and serve as input to the RSTC.

b. **Lessons Learned (*ad-hoc*):** Identified best practice or revealing reliability risk based on an event or group of events. Lessons Learned documents are published by the ERO and serve as input to the RSTC.

3. Promote and increase stakeholder engagement and awareness of reliability risks.

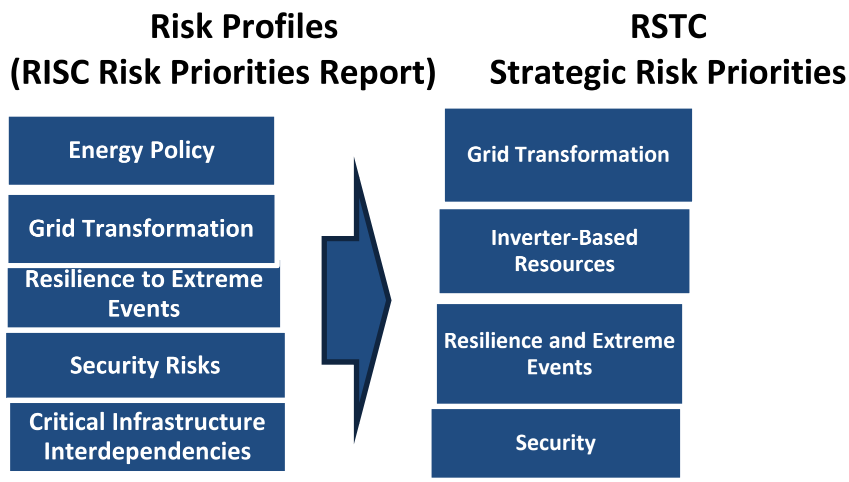
The RSTC will continue to promote outreach to stakeholder and policymaking organizations on reliability, resilience, and security matters through webinars and in-person conferences, workshops, and other mediums to deliver content and reliability messages. The RSTC will leverage strong relationships with industry groups such as NATF, NAGF, IEEE, EPRI etc. as well as regulatory and governmental authorities to target specific technical areas of concern and work together on industry outreach. Primary engagements include:

a. **Reliability Conferences and Workshops (*ad-hoc*):** Convene industry to share and exchange ideas and practices that promote reliability in a variety of technical areas. Conferences can support the RSTC's mission by "creating a forum for aggregating ideas and interests, drawing from diverse industry stakeholder expertise, to support the ERO Enterprise's mission."

b. **Webinars (*ad-hoc*):** Virtual information sharing and exchange provides opportunities to quickly engage industry and achieve our collaboration goals. Webinars serve an integral function of providing insight and guidance by disseminating valuable reliability information to owners, operators, and users of the BPS.

Priority Risks

Based on the Risk Profiles identified by the RISC, the RSTC has identified four strategic priorities: 1) Grid Transformation, 2) Inverter-Based Resources, 3) Resilience and Extreme Events, and 4) Security.



Future actions by the RSTC on its Strategic Risk Priorities are focused on the risk mitigation and deployment parts of the Framework for Risk Mitigation as explained in Appendix A. Through this strategic plan, subgroups are identified and tasked with identifying risk mitigation solutions (e.g., Reliability Standard, Reliability/Security Guideline) and working with the RSTC Executive Committee (EC) and subgroup sponsors to add the risk mitigation projects to the RSTC Work Plan. The RSTC EC authorizes projects to be added to the RSTC Work Plan (which could include collaboration with other groups), rejects proposed tasks that are not aligned with the prioritized risks, or refers matter(s) to the RSTC for further discussion. For each RSTC Strategic Risk Priority, a 2-Year plan is detailed below indicating specific risks, desired outcome and measures of success.

1. **Grid Transformation**

   Unassured fuel supplies, including the timing and inconsistent output from VERs, pipeline deliveries, and uncertainty in forecasted load can result in insufficient amounts of energy on the system to serve electrical demand and ensure the reliable operation of the BPS throughout the year.[3] The RSTC and its subgroups will develop methods, processes, tools, and/or SARs that are needed to address energy security – factoring in modelling requirements, extreme events and critical infrastructure interdependencies.

   A part of the grid transformation creates a higher reliance on natural gas resources as a prime flexible resource to ensure reliable operation of the Grid. Coordination between the gas and electric systems will become even more important over the transition. Differences in scheduling requirements, physical capacity constraints, and adequate ramping capability must be addressed to ensure a reliable transition.

   Public policy and economics continue to drive the retirement of traditional resources at a time when load growth is beginning to quickly increase in portions of NERC. Technologies, such as electric vehicles, as well as new computing techniques, are driving substantial portions of this load growth. Some of the loads may have unique characteristics or interactions with other grid loads and resources that need to be fully understood to maintain reliability.

[3] https://www.nerc.com/comm/RSTC/ERATF/ERATF%20Energy%20Adequacy%20White%20Paper.pdf

In addition, across the industry there has been significant discussion regarding the impact of Distributed Energy Resources and aggregation of demand-side resources. The potential BES reliability impacts need to be assessed to ensure appropriate prioritization of industry resources around this topic.

Identified Specific Risks	Technical Areas of Focus	Desired Outcome	Measure of Success
Energy Assurance: Insufficient assessment of energy supplies to ensure operational awareness and energy availability.	• Modeling and data sharing requirements • System Operations • Resource planning	• SAR for Reliability Standards (submitted in 2022) • Supplemental materials developed and disseminated for industry use in performing energy assessments	• Standards Committee approval of new Reliability Standards • RSTC approval / endorsement of Considerations for Performing an Energy Reliability Assessment, Volume 2 • EEA3 trends • Performance during extreme weather conditions • CPS1 trends
Energy Assurance: Insufficient assessment of energy supplies to evaluate resource requirements in the long-term planning horizon.	• Modeling and data sharing requirements • Resource planning	• SAR for Reliability Standards (submitted in 2022) • Work on Long-Term Planning Horizon Standards expected to begin in 2024 • Supplemental materials developed & disseminated for industry use in performing energy assessments	• Standards Committee approval of new Reliability Standards (separate effort and SAR from Operations Planning Standards) • RSTC approval / endorsement of Considerations for Performing an Energy Reliability Assessment, Volume 2 • EEA3 trends • CPS1 trends
Gas-Electric Coordination: Increased dependence on natural gas as fuel for flexible and dispatchable resources	• Resource Planning • Modeling and data sharing requirements • System Operations	• Support WSE Joint Inquiry Report recommendations • Support DOE/NERC balancing study • Proactively identify regions and scenarios of elevated risk	• Reduce risk and actual occurrences of fuel-related generation outages due to lack of pipeline gas
Demand Growth: Accelerated demand growth	• Reliability Assessment • Resource Planning	• Methods to educate Policy Makers are effectively communicating reliability risks associated with the	• SRA/WRA • LTRA • State of Reliability

Identified Specific Risks	Technical Areas of Focus	Desired Outcome	Measure of Success
		evolving resource mix • Methods / standards in place to ensure an adequate level of essential reliability services are maintained throughout the transition	
Demand Growth: New loads may have unique characteristics which could present reliability concerns	• Load Modeling • System Operations • Transmission Planning	• Unique characteristics of new loads are identified & understood. • Viable solutions to address reliability concerns of new load characteristics are identified and documented. • Models of the new load facilities are developed for power system studies that sufficiently captures their unique characteristics.	• State of Reliability • Event Analysis
Distributed Energy Resources: High penetration of DER may pose a reliability risk	• Identify specific reliability risks • Load forecasts • Ride-through • Data sharing protocol	• Complete assessment of existing and expected penetration of Distributed Energy Resources and identification of associated reliability risks	• LTRA • Event Analysis
Demand and DER Aggregation: Increasing aggregation of demand side resources may pose reliability and security risks	• Identify specific aggregation operating modes • Data sharing protocol	• Complete assessment of existing and expected activity of demand side aggregation of distribution-connected resources and identification of associated reliability risks • Evaluate cybersecurity, back-up control, essential reliability service, dispatchability, and reliable integration of DER aggregators. • Identify performance, modeling and data sharing requirements for planning and operating the BES	• LTRA • Event Analysis

2. Inverter-Based Resources

The bulk power system in North America is undergoing a significant transformation in technology, design, control, planning, and operation. These changes are occurring more rapidly than ever before. Particularly, technological advances in IBRs are having a major impact on generation, transmission, and distribution systems. The speed of this change continues to challenge grid planners, operators, and protection engineers. Implemented correctly, inverter-based technology can provide significant benefits for the BPS; however, events have shown that the new technology can introduce significant risks if not integrated properly.

The ERO has established a strategy that outlines steps NERC and the Regional Entities will take to mitigate risks associated with the integration of large amounts of IBR.[4] The RSTC will drive improvements in the performance of IBRs by focusing on the improvement of IBR interconnection, planning studies, and operations, as well as staying abreast of new inverter technologies and risks. Communicating risk and mitigation measures across the industry will be a critical component of this strategy to enhance IBR performance.

Identified Specific Risks	Technical Areas of Focus	Desired Outcome	Measure of Success
IBR Performance	• System Operations • Event Analysis	• IBR ride-through of faults • IBR performance standard	• Event Analysis Process • State of Reliability Report • Summer and Winter Reliability Assessments • Long-Term Reliability Assessment
IBR Performance: Monitoring	• Event analysis	• Identify and study Events involving IBR performance	• Event Analysis Process • State of Reliability Report • Summer and Winter Reliability Assessments • Long-Term Reliability Assessment
IBR Modelling versus Performance	• Modeling and Data Sharing • Long-term planning studies • Event Analysis	• IBRs perform as modeled, or actual IBR performance is modeled in planning. • Modelling standards are approved that ensure IBRs perform as modelled.	• Event Analysis Process • State of Reliability Report • Summer and Winter Reliability Assessments • Long-Term Reliability Assessment

[4] https://www.nerc.com/comm/Documents/NERC_IBR_Strategy.pdf

Identified Specific Risks	Technical Areas of Focus	Desired Outcome	Measure of Success
IBR Interconnection Requirement and Evaluation	• Modeling and Data Sharing	• Impact of IBR Interconnection is fully understood and modelled before operating • Standards are approved that specify what assessments and model validation must be carried out as part of the interconnection process.	• Event Analysis Process • State of Reliability Report • Summer and Winter Reliability Assessments • Long-Term Reliability Assessment

3. **Resilience and Extreme Events**

Recent cold weather events (e.g. Polar Vortices, Winter Storms Elliot, and Uri), heat events (e.g. 2020 California event and British Columbia's heat dome), and localized natural events (e.g. hurricanes, derechos and ice storms) represent an increase in extreme natural events that have an impact on the resilience and reliability of the BPS. The RSTC and its subgroups will ensure modeling requirements include new approaches to adequately assess risks from low-frequency, high-impact events, including wide-area impacts to enable reliable operations of the BPS, and improve resource and energy planning.

The RSTC will develop methods, processes, tools, and/or SARs that are needed to address system resiliency and reliability during extreme events.

Identified Specific Risks	Technical Areas of Focus	Desired Outcome	Measure of Success
Planning for High-Impact Events: Assess expected performance of the bulk power system during extreme events	• Load Forecasting • Probabilistic Assessment • Energy Assessment • Model Verification • Transmission Planning	• Develop new approaches in ERO reliability assessments to adequately assess impacts of extreme events. • Leverage existing GridEx events to assess readiness from a confluence of extreme weather and cyber events.	• Event Analysis Process • State of Reliability Report • Summer and Winter Reliability Assessments • Long-Term Reliability Assessment • Special Assessment

Identified Specific Risks	Technical Areas of Focus	Desired Outcome	Measure of Success
Wide-Area Energy Assessment: Assess expected performance of the bulk power system during extreme events involving neighboring regions	• Energy Assessment • Probabilistic Assessment • Model Verification • Transmission Planning	• Enhancement to Reliability Assessment Process to include Wide-Area Energy Assessment Capabilities • Develop new approaches in ERO reliability assessments to adequately assess wide-area energy risks. • Conduct special assessments of wide-area extreme event impacts. • Sponsor joint regional reliability assessments that could occur from extreme weather events.	• Summer and Winter Reliability Assessments • Long-Term Reliability Assessment • Special Assessment

4. Security

Exploitation of security risks could arise from a variety of external and/or internal sources. Additionally, the operational and technological environment of the electrical grid is evolving significantly and rapidly and increasing the potential cyberattack surface. Sources of potential exploitation include increasingly sophisticated attacks by nation-state, terrorist, and criminal organizations. Vulnerability to such exploits is exacerbated by insider threats, poor cyber hygiene, supply-chain considerations, and dramatic transformation of the grid's operational and technological environment. Supply chains, specifically, are a targeted opportunity for nation-state, terrorists, and criminals to penetrate organizations without regard to whether the purchase is for information technology, operational technology, software, firmware, hardware, equipment, components, and/or services.

Supply chain risk management and the threats from components and sub-components developed by potential foreign adversaries should continue to be addressed by NERC and industry with evaluation of CIP-013 standard for any needed improvements. Over the next two years, the RSTC will be focused on determining the risk mitigations.

Identified Specific Risks	Technical Areas of Focus	Desired Outcome	Measure of Success

Identified Specific Risks	Technical Areas of Focus	Desired Outcome	Measure of Success
Physical & Cyber Security:	• Distributed Energy Resources • Demand Side Aggregators • Integration of new technology	• Improved awareness of and resistance to potential attacks	▪ State of Reliability ▪ Event Analysis
Supply Chain Assurance & Protection: Inadequate supply chain security can disrupt, infiltrate, and expose OT systems to unauthorized control.	• Open-Source Software • Provenance • Risk Management Lifecycle • Secure Equipment Delivery • Vendor Risk Management • Cloud Computing • Vendor Incident Response • Supply Chain Procurement	• Whitepaper: NERC Standards Gap Assessment • Coordinate with NATF and NAGF for supply chain evaluation activities	▪ SAR for Supply Chain Standards ▪ Evaluation of the security of the global supply chain and identification of critical components with limited availability

Chapter 3: Primary Subgroup Strategic Direction

In the table below, the RSTC's primary subgroups (those directly under the RSTC) each play a role in meeting the objectives and priorities of the RSTC. To provide additional clarity and direction, strategic direction that aligns with the RSTC's strategic priorities, in addition to what is identified in the scope of the subgroup, is provided below:

Subgroup	Focus	Related Strategic Prioritized Risk
Event Analysis Subcommittee (EAS)	Identification Monitoring	• Grid Transformation • Inverter-Based Resources • Resilience and Extreme Events
Performance Analysis Subcommittee (PAS)	Identification Monitoring	• Grid Transformation • Inverter-Based Resources • Resilience and Extreme Events
Real Time Operating Subcommittee (RTOS)	Identification Monitoring	• Grid Transformation • Inverter-Based Resources • Resilience and Extreme Events
Synchronized Measurement Working Group (SMWG)	Monitoring	• Grid Transformation • Inverter-Based Resources
Resources Subcommittee (RS)	Identification Monitoring	• Grid Transformation • Inverter-Based Resources
Energy Reliability Assessment Working Group (ERAWG)	Determining Deploying Measuring	• Grid Transformation • Inverter-Based Resources • Resilience and Extreme Events
Reliability Assessment Subcommittee (RAS)	Identification Monitoring	• Grid Transformation • Inverter-Based Resources • Resilience and Extreme Events
Security Integration and Technology Enablement Subcommittee (SITES)	Determining Deploying Measuring	• Grid Transformation • Security
6 GHz Task Force (6GTF)	Determining Deploying Measuring	• Grid Transformation
Electric-Gas Working Group (EGWG)	Determining Deploying Measuring	• Grid Transformation • Resilience and Extreme Events

Subgroup	Focus	Related Strategic Prioritized Risk
Electric Vehicle Task Force	Determining Deploying	• Grid Transformation • Security
Facility Ratings Task Force (FRTF)	Determining Deploying Measuring	• Resilience and Extreme Events
Inverter-Based Resource Performance Subcommittee (IRPS)	Determining Deploying Measuring	• Inverter-Based Resources
Large Loads Task Force	Determining Deploying	• Grid Transformation • Security
Load Modeling Working Group (LMWG)	Determining Deploying Measuring	• Grid Transformation
Security Working Group (SWG)	Determining Deploying Measuring	• Security
Supply Chain Working Group (SCWG)	Determining Deploying Measuring	• Security
System Planning Impacts from Distributed Energy Resources Working Group (SPIDERWG)	Determining Deploying Measuring	• Grid Transformation • DER
System Protection and Control Working Group (SPCWG)	Determining Deploying Measuring	• Inverter-Based Resources

Appendix A: RSTC Strategic Planning Process

The RSTC Strategic Planning Process ensures high priority risks are systematically addressed by the RSTC using a common framework for decision-making with broad concurrence, as well as ensuring all committee members and stakeholders have clear expectations on how the RSTC plans to meet its objectives.

Following the issuance of the RISC report, a Strategic Planning group convenes to conduct the 2-year Strategic Planning Process

The Strategic Planning Process begins with the latest version of the RISC Risk Priorities report, which presents the results of strategically defined and prioritized risks, as well as specific recommendations for mitigation. The RSTC provides input into the development of this report and the RISC's risk assessment through a variety of mechanisms, including reliability assessments and event reports.

The RSTC Strategic Plan (this document) then aligns the highest-priority risks and recommendations from the Risk Priorities Report and with the priorities outlined for the RSTC over the next two years. Additional priorities based on high-priority emerging risks identified by the RSTC may be included within the 2-year Strategic Plan (as determined by the RSTC's Executive Committee).

Once all priorities are identified for the RSTC, specific risks are identified and RSTC subgroups determine the recommended mitigation steps. These risk mitigation projects, along with programmatic actions, then comprise the detailed RSTC Work Plan. Many of the identified risks share interdependencies that will be considered in the development of the work plan.

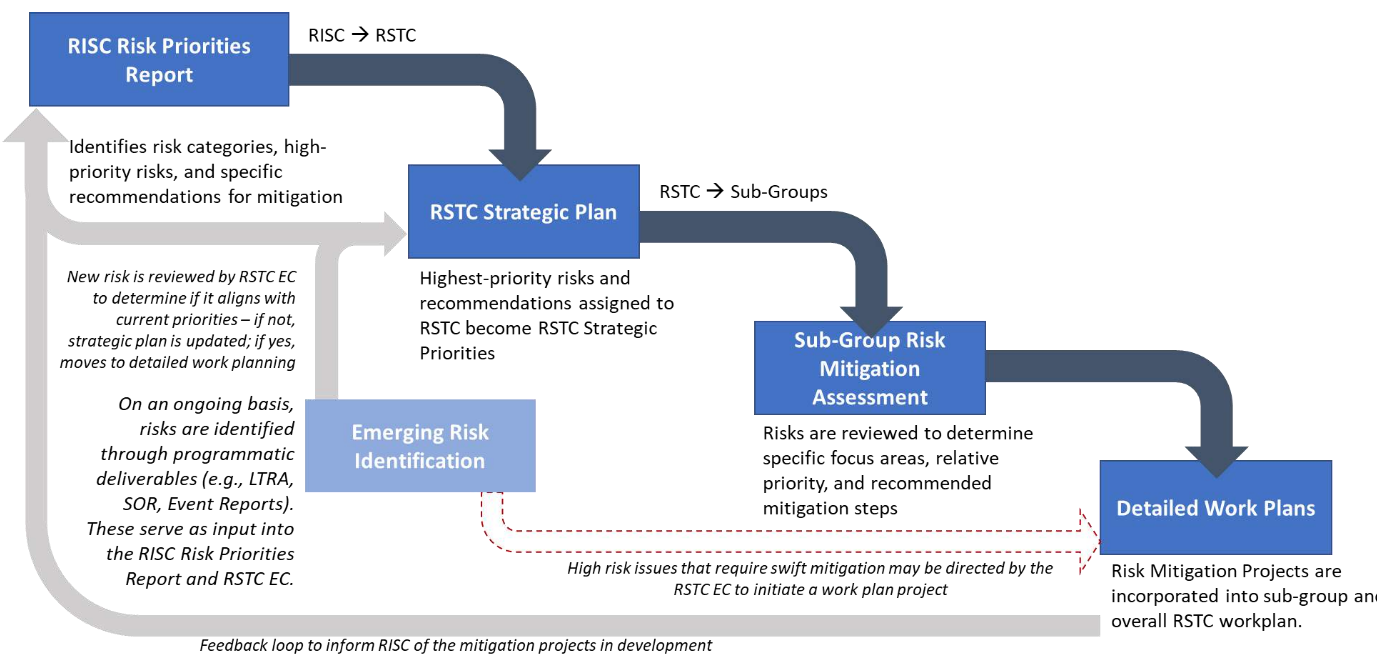


Figure 1: RSTC Strategic Planning Process Flow Chart

RSTC Strategic Plan Role in Risk Mitigation

The RSTC provides expertise in reliability, resilience, and security, and plays a key role in the mitigation of reliability, resilience, and security risks. As identified in the RISC's Framework[5] for Risk Mitigation, the RSTC is responsible for all steps of the framework, including: Risk Identification and Validation, Risk Prioritization, Determination of Risk Remediation/Mitigation, Deploying Risk Remediation/Mitigation, Measure Success, and Monitor Residual Risk. Therefore, the strategic plan includes key activities to support each of these steps.

The Risk Mitigation Framework guides the ERO in the prioritization of risks and provides guidance on the application of ERO policies, procedures, and programs to inform resource allocation and project prioritization in the mitigation of those risks. Additionally, the framework accommodates measuring residual risk after mitigation that enables the ERO to evaluate the success of its efforts in mitigating risk and provides a necessary feedback mechanism for future prioritization, mitigation efforts, and program improvements.

The successful reduction of risk is a collaborative process between the ERO, industry, and the technical committees including the RSTC and the RISC. The framework provides a transparent process using industry experts in parallel with ERO experts throughout the process—from risk identification and deployment of mitigation strategies to monitoring the success of these mitigations.

Figure 2: ERO Mitigation Framework for Known and Emerging Reliability Risks

The RSTC's Notional Work Plan Process[6] provides a detailed review of each step and how the RSTC supports and actively contributes to the risk mitigation framework. The following table summarizes how the RSTC performs each step and the expected deliverables that support the Risk Mitigation Framework:

Risk Mitigation Framework Steps	RSTC Role	RSTC Deliverable Type

[5] https://www.nerc.com/comm/RISC/Related%20Files%20DL/Framework-Address%20Known-Emerging%20Reliabilit-Securit%20%20Risks_ERRATTA_V1.pdf
[6] https://www.nerc.com/comm/RSTC/Documents/RSTC%20Work%20Plan%20Notional%20Process_Approved_Sept_2020.pdf

Risk Mitigation Framework Steps	RSTC Role	RSTC Deliverable Type
1. Risk Identification and Validation	RSTC identifies and validates risks through its performance, event, and future technical analysis and assessments	• Identification and Monitoring ▪ Long-Term and Seasonal Reliability Assessments ▪ Special Assessments ▪ Event and Disturbance Reports ▪ State of Reliability Report ▪ Other reliability/security indicators, whitepapers, gap assessments
2. Risk Prioritization	RSTC provides support and consulting to the RISC prioritization and risk ranking actions.	
3. Determination of Risk Remediation/Mitigation	RSTC proposes remediation/mitigation	• RSTC Biennial Strategic Plan
4. Deploying Risk Remediation/Mitigation	RSTC develops and deploys remediation/mitigation	• RSTC Work Plan ▪ Standard Authorization Requests – SAR ▪ Reliability/Security Guidelines ▪ Compliance Guidance ▪ Reliability and Security Assessments ▪ Stakeholder Outreach ▪ Technical Reference Document ▪ NERC Alert
5. Measure Success	RSTC ensures an approach to measure the effectiveness of the risk remediation/mitigation and deploys it. Measurement approach should be included in the approval of the deployed remediation/mitigation.	• Identification and Monitoring ▪ State of Reliability Report ▪ Event and Disturbance Reports ▪ Special/Specific Reliability and Security Indicators
6. Monitor Residual Risk	RSTC monitors residual risk through established programs.	• Identification and Monitoring ▪ Long-Term, Seasonal, and Special Reliability and Security Assessments ▪ Event and Disturbance Reports ▪ State of Reliability Report ▪ Other reliability and security indicators and whitepapers

Determination of Risk Remediation/Mitigation

Technical group, RSTC EC, and Sponsors discuss the reliability/resilience issues, technical justification, and consider possible solutions. Potential outcomes or solutions include deliverables in the RSTC Charter such as white papers, reference documents, technical reports, reliability guidelines, SARs, and compliance implementation guidance. Other potential solutions are contained in NERC Rules of Procedure (ROP), ERO Event Analysis Process, NERC Alerts, and other risk management measures. Finally, the RSTC EC authorizes tasks to be added to the RSTC Work Plan (which could include collaboration with other groups), rejects proposed tasks, or refers matter(s) to the RSTC for further discussion.

RSTC Subordinate Group Review Recommendations

Action
Approve

Background
The RSTC Charter specifies a “sunset” review of all working groups and task forces be conducted each year.

Summary
Each working group and task force submitted a self evaluation for review by the RSTC Executive Committee (EC). The RSTC EC reviewed each groups self evaluation and request for changes and has made recommendations based on these requests.

The RSTC EC is seeking approval for their recommendations.

RSTC Working Group and Task Force Sunset Review Process

John Stephens, RSTC Vice Chair
Reliability and Security Technical Committee Meeting
December 11, 2024

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WG/TF Review Process

- The RSTC Charter specifies periodic reviews in Section 6:
- Charter Provisions – Working Group (WG)
  - The RSTC will conduct a "sunset" review of each working group every year. The working group will be accountable for the responsibilities assigned to it by the RSTC or subcommittee and will, at all times, work within its assigned scope. The RSTC should consider promoting to a subcommittee any working group that is required to work longer than one term.
- Charter Provisions – Task Force (TF)
  - Each task force will have a finite duration, normally less than one year. The RSTC will review the task force scope at the end of the expected duration and at each subsequent meeting of the RSTC until the task force is retired. Action of the RSTC is required to continue the task force past its defined duration. The RSTC should consider promoting to a working group any task force that is required to work longer than one year.

WG/TF Review Process

- A RSTC Review Team was established consisting of the following:
  - Marc Child
  - Vinit Gupta
  - Ahmed Maria
  - Darrel Richardson
- Review templates were distributed to working groups and task forces within the RSTC organization.
  - This review included the RSTC Sponsors in coordination with group leadership and NERC Staff Liaisons to review the working group or task force deliverables and work plans to complete the information in the template.
- The templates were completed by the WG/TF and returned to the RSTC Review Team for review.

WG/TF Review Process

- The following working groups and task forces were reviewed:

Synchronized Measurements Working Group	SPIDER Working Group
6 GHz Task Force	Facility Ratings Task Force
Failure Modes and Mechanisms Task Force	EMS Working Group
EMT Task Force	System Protection and Control Working Group
Electric Gas Working Group	Energy Reliability Assessment Working Group
Load Modeling Working Group	Probabilistic Assessments Working Group
Reserves Working Group	Frequency Working Group
Security Working Group	Supply Chain Working Group

Review

- The 6 GHz Task Force is anticipating completion of their work plan in September 2024.
  - All deliverables in the scope document have been completed. Retire at the RSTC March 2025 meeting to allow time for discussion and approval of new communications related task force.

Review

- The ERAWG and EGWG recommend combing the two groups into a single group.
  - Valuable guidance for performing Energy Reliability Assessments is dependent upon an understanding of the gas-electric interface. Gas/electric issues lead to overall energy issues. Once you solve one, the other becomes apparent. They’re very much the same topics across the spectrum. To better support energy reliability, it is recommended to combine the membership and leadership of the Electric Gas Working Group (EGWG) and the Energy Reliability Assessment Working Group (ERAWG) into a single working group. The EGWG would be absorbed into the ERAWG with membership from both existing groups. The scope of the combined group would be the combination of the scopes of the existing groups.

Review

- The SCWG is recommending that the group be promoted to a subcommittee.
  - Supply chain risk management (SCRM), one of NERC's four strategic risks, encompasses broad hardware, software/firmware, and services processes. These risk management processes start with contracting/procurement and span the entire supply chain through delivery, maintenance, and support. Multiple government agencies have implemented SCRM requirements in areas addressed by various CIP standards. Concerns requiring proper risk assessments include inferior and counterfeit components. Focus area #2 of a 04/22/21 FERC RFI addressed the supply chain, and on 09/19/24, FERC issued an SCRM NOPR. During this period, the SCWG has evolved, leveraging industry and government leadership to address procurement, risk assessment, and incident response strategy, playing a leading role in broad SCRM. However, the supply chain threat landscape is dynamic and continuously evolving.
  - Third- and fourth-party supply chain risk grows continuously, requiring ongoing collaboration to help critical infrastructure partners. The SCWG expects to play a leading role in SCRM, as described in the FERC SCRM NOPR, and as necessary for the grid's overall reliability, safety, and security. These efforts encompass developing, reviewing, and updating SCRM practices related to contracts, co-creating meaningful assets such as checklists, job aids, etc., and managing cyclical deliverables such.

Review

- The SCWG is recommending that the group be promoted to a subcommittee
  - Quarterly supply chain disruption report describing and summarizing grid-related risk events. These tasks align with subcommittee scope and include overseeing the drafting of new or modifying existing supply chain standards through thought leadership that leverages current processes and incorporates the diverse group's SCRM subject matter expertise. Subcommittee status would greatly enhance industry engagement and participation toward achieving these goals.

Review

- The EMTTF is recommending that the group be promoted to a working group.
  - Recommend upgrading to a working group due to the following reasons:
    - EMT modeling and requirements for IBR-related reliability studies continue to evolve. Revision to EMT Modeling Guideline (2023) is needed and should be a living document which should be updated as industry continues to learn more regarding the modeling needs and impacts of IBRs. There is a need to continue driving harmonization and consistency across the industry, thus, increasing efficiency for the vendors and developers. Continue to support Project 2022-04 EMT Modeling. As industry experience grows, the lessons learned need to be captured and shared broadly. As more industry adopts, we can expect more strain on the already constrained resources, highlighting the need for more ways to streamline the processes.

Review Team Recommendations

- The RSTC review team recommends retaining the Working Groups and Task Forces that were reviewed in 2024 in their current form with the exception of those noted below.
  - The review team recommends that the 6GHz Task Force be retired in March 2025.
  - The review team recommends that the ERAWG and EGWG be combined into a single working group using the methods described in their recommendation.
  - The review team recommends the SCWG be promoted to a Subcommittee due to the complexity of the issues surrounding supply chain and the inherent risk to the grid as identified in their recommendation.
  - The review team recommends the EMTTF be promoted to a working group.

RSTC Review Team Motion

- Motion: Approve the RSTC Review Team recommendations to:
  - Retire the 6GHz Task Force in March 2025.
  - Combine the ERAWG and EGWG into a single working group.
  - Promote the SCWG to a Subcommittee.
  - Promote the EMTTF to a Working Group.
  - Retain all other Working Groups and Task Forces that were reviewed in 2024 in their current form.

Questions and Answers

6 GHz Task Force Closeout Summary

Action
Information

Background
During the December 2021 meeting, the RSTC established the 6GHZTF to perform the following activities:

- Gather information related to the risk of harmful interference in the 6 GHz spectrum
- Identify penetration and BPS users relying on 6 GHz
- Request industry information related to harmful interference experience
- Identify potential mitigation strategies
- Evaluate options for industry outreach
- Develop suggested recommendation related to the issue

The task force has completed its outlined scope and presents a summary of the completed activities and recommends retiring the task force.

Implementation Guidance: TPL-001-5.1 Interpretation Footnote 13.d

Action
Endorse

Background
TPL-001-5.1 uses the term “trip coil” in the language that allows exclusions to single control circuits in footnote 13.d. Trip Circuit Monitors (TCM) are widely used by industry to monitor trip circuits and alarm for failures of the circuit. The SPCWG would like to establish that the trip ***circuit*** may be excluded as a non-redundant component of a protection system if it is both monitored and reported to a control center.

The examples provided in this implementation guidance show clearly what portions of a trip circuit are monitored by a typical TCM function.

This issue is relevant to the applicable Functional Entities for consistently evaluating and defining the scope of work necessary to meet the compliance requirements for TPL-001-5 Table 1 Footnote 13.d: “*A single control circuitry (including auxiliary relays and lockout relays) associated with protective functions, from the dc supply through and including the trip coil(s) of the circuit breakers or other interrupting devices, required for Normal Clearing (the trip coil may be excluded if it is both monitored and reported at a Control Center).*”

Summary
This document will serve as a reference for the previously submitted SAR that identifies modifications needed to TPL-001-5.1 Table 1 Footnote 13.d.

The intent of this document is to confirm and establish a trip circuit monitor methodology that will be accepted as an exclusion for single control circuits according to TPL-001-5.1 Footnote 13.d until such time as the standard can be revised.

The SPCWG is requesting that the RSTC approve the Implementation Guidance document for TPL-001-5.1 that provides clarification with respect to issues in footnote 13.d regarding Trip Circuit Monitoring.

Reliability and Security Technical Committee (RSTC)

System Protection and Control Working Group (SPCWG)

Implementation Guidance TPL-001-5 Trip Coil Interpretation

TPL-001-5 Table 1 Footnote 13.d

December 2024

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Introduction

Industry interpretations of the terms "trip coil" and "trip circuit" and the demarcation between the two functions, vary. These variations are compounded by the acronym "TCM" (trip coil monitor or trip circuit monitor), leading to imprecise discussions among protection subject matter experts. This implies a need to settle on a common understanding of the subject. For example, Section 2.5.3, Trip Circuit Monitors, of the IEEE PSRC Committee *Relay Scheme Design Using Microprocessor Relay* report uses the phrase "trip coil monitoring" when discussing "trip circuit monitoring."

The examples provided in this Implementation Guidance (IG) show clearly what portions of a trip circuit are monitored by a typical TCM function to improve the understanding of Standard TPL-001-5.1.

This issue is relevant to the applicable functional entities for consistently evaluating and defining the scope of work necessary to meet the compliance requirements for TPL-001-5 Table 1 Footnote 13.d: "*A single control circuitry (including auxiliary relays and lockout relays) associated with protective functions, from the dc supply through and including the trip coil(s) of the circuit breakers or other interrupting devices, required for Normal Clearing (the trip coil may be excluded if it is both monitored and reported at a Control Center).*"

This document is issued in conjunction with a NERC-approved standard authorization request (SAR) titled TPL-001-5.1 Table 1 Footnote 13.d. The Standard Drafting Team will address the SAR and incorporate necessary changes in the future update of TPL-001.

Goal/Problem Statement

Reference material for NERC compliance interpretation of a range of dc control circuit configurations is not available for use by the applicable functional entities. This document will serve as reference material for identifying the modifications to TPL-001-5.1 Table 1 Footnote 13.d as a result of the SAR to enhance the language of the Footnote 13.d exclusion to include "any non-redundant components of the control circuitry that are both monitored and reported" in addition to the current exclusion of the single trip coil. The intent of this document is to help applicable entities evaluate and identify Table 1 Footnote 13.d applicability.

Scope

Substation dc control circuit design usually includes a "trip circuit monitor" (TCM) located within a control room that monitors both the combined configuration of the "trip circuit" and the interrupter "trip coil." Breaker configuration (single-pole tripping capability, for example) and TCM placement require evaluation to understand the effective extents of the monitoring system.

The TCM functions by detecting a loss of voltage or a loss of circuit continuity from the positive source terminal of the circuit to the negative source terminal of the circuit. The logic generally includes an element sensing voltage across the normally open protective relay tripping contacts—typically between the positive bus of the circuit and the trip bus of the circuit. The logic also requires an element sensing the status of the breaker. The trip circuit includes a contact in series with the trip coil that is open when the breaker is open, 52A. This contact is necessary to interrupt the coil's dc current when the breaker successfully opens. The status input blocks the TCM function from false alarms for this normal condition. A timer is also required to ride through the period between when the trip contact closes, shorting the TCM sensing element, and when the breaker successfully opens. The source of breaker status sensing is a critical detail in the implementation of the TCM function. For example, if the logic senses 52A status that obtains its voltage from the trip circuit being monitored, loss of dc to the circuit would indicate that the breaker is open, meaning that de-assertion of the TCM sensing element is expected and the TCM alarm should be blocked. Three solutions are generally used to eliminate this common mode failure, as follows:

- Obtain the breaker status from a circuit independent of the trip circuit being monitored
- Obtain the breaker status from a contact that is open when the breaker is closed, 52B
- Include separate sensing to alarm for complete loss of dc to the trip circuit

This document will provide four examples of dc control circuit configurations using three composite protection systems. In these examples, all three composite protection systems are essential for meeting the TPL performance requirements. The examples will also show the importance of the location of the TCM. These examples will result in a better understanding of the TPL-001-5.1 Table 1 Footnote 13.d exclusion interpretation.

The illustrations that follow are described below:

Composite protection system “W” is inadequate for the following two potential reasons:

- Relay inadequacy – One protection system relay (TPL-001-5.1 Table 1 Footnote 13.a) or,
- DC control system – One auxiliary relay actuated by redundant relays with a single auxiliary relay contact in the tripping circuit

Composite protection system “X” is inadequate for the following potential reason:

- DC control system inadequacy – Redundant relays A and B tripping contacts connected upstream of the trip circuit

Composite protection system “Y” is adequately designed depending on the position of the TCM.

Test switches are not shown and can be assumed to be wired in series with each tripping output if they are used.

Trip circuit graphics in blue shading with a checkboard pattern represent portions of the trip circuit that are monitored and exempted by the exclusion.

Trip circuit graphics in red shading with a cross-hatched pattern represent portions of the trip circuit that are non-redundant and not adequately monitored. The exclusion does not apply.

Trip circuit graphics without shading and pattern represent adequate redundancy; use of the exclusion is not necessary for that portion of the circuit.

Commented [NS1]: Should “for the following potential reason:” be added here?

Reliability Standard

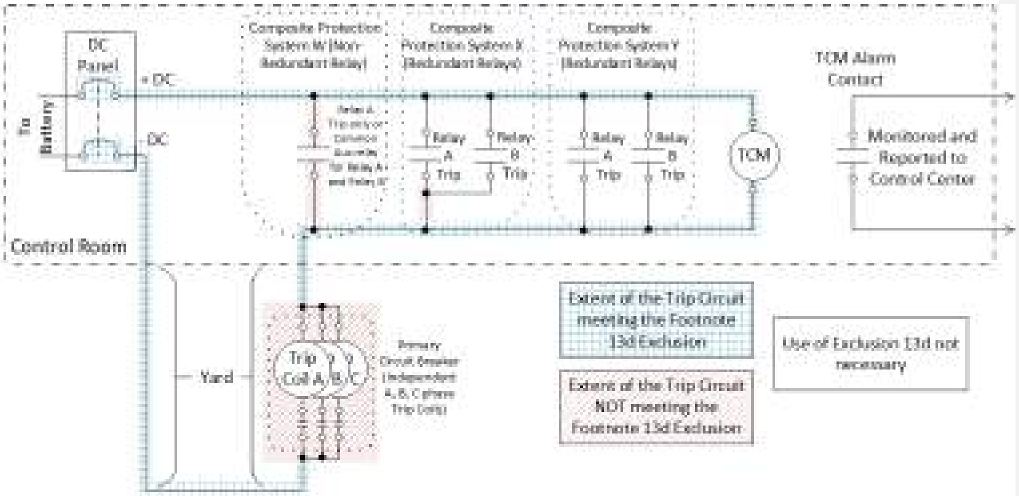
TPL-001-5.1 Table 1 Footnote 13.d.

Requirement X

Meeting the redundancy or monitored exclusion criteria for TPL-001-5 Table 1 Footnote 13.d

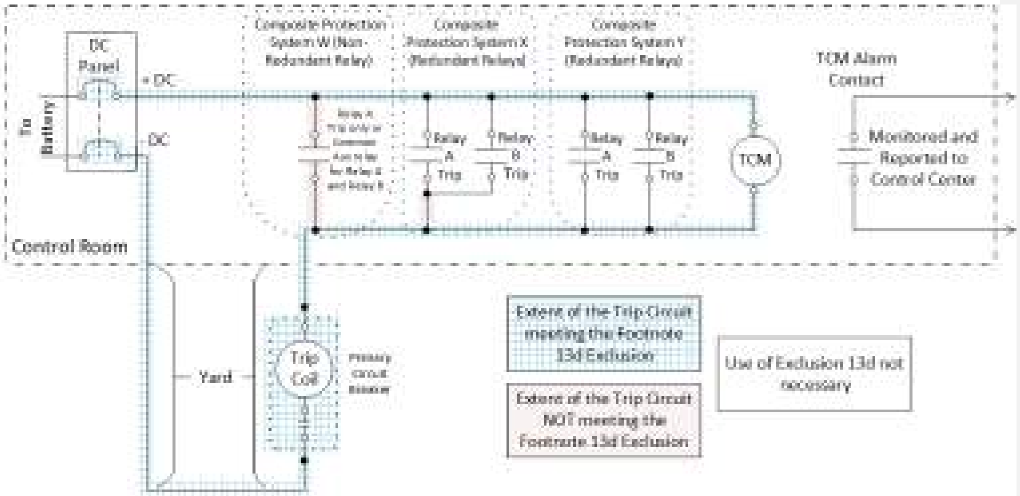
Example 1

Individual phase interrupter trip coils (phase A, phase B, and phase C) cannot be adequately monitored by a single TCM located within a control room utilizing a single trip circuit.



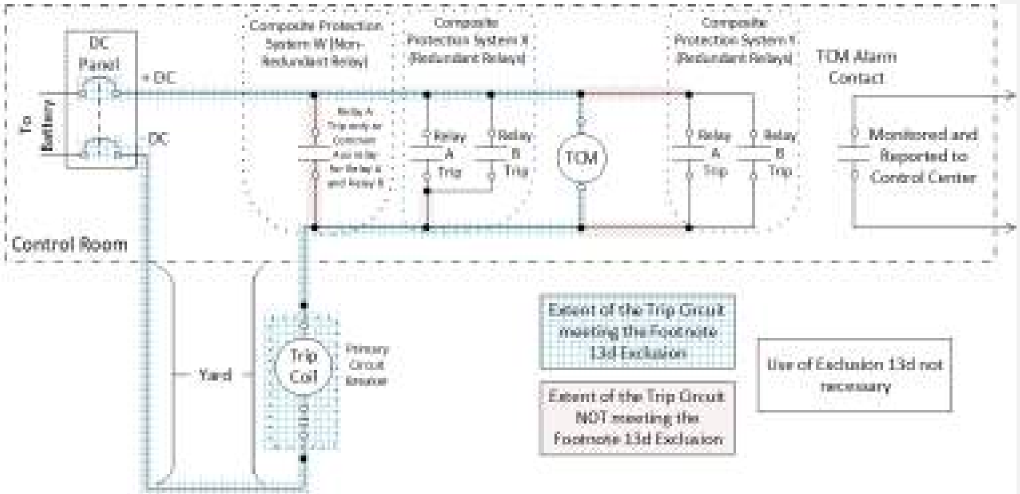
Example 2

In a case where composite protection systems W and X are used, this example shows a partially monitored dc trip coil and trip circuit with a depicted location of the TCM. When composite protection system Y only is used, the dc trip coil and trip circuit are adequately monitored with the depicted location of the TCM.



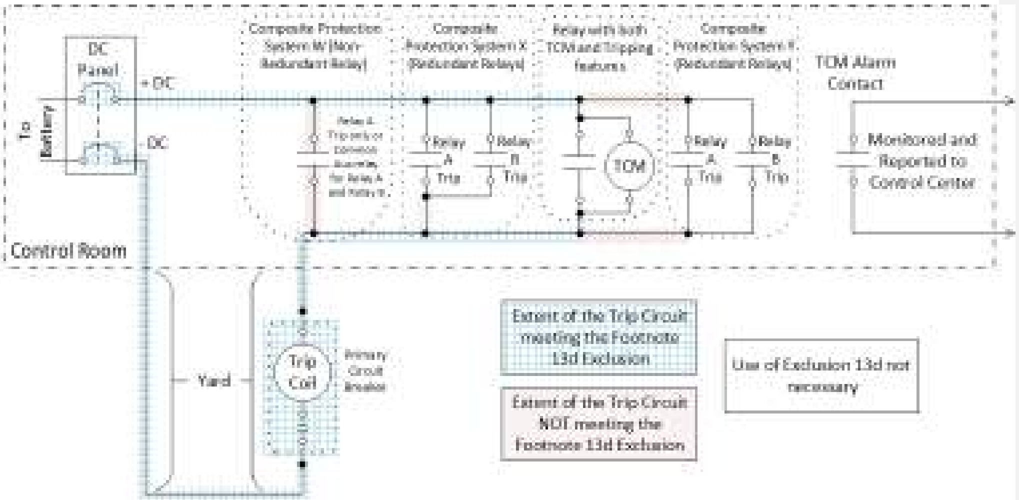
Example 3

In this example, the consequence of the electrical placement of the TCM is illustrated. The dc trip coil and trip circuit are not adequately monitored with either composite protection system.



Example 4

In this example, the TCM device also has a tripping contact in the dc control circuit. But as in example 3, the dc trip coil and trip circuit are not adequately monitored with either composite protection system.



Periodic Review

The System Protection and Control Working Group (SPCWG) will review this IG every three years or upon a new version of the standard being approved.

White Paper: New Tech Enablement and Field Testing

Action
Approve

Background
Security Integration and Technology Enablement Subcommittee (SITES) formed a sub-team for New Tech Enablement to develop this whitepaper with the purpose of broadly discussing the role of technology innovation and technology adoption in the electric industry, including relations to regulatory processes, and looking at topics such as field or production testing of new technologies. SITES is requesting Reliability and Security Technical Committee's approval of the White Paper: New Tech Enablement and Field Testing. Upon approval the whitepaper will be posted publicly on the RSTC Approved Documents Page[1].

Summary
To better drive technology adoption and innovation, the paper makes a key recommendation of for industry to adopt a high-level process for industry-coordinated new technology pilots whose initiation and execution is not dependent on current standards development processes including standards authorization requests (SAR) or standards drafting teams (SDT). The purpose of the recommended pilot process, called Regional Engagement for Technology and Integration Innovation Acceptance (RETINA), is to further enable the transparent exploration of new technology risks and benefits in the industry and potentially offer even more informed standards development efforts on the backend.

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

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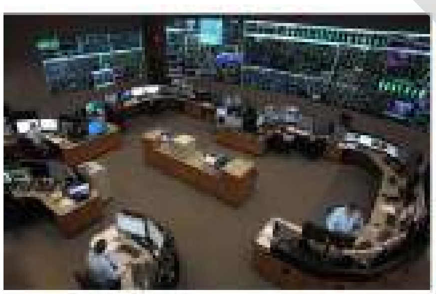
New Technology Enablement and Field Testing

NERC Security Integration and Technology Enablement Subcommittee Whitepaper

December 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, 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

Executive Summary

In this whitepaper, the term utilities is used to broadly encompass all entities involved in the electric industry's management and operation of the electric grid, including those responsible for transmission, generation, and distribution. This definition is inclusive of independent power producers (IPP), despite their traditional distinction from utilities. For the purposes of simplicity and coherence within this document, both utilities and IPP will be collectively referred to as utilities.

While this is a broad discussion that goes beyond the Bulk Electric System (BES), some of the mechanisms to address challenges that are discussed, such as the Regional Engagement for Technology & Integration Innovation Acceptance (RETINA) program, are meant to address challenges specific to those entities who must comply with NERC Reliability Standards.

Statement of Purpose

As a general principle, Security Integration and Technology Enablement Subcommittee (SITES) believes that the exploration and adoption of new technologies—when implemented reliably and securely—should be accessible to utilities throughout the industry. As the electric grid evolves to meet the challenges of digitalization, renewable integration, and changing energy demands, utilities face significant barriers to adopting innovative technologies. This whitepaper aims to open and invite industry to the broad conversation about these challenges while emphasizing that minimizing risk through collaborative solutions is essential.

Chief among the electric sectors challenges for new technology innovation and adoption is the need to ensure that new endeavors do not compromise existing physical or electronic security protections. Utilities must maintain the security and reliability of the BPS while also mitigating the substantial risks of regulatory penalties for non-compliance. By uniting industry stakeholders to develop and endorse Reliability Standards and technologies that enhance security and reliability, we can reduce risk profiles while ensuring reliability.

Rather than providing prescriptive answers, this whitepaper encourages an expansive view that goes beyond the confines of the BES and the scope of the NERC Critical Infrastructure Protection (CIP) Reliability Standards.

As the electric grid transforms in response to digitalization, renewables and changing energy demands, innovative technologies present opportunities to boost reliability, security and optimize operations. However, utilities face numerous challenges in evaluating and seeking adoption of new technology solutions including regulatory Reliability Standards and requirements interpretations and conflicts, employee training and new skill development, and the ability to incorporate technology investments into existing rate structures. Utilities may struggle to simply understand the impacts of new technology to operations, including benefits or risks to reliability and security. The electric industry would benefit from greater collaboration between registered entities, the ERO Enterprise, and technology vendors who have the ability to innovate based on stakeholder needs. Collaboration can help to ensure that the security, risk, and operational needs of the industry are not only met by new technology, but that they are able to be evidenced through technology pilots and trials, better enabling adoption at a pace that supports the speed of the evolving electric grid.

Broadly, our industry shows a willingness to seek out and embrace new technology to support the changing grid, and likewise supports the development and implementation of new security and Reliability Standards when appropriate. In fact, the electric industry is seeing a greater workload and pace of standards development than ever before, and these efforts deserve to be applauded. As the grid continues to evolve and the pace of technology rapidly accelerates, the electric industry needs mechanisms to enable and support entities willing to invest efforts in testing and deploying new technologies in secure, reliable ways that can be shared with their peers.

To address the challenges utilities face in adopting new technologies that must comply with the mandatory NERC Reliability Standards, this whitepaper proposes the development of a mechanism to facilitate pre- Standards

Authorization Request (SAR) and pre- standards development coordinated field trials of emerging technologies, operating outside of the traditional standards development process. The proposed mechanism is conceptual and will require coordinated industry effort and buy-in to ensure that it meets the security, reliability, and efficiency objectives as outlined in this whitepaper. It is proposed as the RETINA program.

Utilities required to comply with the mandatory NERC Reliability Standards have mechanisms to test new technologies through existing programs such as Field Tests which can be approved in conjunction with a standards development project. The Field Test process is limited by procedural constraints such as requiring an approved SAR prior to seeking approval for the Field Test, meaning that the utility has to understand the security or reliability gap and how it aligns with the Reliability Standards prior to initiating the test. RETINA eeks to provide a more flexible and proactive approach. By conducting technology trials outside of the standards development framework, RETINA enables earlier exploration and assessment of new technologies without the immediate assumption of Reliability Standards revision work.

In addition to initiation and oversight provided by NERC and industry stakeholder technical committees such as those under the Reliability and Security Technical Committee (RSTC), RETINA would leverage Regional Entities, given their connections across the industry and unique perspectives for each region's respective differences, to coordinate trials within their region. These trials would evaluate reliability, security impacts and regulatory challenges of technologies like cloud computing[1], artificial intelligence (AI), including generative AI, and machine learning (ML), and real-time decision enhancement using synchrophasor data.

By cultivating guidance from trial results, RETINA aims to enable faster, secure and reliable adoption of beneficial solutions. It complements the existing Field Test process by providing a pathway for industry collaboration on technology trials before determining that Reliability Standards revisions are necessary and the Reliability Standards Development Process is initiated. SITES believes that such collaboration will expedite new technology exploration, inform potential standards development when necessary, and increase education and awareness of thoroughly vetted technologies that support BPS security and reliability.

RETINA is proposed strictly as a high-level concept that SITES encourages to be implemented independently by each region with input from industry stakeholders. This approach allows the industry to discover and adopt best-in-breed practices over time, fostering innovation while maintaining flexibility.

Continued improvements to our self-regulated industry necessitates Federal Energy Regulatory Commission and ERO Enterprise leadership commitment and support, flexible regulatory enhancements, and close coordination between stakeholders. Collaborative efforts like RETINA can modernize grid operations through secure technology integration, optimizing reliability, resilience, and cybersecurity for the future. There are opportunities to address the additional challenges described in this whitepaper through collaborative efforts outside of the RETINA program that have not been proposed directly in this whitepaper. The intention is for these challenges to spark conversation about what those efforts could look like.

[1] This whitepaper was developed before the development and submission of the SAR that led to Project 2023-09 Risk Management for Third-Party Cloud Services. However, the example is pertinent to the potential benefit of pre-SAR trials.

Introduction

Background

With the aim of supporting the BPS in a secure, reliable, effective manner, SITES tasks itself with the goal to "identify potential barriers (e.g., regulatory, technological, and complexity) and support the removal of these barriers to enable industry to adopt emerging technologies. [2]" Due to the nature of critical infrastructure, and the unbending need for a focus on reliability, the electric industry is cautious to adopt newer and innovative technologies. Other critical infrastructure sectors including health care, specifically pharmaceuticals, financial services, and the defense industrial base (DIB) have adopted newer technologies more rapidly despite also being part of critical infrastructure due to mature assessment processes including third-party assessment processes, clear engineering and design specifications, among other factors. While the security, reliability, and resiliency need of these critical infrastructure sectors are not directly aligned with those of the electric sector, the implementation and use of advanced technologies in those sectors can serve as a foundation for consideration. Herein we discuss various factors that are inhibiting adoption by the electric sector and factors that are stifling ongoing innovation of new technology. The paper makes a formal recommendation to address what SITES considers the greatest roadblocks to adopting new and advanced technologies within our industry.

Among the challenges related to new technology in the electric industry, special attention is given in this whitepaper to assessing the electric industry's regulatory framework, including the NERC CIP Standards and the standards development process, with an aim to identify enhancements or complementary processes to better facilitate new technology adoption.

Appendix A further offers discussion and insights into industry struggles with workforce, financing, and internal regulatory compliance approaches, which can hinder adoption of new digital technologies among utilities. These challenges are not addressed by the RETINA program.

NERC CIP Standards and Standards Development

NERC CIP Reliability Standards are designed to protect the BES from cyberattacks and other threats. These Reliability Standards consist of multiple requirements. Within the *NERC Standard Processes Manual*[3], one of the many processes outlined is the development process for modifying or creating these standards, which begins (i.e., Step 0 in the *Standards Process Manual*) with a SAR, documenting the scope and reliability benefit of proposed projects for new or modified standards or the retirement of existing standards. This process involves a review by NERC Reliability Standards staff and action by the Standards Committee (SC), which decides whether to accept, remand, or reject a SAR. If accepted, the project is added to the list of approved projects and assigned a priority in the Reliability Standards Development Plan[4]. A drafting team is formed which reviews the SAR, makes necessary revisions based on formal or informal industry comment, and returns the revised SAR to the SC for the drafting team to begin. So begins a cycle of drafting, quality reviews, comments, balloting[5], and sometimes SAR revisions. Eventually the team ends with a successful ballot(s) and a final adoption ruling. For a given standards project, this process may take anywhere from a year to many years. While the pace of standards development depends on a number of factors, including prioritization and complexity, processes that include the development of technical support and/or scoping can help to reduce timelines.

[2] https://www.nerc.com/comm/RSTC/SITES_/SITES%20Scope.pdf
[3] https://www.nerc.com/pa/Stand/Revisions%20to%20the%20NERC%20Standard%20Processes%20Manual%20SP/SPM_Clean_Oct2018.pdf
[4] https://www.nerc.com/pa/Stand/pages/reliabilitystandardsdevelopmentplan.aspx
[5] https://www.nerc.com/pa/Stand/Pages/Balloting.aspx

The collaborative nature of the standards development process is a success story for industry. SITES acknowledges that it takes time to get a Reliability Standard right given the consequence of noncompliance or reliability impacts. Often, a given standards development project for NERC CIP may take up to a year - which does not seem unrealistic for the entirety of the industry to develop, iterate on, and approve a Reliability Standard. In some cases, taking multiple years is justified. However, in this length of time, technology is likely to advance significantly, potentially requiring additional iterations or a new SAR. This merely underlines the challenge faced by industry to achieve the balance of reliability and security along with the flexibility of supporting new technology adoption within the NERC Reliability Standards.

Technology Adoption

SITES views technology adoption as the process by which new technologies are embraced and utilized by individuals, vendors, utilities, or the electric industry at large. This process often begins with the initial awareness and understanding of a new technology, including its impact on reliability and security, followed by its evaluation against existing solutions in terms of efficiency, cost, and potential benefits. Once deemed beneficial, the technology is then implemented and integrated into existing systems or practices on an individual entity basis. The adoption process is influenced by various factors, including but not limited to technological capabilities, funding, regulatory compliance, vendor support, and the overall impact on operational efficiency and productivity through the lens of each individual organization. New technology, when tested, assessed, and implemented in accordance with the security and reliability needs of the grid, can help the electric industry achieve modernization, improve grid reliability, efficiency, and security, as well as meet evolving Reliability Standards. This process is also key to addressing current challenges and leveraging opportunities presented by advancements such as renewable energy sources, smart grid technologies, and digitalization.

Technology Innovation

Innovation may originate from two main sources: direct utility needs and vendor-initiated development. Vendors may initiate technology development independent of expressed utility needs, forging forward based on internal research and development projections or perceived future market demands. This occasionally results in a mismatch between offered technological solutions and practical utility adoption. Therefore, a two-way collaborative dialogue between utilities and vendors, focused on co-developing solutions that are keenly attuned to specific operational and regulatory needs, is pivotal. Within this synergy between vendors and utilities, SITES recognizes that the drive for ongoing technology innovation is affected by the appetite for adoption among the utilities. Therefore, barriers to adoption negatively impact the drive to innovate as well.

Chapter 1: Drivers For Technology Innovation and Adoption

Grid Reliability, Resilience, and Security

Broad advancement of the grid through the combination of technological innovation and adoption are requisite to bolstering grid reliability and security in the face of grid transformation and an emerging threat landscape. New technologies can enhance response mechanisms to grid disturbances, help ensure consistent service reliability, improve grid resiliency to cyber threats, and more. With the integration of new grid technologies such as inverter-based resources, distributed energy resources (DER) and DER aggregators, electric vehicle charging, ongoing innovation is necessary to keep up with energy demand and safeguard the grid from cyber and physical security threats. Cloud technology including software as a service (SaaS), AI and ML find themselves at the forefront of example digital technologies which may offer reliability, resiliency, and security benefits to the BPS, and yet may be inhibited by different challenges discussed in this whitepaper.

Utility and Innovator Relationships

Ensuring the relevance and applicability of technological innovations in the electric industry necessitates ongoing investment in a strong, synergistic relationship between utilities and innovators such as vendors, national laboratories, and universities. Ongoing dialogue between these entities, especially in the conceptual and development phases of technology creation, is crucial for relevant innovation and adoption. As an example, utilities can provide real-world perspectives and operational data, while vendors bring technical expertise and solution development capabilities to the real-world challenges faced by utilities. Co-developing technology ensures the delivered solutions are not only operationally viable, but also forward-looking, thereby paving the way for future-ready utility operations. Even with such cooperation, however, further collaboration is often necessary from these entities to participate at the regulatory level. This work is necessary to help ensure Reliability Standards and audit practices can evolve, when necessary, to accommodate new leading technology solutions, no matter if vendors and utility operators agree that the adoption of the technology is ready and will conceivably result in a more reliable, resilient, and secure grid.

Risk Management Frameworks and Innovation

In a perfect world, compliance with Reliability Standards, like NERC CIP, as well as internal control frameworks and metrics, should be viewed as a tool that facilitates and iteratively drives maturity. The result of that maturing program could be modernization through technological advancement, or adding additional security, reliability, or risk management controls or internal validations to existing technologies over time. Entities can leverage compliance as a guide to embedding an ever-improving risk management framework, enabled through ongoing adoption of technological innovations securely and effectively, within their operational systems and processes. This speaks to a mature strategy where regulatory compliance and technology enablement are interwoven. This strategy can only be realized when enacted through the ongoing effort of standards development to achieve a robust and flexible regulatory framework that is in sync with the scale and pace of new technology, as well as mature approaches to internal compliance strategy by registered entities that enables change in their organization rather than stifling change.

Chapter 2: New Technology Adoption Use Cases

Rapid advancements in available technologies are reshaping how utilities operate, manage resources, and interact with the grid. Nevertheless, the scale, pace, and outcome of any particular technology's adoption in our industry is subject to many of the roadblocks identified in this whitepaper. Some use cases are widely viewed as simply disallowed, even if indirectly, under current Reliability Standards, such as the broad scope of NERC CIP applicable systems used in cloud service provider environments. Other use cases, including some entirely outside of the scope of the NERC CIP Standards or even the BES and not intended to be addressed via the RETINA program, may see limited adoption at current but still suffer challenges that inhibit the technology's wider adoption. Wider adoption of some use cases below may be stifled from the perception of regulatory applicability uncertainty (present AND future), lack of industry awareness of the technology, including not just vendor or product availability, but its reliability or security benefits and risks, and finally, gaps in skilled labor to implement and utilize a given technology. Below is a non-exhaustive list of technology use cases which promise potential benefits to grid reliability, resiliency, or security while not experiencing wide adoption at current due to one or more significant challenges for the average utility to adopt and implement:

- **Cloud - PaaS/IaaS/SaaS (Platform, Infrastructure, or Software as a Service)**: The adoption of cloud computing in the utility sector offers numerous benefits, including enhanced scalability and flexibility of computing infrastructure. It can facilitate advanced data analytics, improve operational efficiency, and reduce IT infrastructure costs. Cloud technology enables utilities to quickly adapt to changing demands and integrate new services without significant upfront investments in physical infrastructure. SaaS allows utilities to use cloud-hosted software applications, reducing the need for on-premises installations. This approach provides agility in software deployment and maintenance, leading to potential cost savings and/or enhanced operational efficiency. SaaS models enable continuous updates and access to the latest features without the traditional complexities of software upgrades.
- **EACMS and PACS in the Cloud (Electronic Access Control or Monitoring System, and Physical Access Control System)**: By migrating EACMS to the cloud, including utilizing industry-leading cloud-based security tools including Managed Security Service Providers (MSSPs) and Managed Detection and Response (MDR) solutions, utilities gain enhanced capabilities in analyzing and triaging security data. This cloud-based approach allows for more efficient system and data integration, leading to improved cybersecurity measures, with controls and architectures that are commensurate to the security objectives of the NERC CIP Standards. Cloud-based PACS offer utilities enhanced security management of physical perimeters across geographically dispersed facilities. By centralizing control, these systems allow for real-time monitoring and management of access points remotely, improving response times to security breaches and streamlining compliance with security standards.
- **ML/Analytics Platforms**: ML and analytics platforms are critical for processing and interpreting large volumes of data generated by utility operations. These platforms aid in predictive maintenance, forecasting, and enhancing operational decision-making. They enable utilities to identify patterns and insights that would be impossible to discern manually, leading to more informed, data-driven decisions.
- **AI LLM/Generative AI**: AI, including large language models (LLM) and generative AI, offers significant potential for optimizing grid operations, automated customer interactions, and advanced data analysis. These AI applications can predict demand, optimize resource allocation, and improve customer service through automation and enhanced personalization.
- **DER/DER Aggregators/DERMS**: DERs and DER Aggregators, combined with DER Management Systems (DERMS), provide a new flexible approach to grid management. They facilitate the integration of decentralized energy production and distribution. DERMS aggregate, simplify, translate, and optimize these resources, ensuring stability and efficiency in the grid.

- **Outage and Vegetation Management**: Modern technologies in outage and vegetation management enable more precise prediction and faster response to power outages. Advanced analytics and imaging technologies help in efficient vegetation management, reducing the risk of outages and maintaining safety standards.
- **Simulation and Training Environments**: Utilizing cloud-based simulation and training platforms, utilities can offer realistic, scalable training for their staff without requiring additional assets in the utility's Electronic Security Perimeter. These environments simulate real-world scenarios, enabling employees to hone their skills and prepare for various operational situations in a cost-effective and controlled setting.
- **Asset Management, Inspection Scheduling, and Route Planning**: Advanced asset management systems, coupled with intelligent inspection scheduling and route planning, optimize maintenance workflows. These tools ensure effective resource allocation, minimize downtime, and enhance the lifespan of assets through predictive maintenance strategies.
- **Grid Planning Studies and Decision Support in the Cloud**: Cloud platforms for grid planning and decision support enable dynamic and complex analyses, facilitating better informed long-term strategic decisions. They provide utilities with tools for scenario analysis, load forecasting, and resource planning, allowing for more efficient and sustainable grid management.
- **CIM Modeling and GIS Platform in the Cloud**: Integrating Common Information Model (CIM) and Geographic Information Systems (GIS) in the cloud enhances the management and visualization of utility assets and infrastructure. This integration offers improved data accuracy, real-time updates, and better decision-making support for asset management and network planning.
- **EMS Historical Data Management in the Cloud**: Managing historical data from Energy Management Systems (EMS) in the cloud provides utilities with better access to and analysis of historical trends. This approach aids in operational planning, performance analysis, and long-term strategic decision-making, leveraging the power of cloud storage and computing for large-scale data management.
- **Synchrophasors/PMUs**: Synchrophasors or Phasor Measurement Units (PMUs) represent a significant advancement in real-time monitoring of the electric grid. These devices measure the voltage, current, and frequency at specific locations on the grid, providing detailed insights into grid conditions. By utilizing PMUs, utilities can enhance real-time or near real-time decision-making in a multitude of ways.

Chapter 3: Regulatory Frameworks and Technology

Often, modifications or advancements in Reliability Standards may not coincide timely with the evolving technology innovation curve, potentially slowing the adoption of emergent, beneficial technologies. This misalignment could risk inhibiting early-stage technology adoption, as entities may exercise caution to ensure continuous compliance alignment, resulting in a tendency towards late-stage or post-maturation adoption of technologies. Consequently, the regulatory process, along with limited audit flexibility, may inadvertently stifle innovative endeavors and their subsequent potential advantages to the electric industry. With this in mind, we may examine regulatory adaptation mechanisms and audit methodologies around NERC CIP to assess the potential for fostering an environment even more conducive to technological exploration and adoption.

NERC CIP Assessment

NERC CIP, while embodying performance-based control objectives, adopts a notably device-centric and defined network perimeter approach that infuses a degree of prescriptiveness into the framework. The effective limitation to on-premises systems and the delineation of static network perimeters intrinsically guides utilities toward a structured, and somewhat inflexible, cybersecurity model. This methodology, while robust in establishing a secure, controlled environment, inadvertently restricts the deployment of more dynamic, distributed technologies, such as cloud computing, which inherently defy traditional perimeter and device definitions, while bringing potentially industry revolutionizing technologies.

NERC CIP's current audit limitations for accepting third-party evidence adds further administrative and operational burden onto both the regulatory bodies and registered entities when exploring available new technology. This constraint fundamentally diverges from practices observed in alternative industry regulatory contexts. Notably, the Payment Card Industry Data Security Reliability Standard (PCI DSS) often permits entities to leverage third-party attestations and certifications, such as those from cloud service providers, to substantiate compliance. This approach not only pragmatically reduces the audit scope for entities but also alleviates associated operational burdens by capitalizing on externally validated secure solutions.

Due to registered entities owning all responsibility for evidence in NERC CIP assessments, there is a perceived distinction between permissible consultative services, like threat intelligence or incident response consulting, and the restrained adoption of managed security services. This points towards a nuanced, yet impactful limitation on technological enablement. Managed Security Service Providers (MSSPs) and Managed Detection and Response (MDR) solutions, inherently operate on architectures that often integrate cloud technologies and external management of data – components traditionally scrutinized or complexly navigated under NERC CIP. Whereas consultative services might provide advice or analysis without directly interacting with or managing an entity’s security systems and data, Managed Security Service Providers (MSSPs) and MDR solutions are often embedded within an entity’s technology and security operations, thereby requiring more operations-centric evidence under NERC CIP. While regulations like Health Insurance Portability and Accountability Act (HIPAA) offer more flexibility by recognizing external audits and certifications to some extent, NERC CIP’s current audit constraints do not generally accommodate third-party (to the registered entity) evidence validations, thereby limiting utilities’ capacity to seamlessly integrate with the broader, constantly evolving technological and cybersecurity landscape, effectively hampering the adoption of globally-recognized, secure, and innovative ideas and solutions.

As the NERC CIP Standards continue to be revised from standards development projects due to emerging threats and new technologies and cyber security paradigms such as zero trust, the electric industry should endeavor to evaluate the Reliability Standards with a fresh perspective, beyond the traditional adding of new requirements. While standards development efforts continue to raise the security baseline through additional and revised requirements, we must also recognize when it is appropriate to retire and relax outdated requirements[6]. Ultimately, striving for compliance should be about enhancing performance and reliability, making it a driving force for positive change rather than a mere obligation.

Standards Development Process and Field Tests

To foster technology innovation and adoption, the electric industry must have the capability to conduct proof-of-concept deployments that extend beyond alternative or simulated environments. While preliminary testing in controlled settings is essential, there comes a stage in the evaluation process when a technology is ready for a limited deployment within a live operational system. At this point, the industry should be empowered to pilot and trial new technologies in real-world environments across various regions. This approach enables exploration of practical use cases, comprehensive assessments of reliability and security impacts, and a deeper understanding of the regulatory challenges that may arise.

However, for these trials to be effective, it is crucial to establish a collaborative framework between the electric industry and regulatory bodies. There must be an understood 'safe' space, to promote beneficial experimentation, learning, and the responsible integration of cutting-edge technologies, while ensuring that security, reliability and public safety are not compromised.

Under the NERC Rules of Procedure, a precedence currently exists in the way of field tests which offer potential opportunities for compliance waivers, as needed, to establish that 'safe' regulatory space for the testing – however, there are limitations. The current standards development process lays out a process for initiating field tests, but only through their relation to a standards development project and SAR[7]. The tie-in to standards development limits the benefit this field test process offers to industry, due to new technologies often found in a limbo state of compliance ambiguity or perceived non-auditability, resulting in no SAR submissions for years.

With no other formal and endorsed process for conducting 'safe' pilots and trials for new technology in production environments, and when there is insufficient direction and guidance being produced by industry collaboration with the ERO Enterprise regarding a given new technology to facilitate secure and reliable early adoption, registered entities may be left with few if any options to explore an affected technology use case. In the case of compliance roadblocks, the result tends to be a drastically slowed to outright stifling of adoption, such as with cloud technology and real-time decision use of PMU's. In other cases, where an applied technology is out of scope, limitedly or non-applicable, or non-jurisdictional, we see outright proliferation, such as in inverter-based resources (IBR), DER, and electric vehicle charging. It should be noted that the proliferating technologies are also predominantly integrated with cloud technology, underscoring regulatory as the primary barrier for cloud technology adoption for in-scope NERC CIP systems.

6 https://www.nerc.com/pa/Stand/Project%20200812%20Coordinate%20Interchange%20Standards%20DL/Paragraph_81_Criteria.pdf

7 https://www.nerc.com/AboutNERC/RulesOfProcedure/Appendix_3A_SPM_Clean_Mar2019.pdf

Chapter 4: RETINA – Regional Engagement for Technology and Integration Innovation Acceptance Program

When a significant interest emerges in exploring new technology, industry readiness often follows, prompting a willingness to trial the technology in real-world settings. SITES believes that through carefully managed voluntary field trials, we can cultivate awareness, align interests, endorse good practices, and ultimately establish a precedence for the secure and reliable application of new technologies. By breaking these trials away from the standards development and SAR process, we create an opportunity for greater responsiveness to technology innovation and allowing industry to lead and direct the adoption curve thoughtfully and intentionally. These trials, and the subsequent reports and guidance produced, may not only help cultivate industry knowledge around the security and reliability risks or benefits of a given technology, but may additionally identify regulatory needs, leading to SARs, or informing ongoing standards development. This further allows standards development work to more effectively be a leading indicator, rather than a lagging indicator, of reliability and security risk mitigation. Above all else, such trials may empower industry to achieve swifter adoption of secure and reliable technologies by utilities, even in cases where it is found that standards development work may be needed.

SITES envisions Regional Entities as the vanguard of conducting and coordinating these voluntary field trials with each volunteer entity in their region due to their deep-rooted connections with local utilities, policymakers, and stakeholders, enabling tailored and responsive trials. Likewise, the DOE, National Labs, Universities, and other research organizations would be invited to coordinate their own field trials. High level oversight and organization of each technology field trial project is recommended to be initiated, as well as facilitated by, NERC in collaboration with industry stakeholders, through committees and working groups under the RSTC (such as SITES). These committee-sponsored field trial project groups would work directly with individuals from the Regional Entities leading the trial effort within their respective region.

In addition to consideration for waivers or specialized audits, parameters such as duration, goals, number of volunteers, and specific volunteer requirements should be clearly defined early on. Initial planning of a field trial may set its broad parameters, and on a given trial basis, Regional Entities may be offered flexibility to tailor certain aspects of the trial scope for entities within their region, where the added regional diversity may offer valuable additional insights to the trial.

Presented as a high-level concept rather than a prescriptive process, these voluntary field trials represent an opportunity for the electric industry to pro-actively walk hand in hand with regulators to seek secure and reliable implementations of emerging technology. Technology which, our increasingly diverse and complex grid will become dependent on, whether we are pro-active or not in guiding their implementations. By taking the pro-active and collaborative approach to the exploration of new technologies with field trials, we can reduce grid reliability risk from edge case experimentation, while safeguarding the grid's operational integrity, and increasing industry's agility and efficacy in ensuring technology innovation and adoption supports a more secure and reliable energy future. To summarize, the following measures are proposed to ensure the effective oversight and execution of technology field trials for industry:

- Field Trial Project Structure: While Regional Entities are seen as a focal point of coordination for trials, the recommended organization structure for project oversight is the following:
- NERC -> Stakeholder Subcommittee or Working Group under RSTC -> Regional Entities (or DOE, National Labs, etc.) -> Registered Entities
- Initiation: Field trials are first incorporated and assigned as potential work plan priorities under the RSTC, then initiated by the subcommittee or working group owning the work item. No SAR requirements.

- Developing Scope: Identify fixed and/or flexible parameters for each field trial project, including but not limited to duration, goals, minimum or maximum numbers of volunteers, volunteer requirements, and more.
- Regulatory Approvals, Waivers, and Audits: Alongside developing initial scope, secure necessary ERO Enterprise approvals for trials that might impact current Reliability Standards and necessitate temporary compliance waivers, or specialized audits. Where uncertainty exists for a given field trial project, define milestone events for potential re-evaluation of criteria for compliance needs.
- Data Sharing and Analysis: Establish clear protocols for the collection, sharing, and analysis of trial data, maintaining the strict confidentiality of participating utilities' information.

Chapter 5: Conclusion

The electric utility industry stands at an inflection point as modernization and digital transformation accelerate. New and innovative technologies promise to transform grid reliability, resilience, and security if adopted at scale. However, as this white paper outlines, significant barriers currently inhibit widespread technology innovation and adoption across the industry. Workforce challenges, financial limitations, rigid compliance approaches, and an standards development process not fully aligned with the pace of innovation all contribute to lagging technology uptake. Looking ahead, collaborative solutions are needed to overcome these obstacles and propel the industry forward. More active participation from utilities and vendors in the standards development process will be crucial. By engaging in technical committees and working groups, industry organizations can help guide Reliability Standards that embrace new technologies while enhancing the security baseline of the grid.

Further, initiatives like the proposed RETINA program offer a path to organize real world technology trials, cultivate guidance, and establish precedents that enable faster adoption within a compliant framework. Ultimately, overcoming barriers to technology innovation and adoption will require commitment from leadership, flexible yet prudent compliance approaches, supportive regulatory structures, and synergistic collaboration between utilities, vendors, regulators and other stakeholders. By working together through initiatives like RETINA, the electric industry can collaboratively strengthen the electric grid, optimize operations, and help ensure the reliable, resilient, and secure delivery of power.

Appendix A: Demoing New Technology

Utilities have a significant opportunity to explore and assess new technologies by establishing or utilizing dedicated lab and pre-production or even alternate production environments (e.g. corporate network). These settings allow for rigorous testing and simulation outside of compliance-impacted systems, minimizing risk while assessing potential benefits and impacts. By collaborating with entities including other utilities, external labs, and universities, utilities can gain insights into how new technologies might integrate into their current systems, ensuring that innovations align with operational goals and regulatory requirements before full-scale implementation.

Vendors often provide opportunities for utilities to trial new technologies through proof-of-concept installations, sometimes at low cost or even free. These trials allow utilities to evaluate the technology's effectiveness and integration capabilities within their existing infrastructure before committing to a full-scale deployment. Proof of concept deployments are a valuable way for utilities to assess potential solutions with minimal financial risk.

All of these share the same challenge however, in that these alternate environments have an eventual limit to their ability to effectively emulate a real-world production system and field asset. Eventually, risk-calculated limited field trials in production are often necessary to fully test integration in real-world scenarios which is crucial to ensure the desired outcome is achieved.

Roadblocks for Technology Innovation & Adoption

To better enable technology advancement for the industry with the aim of furthering grid reliability, resiliency, and security, we must first explore the various challenges and obstacles that are hindering the introduction and utilization of new technology. Effectively, these factors can be understood as bottlenecks to advancing the overall technological state of the BPS. Below, the major factors are explored which are slowing or impeding innovation and the widespread adoption of these advancements, including internal compliance strategies, workforce, financing, and regulatory framework challenges.

Workforce Acquisition and Retention

The acquisition and retention of a skilled workforce are current challenges in the electric utility sector, crucially influencing the rate and scope of technology adoption. These struggles are not isolated incidents but are common across the industry. An awareness of these challenges often leads organizations, intentionally or not, to adopt a conservative approach towards technological advancement. This can range from settling for a lower level of technology maturity to an outright avoidance of significant technological changes. This issue is especially pronounced for smaller utilities that are frequently constrained from accessing a diverse talent pool. The ability to implement and efficiently manage new technologies depends heavily on the presence of skilled professionals. These individuals need to be not only technically adept but also versatile in adapting to the ever-changing technological environment. A shortage of such expertise can severely delay the introduction of innovative solutions, undermining efficiency, and the utility's competitive edge. The continual loss (i.e., lack of retention) of skilled workers can create a knowledge vacuum, further hindering the electric sector's capacity to keep up with technological progress. These scenarios may lead to outsourcing, leading to increased remote access and other consequences which may further aggravate financial, compliance, and risk concerns. Compounded by the attractiveness of new industries, the evolving nature of required skillsets, and a highly competitive job market, these workforce challenges significantly shape the industry's approach to embracing and utilizing new technologies. This cautious, sometimes reluctant, attitude towards technological change highlights a critical link between workforce dynamics and the sector's technological evolution. The difficulties of acquiring and retaining a skilled workforce include several factors:

- Lack of Expertise: Smaller utilities often struggle to attract the necessary expertise, especially in specialized areas like operational technology (OT), combined security and engineering skillsets, and cloud technology. This scarcity of talent is exacerbated by the rapid pace of technological adoption and innovation, requiring skills that are not only current but also adaptable to evolving technologies.

- Technology and Equipment: The presence of outdated or legacy equipment and architecture can deter talent, particularly those who are seeking to work with cutting-edge technologies. Skilled professionals may see jobs that support older technology as a risk to their career. Given the pace that technology advances, security and IT professionals are especially likely to view the electric industry, with its lagged technology adoption, as a poor fit for their need for continuing technology education and experience. This results in fewer numbers of professionals crossing from other industries, and increased numbers of professionals fleeing our industry for more appealing jobs. Contrast this with messaging from forward-thinking utilities who have begun adopting these new technologies, marketing themselves as “technology companies that deliver electricity,” and coupling that with a mission to “green and save the planet.” This kind of thinking and messaging is attracting younger generations, who will only stay if the utility continues to live up to that mantra through ongoing technological evolution.
- Process Maturity: The degree of process maturity within a company can impact the perception of that organization’s readiness to evolve and achieve a steady pace of technology advancement, thus also playing a crucial role in retaining talent.
- Pay and Benefits: Offering competitive pay and having available budget to invest in ongoing employee learning are generally regarded across most industries as attractive and essential benefits to retain skilled employees.
- Culture: Increasingly, the organizational culture of a utility plays a pivotal role in retaining talent. A positive and supportive work culture can significantly enhance employee satisfaction and loyalty, encompassing aspects such as inclusivity and diversity, open communication, recognition and growth opportunities, work-life balance, an innovation-friendly environment, and a focus on psychological safety and well-being.
- Travel, Training, Remote Work: Factors such as inadequate training, limited travel, and poor flexibility options (including remote work capabilities) can all affect employee satisfaction and retention. Utilities should review these policies and associated budgets with an aim for flexibility.

Utilities have a few considerations to address these challenges:

- Leadership Priority: Making workforce development a leadership priority is crucial. This involves recognizing the importance of skilled personnel in driving technology innovation and operational efficiency.
- Technology Refresh Cycles: Adopting more aggressive technology refresh cycles can attract talent interested in working with advanced and emerging technologies. Implementing external or bolt-on solutions like gateways, security monitoring, and reporting/analysis can help retain the return on investment on old/legacy equipment while appealing to tech-savvy professionals.
- Training Offerings: Enhancing training offerings to include the latest technological and security trends can increase the value proposition for potential and current employees.
- Improving Pay, Benefits, and Flexibility: Improving compensation packages, including better pay, benefits, and offering travel and flexible working options, can significantly boost both acquisition and retention of talent.
- Prioritize a Positive Organizational Culture: Ensure culture has a place in the priorities of your leadership strategy. Fostering an attractive culture impacts an organization’s reputation outside of its current workforce and serves to draw new talent in addition to helping the organization retain its key performing employees.

Finance & Accounting

In the electric industry, navigating financial and budget-related challenges is crucial for adopting and implementing new technologies. Decisions around investments are significantly influenced by factors such as capital expenditure classification, monetary or financial regulatory policy, and funding opportunities and strategies. Below, we delve into some key financial considerations that utilities should manage in order to innovate more effectively:

- CapEx vs. OpEx: Utilities earn a return on capital expenditures (physical assets) but not on operating expenses (like fuel and maintenance), thereby impacting much of the decision making around implemented technology in our industry. Some utilities may find success in classifying on-premises IT infrastructure (like servers, and telecommunications equipment) and even software (like EMS, and SCADA) as CapEx, highly dependent on state Public Utility Commissions (PUCs) and other oversight policies. Technology that fails to be designed-in and added to larger capitalized projects is often relegated to operating expenses, as is often the case with software and hardware dedicated to cyber security, in addition to new technology initiatives. Additionally, cloud services such as Software-as-a-Service (SaaS) are often considered OpEx, which can be a deterrent due to the lack of return on these expenditures. This classification can disincentivize moving to potentially more efficient cloud services due to utility industry specific financial and regulatory structures.
- Licensing Flexibility: Vendors sometimes reclassify their software to help utilities capitalize on expenses, turning what might typically be operational costs into capital expenditures. This can make new technologies more financially feasible by spreading out their costs over time as a depreciating asset.
- Government Subsidies and Incentives: Utilities may be able to leverage government subsidies and incentives for updating infrastructure, incorporating renewable energy, enhancing grid resilience, and investing in cyber security. For example, the Inflation Reduction Act and the Infrastructure Investment and Jobs Act in the United States provide significant funding for energy security, renewable resources, and electric vehicle infrastructure. This funding supports various aspects of energy technology development, from generation to consumption, offering utilities financial support for adopting new technologies.
- Innovation Pilots and R&D Funding: Exploring new technologies often requires upfront investment in research and development. Government R&D funding can support innovation trials, especially for technologies at a lower technical readiness level. This external funding source can be crucial, as utilities might struggle to justify these investments directly through revenues that are tightly regulated by PUCs.
- Partnerships and Collaboration: Utilities can partner with other industry players such as national labs, research institutions, universities, industry consortiums, and government agencies to leverage collective knowledge, resources, and potentially funding opportunities. Such partnerships can help utilities access new technologies and share the financial risks and rewards associated with innovation.
- Risk Management and Assessment: Utilities must assess the financial risks of new technologies, considering factors like initial investment costs, potential operational disruptions, and long-term returns. Implementing a robust risk management framework helps in evaluating these technologies' viability, aligning them with the utility's financial health and strategic goals. This approach ensures that utilities can balance innovation with financial stability and risk management.
- Consumer-Centric Strategies: Utilities should focus on understanding and segmenting their customer base to tailor their services and communication strategies effectively. This understanding can help them invest in technologies that directly benefit their consumers, making it easier to justify these investments to regulators and stakeholders. Understanding the connection between a technology initiative and the value to the customer can aid in the development of strong business cases and enable more successful CapEx applications.

Relationship between Innovation & Regulation

Within the electric sector, a significant challenge arises in the relationship between innovation and regulation, particularly regarding vendor-produced technologies. This challenge is rooted in the inherent lag between technological advancement and regulatory response, which often slows or limits innovation. Below we explore the various ways this challenge manifests:

- Compliance as a Prerequisite for Adoption: Without clear compliance precedence, utilities, especially those sensitive to compliance risk, hesitate to adopt innovative solutions. The common question from utilities is, "How will it meet compliance?" which underscores the need for compliance assurance before widespread adoption can occur. This scenario restricts innovation to the confines of existing Reliability Standards.
- Resource Disparity and Risk Appetite: Larger utilities with more extensive staffing and resources are better positioned to navigate and articulate internal controls and compliance issues in comparison to smaller, more resource constrained utilities. The resource disparity influences the risk appetite of utilities, with larger utilities more likely to explore and adopt innovative solutions compared to their smaller counterparts. This places larger utilities in a more influential seat than their smaller counterparts to drive innovation in directions that suit their needs, through their vendor relationships.

The Innovation-Regulation Gap: Innovation almost always precedes regulation, making it challenging for regulators to define Reliability Standards for technologies that have yet to be fully realized. In the absence of explicit regulations, vendors may interpret or press industry definitions to align with their solutions Vendors often lack direct access to compliance decision-makers and their opinions before deploying technology at client sites, further complicating the landscape. Tesla, though not a classic utility, serves as an illustrative example of a technology company pushing the boundaries in a regulated industry. Tesla managed to introduce electric vehicles and autonomous driving before specific safety standards were fully developed, showcasing how repurposing existing concepts for new uses can outpace regulation. This example reflects the broader trend of innovation outstripping regulatory frameworks.

- Software Lifecycle: The focus on available patches, rather than addressing vulnerabilities and/or inherent risk due to broader software architecture problems, exemplifies another issue. Situations like the end of support for software (e.g., Windows XP), which will no longer receive new patches, highlight the limitations of current approaches. Vendors find themselves pressured to maintain outdated technologies simply because they meet existing Reliability Standards, even when new technologies might offer enhanced security, performance, and scalability.
- Hardware Lifecycle: Operations technology in the electric sector often faces extended lifecycles, sometimes ranging from 10 to 30 years. This longevity can challenge vendors striving to integrate modern solutions, as the hardware in place may not support or fully utilize the advancements they offer. The discrepancy between the rapid evolution of technology and the slow turnover of OT devices creates a scenario where innovations may be technically feasible but practically unimplementable, leading to a slower pace of technological adoption and potential missed opportunities for reliability and security enhancements.

Internal Compliance Strategies

The electric utility sector often perceives compliance as a barrier, especially when it comes to adopting new technologies. This perception can be influenced by the level of rigidity of a registered entity's internal compliance approach, fear of financial repercussions, and the variability in flexibility among different Regional Entities. We explore this in finer detail below:

- New Technology and Prescriptive Reliability Standards: Appropriately, innovative technologies are rarely defined in prescriptive standards, such as in the NERC CIP Standards. However, this can lead to inconsistencies in adoption, as entities may fear falling out of compliance due to a lack of, or unclear, implementation or security guidelines available to industry, or the perceived lack of endorsement and audit support for a given technology by Regional Entities. A strong relationship with Regional Entities is thus crucial for utilities to maintain a state of compliance while pursuing innovative technology adoption.
- Innovation versus Regulatory Cycle: Utilities aiming to rapidly adopt new technologies might find themselves in a constant state of conflict with demands for internal compliance evidence, and ultimately auditors. Major patches to key technologies, such as virtualization and remote access tools, can introduce entirely new feature sets and even completely rework the underlying technical workings of a system. Something as

obvious as keeping technologies updated and patched, as required by vendors for support, can inadvertently place entities at odds with compliance expectations, leading to a cycle of continuous adjustment.

- New Approaches to Mitigating Risks: Technological innovation can introduce novel risk mitigation strategies that may initially seem restricted by classic interpretations of requirements and evidence measures. For example, the shift from signature-based antivirus software to heuristic or ML-based systems for malicious code detection requires a reevaluation of compliance approaches to accommodate these advancements, especially where cloud technology plays a role. The transition between awareness and understanding, whether a Reliability Standard is truly restrictive of a new technology or not, happens at different time scales for individual entities, and the electric industry as a whole. Traditional networking transitioning to software defined is another example, challenging traditional static documentation evidence measures in the presence of policy-driven ephemeral configurations and baselines. *Reliability Standards Project 2016-02* is an example of an industry-wide effort that leads the way for these transitions, and even paving a way for adoption before standards development is completed, such as with on-premises virtualization technologies, software-defined networking, and zero trust architectures.
- Ambiguity and Lack of Guidance: The absence of clear guidance can slow down innovation. Whether simply for awareness or input, compliance staff should proactively engage with industry committees, regulatory updates, and discussions. This way, compliance staff stay informed, take advantage of available guidance, and facilitate more flexible compliance approaches. Small utilities, which outnumber larger utilities more than ten to one, suffer this burden on their staffing resources and compliance programs disproportionately.
- Compliance as a Foundation, Not an End Goal: Compliance should not be the ultimate goal but a part of the overall security program. It should set the foundation for operational teams that can be built upon to achieve the risk reduction objectives of the organization. Active participation in standard development teams, committees, and industry working groups like SITES is crucial for utilities to ensure that proposed Reliability Standards support their innovation roadmaps. This participation and interaction is the foundation of our self-regulated industry.
- Beyond Minimal Compliance: Aiming for mere compliance can lead to complacency. The threat actor groups targeting our grid are ever evolving, unencumbered by compliance, and never complacent. Therefore, we must ensure utilities are enabled to be appropriately nimble in the adoption of new technology towards securing the grid. Utilities should strive for overarching security where compliance is a component, not the entirety. Compliance is not security, and security is not compliance. The NERC CIP Standards should be viewed by industry as a minimum baseline; not a constraint on innovation, nor a replacement for registered entities performing independent security risk assessment.

While compliance is necessary to establish the basics for safe and reliable operation of the electric grid, the advised approach is one that encourages innovation and flexibility. Utilities need to actively engage in the regulatory process and advocate for Reliability Standards that support technological advancements while maintaining grid reliability, resilience, and security. Additional recommendations to promote are more mature and flexible culture of compliance follows:

- Aim to be risk-adverse, rather than change-adverse.
- When evaluating new technology without existing available guidance, consider engaging regulatory bodies and auditors upfront.
- Improve awareness of available regulatory guidance papers. More knowledge creates more options.
- Towards cultivating a culture of compliance internally within an organization, create a safe, and mutually beneficial space for both internal disclosure on compliance risks
- Seek mock audit from outside consultants or regional entity after initial implementations of new technology.

Lessons From Alternative Regulatory Frameworks

In gauging the effectiveness and impact of Reliability Standards like NERC CIP, a comparative lens aimed at alternative frameworks and industries could be enlightening as the other Reliability Standards could offer insight into the symbiosis between technology enablement and regulatory landscapes. PCI DSS, and Reliability Standards applied in diverse sectors like insurance and safety, present a spectrum of methodologies and outcomes concerning technology adoption and security governance. Various Reliability Standards embody different approaches and imperatives, potentially shaping and constraining technology adoption in distinct manners. The non-mandatory and non-enforceable nature of certain frameworks, unlike NERC CIP, might pave the way for a more flexible, albeit less controlled, technological adoption trajectory. Understanding how these alternative models influence technology enablement, risk management, and operational consistency across different sectors may unlock valuable insights.

Assessment of PCI DSS:

The *Payment Card Industry Data Security Reliability Standard* (PCI DSS) navigates a carefully structured, highly prescriptive path to ensure secure handling of cardholder information, stipulating explicit security protocols which, while bolstering a uniform cybersecurity posture across adherents, potentially imposes constraints on expedient technological innovation and adoption. Such specific and articulated guidelines ensure a clear, auditable compliance trajectory but may inadvertently anchor organizations to established, certified technologies, potentially inhibiting exploration into emerging solutions. The PCI Security Standards Council's practice of validating specific vendors and products, effectively green lighting them for use, has merit and risks. The certification and validation of specific products and vendors does provide entities with a clearer, predefined path towards compliance. The prescriptive nature and clear delineations within PCI DSS serve to eliminate ambiguity regarding compliant technologies and practices, which can be especially advantageous for entities with limited cybersecurity expertise or resources. This approach to validation also fosters a degree of uniformity in security postures across entities, ensuring that baseline cybersecurity protocols are consistently upheld across the payment card industry. However, the downside surfaces in some potential stifling of innovation, as the explicit guidelines and rigid adherence to validated technologies might inhibit the exploration and adoption of emerging, potentially superior, technologies that have yet to be validated by the council. Finally, there's a bureaucratic element that potentially creates a lag between technological advancements and their subsequent validation and approval for use within the PCI DSS framework, presenting an inadvertent obstacle to immediate adoption.

Assessment of HIPAA

HIPAA ensures protected health information (PHI) is secured through adherence to a set of administrative, physical, and technical safeguards. Noteworthy is its comparatively less prescriptive stance toward compliance, which enables healthcare entities to employ a variety of technological solutions, as long as the foundational objective – safeguarding PHI – is met. This intentional flexibility, while fostering an environment conducive to technological innovation and adaptation, presents a potential drawback in the form of varied compliance interpretations and implementations across entities. Given HIPAA's merging of both prescriptive and flexible elements, there is an implied security risk of inconsistency in technology implementation strategies across entities in the healthcare sector. Entities may engage with new technologies and innovate under the flexible aspects of HIPAA, potentially advancing the overall cybersecurity posture of the healthcare sector. However, without a centralized and standardized validation mechanism or clear-cut technological guidelines, entities with limited cybersecurity expertise might inadvertently integrate technologies that inadequately safeguard PHI, thereby elevating the sector's susceptibility to cyber threats and data breaches. The industry, while potentially benefiting from more rapid technology adoption, may also contend with disparities in cybersecurity efficacy and resilience across different entities, pivoting the risk landscape towards a scenario where the security of PHI may be as strong or as weak as the most innovative or change-adverse entity respectively. This dichotomy inherently creates an environment where technological innovation and adoption must be meticulously balanced with rigorous internal risk assessments and cybersecurity expertise, to safeguard against the unintended elevation of cybersecurity threats within the healthcare sector.

Assessment of SOX (Sarbanes–Oxley Act)

SOX, centered around financial integrity, delivers guidelines without delving into technical cybersecurity specifications. This regulatory framework, while emphasizing financial accuracy, doesn't stipulate a detailed technological roadmap, potentially allowing entities to explore innovative financial or cybersecurity technologies freely. However, this general approach may also induce challenges where organizations, in ensuring compliance, could opt for established, proven technologies, potentially circumventing innovative but unvetted solutions. The resulting cybersecurity strategy, while adherent to SOX's overarching mandate, may navigate a path that, due to its inherent ambiguity, fosters a cautious, and potentially innovation-limiting, approach to technology adoption. Viewed in the lens of the electric industry in contrast, however, staple technologies are seen as appropriate, where the risk to adopting a technology with uncertain reliability or security impacts trumps achieving a competitive edge.

Assessment of CJIS (Criminal Justice Information Services)

CJIS, crafted to safeguard sensitive Criminal Justice Information, exhibits a distinctive blend of flexibility and precision in its policy framework, designed to accommodate the varied technological and operational contexts of diverse law enforcement entities. The policy delineates clear security controls but leaves room for entities to select and implement technologies that align with these mandates. These policies potentially foster an environment conducive to technology exploration and adoption. However, the very flexibility that allows for technological exploration can, paradoxically, render the compliance validation process somewhat ambiguous, particularly when considering innovative solutions that may not have a clear precedent in the CJIS context. This framework might oscillate between being an enabler and an inhibitor when it comes to technology adoption and innovation within the realm of law enforcement and related entities. The strategy of not binding entities to specific technologies or vendors implies that law enforcement agencies could, in theory, explore and integrate innovative technological solutions, provided they meet CJIS security controls. Conversely, ensuring that new and innovative technologies comply with CJIS's stipulations may prove resource-intensive and complex, particularly for smaller entities or those with limited cybersecurity expertise. Consequently, while CJIS provides a robust and flexible framework for safeguarding CJI, its inherent complexity and the requisite resources for ensuring compliance might potentially curtail rapid technology adoption and innovation to a certain extent.

Appendix B: Contributors

SITES would like to thank the following individuals for their contributions towards the development of this whitepaper:

- Dan Goodlett
- John Graminski
- John Skeath
- Matthew J Yourek
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- Kristine Martz
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- Lew Folkerth
- Song Zhang
- Thomas Peterson
- Tom Hofstetter
- Ryan Quint

White Paper: New Technology Enablement & Field Testing

Thomas Peterson, SITES Vice-Chair
Marc Child, RSTC Sponsor
Reliability and Security Technical Committee Meeting
December 11, 2024

White Paper Purpose

- Bring clarity to the processes of technology innovation and adoption, i.e., the interactions between innovators, researchers, vendors, and utilities.
- Illuminate the challenges the electric industry broadly faces with technology innovation and adoption.
- Provide guidance to bring down some of these barriers.

Background

‘Aim to be in front of change, not behind it.’

- Drivers
  - Grid-transformation
  - Proliferation of new available technologies with unknown or untested impacts to grid operations, or to the reliability and security of the grid
  - Increasingly rapid pace of technology development
  - Need for regulatory efforts and processes to reflect the pace of technology

Approach

- Broadly discusses the role of technology innovation and technology adoption in the electric industry.
- Looks at the role of ‘production’ or ‘field testing’ of new technologies.
- Evaluates the relationship between new technology, regulatory processes, and NERC CIP standards.
- Draws on lessons from other regulatory frameworks in other industries.
- Key Recommendation: Seeking broad industry adoption of a high-level process for industry-coordinated new technology pilots whose initiation and execution is not dependent on current standards development processes including standards authorization requests (SARs) or standard drafting teams (SDTs).

Draft Changes from Comment Period

- Small changes made throughout paper to frame the paper's purpose more clearly – that of a conversation starter.
- White Paper areas updated:
  - Executive Summary
  - RETINA Recommendation
  - New Technology Use Cases

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Restatement of Request

- SITES requests the RSTC approve this white paper.

Questions and Answers

Technical Reference Document: Clarity of DERs in Operational Planning Assessments and Real-Time Assessments

Action

Approve

Summary

This document is a result of the NERC Reliability and Security Technical Committee's posting of the NERC System Planning of Impacts from Distributed Energy Resources Working Group's (SPIDERWG) Standard Authorization Request (SAR) for clarifying distributed energy resources (DERs) in Operational Planning Assessments (OPAs) and Real-Time Assessments (RTAs). This report's purpose is to document the type and tenor of industry comments related to the posting of this SAR and to document SPIDERWG's technical opinion on how these comments could be resolved. This is in lieu of continued development on the draft SAR as the SPIDERWG sought to table the draft OPA and RTA clarity SAR, which was approved by the RSTC Executive Committee (RSTC EC) in Q2 of 2024 and part of the approved June RSTC consent agenda. This document went for review in Q3 of 2024 and received no RSTC comments during that period.

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Technical Reference Document

Clarity of DERs in Operational Planning Assessments and Real-Time Assessments

December 2024

RELIABILITY | RESILIENCE | SECURITY




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Table of Contents

Preface

Electricity is a key component of the fabric of modern society and the Electric Reliability Organization (ERO) Enterprise serves to strengthen that fabric. The vision for the ERO Enterprise, which is comprised of 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

This document is a result of the NERC Reliability and Security Technical Committee's (RSTC) posting of the NERC System Planning of Impacts from Distributed Energy Resources Working Group's (SPIDERWG) Standard Authorization Request (SAR) for clarifying distributed energy resources (DERs) in Operational Planning Assessments (OPAs) and Real-Time Assessments (RTAs). This report's purpose is to document the type and tenor of industry comments related to the posting of this SAR and to document SPIDERWG's technical opinion on how these comments could be resolved. This is in lieu of continued development on the draft SAR as the SPIDERWG sought to table the draft OPA and RTA clarity SAR, which was approved by the RSTC Executive Committee (RSTC EC) in Q2 of 2024 and part of the approved June RSTC consent agenda.

Chapter 1: Review of SPIDERWG SAR and Comments Received

The SPIDERWG developed a draft SAR out of the RSTC approved recommendations in the *White Paper: NERC Reliability Standards Review*.[1] This SAR was developed with the priority order approved by the NERC RSTC Executive Committee in December 2022, with this SAR developed in the later third of the expected period. As such, it was deemed "low" in relationship to the other SARs SPIDERWG was developing. The draft SAR was posted for 30-day industry comment period starting March 25, 2024 and ending April 24, 2024. Comments were received by the NERC staff liaison for SPIDREWG, compiled, and circulated to SPIDERWG members as part of drafting this technical report.

Review of SPIDERWG Identified Reliability Concern

The NERC SPIDERWG reviewed in the *White Paper: NERC Reliability Standards Review* the entire set of NERC Reliability Standards except for where their expertise was insufficient to determine if the DERs were clear in the set of NERC Reliability Standards requirement language. The SPIDERWG found in that paper that for TOP-001, TOP-002, TOP-003, and TOP-010, the consistent language used to relate to OPAs and RTAs was dependent on the quality of models and methods used to perform the analysis of OPAs and RTAs. They found that "not accurately accounting for aggregate DER levels with a reasonable allocation of their connection points to the BPS could affect the quality and accuracy of OPAs and RTAS." The SPIDERWG thus recommended that a SAR be drafted to alter the language description of the OPAs and RTAs such that it was clear to explicitly account for aggregate DERs (and non-BES generation output levels) in order to ensure quality and accuracy of the OPAs and RTAs. The definitions of the OPAs and RTAs in the NERC Glossary of Terms[2] are reproduced below:

> "**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.)"

SPIDERWG found that the terms "load", "load forecast", and "generation output levels" are also not defined in the NERC Glossary of Terms. This indicated to SPIDERWG membership at the time of review that the interpretation of these terms could limit OPAs and RTAs from excluding DERs entirely from the analysis. SPIDREWG also found that specific language in TOP-002 such as "expected generation resource commitment and dispatch" in R4.1 and "demand patterns" in R4.3 was related to including DERs. As DERs have historically embedded in the gross load, SPIDERWG found that the "demand patterns" and "expected generation resource commitment and dispatch" could include DERs in both values, thus leading to double counting the contributions of DERs depending on entity interpretation. In summary, SPIDERWG found that the terms used to describe the needed inputs for the evaluation was unclear related to aggregate DERs and should be addressed through a Standard Drafting Team (SDT).

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[1] This white paper is available here:
https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Whitepaper_SPIDERWG_Standards_Review.pdf
[2] This glossary is available here: https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf

Review Method

The SPIDERWG Coordination sub-group performed a comprehensive review of the NERC Reliability Standards to identify any possible reliability gaps or areas of improvements with the existing standards as the penetration of DERs continues to increase across North America. The review team (48 members) documented its findings in detailed review sheets and consolidated those reviews into the white paper presented here. A total of 77 of the 96 NERC Reliability Standards were reviewed. The NUC were not reviewed because they are not relevant to DERs, and the CIP standards were not reviewed because SPIDERWG does not have security-related expertise. Lastly, MOD-032 and TPL-001 were not reviewed as those standards have already been reviewed in great depth by SPIDERWG recently.

A review template was developed by the team to cover the most relevant and important information that the reviewers should consider during the review. The template provided operations under each question in order to maintain a consistent review. However, a comments section at the end was also provided for reviewers to elaborate on any issues identified. The questions posed to the reviewers are provided below.

Review Outcomes:

- What is the outcome of this review?

Review Details:

- Does the standard require any revisions?
- Is Compliance Implementation Guidance needed to provide examples for implementing the standard (i.e., how to be compliant with the requirement(s) of the standard)?
- Is a Reliability Guideline needed to provide industry recommended practices related to the standard?
- Items Considered during Review:
- Should the standard Applicability section be updated to consider aggregate DERs?
- If the standard uses the terms "Load" or "Demand", are these terms still clear with the consideration of DERs so that no changes to the standard requirements are needed?
- Are the standard requirements clear regarding how to account for DERs? (e.g., in planning, operating, modeling, and/or design activities)
- Will the effectiveness of the standard be affected by increasing levels of DERs?
- Would the collection of DER data affect the implementation of the standard (i.e., would the ability to gather DER data affect the ability to fulfill the purpose of the standard)?
- Will the increasing penetration of DERs require entities to change the methods they use to implement the standard requirements?
- Other Comments

Qualifiers of SPIDERWG Review in Relation to Current Surveys

SPIDERWG membership has fluctuated between lows and highs. At the time of the review, 48 subject matter experts contributed to the drafting of the document, with even more polled for consensus at the entire working group level. These 48 experts represented Transmission Planners (TPs) and Planning Coordinators (PCs) primarily, however Transmission Operators (TOPs), Reliability Coordinators (RCs), Balancing Authorities (BAs), and Distribution Providers (DPs) were also part of the 48 experts.

SPIDERWG Development of the SAR

As an outcome of this review, SPIDERWG developed a SAR to begin drafting revisions to the OPA and RTA definition so that it was clearly addressing and clarifying the expectations in NERC Reliability Standards. As part of this development, SPIDERWG circulated this SAR to the NERC Real-Time Operating Subcommittee for initial comment and consideration before asking for broader industry comment. During the time between the initial review and the development of the SAR, FERC issued two orders related to Inverter-Based Resources (IBRs). The first order was to identify and register BPS-connected IBRs that currently are not registered,[3] and the other order (No. 901)[4] was to direct NERC to submit new or modified Reliability Standards to mitigate specific IBR concerns. These standards would apply to current registered BPS-connected IBRs, the above-mentioned newly registered BPS-connected IBR (previously unregistered BPS-connected IBR), and IBR-DERs in the aggregate that materially affect the BPS. This last category is a specific technology type (IBRs) that SPIDREWG has accounted for in their review of Reliability Standards, and thus there is some potential overlap with the SPIDERWG identified concern and the mandated revisions to NERC Reliability Standards from Order No. 901.

SPIDERWG's draft SAR had the following scope items:

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.
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.

As there was a potential overlap between the FERC Order No. 901 and this draft SAR, SPIDERWG included the following details in the SAR:

> "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]"

Additionally, the SPIDERWG added that the ongoing work with Project 2022-02 and the operational needs for FERC 901 in the statement above would require review of the standards project work in those areas to align with the work in the SAR. SPIDERWG also added that "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."

[3] Available here: https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20221117-3113&optimized=false
[4] Available here: https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20231019-3157&optimized=false

Comments Received

The NERC SPIDERWG received 35 comments from 11 different entities. Two of the submitted entities had one comment that supported and incorporated by reference a different entity's comments, narrowing down the total number of unique comments to 33 from 11 different entities. The comments were generally themed into the following categories:

1. There is difficulty in including DERs as many entities are not registered as a DP and the Load Serving Entity (LSE) category is retired. Thus, data obligations for DERs connecting through these entities could not be fulfilled yet the standard revisions would require entities to incorporate DER data.
2. Relationship to the IBR registration effort is limited to not only BPS-connected entities, further reinforcing the first bullet's point except for bulk connected resources opposed to distribution-connected resources
3. There is little to no modeling information available to DERs, and obtaining it is next to impossible.
4. The SAR has not identified the totality of standards impacted by the alteration of the OPA and RTA definition
5. RTAs reflect current conditions at the T-D Interface, and the RTA already covers load.
6. OPAs reflect anticipated operating conditions at the T-D Interface and the OPA already covers load forecasts.
7. Bad modeling information is worse than having no modeling information for OPAs and RTAs.
8. The SAR has the incorrect options and principles checked and the text in the scope and detailed description sections should match the reliability principles.
9. The SAR needs clear articulation on the BA, RC, and TOP roles and discretions for determining the appropriate method to obtain DER information for OPAs and RTAs.
10. Some voices of support on project need but provide a sequence of events prior to commencing work on the project.

Chapter 2: SPIDERWG Technical Opinion on Comments Received

From the identified ten themes of comment, SPIDERWG identified the following technical opinion on the theme and provides some ideas on how to incorporate the comment.

Theme 1 – Lack of Registration of DP or LSE to Provide Data

SPIDERWG notes that the current language and version of TOP-003[5] requires the Transmission Operator (TOP) to maintain a document specification for the data needed for its OPAs and RTAs. This specification is required to include "a list of data and information needed by the TOP to support its Operational Planning Analyses, Real-time monitoring, and Real-Time Assessments including *non-BES* data and external network data as deemed necessary by the Transmission Operator" [emphasis added]. This link to non-BES data could include items like wind speeds, irradiance values, or other weather measurement data that comes from weather monitoring stations. These monitoring stations are not registered entities and as such, have no obligation to provide such data to the TOP when requested. However, TOPs have had great success in using such information to predict the future availability of multiple technologies of Inverter-Based Resources. Further, previous FERC Order 881[6] improved the transmission line ratings by requiring transmission providers to implement ambient temperature adjusted ratings for their transmission lines. Metering of the ambient temperature is not a BES quantity, and yet there are methods to inform the TOP the transmission line capacity through use of non-BES data through non-registered entities.

The SPIDERWG acknowledges that because of the lack of a registered entity to provide specific telemetry, the provision of specific information and telemetry will be difficult if not impractical to achieve in the operating room. SPIDERWG's review is not intended to require real-time metering of all DERs to supply data to the Transmission Operator. While having a registered entity can improve the success of a standards revision to improve visibility of DERs in real-time, SPIDERWG notes that such data is not currently available. Thus, any potential revision to standards language should follow similar methods as FERC Order 881 and use available information to forecast and predict operational availability of aggregate DERs rather than focus on requiring individual certainty of DER output.

Theme 2 – Undefined Relationship to IBR Registration

SPIDERWG found that commenters were unsure about the final state of the IBR registration effort as commenters believed the effort to include distribution-connected generation. SPIDERWG's scope is solely on distribution-connected generation (i.e., DERs). At the time of the comments, FERC had not yet released its final order. On June 27, 2024, FERC approved the NERC Rules of Procedure[7] revisions to identify that a Category 2 GO is an entity that "owns and maintains non-BES inverter based generating resources that either have or contribute to an aggregate nameplate capacity of greater than or equal to 20 MVA, connected through a system designed primarily for deliver such capacity to a common point of connection at a voltage greater than or equal to 60kV". This definition is dissimilar from DERs per SPIDERWG as such DERs are not connected through a system designed primarily for delivery of power to a common point of coupling, but rather the DERs are connected through a distribution network. SPIDERWG notes that primary and secondary distribution network voltages are not at a voltage class of 60kV or higher. Rather, such voltages are less than 60 kV. Furthermore, individual large DERs are typically less than 20 MVA. As such, SPIDERWG does not anticipate the definition of Category 2 GO applying to DERs for these reasons.

[5] https://www.nerc.com/pa/Stand/Reliability%20Standards/TOP-003-3.pdf
[6] https://www.ferc.gov/media/e-1-rm20-16-000
[7] https://www.nerc.com/AboutNERC/RulesOfProcedure/NERC%20ROP%20effective%2020240627_with%20appendicies_signed.pdf

Theme 3 – No Modeling Information Exists for DERs

SPIDERWG has produced reliability guidelines on the collection of data to populate aggregate DER models[8] as well as an initial set of dynamic parameters for the DER_A dynamic model.[9] Such information and procedures can serve as the initial set of engineering judgement to estimate DER capacity and information for each load record. SPIDERWG has interpreted these types of comments as ones that desire specific, attributable information for each individual DER and does not believe such information to be suitable for operational or planning assessments. Rather, SPIDERWG identified that treatment of DERs in such assessments was unclear and would recommend that aggregate DER at each T-D Interface have an appropriate representation.

SPIDERWG notes that generation connected to the distribution system is complicated when reflecting the aggregate to the T-D Interface. As multiple generators impact the net flow seen at the T-D Interface, attributing the loss of net flow to the correct individual DER is impractical. As such, SPIDERWG recommended modeling DERs in aggregate at the T-D Interface.

Theme 4 – The SAR did not Identify all correct Reliability Standards

SPIDERWG's initial review only found that the treatment in the identified TOP standards was unclear for how DERs were performing in an operational setting. SPIDERWG's members are primarily not operators but have some operator representatives on the roster. SPIDERWG notes that the Standards Authorization Request can have the correct standards added to it based on the comments received and SPIDERWG agrees that the totality of Reliability Standards impacted by a OPA and RTA definition change should be included in the impacted standards section. In the draft SPIDERWG SAR, the SPIDERWG desired for the SDT to read their change in context for all impacted standards to ensure that changes did not remove clarity when read in context in other standards. SPIDERWG would recommend review of all TOP and IRO standards when adding clarity for how aggregate DERs should be treated in these operational assessments.

Theme 5 – RTAs reflect the Current Conditions at the T-D Interface and RTAs already cover load

SPIDERWG noted in its review that the RTAs already covered the terms "load" but did not have similar terms for the generation that affects the net flow at the T-D Interface. As such, SPIDERWG believes RTAs to be unclear with treatment of distribution-connected generation as this is separate than the "load" at a T-D Interface. Should terms like "Demand" be used it would bring more clarity to the assessment as it pertains to the generation piece of the net flow at the T-D Interface. As the term demand is "the rate at which electric energy is delivered to or by a system or part of a system, generally expressed in kilowatts or megawatts, at a given instant or averaged over any designated interval of time" or "the rate at which energy is being used by the customer", this is more clear than the term "Load" which is the "end-use device or customer that receives power from the electric system". As the RTA definition does not link to the term "Load", but rather "load", such a term is left to interpretation.

As such, SPIDERWG agrees that RTAs should reflect the net loading at the T-D Interface but should be representative of both gross load (i.e., "Load") as well as the generation (i.e., DER) impacting the net flow measured at the T-D Interface. The SPIDREWG does not believe that current practices of using net flow are incorrect, but rather that the model such measurements influence is needed to have clarity in areas where DERs impact the net flow seen at the T-D Interface

[8] https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Reliability_Guideline_DER_Data_Collection_for_Modeling_and_Model_Verification.pdf

[9] https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Reliability_Guideline_ModelingMerge_Responses_clean.pdf

Theme 6 – OPAs reflect Anticipated Conditions and OPAs already cover load forecast

SPIDERWG believes this is like the comments in Theme 5 and reiterates that distinction between “Load”, “load”, and “Demand” for the clarity in treating distribution-connected generation. Furthermore, as anticipated conditions may involve weather forecasts to identify available solar PV resources, DERs could be impacted by such forecasting and should be clearly articulated in such procedure. As next-day conditions for both load and generation are temperature and weather dependent, SPIDERWG believes that similar information that is fueling the load forecast can inform the DER prediction for next-day behavior. As such, the process for predicting future hour Demand should not change; however, the clarity improvement to include DER as part of this process will improve the operational forecast and thus better inform the decisions based on the OPAs. As OPAs are heavily relied upon for next-day generation reserves, better information fueling the generation commitment and dispatch can help operators plan for next-day conditions and help pre-position the system for greater resilience.

SPIDREWG does note that in areas of low DER penetration, this information is not likely to change the outcomes of the OPA and would reiterate that clearly defined aggregate DER is for both areas with large amounts of aggregate DER as well as those areas with minimal amounts of DERs.

Theme 7 – Bad Information is Worse than No Information

SPIDERWG does not agree that bad information is worse than no information. SPIDERWG would agree that no information is a form of bad information. To the extreme, if the limit of entering bad information prevents improvements of models, then no detailed model should be built, and the evaluation of reliability be performed on a “copper sheet” representation to avoid bad model data. As such a representation is not how the interconnected system is assessed, there is a different and practical way to handle introducing new information to the operator set of models and can be handled by an appropriate change management process. However, SPIDERWG does note that bad information that gets past this change management process could cause:

1. Powerflow solvers to fail
2. Topology processing to fail
3. Contingency Processors to not solve one or more Contingencies
4. Contingency Processors to not solve within an adequate amount of time
5. Degraded Situational Awareness

These issues underscore the need for high quality information to be used for OPAs and RTAs. SPIDERWG believes that with proper change management procedures, the bad data concern is alleviated. Furthermore, SPIDERWG notes that OPAs and RTAs do not require specific tools to complete their objectives as defined in NERC Reliability Standards. Operators can perform OPAs and RTAs without their common tools; however, such tools do improve the ability of the operator to take appropriate action.

Theme 8 – The SAR has the Incorrect Options and Principles Checked

Some comments received indicated that the checkbox for the Reliability Principle #3 should be checked rather than left unchecked. SPIDERWG’s posted SAR has this box checked and agrees that the SAR was related to providing “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.” These comments did also include requests to expand the scope of the posted SAR to include requirements on specific entities to provide this information, related to Theme 1. SPIDERWG agrees that while a registered entity could provide specific information, improving the clarity of DER in OPAs and RTAs is not entity-limited and can use other non-BES information. SPIDERWG does agree though that the Distribution Provider is the most likely entity to provide any estimation, data, or parameters to a TOP, BA, or RC for use in their operational assessments.

Theme 9 – Operator Discretion to Obtain DER information for OPAs and RTAs

SPIDERWG agrees with this comment theme that operators should be given discretion for how they should obtain DER information for their OPAs and RTAs. SPIDERWG notes that current language in TOP-003 and IRO-010 allows TOPs, RCs, and BAs, the full discretion on determining the "documented specification for the data necessary for it to perform its Operational Planning Analyses, Real-Time monitoring, and Real-time Assessments" in R1. Registered entities that receive such a request are to "satisfy the obligations of the documented specifications using a mutually agreeable format, a mutually agreeable process for resolving data conflicts, and a mutually agreeable security protocol" in R3. SPIDREWG agrees that this is how registered entities should interact with the method to obtain DER. Using non-BES or non-registered entity sources of data, SPIDERWG would agree that the TOP, RC, and BA should have flexibility to obtain the most relevant and accurate data to use in their OPAs and RTAs.

Theme 10 – Some Comments of Support, but Need Further Action Before Work

The comments that were supportive of this project recommended that before the work progresses for clarity in treatment of DERs in OPAs and RTAs, some additional actions were necessary. These actions were to 1) develop a DER definition, 2) Identify which reliability entities must provide aggregated DER information, 3) review and identify whether existing registration requirements are adequate to acquire the information and if not, develop and implement a registration plan, and 4) develop and implement appropriate standards to address BPS reliability performance. SPIDERWG notes that current ongoing Projects have some of these items already in scope such as the DER definition. Project 2022-02[10] is currently defining DER among its other responsibilities, and SPIDERWG agrees that any revision to OPAs and RTAs should have a clear definition of DER before beginning standard language revisions. However, the remaining actions to identify the correct entity to provide are all housed under progress for FERC Order 901. As standard revisions for 901 are comprehensive, SPIDERWG would agree that incorporating clarity for treatment of DERs in OPAs and RTAs are included in specific language in FERC 901. Should treatment of DERs still be unclear after FERC 901 revisions, SPIDERWG's initial review and action would still be recommended. That is, improve clarity in treatment of DER in OPAs and RTAs.

[10] Project 2022-02 Uniform Modeling Framework for IBR (nerc.com)

Agenda Item 10
RSTC Meeting
December 11, 2024

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

Action

Approval

Summary

This reliability guideline provides best practices and guidance to assist TPs and PCs seeking to assess the reliability impacts of increasing aggregate DERs in their transmission planning studies. This document can help planners better understand the impacts and risks of increasing DER penetration and enable entities to better prepare for, adapt to, and mitigate impacts found in their planning studies. This document includes responses and incorporation of industry comments.

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Reliability Guideline

Bulk Power System Planning Under Increasing Penetration of Distributed Energy Resources

December 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 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

In this reliability guideline, the NERC System Planning Impacts from Distributed Energy Resources Working Group (SPIDERWG) identifies suggested planning practice enhancements for Transmission Planners (TP), Planning Coordinators (PC), and other relevant entities to better account for the growing impacts of distributed energy resources (DER) on BPS reliability. First, the SPIDERWG reviewed relevant planning functions ranging from model development, management, and maintenance to interregional or wide-area planning studies, including Interconnection-wide reliability studies or assessments. Related to the model development for DERs, the SPIDERWG previously focused its guidance[1] on aggregate modeling practice enhancements and the procurement of data to parameterize and validate such models. This guideline assumes that the model parameters and information are available to develop, manage, and maintain the DER component of the aggregate distribution system representation. Just as planning studies rely on accurate models, they also rely on accurate procedures to capture expected conditions in a planning study—the focus of this reliability guideline. The growing penetration of DERs pushed the SPIDERWG to provide additional guidance to TPs and PCs experiencing high DER penetration with the intent of improving BPS reliability through voluntary steps that could be considered when conducting TPL-001 assessments or other planning assessments. While there is no requirement to follow these steps, the SPIDERWG believes that they represent best practices and will facilitate registered entities' understanding of how DERs are impacting Bulk Electric System (BES) reliability along with steps to help mitigate impacts from growing aggregate DERs. While TPs and PCs with high or extremely high DER levels in their area of responsibility are the target audience, all TPs and PCs can benefit from this guideline's recommendations.

The SPIDERWG found that steady-state, transient stability, and transfer capability studies are the study types most impacted by growing DER penetrations; however, the SPIDERWG reviewed numerous distribution- or transmission-focused study types to identify a priority order based on DER penetration at the transmission-distribution interface (T-D interface). In steady-state studies, the SPIDERWG identified impacts to thermal assessment, voltage assessment, and voltage stability analysis. The SPIDERWG found that, updates on quantities of DERs tripped[2] from transient stability should be used to improve the steady-state voltage stability studies for the same contingencies. Regarding transient stability, the SPIDERWG found that the voltage and frequency response of local BPS modeled buses is the most significant choice a planner can make. These choices are largely made in the parameterization of the DER model to reflect the aggregated distribution system,[3] as covered in detail in the previous SPIDERWG guidelines. For transfer capability, the SPIDERWG members provided best practices on representing the transfer of BPS generation to DERs. Some transfer paths contain remedial action schemes (RAS) tied to BPS generation such that the total transfer capability is improved. Displacing this generation could reduce or degrade transfer capability, and the SPIDERWG has provided recommendations to improve the fidelity of studies that evaluate transfer capability.

Improved Practices for Planning Studies

The SPIDERWG has made efforts to develop and identify an adaptable framework that any TP or PC can apply to their planning practices associated with the TPL-001 standard to improve identification of potential reliability impacts of DERs on the 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

[1] All the SPIDERWG guidelines are available on the RSTC website here: https://www.nerc.com/comm/Pages/Reliability-and-Security-Guidelines.aspx

[2] With the assumption the DER's return to service duration is extended. Current return to service times are 300 seconds, well into a steady-state time domain. This practice is uncommon, but the SPIDERWG recommends its adoption.

[3] e.g., inverters, distribution utility reclosers, equivalent feeder representations. These are shared with current load model practices.

4. Performing steady-state simulations
5. Performing stability simulations
6. Performing short-circuit simulations

The SPIDERWG has also identified that TPs are increasingly using electromagnetic transient (EMT) studies in planning assessments. These studies are generally focused on a small area of the transmission system near bulk-connected IBR plants; however, these studies sometimes require translating the positive sequence T-D interface into the EMT domain. As such, the SPIDERWG documented specific lessons learned and procedures when incorporating aggregate DERs into EMT simulations.

Recommendations

Based on its identification of enhancements to planning practices under high DER penetration at the T-D interface, the SPIDERWG developed a set of high-level recommendations that cover the general practices in a planning department. More specific study refinements are provided in **Appendix A:**. At a high level, TPs and/or PCs should do the following:

- Identify DER impacts in their steady-state, stability, and short-circuit assessments and highlight the role of DERs in steady-state, stability, or short-circuit violations in their study reports.
- Account for known levels of DER tripping in their steady-state contingency definitions.[4]
- Ensure the accuracy of the DER trip settings in the dynamic model representation.
- Document DER-related common modes of failure in their set of contingencies applied to planning assessments (e.g., cyber attack, cloud cover). TPs should seek to improve their understanding of these common mode failures through studies on their system.
- Review planning criteria to ensure that it is accurately flagging areas of risk under increasing penetration of DERs.
- 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.

[4] To avoid duplicating procedure, this can be done alongside validation of load response for these same contingency definitions.

Chapter 1: Guideline Purpose and Planning Function Overview

The growing penetration of distribution-connected sources of power across the NERC footprint makes it paramount for the appropriate study procedures to properly reflect the performance of such DERs and their potential impact on BES reliability. This reliability guideline seeks to provide bulk system planners with recommended practices to study the various aspects of DERs in the planning horizon, including information-sharing practices in a utility that serves both the distribution and transmission functions.

Purpose

This reliability guideline provides best practices and guidance to assist TPs and PCs seeking to assess the reliability impacts of increasing aggregate DERs in their transmission planning studies. This document can help planners better understand the impacts and risks of increasing DER penetration and enable entities to better prepare for, adapt to, and mitigate impacts found in their planning studies.

Applicability

This reliability guideline is applicable to TPs, PCs, and Resource Planners (RP). Other entities that perform reliability studies on the bulk system may also find this guideline useful. Some recommendations may also be applicable to Reliability Coordinators (RC) and Balancing Authorities (BA).

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 systems. While this is not compliance guidance, the concepts apply generally to TPL-001, which references MOD-032 in its requirements to use consistent data among the planning standards. However, standards are listed in the **Non-TPL-001 Uses for Base Cases** section.

Applicable Planning Assessment Types

A few broad categories describe the types of planning assessments performed in any given planning department. These 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 the ones 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[5] Planning Studies
- Interregional or Wide-Area Planning Studies
- Interconnection-Wide Reliability Studies

[5] 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 the equipment models. Their responsibilities may extend beyond transmission-level equipment to include the development of models for resources, loads, and flexible AC transmission system (FACTS) devices connected to the system. At some utilities, these engineers coordinate with the corresponding 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 DERs in their area. This function typically supports the other planning department functions.

Interconnection Planning

As 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., Generator Owners (GO) or Federal Energy Regulatory Commission (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 in proposals for bulk-connected projects. Planners typically perform these studies for their own system but sometimes are required to coordinate with other utilities or companies that could be impacted by the interconnection agreement. These types of studies may use positive sequence and/or EMT studies as specified in a TP's planning and interconnection processes.

Long-Term Planning Assessments

For planners, these assessments are sometimes referred to simply as "TPL Studies" as they are typically performed for TPL-001. A public utilities commission can sometimes request an ad-hoc study to support specific state requirements while planning departments may have a 10-year expansion plan that falls under these long-term studies at other times. These studies are typically 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 transmission system improvements. For example, the type of question that 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 its service territory. In market-driven environments, these expansion assessments 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 the 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 may also span many service territories (i.e., TPs) and connect wide regions and may include high-voltage direct current (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 classified as interregional or wide-area studies, as described below.

Interregional or Wide-Area Planning Studies

In some Interconnections, PCs convene to study a very broad expansion plan that is intended to aid many areas of the 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 and 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 that each PC designs per PRC-010.[6] 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 the Regional Entities performs a planning assessment that covers the entire Interconnection or requires Interconnection-wide cooperation and analysis to accomplish the study objective. For instance, NERC's *Long-Term Reliability Assessment* takes each Interconnection into account and requires strong Regional Entity input. Other assessments specific to a Regional Entity include WECC's *Western Assessment of Resource Adequacy*,[7] 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 that the study assesses impact on the entire Interconnection. A "special studies" team is sometimes 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 BPS. As the recommended model framework in the SPIDERWG's previous reliability guidelines suggests, the aggregate DER model is also an important representation for a planner to use when representing the power flow and transient dynamic behavior of DERs. However, to properly study DERs, TPs and PCs, with original equipment manufacturer (OEM) and distribution provider (DP) support, need to ensure that the model behavior appropriately reflects the study assumptions.

The 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 is available on the RSTC website.[8] The practices contained in this reliability guideline assume that DER data has 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 judgment. **Figure 1.1** summarizes key content of the past reliability guidelines.

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

[7] 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

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

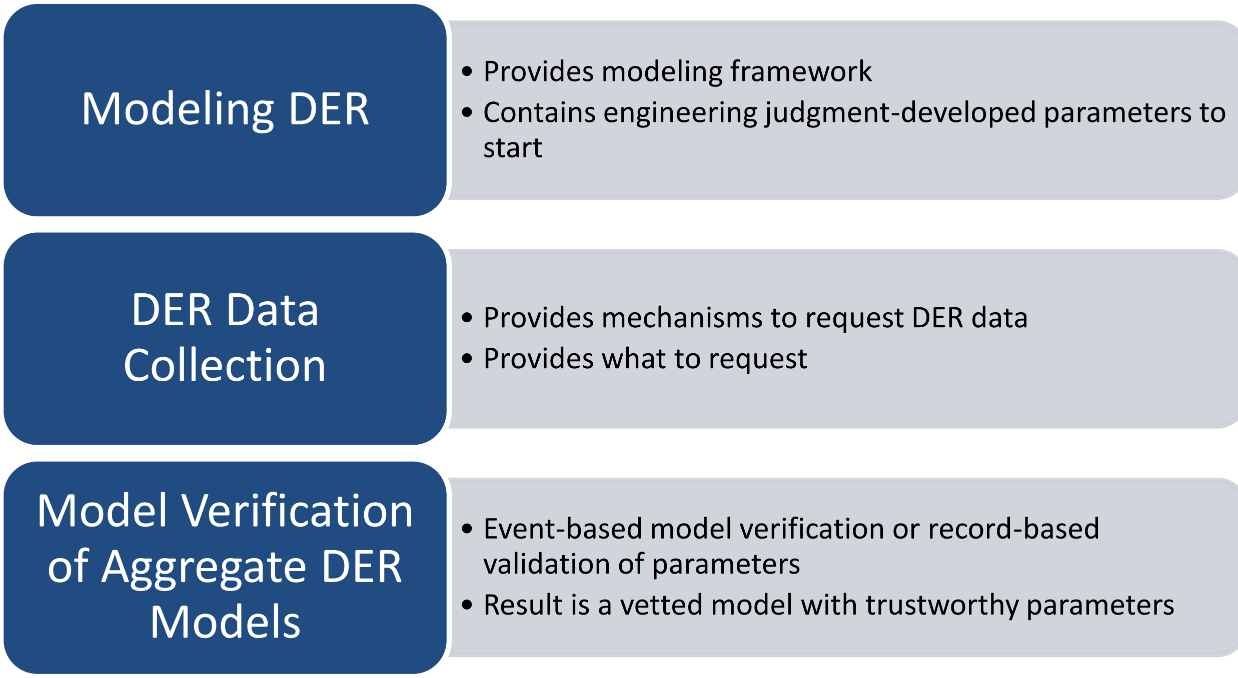

Figure 1.1: Previous SPIDERWG Guidance on DER Modeling

Previous SPIDERWG guidelines on modeling DERs proposed a modeling framework (see **Figure 1.2**) and a process to allow for DERs to be classified into utility-scale DERs (U-DER) and retail-scale DERs (R-DER) as well as a procedure for TPs and PCs to establish modeling thresholds. DER data or engineering judgment is needed to populate the DER models that are included in the Interconnection-wide cases; the SPIDERWG has provided guidance on populating the DER models.[9] An entity can use the past SPIDERWG data gathering and model verification guidance[10] 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. Another previous SPIDERWG document identified specific simulation software improvements[11] that software vendors can employ to guide the next generation of software tools to aid planners in their analysis for large-scale simulation of multiple T-D interfaces affected by growing penetrations of DERs. The SPIDERWG also released a technical report[12] on the methods for co-simulation of positive sequence tools with three-phase, EMT, or other non-positive sequence tools to represent the distribution system impacts on the transmission system, primarily in the verification of positive sequence parameters used in representing the aggregate DERs at the T-D interface. These past documents also serve as a foundation for the content in this reliability guideline.

[9] Available here: https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Reliability_Guideline_ModelingMerge_Responses_clean.pdf
[10] Available here: https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Reliability_Guideline_DER_Data_Collection_for_Modeling_and_Model_Verification.pdf
[11] Available here: https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Software_Vendor_DER_Recommendations_SPIDERWG_postPubs.pdf
[12] Available here: https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Beyond_Positive_Sequence_Technical_Report.pdf

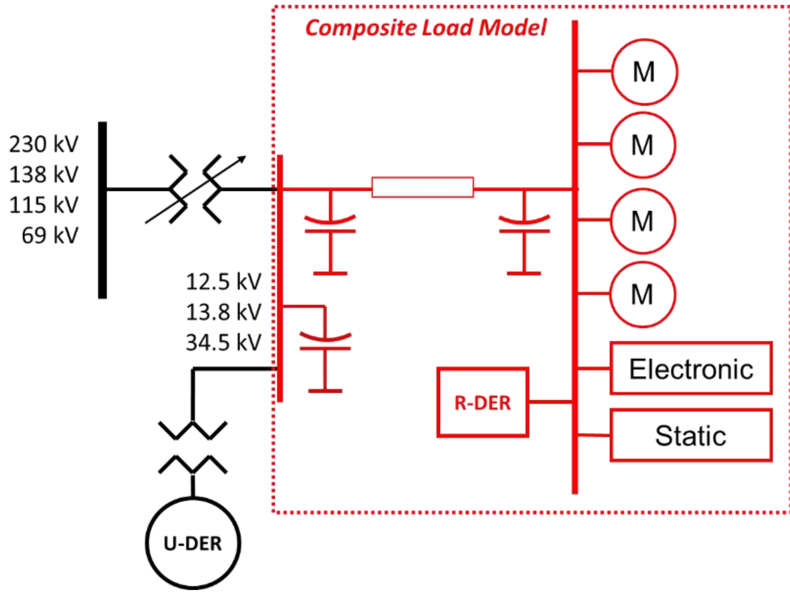

Figure 1.2: SPIDERWG Recommended DER Modeling Framework

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 with which entities should be familiar prior to implementing the recommendations in this guideline, specifically these two:

- Reliability Guideline: Parameterization of the DER_A Dynamic Model for Aggregate DER[13]
- Reliability Guideline: DER Data Collection and Model Verification of Aggregate DER[14]

These guidelines may be subject to future revision or replacement under a new title; however, all currently approved reliability guidelines are posted on the RSTC webpage.[15] Per RSTC procedure, all approved reliability guidelines can be archived and retired.[16]

[13] Available here: https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Reliability_Guideline_ModelingMerge_Responses_clean.pdf
[14] Available here: https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Reliability_Guideline_DER_Data_Collection_for_Modeling_and_Model_Verification.pdf
[15] The SPIDERWG set of reliability guidelines are available at the RSTC page here: https://www.nerc.com/comm/Pages/Reliability-and-Security-Guidelines.aspx.
[16] The listed documents in this document are the latest versions and titles of the active modeling-related SPIDERWG guidelines.

Chapter 2: Planning Study Changes Due to Increasing DERs

This chapter highlights the types of studies impacted by increasing DER penetration in an area. A high DER penetration can impact both BPS planning and operation. This guidance concentrates on the impact of DERs on transmission planning, but distribution engineers may benefit as well.

Impacts from High Levels of DERs 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 BPS. The impacts of DERs on steady-state or dynamic transient studies are typically unique to the study type in question. The 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. In thermal assessments, an increasing DER penetration is seen in the change in flows not only on the distribution feeders where DERs are connected but also in the transmission system.[17] These changes in flow may reduce loadings and mitigate some overloads but may also increase loadings and create new overloads post-contingency. Whether the loading will increase or decrease with the addition of DERs depends on the DER locations, the aggregate levels at the point of interconnection, and the topology of the network. When DERs are tripped following contingencies, usually due to low voltages, there may also be large changes in flows due to net load increase and possibly overloads.[18] Large amounts of DERs can also create reverse flows in distribution feeders if DER output exceeds the magnitude of load connected to the feeder. Such conditions are often expected during spring or summer off-peak conditions.[19] Reverse flows may cause thermal overloads in the feeders if the installed DER capacity exceeds the hosting capacity of the feeders, but this is usually not expected because the feeder's hosting capacity is typically taken under consideration when planning total DER installations.

The expected impact of increasing DER penetration on voltage assessments includes high voltages due to reduction in net load with the addition of DERs as well as low-voltage issues.[20] Under light gross load conditions and high DER output, distribution voltages may be excessively high, and light net loading and reversed power flow across the T-D interface may cause high voltages on the transmission system as well. High transmission voltages may require the installation of additional reactive support that would absorb reactive power (e.g., shunt reactors), which would not be needed without DERs. 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 DER output and low load will need to be turned off during low DER output. As such, increasing DER penetration is anticipated to impact both high- and low-voltage conditions studied in the voltage assessment.

Voltage stability issues that appear with increasing DER penetration are primarily the large voltage deviations seen with contingencies where DERs trip due to low voltage. Extreme cases with significant DER tripping may see voltage collapse. Power flow studies may be challenged to identify precisely how much of the aggregate DERs at the T-D interface will trip for low voltages for a given contingency. DERs may trip with faults due to low transient voltages, and transient stability analysis will validate the expected long-duration tripping of DER equipment to determine how many DERs will trip at the T-D interface. If transient stability analysis shows that DERs are expected to trip and not

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

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

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

[20] 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

recover in the time frame of the transient simulation, then power flow studies should be repeated with the tripped DERs through updates to the steady-state contingency definition where possible and feasible.

While this above back-and-forth process is uncommon, the process and findings will be most helpful over time if care is taken to document the DER's long-duration tripping in the steady-state contingency files and review for their applicability at similar T-D interfaces. TPs should also consider validating their model of expected steady-state DER tripping performance to actual DER tripping and align their studies accordingly. DER tripping in the post-contingency operating state may lead to a more conservative evaluation of expected performance. A dynamic transient stability simulation can inform this validation. Depending on the aggregate representation of DERs at the T-D interface, the DER tripping may be partial, so this value may not represent the entire DER capacity at a given load bus.

Transient Stability Studies

In transient stability, the increasing DER growth primarily impacts the voltage and frequency response of a given planner's system.[21] When analyzing transient voltage performance, it should be considered that delayed voltage recovery may occur following faults in the systems with high induction motor load. Fault-induced delayed voltage recovery (FIDVR) is mostly a concern during summer peak-load conditions in areas with large amounts of residential air conditioners or heavy motor load. Residential air-conditioning load is made up of single-phase induction motors that are prone to stall during faults. DERs may impact FIDVR conditions, especially when DER penetration coincides with high induction motor load operation. If DERs can provide voltage support, they may be able to improve transient voltage recovery and may even prevent induction motor stalling. One negative impact of DERs in relation to transient stability performance is that DERs may trip following faults due to low voltage, potentially degrading system stability and exacerbating FIDVR conditions. Whether DERs will trip depends on the ride-through capability, the distribution utility practices, and the voltage trip settings implemented for the DER facility.

Also of concern for inverter-based DERs is the momentary cessation that may occur in addition to (and before) tripping.[22] During momentary cessation, inverters stop injecting current but stay connected to the grid. Within 400 ms, the inverter's output is substantially restored, leading to less bulk system impact than if the DERs were tripped. Momentary cessation may occur at a higher voltage than tripping, and this difference may be slightly detrimental for the bulk system's transient stability.[23] This issue is anticipated in areas where distribution utilities require enablement of momentary cessation functionality (i.e., IEEE 1547-2018 Performance Category III) in their practices. Long delays in restoring pre-disturbance output from tripping[24] can degrade post-disturbance voltage recovery. As recommended in a previous SPIDERWG document,[25] TPs should account for momentary cessation and DER tripping in their studies. A thorough understanding of known DER capability and performance requirements in each jurisdiction can aid in making appropriate assumptions regarding DER modeling related to momentary cessation and tripping.

Systems with high aggregate DER penetrations at the system level may have inadequate frequency response or frequency reserve due to the increasing percentage of load served by aggregate DERs. Though inadequate frequency response is not solely related to DERs, they contribute to the overall decline of frequency-responsive equipment due to their equipment design defaults. This means that, unless the BAs procure other reserves, increasing DER dispatch

[21] 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

[22] 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

[23] 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 DERs.

[24] Momentary cessation in the distribution context is set at a 400 ms time frame; afterward, 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."

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

(i.e., by default frequency non-responsive) may degrade the available frequency-responsive reserve. In addition, system inertia may be reduced if a large amount of DERs are inverter-based (e.g., solar PV), which may contribute to higher rates of frequency decline that could trigger under-frequency load shedding (UFLS) for contingencies that involve the loss of large amounts of generation. DERs interconnecting in accordance with IEEE Std. 1547-2018 are required to be able to provide sustained primary frequency response, but utilities are not required to use the capability from the equipment or plant. Furthermore, IEEE 1547-2018 does not require DERs to maintain energy/power headroom to use for sustained frequency response by default. Thus, the impact of increasing penetrations of DERs on frequency response is dependent not only on the capability of the DERs but also the dispatch of the DERs to allow for frequency response. Studies related to frequency response should 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, BAs should ensure that their frequency-responsive reserve procurement strategies and studies account for DER impacts to the growing non-responsive (to frequency) generation. The TPs' studies should identify if their study case does not reflect the expected frequency-responsive reserves when assessing the response to credible contingencies and correct the case where appropriate. Furthermore, TPs should ensure that the frequency response of the aggregate DER model is reflective, in aggregate, of distribution utility practices, utility protection at the point of interconnection, and specific equipment and plant protection[26] at the DER facility.

Transfer Capability

Large amounts of DERs in the system may impact transfer capability and transfer limits if DERs displace the conventional resources that are armed for RAS that allow for high path flows.[27] 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 this may potentially influence allowable transfer path ratings. Transfer capability studies should ensure that their path ratings account for any impact of this capacity transfer on the studied path. Thus, transfer capability studies should incorporate appropriate DER modeling to identify any potential reliability issues that may be caused by increasing DER levels. More information on the improvements that PCs can make to account for this potential influence on transfer path ratings is provided in **Appendix A:**.

Types of Studies Under Consideration

Historically, TPs 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 for focuses like protection systems that needed more detailed information. While that paradigm still holds true in many areas, some planners see a need for representation of inverter-based resources (IBR) 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 the model increases in detail, it becomes apparent that the distribution system itself plays a factor in how entities are studying the impact of DERs on the transmission system. The SPIDERWG work product *Technical Report: Beyond Positive Sequence*[28] 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 is not performed on settled quantities, yet long-duration controls like automatic governor control may impact the analysis. The EMT average vs. EMT switched relates to whether the controls on the

[26] 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 information necessary to reflect performance. 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 under-frequency conditions.

[27] 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

[28] Available here: https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Beyond_Positive_Sequence_Technical_Report.pdf

transistors are modeled (in the switched domain) or compared against the reference waveform output (in the average domain).

TPs and PCs likely do not perform all these studies in their planning assessments, and specific studies that a DP may perform are listed in the below table. In general, DER integration studies are solely performed by DPs; it is unlikely that a single DER would significantly impact transmission reliability. However, the aggregate impact of large amounts of DERs should be assessed by a TP or PC. For studies that evaluate the electrical performance at a T-D interface (e.g., ride-through studies), coordination among the DP, TP, and PC is recommended.

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

Evaluation Category in Study	Duration of Study	Simulation Domain (DER Model Type)
Distribution Provider		
Harmonics	Steady-state	EMT (switched), Phasor (dynamic and steady-state)
Branch current, filter dynamics	Transient	EMT (switched or average)
Current controller tuning	Transient and steady-state	EMT (average) or phasor (dynamic and steady-state)
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 and 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 DERs on the distribution system. When DER capacity as a percentage of gross load (i.e., DER penetration at the T-D interface) is low, TPs and PCs are unlikely to perform any DER impact studies. However, the SPIDERWG believes that it is important to understand the aggregate impact of DERs in a TP/PC area even at low penetration levels as seen in the findings of the *DER Modeling Study: Investigating Modeling Thresholds*.[29] While DER impacts are diminished at low penetration levels, beginning the process of incorporating these resources into entity planning studies is a best practice that, if employed, could help ensure that unexpected impacts are identified while developing improved planning skills and practices in advance. Moreover, at low penetrations, DERs 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 DERs (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 that proper ride-through, phase-lock-loop (PLL) response, and equipment behavior are accounted for in transmission studies. This may include outreach to DER owners or operators as well as other distribution entities to ensure successful collaboration.

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

TPs should review the priority order[30] 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 DERs 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**.

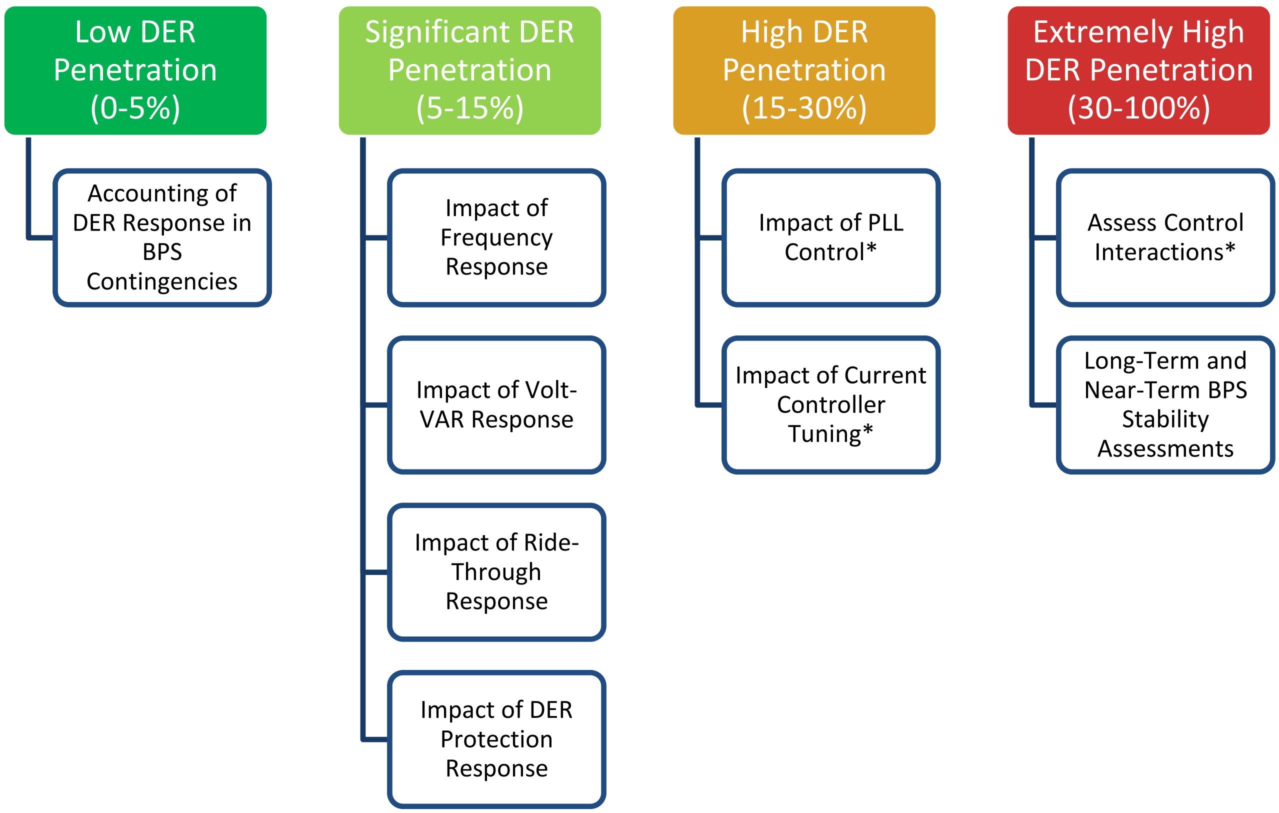

Figure 2.1: Priority Order for DER Transmission Studies Based on T-D Interface DER Penetration

The asterisks in the figure above refer to the fact that, while there is a loose connection between DER penetration 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.

[30] 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, the SPIDERWG developed recommendations for running transmission planning studies that include DERs. The following sections summarize the provided guidance.

TPL-001 Planning Assessment

NERC TPL-001[31] 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 are applicable to TPs and PCs.[32] The sections below trace the practices associated with the 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:

- Development of base case
- Development of credible contingencies
- Development of scenario case(s)
- Steady-state study
- Stability study
- 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[33] and, as such, are highly dependent on the engineering judgment and assumptions in the case. Historically, peak-loading conditions have been assumed to present the most stressed system conditions to assess the presence of 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[34] 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. The proliferation of DERs is making it 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 DERs. 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 (e.g., peak net load, peak gross load,

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

[32] The SPIDERWG has performed an extensive review of TPL-001 to ensure clarity regarding DERs 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

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

[34] 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.

high DER output) may be needed to assess the impact of DERs on BPS reliability in transmission planning. Concerning aggregate DER dispatch in the base case, the major assumptions that a TP should review are as follows:

- Time of day
- DER output at the T-D interface
- DER control logic,[35] enabled/disabled for each control, represented in the aggregate at the T-D interface
- Case dispatch

Table 3.1 provides some guidance on how the assumptions play out during base case development. For a rigorous study, more than one base case will need to be developed to capture diverse system conditions. These would not be considered sensitivity cases to be compared to a base case without DERs.[36]

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 historical values that drive base cases and 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 for summer due to the high amount of air-conditioning load during that time. It would not make sense to choose early morning (e.g., 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 Interconnection-wide case dispatch.	Since most DERs are solar PV, most, if not all, of the output can be estimated using average irradiance[37] as a guide. Should other types of DERs be included, engineering judgment 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 battery energy storage system).
Base-Case Assumption Review	No	TPs and PCs should pay close attention to the area where DERs are located and how their control logic is set by the regulators of that interconnection. Protections applied by DPs that may supersede DER ride-through performance should also be considered. This is a case quality check or "sanity check" to avoid accidentally inputting incorrect parameters from other assumptions where those assumptions do not hold. Typically, IEEE 1547 vintage provides some insight into 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 provided as a guideline by IEEE 1547. In

[35] For example, primary frequency response or voltage control.

[36] 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.

[37] 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**
		particular, the control logic parameters of voltage and frequency control settings and ride-through parameters should receive attention.
Bulk Generator Dispatch Assumptions	No	Historically, case dispatch was performed under a priority commitment process where each generator was weight against the case 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 on-line in a base case under growing amounts of DERs. If DERs are considered a "must-take" resource[38] in their independent operation, they are not a candidate for being off-line when determining the base-case dispatch unless known to be unavailable for a given base-case condition (e.g., solar PV for nighttime conditions).

Non-TPL-001 Uses for Base Cases

These Interconnection-wide base cases have uses outside of the TPL Annual Planning Assessment performed by TPs and PCs. While the guidance in this document is for the planning assessments (including the Annual Planning Assessment), the base cases developed for these assessments are regularly used elsewhere. This section shows the various areas in which base cases are used outside of TPL-001. 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 DERs is included in their studies, which can include their regular assessments (inclusive of TPL-001) or other (non-TPL-001) procedures. As special base cases are not developed for each use listed in **Table 3.2**, the base-case assumptions and DER representation should be carefully reviewed before a base case is used for the purposes listed in the table.

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-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[39]

[38] This assumes that the DERs are not controlled via a DER Aggregator or other entity that can curtail the output of the DER. Utility-owned DERs 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.

[39] The 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

Table 3.2: Base-Case Uses	
Associated NERC Standard	**Description of Use**
PRC-010	Establish and study the PC or TP UVLS scheme[40]
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
IRO-017	Assess, establish, and coordinate outages across Reliability Coordinators

Development of Credible Contingencies

After a base case is developed, the next step in a planning assessment is 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 important; the following should be used to determine when to include DERs in the contingency:

- Quantity of nearby DERs that can trip in response to the contingency[41]
- Common mode failure of DERs that can impact the performance of the T-D interface

The loss of nearby DERs may need to be included in steady-state contingency definitions because it is likely DERs trip due to the system disturbance (i.e., failure to ride through). This is not covered by consequential DER tripping 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.

TPs should verify their set credible contingencies for the chosen base case against the topology and base assumptions. As DERs and load response are not held to different model fidelities, TPs should perform their validation of contingencies on both DERs and load collaboratively. As the distribution system impacts are aggregated representations in the transmission study, onerous back-and-forth DERs and load-tripping verification for the set of contingencies is not a feasible outcome. Rather, TPs should perform both load and DER validation together when updating the amount of local load or DER tripping to more accurately represent the resulting actions in each system disturbance.

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 performs 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 specified conditions to vary 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 but may not create a sensitivity that would stress the local area. TPs and PCs should develop sensitivities that highlight the impact of notable changes

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

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

to the greatest extent possible. For example, 100 MW of solar PV DER growth being added into the base case could constitute 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 DERs in simulation should be considered:

- Load distribution and composition
- Transmission topology changes
- Inertia of the system
- Flows on major transmission paths

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

TPs should review the following sensitivity case descriptions to determine the appropriate case(s) that they need to assess the reliability impacts associated with high aggregate DER penetrations:

- **Peak net load (demand)**: This case aligns with historical pre-DER peak-load conditions. That is, the case contains the heaviest (for a certain percentile) net load seen by the grid.
- **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 can sometimes be referred to as a “High Solar” case in the summer depending on the DER composition. DERs should be adjusted according to expected availability in this light gross load/high DER output case. TPs and PCs can plot gross load against DER output to find historical conditions[42] in areas with significant DER penetration.
- **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 DERs fail to ride through disturbances, overloads and voltage stability are a concern here.
- **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.[43] 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 that the predominant DER technology type is solar PV. This DER case should not be duplicative with other “High Solar” cases but rather included in other case builds.
- **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 overnight, so the primary DER fuel type (i.e., solar PV) would not be producing power. Battery storage DERs could be dispatched, but these conditions are typically beneficial for battery charging. This condition could be a “No Solar, High BESS” scenario or 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

[42] 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

[43] 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 off-line 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.

voltage control issues as the reduction of bulk connected generation destabilizes the transmission grid. The SPIDERWG highly recommends that all TPs study this condition 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 could also trip post-contingency due to ride-through capability limitations. In addition, although they are usually equipped with voltage control capability, it is not practical for DERs to regulate BPS voltage. Because distribution and transmission voltage levels are most often decoupled by on-load tap changers (OLTC) or feeder regulators at or near the T/D interface, DERs cannot provide the BPS with steady-state voltage support unless a communicated control system, such as a distributed energy management system (DERMS), is applied. The BPS might experience high voltage 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 provided in Error! Reference source not found..

High DER output levels could complicate thermal studies for either load-supply reliability issues or generation congestion issues. Congestion issues could occur in a pocket with lower net load combined with high output from transmission-connected baseload generation (e.g., wind, solar, nuclear, coal). If generation needs to be reduced to decrease 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 DERs 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,[44] 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 that part of the system may be reduced. This can potentially cause congestion or high-voltage issues in other parts of the system due to switched capacitor banks anticipating higher flows into the distribution system, which may require a modification to capacitor switching practices.[45] For contingencies that trip DERs or reduce DER output, thermal overloads could happen.[46] For these studies, gross load[47] is the primary factor that drives flow. As such, it directly relates to potential thermal overload. During conditions that trigger DER tripping, load could also be tripped and offset the impact of the DER tripping and potentially result in a non-overload post-contingency operating state. TPs should consider initiating causes that trip just DERs against those that could trip both DERs 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 the following:

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

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

- High-voltage issue during light net load conditions

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[44] 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

[45] 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.

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

[47] Assuming gross load also does not trip during the simulation.

- Low voltage caused by tripping of DERs or reduction of DER output
- Steady-state voltage stability issues

When integrating high penetrations of DERs at the T-D interface into the active power-voltage (PV) and reactive power-voltage (QV) analysis, the TP should recognize the limitations of software modeling capabilities concerning DERs at low voltages. An important parameter to note is the power flow software's alteration of load values as voltage lowers, which is a true steady-state phenomenon for non-converter connected electrical motors. The parameter[48] is a voltage setpoint in the power flow solution software for load buses that will alter the constant power and constant current representation of the load and convert it to a constant impedance representation below the specified voltage to help aid in convergence of solutions in steady-state or dynamic transients. As most phasor-domain software adds DERs as part of the load record, TPs should 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 load. However, both aggregate DERs and load in the post-disturbance steady state should be accurate to the expected on-line 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 simulation and verify that if that equipment is expected to stay off-line 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:

- In areas of high DER penetration, TPs should run sensitivities where the output of the DER is changed significantly from the base case.
- TPs should understand how the simulation's altering of load under low voltage for convergence affects DER injection in their steady-state studies and consult their software vendor if necessary. If DER injection is altered because of this software option, the contingency may need to be studied in a dynamic simulation to see if the DER will trip off-line. Furthermore, the contingency should be re-studied by breaking out the aggregate DER as a separate generator record and studied as separate component.
- TPs should update[49] their contingency definitions to account for DER tripping response (utilizing known or expected DER performance—possibly based on results from stability studies). TPs should also perform the following:
  - TPs should prioritize the areas (T-D interfaces) with high penetrations of legacy DERs or where distribution utility practices would increase the likelihood of DER tripping due to a contingency.
  - TPs should update their contingencies based on their stability studies where tripping of load or DERs is shown to have extended into the steady-state period. This should also be done in collaboration with load model updates as the intent is to not hold load and DERs to different modeling fidelities and to not duplicate work.

Stability Simulation

This section highlights the impacts of DERs on stability simulations; more specific study methods are provided in **Appendix A:**. A higher penetration of DERs can potentially impact system dynamic stability in various ways, including the following:

- Contribution to 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[50]

[48] The name of this parameter changes based on specific power flow 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."
[49] At a minimum, TPs should perform the update annually.
[50] DERs can be designed to provide frequency response. However, the majority of existing DERs do not provide frequency response.

- 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 DERs 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 assessments 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. This can be done by an explicit generation record and modeled distribution system or combined with the composite, component, or other load models that integrate DER dynamic response. Furthermore, aggregate DERs should have a properly parameterized model to represent installed or expected equipment behavior for large signal disturbances. DER voltage and frequency protection settings should be modeled.[51] When studying FIDVR, particular attention should also be paid to the load components in the composite load model.

Contingencies in an annual planning assessment (TPL-001) that should be considered include the following:

- **Event for loss of DER capacity:** Some cyber-based contingencies[52] may equal to 1–2 times the largest generator. Other physics or topological contingencies include normal BPS faults.
- **Contingency type P3 modifications:** The initial condition (i.e., the loss of generator unit followed by system adjustments) should reflect reduced aggregate DER capacity[53] 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

Active and reactive power output of aggregate DERs at the T-D interface, system bus voltages, and transmission line flows should be monitored to compare the trajectory and calculate stability margins for a TP's system when assessing dynamic analysis results. 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.

Furthermore, TPs may also want to consider including small-signal stability and low-frequency inter-area oscillation analysis in their planning assessments. At the Interconnection-wide study level, the inter-area oscillatory impact of DERs should be studied to identify changes to the oscillatory modes and to known system interactions. As this study is typically more specialized than any one TP's planning area, PCs or Regional Entities can have a "special studies" team identify oscillatory model shifts. However, the small-signal stability of a TP's system is important to assessing the impact of aggregate DERs as penetrations grow. As such, the TP should consider performing an eigenvalue analysis to assess whether its system is stable. The linear analysis can be performed on the BES integrated with DERs

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

[52] While novel, these types of contingencies can occur through an OEM's compromised facilities. Presentations to the SPIDERWG have demonstrated that 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

[53] DER capacity may be limited in times of widespread cloud cover for temporary, bus-sustained periods. These situations may mirror an N-0 typical system that has been adjusted to the reduced DER output. Note that such conditions would still have seasonal capacitor schedules even if not optimal for the operating condition.

with varying operating conditions, and corresponding eigenvalues can be obtained from the system state-space matrix. As the penetration of DERs increases, the system's poles move toward the right half of the s-plane and make the system small-signal unstable.

DERs are required to have islanding detection technology per requirements in IEEE 1547-2018 equipment standards that require DERs to avoid energizing into an island. Since the standards do not specify how such functionality is implemented, a wide variety of schemes, mostly proprietary, exist. 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 aggregate DER penetrations by doing the following:

- TPs should ensuring that DERs are not netted with load in their stability simulations and use proper frequency and voltage-trip parameters to capture expected equipment behavior. DERs can be integrated into load models in an explicit manner or modeled as standalone aggregate generation at the T-D interface.
- TPs should vary the depth and type of BPS faults to assess the ride-through performance of their DERs in high penetrations of DERs at the T-D interface. The TP should ensure that phase-to-phase interactions are benchmarked against a beyond positive sequence method to ensure that their positive sequence representation is appropriately depicting this ride-through.[54]
- TPs should study the impact of widespread DER integration and subsequent inter-area oscillatory mode changes with their PC or other Regional Entities. These studies should focus on DER penetration, mode frequency, mode damping ratio, and mode shape changes.
- TPs should perform a small-signal stability study that assesses the stability of aggregate DERs in their system. This study should focus on areas of the TP's system that includes high-IBR penetration at the bulk level and with high DER penetrations at the T-D interface.

Furthermore, TPs should revise their contingency definitions used in the steady-state studies if the stability simulation shows that a portion or all the DER trips and is expected to stay tripped into the next steady-state period. This should be part of the method that a TP uses to account for DER tripping in steady-state analysis, but the TP should exercise engineering judgment on which method to account for DER tripping in steady-state analysis is best suited for its area. This recommendation can also be performed for the gross load that trips off-line and is not expected 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 have been challenged, especially with close-in single-line-to-ground faults on the distribution side of the substation.[55] 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 short-circuit models are one piece of the study, the goal for short-circuit assessments is to evaluate the effect on system fault currents from sources of fault current (that can include DERs), identify underrated breaker equipment, and propose upgrades to equipment where underrated.

[54] Some methods are documented in previous SPIDERWG papers, such as this:
https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Beyond_Positive_Sequence_Technical_Report.pdf
[55] As seen in: https://ieeexplore.ieee.org/document/10078461

The short-circuit models themselves can be linked to the MOD-032 data requests jointly developed by the TP and PC for the area. To assist in assessing DER impacts on a T-D interface for short-circuit studies, the following should be addressed via modeling information or engineering judgment at the T-D interface:

- T-D transformer winding configuration
- T-D transformer sequence impedances
- T-D transformer grounding resistance
- DER capacity to deliver fault current[56]
- The lumped circuit equivalent (including sequence components) for the distribution system

Entities performing short-circuit studies for areas known to have high DER penetrations at the T-D interface should include the fault current contributions from aggregate DERs and load from the distribution system to evaluate the required interrupting capability and breaker duty for nearby bulk-connected breakers. The SPIDERWG has found that these breaker duty impacts typically only occur 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. Furthermore, the following methods can be used to evaluate if the "correct" amount of generation is "on-line" (and thus able to provide its fault current) in the case:

- Determine the gross loading of the area where the study is being conducted, typically a few electrical buses from a BPS bus (including non-BPS elements where appropriate).
- Determine the DER dispatch in that area.
- If the DER penetration in the study area is 5% or more, account for the DER by adding a generator record representing the aggregate DER behind the T-D transformer.[57] Then, evaluate the fault current contribution at full DER and no DER contribution conditions.

The above steps assume that the majority of DERs 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 DERs 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 initial voltage and impedance assumptions for all fault current sources) should be reviewed to assure the adequacy of the study assumptions. Presentations to the SPIDERWG[58] have indicated that high PV penetrations on the distribution grid have not resulted in widespread protection coordination misoperation but rather indicated local areas that need enhancements to account for the impacts of DERs on relay operating times. Short-circuit studies should identify the available short-circuit 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:

- TPs should ensure their short-circuit models accurately reflect the fault current contribution and expected ride-through of DERs.
- TPs should ensure that their short-circuit models have the expected fault current sources "on-line" in the case. For some areas, this means turning off-line bulk system generation[59] under high aggregate DER

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

[57] Note that this also would require representing the T-D transformer and its sequential components in the study as well.

[58] 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

[59] One example of how the penetrations may change day to day is ISO-NE's Easter Day load curve in 2023. Its DER penetration rose to nearly 36% instantaneous penetration.

penetrations and comparing to the case where no DER is on-line, and all fault current comes from bulk system generation.

- TPs should 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 DERs

The use of 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 DERs in EMT studies, but a few entities have identified specific motivations for incorporating DERs into EMT studies. Motivations for including DERs in these studies include the following:

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

ISO-NE requires DERs of 1 MW or greater to notify ISO-NE that they are seeking to interconnect and to follow a study process similar to the bulk-connected side.[60] Furthermore, ISO-NE gathers information about in-service DERs from a voluntary survey.[61] Based on this information, ISO-NE uses the monitored load, DER capacity, and irradiance data to develop representative models of the gross load and DERs. 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. ISO-NE's initial work in this matter offers a few lessons learned, including the following:

- 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.
- 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, it is better to use generic EMT representations and assumptions than netting DER with the load.
- 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 increases. It is a common practice to reduce the number of buses via a mathematical equivalent model, and ISO-NE's process does not require the explicit and detailed representation of the approximation distribution system in a transmission-level EMT simulation that reflects the impact and interaction of aggregate DERs.

[60] The 1 MW threshold is uniquely low in this regard. The 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.

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

- ISO-NE used conversion software tools to translate the positive sequence transmission network model to the EMT domain. These tools ensure topology consistency between positive sequence and EMT models and facilitate a more efficient EMT case development process.
- 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.
- EMT studies at the transmission level are still in the 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.
- In its processes, ISO-NE acts as a coordinator of studies performed by its Transmission Owners (TO) or the consultants of the TO. The SPIDERWG notes that running an EMT study will increase the number of manhours spent on a project due to the complexity and trouble-shooting challenges associated with EMT simulations. Increasing expertise should provide some reduction in necessary manhours over time, but performing EMT studies at this time requires significantly more labor than traditional stability studies.

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

Chapter 4: Interpretation of Planning Study Results

While not widely discussed in the planning analysis, the planner's interpretation of the study results is fundamental to planning assessments. For this reason, it is important that planners consider evaluating their area's performance against a wide array of criteria review in their studies while recognizing that not all criteria violations can be mitigated by DER-specific corrective action plans (CAP). This chapter details the stages of results comparison and development of mitigations. It also summarizes the broad recommendations of the reliability guideline.

Comparison of Results to Established Planning Criteria

After planning simulations are completed, study results are evaluated against a set of planning criteria to identify violations and determine corrective actions, if necessary. Examples of planning criteria[62] are listed below:

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

As seen above, certain criteria can 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) go 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). Currently, EMT criteria are in development and current best practices are to translate the positive sequence criteria into the 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.[63]

The historic planning criteria that dictate acceptable performance of load buses in the simulation have been developed with the assumption that they will serve gross load. As DER penetrations rise, this challenges the assumption that the planning criteria are effective for 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 DER penetrations and load.

Development of Mitigations Related to DERs

If a CAP is required, a wide variety of technologies and solutions can be considered. Simulation results with and without the CAP implemented should be compared to identify if the CAP accomplishes its reliability objective. In

[62] Specific thresholds and/or exceedance levels may vary based on the disturbance event severity.
[63] The protection modeled in EMT, however, would use this instantaneous voltage for performance. Criteria violations would use the derived three-phase quantity.

addition, the most comprehensive CAPs rank alternatives that can mitigate the reliability gap such that a variety of solutions are studied. TPs may need to evaluate equipment upgrades on the distribution system as a potential solution for criteria violations related to DERs. Per IEEE 1547-2018, the DER equipment is allowed a significant number of frequency and voltage control parameters and operational modes. TPs may be able to identify a CAP that includes DER conformance to a set of parameters to mitigate the identified violation(s). As a best practice, TPs should consider the following questions when developing CAPs for assessments that involve interactions of aggregate DERs on the bulk system:

- Are instabilities associated with aggregate DERs observed throughout the system or is it a single T-D interface that experiences the problem?
- Does the DER model quality[64] limit ability to implement the CAP on DER equipment?
- 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, certain common improvements can be made to planning practices and studies to capture the impact of DERs as their penetration grows. TPs and PCs should consider the following recommendations and implement as appropriate for their practices:

- TPs and PCs should 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, or short-circuit criteria violations. TPs and PCs should review **Appendix A:** and adopt the study-dependent recommendations.
- TPs and PCs should reflect expected dynamic reactive power performance of DER equipment in their stability simulations. Dynamic injection and withdrawal of reactive power by DERs during system disturbances can impact study results.
- TPs and PCs should account for DER tripping in their steady-state contingency definitions and properly reflect expected DER trip characteristics in stability simulations. This should be done alongside load model updates to avoid duplicating contingency definition revisions.
- PCs should engage neighboring PCs to develop a common understanding of DER settings (i.e., share appropriate DER models through Interconnection-wide case building processes) in their system when coordinating their planning assessments. PCs should also endeavor to document any DER-related impact(s) in their planning assessments.
- TPs should document known DER-related common modes of failure in their set of contingencies applied to planning assessments. TPs should seek to improve their understanding of these common mode failures through studies.
- TPs and PCs should develop a process to review their planning criteria to flag areas of risk under increasing penetration of DERs. TPs and PCs should consider developing criteria[65] 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 DERs on Transmission Studies** section.
- When developing CAPs, TPs should ensure that the action taken in the plan solves the root cause of the issue and document how growing DER penetration can impact the plan’s viability. TPs may also coordinate

[64] 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.

[65] 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.

with system operators to obtain data that might help them better understand whether their proposed mitigations address the root cause of the issue.

Appendix A: Types of Studies and How to Incorporate DERs

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 DERs into the study methods, results, and analyses. These methods were developed based on the review and input of SPIDERWG members and from various presentations to the SPIDERWG.[66]

Specific Steady-State Study Methods

The 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 DERs

Since DERs are decoupled from transmission system steady-state voltages by OLTC or feeder regulators at or near the T-D interface, there is no transmission voltage regulation provided even for DERs with voltage regulation capability ("volt-var function"). 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. 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. Furthermore, DERs that may operate in voltage control mode are not likely to directly regulate BPS voltage.

Other factors that should be considered are distribution-connected voltage support devices and the 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 on-line than are needed under conditions that were previously not contemplated. One such example would be a distribution system having its fixed shunt capacitors on-line 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 its expected capacity. This may further contribute to high voltages in the distribution system and BPS 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 that 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.

[66] 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

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 DERs reducing net load; both conditions may need to be studied). TPs should consider the DER's shape and gross load to understand where this may occur.[67]
- 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.[68]

Assumptions

To study high-voltage issues during light net load conditions, TPs should consider the following study assumptions to capture the impact of high penetrations of DER at the T-D interface:

- Distribution and transmission shunt caps may still be uneven 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 off-line given specific conditions (e.g., time of day, year, loading, voltage, order).[69] 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.[70]
- 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 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[71] and zero crossings at approximately sunrise and sunset.

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[67] 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., 3 a.m. 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 DERs are significant).

[68] The 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

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

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

[71] 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 judgment should be used to determine the expected available power for the season represented in the planning case.

- 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- 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:

- TPs could modify their shunt switching practices.
- TPs could add voltage control devices on the transmission side of the T-D interface.
- TPs could thoroughly coordinate 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 to reliability risk (e.g., overload/low voltage/voltage stability issues) under contingencies that significantly reduce DER output and therefore increase net load (e.g., DER tripping). These risks were low when there were no DERs but are higher with heavy DER penetration.

Low-Voltage Issues Due to DER

Low-voltage issues might be observed while the DER penetration level increases. For areas with high DER penetrations at the T-D interface, higher DER output results in net load reduction, potential large-scale changes in generation dispatch,[72] 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 section **High-Voltage Issues during Light Net Load Conditions Due to DERs**, 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 capacitor banks might be switched off-line to manage over-voltage under system normal (pre-contingency) operating conditions. In the post-contingency state where DERs trip off-line, 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 cannot use automated switching for post-contingency purposes. The potential loss of local DERs that are 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 at the T-D interface, the on-line status of existing capacitor banks and their switching logic (manual or automatic) should be properly considered.

Base Case

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

- 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 and reliability must-run and spinning reserve requirements and considering economic dispatch.

[72] 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 that sufficient reactive reserves are maintained on the BPS.

- Shunt device status should reflect expected operation: Normal voltage ranges should be met in the pre-contingency base-case setup. Re-dispatch, including switching of shunt compensation and any automatic actions, can be considered for N-1-1 contingencies in many cases.

Assumptions:
To study low-voltage issues resulting from high penetrations of DERs at the T-D interface, TPs should consider the following study assumptions:

- The steady-state load-flow controls should be represented as accurately as possible, 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 reach their voltage regulating limits. These should be configured in the pre-contingency base case but should not be switched post-contingency.
- Assume that DERs will not provide voltage support.[73] 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 the high voltages caused by high penetrations of DERs at the T-D interface by incorporating the following suggestions:

- Aggregate DERs should be modeled explicitly (either integrated in the load record or standalone generation with feeder impedance modeled).
- 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 voltage or frequency); NERC TPL-001 inclusion of contingent event for widespread 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 add more automatic functions where manual switching still exists
- Add voltage control devices on the transmission side of the T-D interface
- Thoroughly coordinate 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 then tripping subsequently overloaded elements until all overloads are below the emergency rating. Engineering

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

judgement confirms the assumption that no further tripping will occur prior to operator actions by following that process. 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, a 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 decrease 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 BPS, 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.

Transformers are designed to be optimized for power flow 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.[74] 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, resulting in magnetic flux being concentrated at the core of the transformer instead of the edges, increasing the core losses.[75] Consequently, this can cause extra heating of the core and severe damage to the transformer. Proper transformer maintenance can limit the impact of the above factors, but additional designed transformer steps and cooling may be required 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 transformer from DER can present needed reinforcements to ensure that the transformer does not trip off-line 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 consider the following generic assumptions when studying the thermal overload impact of high penetrations of DERs at the T-D interface:

- The TP's load modeling should use gross load and 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.

[74] A common rule of thumb for what reverse power flow can cause transformer core saturation is 60% current for a three-winding transformer.

[75] 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

- 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 BES and non-BES extended 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.[76]
- 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 consider the following method when conducting a thermal assessment analyzing the thermal impact of high penetrations of DERs at the T-D interface:

- Perform power flow analysis for sensitivities that have high DER penetration at the T-D interface 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 on-line 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).

Potential Solutions

Potential solutions for reliability concerns resulting from thermal overloads driven by high DER penetrations at the T-D interface are varied but generally include 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.[77]
- **DER generation limits at planning stage of new connection of DER:[78]** As part of the planning procedures to interconnect new DER, the DP can assess the impact of new connection of DERs on the 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. This assures that the reverse power flow limits are not violated during high DER generation and low-load condition.

[76] 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.

[77] 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.

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

- **Reassessment 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. Furthermore, 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 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[79] of DER in the transient dynamic simulation so that the reliability impact can be evaluated. These sections may not constitute the entirety of the transient dynamics studies that may need to be performed, but the methods here should be adopted when studying the impact of high penetrations of aggregate 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 torque in the system. This can be exacerbated by the 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 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.[80] 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 at the T-D interface, the study case should use dynamic composite load models and the aggregate DER dynamic model.[81] Each TP should ensure that DER dispatch and the enabled control features in the base case and sensitivity case reflect 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 to meet 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

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

[80] See the 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

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

settings, current and voltage limit settings, ride-through settings, and trip settings.[82] Angular stability studies will largely use the same parameter focus to evaluate the impact of aggregate DER 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*[83] for relevant parameter assumptions and engineering analysis. Furthermore, 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*,[84] with the relevant outcomes reproduced below in **Table A.1** .

Table A.1: DER Dispatch Situations

Powerflow	Dynamics Model Active Power to Frequency 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 dynamic model parameters are selected
$P_{gen} < P_{max}$	Disabled	No action needed.

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 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

As many of the angular stability solutions are historically transmission based, TPs should continue to ensure their effectiveness. As such, TPs should review the following additional potential solutions when developing CAPs that mitigate against violations of planning criteria from angular stability studies:

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

[82] 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.
[83] Available here: https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Reliability_Guideline_DER_A_Parameterization.pdf
[84] Available here: https://www.nerc.com/comm/PC/NERCModelingNotifications/Dispatching_DER_Off_of_Maximum_Power_during_Study_Case_Creation1.pdf

Transient Voltage Studies—FIDVR

FIDVR is a phenomenon that occurs when ac induction motors stall after a fault causing very slow post-contingency voltage recovery (sometimes several seconds below 0.9 p.u. until loads are tripped and/or reactive power is injected). 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. As FIDVR is primarily caused by the load response and helped by specific enabled DER functions in the aggregate, entities studying FIDVR should ensure an accurate load model in addition to accurate DER models. Inaccurate composition of load or DER could lead to inaccurate studies of FIDVR conditions.

In general, if additional voltage sources ride through the fault, the FIDVR conditions will improve. 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 provides reactive-power voltage control, this effect can be greatly improved.

Base Case and Sensitivity Case Development:

In areas of high DER penetration at the T-D interface, 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 one-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 consider the following assumptions:

- The aggregate DER will operate in P priority.[85]
- The assumed MW level of DER and percentage of motor load in the composite load model must coincide with a realistic condition.[86]
- The transient voltage dip criteria exceeds the recovery criteria in importance as the lower instantaneous dips are more prone to trip DERs that can support voltage during this time.
- Older inverters and interconnections will trip near 0.8 to 0.9 p.u. voltage at their 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.
- 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.[87]

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.

[85] Alternatively, the TP can assume it will operate according to local distribution practices or regulatory requirements, if known.
[86] This is very important in order to obtain visibility of the effect of DER characteristics and its post-contingency behavior under low voltage.
[87] This assumption can be eliminated with thorough validation of the load and generation at the T-D Interface.

- Perform sensitivity studies with variation of DER voltage trip settings to inform future settings.
- Identify CAPs on 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. Some of the functions that could be enabled and studied are as follows:

- DER P-Q priority logic
- DER dynamic voltage support
- DER active power-frequency control versus reactive power-voltage control

Frequency-Response Studies with DER

Increasing DER penetrations 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. The three key metrics when considering the outcome of the frequency response study are: 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 (RoCoF). NERC has published a DER study[88] that identified that the aggregate DER impacts 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 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 IBRs 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 a higher initial RoCoF and a correspondingly lower frequency nadir following disturbances may be seen.

Most synchronous machines will have a speed governor 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).

Automatic generation control (AGC), 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 aggregate 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 attributed to two reasons: (i) If the same recovery time is expected, then as the set of responsive resources has decreased, each remaining resource

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

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 result in an increased oscillatory behavior, (ii) If the same rate and magnitude of change is maintained, then the recovery time would be longer.

Many 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:

- Base-case generation dispatch should focus on the time or conditions in which the maximum amount of load is being served by IBRs. For PV, this is likely to be around noon, and for wind it is likely to be late at night or early morning.
  - 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)
  - This generation dispatch should also first replace the frequency-responsive conventional generators[89] prior to displacing any baseload generators when displacing bulk system generation with DERs.
- 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.
  - Under a high gross loading condition, the high penetrations of DERs at the T-D interface (at other times of day) may not affect the frequency response as the load-responsive units counteract the effect of non-responsive DERs 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 are inherently wide-area studies,[90] the assumptions placed on the aggregate DER represented in the Interconnection-wide base cases (or other wide-area case) are extremely important. The SPIDERWG thus recommends that TPs, PCs, BAs, and RCs consider the following assumptions when performing a frequency response study:

- 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.
  - TPs, PCs, BAs, DPs, and RCs will need to collaborate[91] to identify which category of DER they should assume and the expected frequency ride-through of such equipment.
- Assume no frequency response headroom is available from DERs,[92] even if the frequency regulation control logic is enabled.

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

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

[91] The 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

[92] 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

    - TPs, PCs, BAs, and RCs can challenge this assumption in areas where DER are controlled by a DERMS or if DERs are known to be participating in frequency response markets.
- Assume that AGC will correct any frequency off-nominal settling point during the simulation.[93]

Approach:

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

- TPs and PCs should consider protection coordination with their DPs (registered or not) to identify any protection limits that can reduce the primary frequency response in high aggregate DER penetration conditions.
- TPs and PCs should study frequency response under both light-loading and heavy-loading conditions.
- TPs, PCs, RCs, and BAs should apply a comprehensive set of contingencies that are thorough and conservative in nature. These should include:
    - Faults near T-D interfaces containing large penetrations of DER of varying depths and durations,
    - Bulk system faults requiring a distribution system configuration such that the DER push against a different T-D system, and
    - Dependent failure modes that can affect aggregate DERs (e.g., wildfire, cyber-attack, or other "extreme" event category per TPL-001).
- TPs, PCs, RCs, and BAs should run their simulation long enough to ensure that 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 frequency support is not ubiquitous on every generation asset, it is the BA'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 that the TPs, PCs, and BAs should consider are as follows:

- Requiring fast frequency response of transmission-connected generation or DERs
- Increasing the frequency reserve requirement of generation facilities
- Requiring frequency droop control on DERs as per IEEE 1547-2018
- 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 SPIDERWG's recommendations on these other study methods, including model validation or model tuning studies, that do not cleanly fall into steady-state or transient dynamic objectives.

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

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. Furthermore, 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[94] normal current, this paradigm can change in high DER penetrations at the T-D interface. Furthermore, ride-through of DERs is generally not studied in the protection time frame as the design philosophy of DERs was 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 no fault contribution due to their off-line status. Should fault contributions be lowered, however, the distribution fuse protection time to clear may lengthen, creating a situation where the DERs may trip off-line and cease to provide sufficient fault current due to current protection systems, which reinforces the historical assumption. This highlights the importance of including DERs in protection coordination and protection set point studies to understand the impacts of high penetration of aggregate DERs in each TP's system. The SPIDERWG identified a few specific protection conditions that TPs should include in the impact of aggregate DER as shown below:

1. Potential tripping due to reverse power relay activation
2. Relay loading underestimation resulting from DER tripping post-contingency
3. UFLS or undervoltage load shedding (UVLS) schemes[95]
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 of identifying the voltage sag created by the inrush of current and determining if voltages are within standard limits.[96]

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 current transformers (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. Furthermore, 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. The SPIDERWG also recommends that

[94] 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.

[95] 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. The 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

[96] 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.

the TPs review their planning criteria for motor start studies and identify any voltage sag thresholds. 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 T-D 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, with the planning departments collectively addressing the generation composition and limitations of delivery of that power to the facilities as part of transfer capability studies under high penetrations of aggregate 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. The SPIDERWG encourages PCs to study the aggregate impacts of DERs by performing the following:

- Identify transformer reverse flow steady-state thermal ratings in identified areas of growing or high aggregate DER penetration.
- Incorporate expected DER tripping or reduced DER generation output into contingency analysis to identify planning criteria violations and associated transfer limits.
- 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.
- Perform stability analysis to identify where DER tripping or reduced DER generation output (due to lack of ride-through capability) may occur and affect available transfer capability.

The 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, the SPIDERWG anticipates that the generation composition's ability to serve the transfer capability will be more important in high penetrations of aggregate 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 modeling inaccuracies as well as tune models to represent field tests or the results of benchmark reports.

Generic and user-defined models (UDM) are currently available for DERs, and each model can have its own unique behavior. Each transmission service provider (TSP) or distribution service provider (DSP) may have local criteria or standards for integrating DERs into their footprint. DER behavior and performance are dependent on the DERs' location relative to distribution feeders. Diversity in voltage levels across the distribution footprint where the DERs are connected also presents an issue. 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 judgment, benchmark reports, or field data. In performing transient stability studies with high aggregate DER penetration, adequate model representation is critical, so PCs and TPs should perform regular case validation studies that look at their aggregate DER models.[97]

[97] The 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:

Name	Entity
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Appendix C: Revision History

Revision History		
Version	**Comments**	**Approval Date**
1	Initial Version	TBD

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:

- Improvement in the NERC case quality metrics for metrics that track DER model quality
- Of the studies performed, count and percentage of the TPs or PCs that performed the following:
  - Validated DER model used in study
  - DER model altered for study conditions and assumptions based on OEM and DP support
  - Contingency definitions or lists included DER model alterations
  - DER model performance tracked in simulation
  - DER model affected study results in either a positive or negative way
  - DER model affected study results, but no interpretation on the study outcome was performed
- Of the studies performed, count of the TPs or PCs that identified the following:
  - DERs models were directly included in a corrective action plan
  - DER models were impacted by the corrective action plan, but did not have a direct action for DER
  - Sharing and engagement of DER settings between neighboring entities

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 the following:

- 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
- 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 that use Reliability and Security Guidelines to respond to the short Guideline Effectiveness Survey. [insert hyperlink to survey]

Standard Authorization Request (SAR)	Reliability Guideline: Bulk Power System Planning under Increasing Penetration of Distributed Energy Resources
Instructions	**of Distributed Energy Resources Comments" in the subject line. Only comments submitted in this Microsoft Excel format will be accepted. Both general and specific comments should be provided within this form. Red-line document changes, PDF versions of this**
Review Period	April 22, 2024 – June 6, 2024

Organization(s)	**Page #**	**Line / Paragraph**	**Comment**	**Proposed Change**	**NERC Response**
Southwest Power Pool (SPP)		101-144	SPP is concerned about the recommendations in the Executive Summary as it talks about the Impact of the DER on steady state analysis results as well as dynamic modeling accuracy. Our first concern from a steady state perspective pertains to the DER penetration increasing the load. It's not clear on how the correlation of the increase of DER penetration will be accounted for and align with the increase of load. Additionally, we have a concern about the Composite Load model not reflecting the appropriate load level increase as well as showing accurate representation. SPP recommends SPIDERWG included language aligning the Composite Load model with the steady state process along with the expected results from that analysis. Moreover, we have a concern about the recommendations and expectations of dynamic modeling accuracy. From our perspective, there is not enough clarity on what's the guideline goal with the DER and dynamic model. Again, we know MOD-032 and its Attachment 1 has an impact on the dynamic study, however, it is unclear to us on what guidance this document is to provide to the applicable entities. SPP recommends that the SPIDERWG provide language in the document to clarify the expectations from a dynamic steady perspective.	Provide clarifying language	Thank you for your comment. Added clarifying language in the execuative summary to reflect the guideline contents. Added links to previous modeling guidelines in the executive summary for clarity.
Southwest Power Pool (SPP)		158-168	SPP is concerned that precedence will be taking on running the various types of studies such as Short Circuit and EMT versus focusing on the need of data collection pertaining to the modeling process. Attachment 1 section of the MOD-032 standard will need to be addressed. SPP recommends that SPIDERWG consider adding the MOD-032 Standard to the related section of the guideline (164-168 Lines). It is our understanding that Project 2022-02 is focused on data collection. We recommend that SPIDERWG coordinate with this drafting team to ensure all data collection concerns are addressed.	SPIDERWG coordinate with Project 2022-02 drafting team.	Thank you for your comment. MOD-032 is added to the standards applicability
Southwest Power Pool (SPP)		302-345	SPP is concerned about the steady state process when it comes to the tripping of load representing DERs. At this point, the document doesn't clearly state the expectations for the applicable entities. SPP recommends that SPIDERWG add clarity on expectations of the applicable entities as well as desired results.	Provide clarifying language.	Thank you for your comment. Appendix A houses specific methods for steady-state procedures on specific study types. Further added clarity in tripping of DERs In Chapter 3.
Southwest Power Pool (SPP)		732-740	SPP is concerned about the applicable need for the TP and PC to include the short circuit analysis part of the TPL Study. At this point, the document language doesn't clearly state what expectations this document is setting for the applicable entities and desired analysis results. SPP recommends that SPIDERWG add clarity on expectations of the applicable entities as well as desired results.	Provide clarifying language.	Thank you for yoru comment. Revised the Short-Circuit Simulation section for their recommendations.

Organization(s)	Page #	Line / Paragraph	Comment	Proposed Change	NERC Response
Southwest Power Pool (SPP)		740-783	SPP is concerned in reference data collection via MOD-032 when it comes to the inclusion of the Distributed Energy Resource (DER) pertaining to the Short-Circuit analysis. The guideline mentions that "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." Additionally, the document mentions that any entities performing the short circuit study in high penetration areas 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. From our perspective, this might be a difficult task, because the current MOD-032 Standard does not account for specific DER data via its Attachment 1. Moreover, it will be difficult to build and conduct a reliable analysis associated with fault current when the standard's issues pertaining to data collection in reference to Invertible Based Resources (IBR) and Distributed Energy Resource (DER) has not been resolve. SPP recommends that the SPIDERWG work closely with the MOD-032 drafting team to ensure that that guidelines language aligns with the MOD-032 project's final efforts.	SPIDERWG coordinate wiith MOD-032 drafting team.	Thank you for your comment. Added some clarifying language on the model portion in the Short-Circuit section.
Southwest Power Pool (SPP)		785-835	As for the Electromagnetic Transient (EMT) studies, SPP is concerned about the impact of the DER on the model build for this assessment as well. It's our understanding that the SCR screening has to be conducted first to determine if there is a need for the EMT study. Again, our concerns would be applicable to the data collection via MOD-032. Currently, this standard's Attachment 1 doesn't account for specific IBR and/or DER data collection, nor does it hold an entity like the Original Equipment Manufacturer (OEM) accountable for providing important data such as Phase Lock Loop (PLL) for the model build. With that said, it will be difficult to build and conduct a reliable analysis associated with fault current, IBRs and DERs when the standard issues pertaining to data collection has not been resolve. SPP recommends that the SPIDERWG work closely with the MOD-032 drafting team to ensure that that guidelines language aligns with the MOD-032 project's final efforts.	SPIDERWG coordinate wiith MOD-032 drafting team.	Thank you for your comment, the EMT studies section does not require EMT simulations but details one entities successes in development of a DER study procedure using EMT studies. No change made
CenterPoint Energy Houston Electric, LLC (CEHE)	7	5	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 due to their equipment design defaults.	**General Comment:** Clarification on determining "high DER penetration" as it applies to distribution and how it applies to TP gross load (on system or at substation). Additional note, on page 9 seems to use the language "at the T-D interface." Similar language could be used here for clarity.	Thank you for your comment. Added language as proposed for clarity here and elsewhere for "high DER penetration".
CenterPoint Energy Houston Electric, LLC (CEHE)	9	2	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).	**General Comment:** Provide clarification or additional guidance on the statement "...impact the electrical service at a T-D interface,..."	thank you for your comment. Clarifying edits made on intent to evaluate electrical quantities and not contractual service.
CenterPoint Energy Houston Electric, LLC (CEHE)	15	8	This section highlights the details of the steady state simulation considerations; more specific study methods are found in Error! Reference source not found..	**General Comment:** Correct typo or link in the paragraph.	Thank you for your comment. Cross reference updated to Appendix A.
CenterPoint Energy Houston Electric, LLC (CEHE)	17	8	This section highlights the impacts of DER on stability simulations; more specific study methods are found in Error! Reference source not found..	**General Comment:** Correct typo or link in the paragraph.	Thank you for your comment. Cross reference updated to Appendix A.

Organization(s)	Page #	Line / Paragraph	Comment	Proposed Change	NERC Response
CenterPoint Energy Houston Electric, LLC (CEHE)	19	8	Determine the gross loading of the system and the area where the study is being conducted.	**General Comment:** Add language to define "area." Currently, it is assumed this is within a few BPS buses of the study bus. With the statement, the document shifts from comparing gross loading (system or substation) with DER penetration, to an "area" with DER penetration. This creates some confusion on the defined study area and limits.	Thank you for your comment, added clarifying language to the sentence and removed "system" to clarify.
CenterPoint Energy Houston Electric, LLC (CEHE)	20	5	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	**General Comment:** Define "target interruption current" or revise statement. Potential Revision: "...identify the available short-circuit current and required duty...."	Thank you for yoru comment. Change made as proposed.
Evergy			Evergy supports and incorporates by reference comments of the Edison Electric Institute (EEI) for this Reliability Guideline.		Thank you, see response to EEI comments.
Edison Electric Institute	N/A	N/A	**General Comment:** EEI appreciates the work done by the SPIDERWG in the development of this guideline and believes that with additional work it can be useful to the industry. However, much of the language contained in the guideline does not align with the voluntary nature of a Reliability Guideline and needs to be changed before this document is approved. We further ask that greater care be taken in not utilizing language that is broadly understood and aligned with compliance requirements used in NERC Reliability Standards, such as Corrective Action Plans. While we do not believe it was the intent of the SPIDERWG to imply any part of this guideline is compulsory, the language in this proposed version could be understood as such and we believe that if not changed it will create unnecessary confusion and needs to be changed. We also caution against the use of language that goes beyond the capabilities of the industry as it exists today. We note that expectations that are not practical or achievable at this time can be a disincentive for use of a guideline and should be avoided. For example, expectations that planners have the tools and data to granularly identify performance issues associated individual DERs is not helpful. Instead, this guideline should recognize the capabilities as they exist today and provide best practices guidance that makes the most of what is possible with what's currently achievable.	EEI recommends that this guideline be edited to better align with a NERC Reliability Guideline (i.e., remove language that is more commonly used in Reliability Standards, more clearly align the expectations with the tools and capabilities available to the industry and soften the tone to emphasize the voluntary intent of a guideline).	Thank you for your comment. Language throughout the document has been changed to reflect guidance practices and recommendations. Furthermore, the preamble to any guideline shows that all recommendations are not binding norms or used as akin to Reliability Standards (shall) language. SPIDREWG agree to not identify issues with specific DER installations but rather in the aggregate and has made changes accordingly. Practices in the appendix were also adjusted based on this and other comments.

Organization(s)	Page #	Line / Paragraph	Comment	Proposed Change	NERC Response
Edison Electric Institute	vi	102 - 113	**Executive Summary General Comment:** EEI suggests that the following edits (in boldface) to the executive summary might better clarify the intent of this guideline: ~~The~~ NERC**'s** System Planning Impacts from Distributed Energy Resources Working Group (SPIDERWG) identified in this reliability guideline a set of **suggested** planning practice enhancements for Transmission Planners (TPs), Planning Coordinators (PCs), and other relevant entities **to better account for the growing impacts of distributed energy resources (DERs) on Bulk Power System reliability.** With the growing penetration of ~~distributed energy resources~~ DERs, the SPIDERWG **felt it was time to provide additional guidance to TPs and PCs experiencing high penetration of DERs with the intent of improving BPS reliability through voluntary steps that could be consider when conducting BES TPL-001 assessments through the integration of aggregated DER impacts. While there are no compulsory obligations to do this, we believe these steps represent best practices and will help these registered entities better understand how DERs are impacting BES reliability and what steps could be take to mitigate their impacts. And while the target audience are those TPs and PCs that are seeing high or extremely high DER levels in their area of responsibility, all TPs and PCs could benefit from the recommendations provided in this guideline.** ~~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 **has made efforts to develop and** identif**y** an adaptable framework that a**ny** 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:	EEI suggests changes to the Executive summary as provided in boldface in our comments. The intent of our comments is to suggest language that aligns with what we understand to be the intent of this guideline, as well as a tone more consistent with a NERC Reliability Guideline.	Thank you for your comment. Based on this and other requested changes for the executive summary, edits were made wholesale. The proposed edits were largely accepted with minor alteration.
Edison Electric Institute	vi	109	Editing error (i.e., extraneous language "overviewed better")	Remove "overviewed better"	Thank you for your comment. Removed as proposed.
Edison Electric Institute	vi	121 - 122	Suggest the following edits in boldface: The SPIDERWG has also identified that ~~of focus~~ transmission **planners** ~~planning departments~~ are increasing**ly** ~~the~~ us**ing** ~~of~~ EMT studies within planning assessments.	EEI suggests the following edits in boldface.	Thank you for your comment. Changes made as proposed.
Edison Electric Institute	vi	128 - 144	Recommendations: The recommendations on page 23 do not fully align with the recommendations contained in the executive summary. We also do not agree that the recommendations are appropriate for a NERC Reliability Guideline because they are too prescriptive.	Align the recommendations with page 23 and soften the tone to align better align with a Reliability Guideline.	Thank you for your comment. Reccommendations changes based on this and other comments.
Edison Electric Institute	1	154 - 156	EEI suggests modifying the purpose statement as follows (edits in boldface): ~~There is an inherent risk associated with incomplete or incorrectly parameterized planning models.~~ This reliability guideline ~~seeks to~~ is intended to provide best practices **guidance** to **assist TPs and PCs who are seeking to better assess the reliability impacts of increased amounts of** ~~include and adjust~~ aggregate DERs **into their** ~~models when used in~~ transmission planning studies **as defined in TPL-001. While including the impacts of DERs within TPL-001 planning studies is not required, the guidance in this document could help planners better understand the impacts and risks of increased penetration of DERs while preparing those entity to better prepare, adapt mitigate those impact.**	EEI suggests edits to the proposed Purpose statement.	Thank you for your comment, changes made based on the proposed edit.
Edison Electric Institute	6	309	EEI suggests deleting footnote 11. While we are confident this presentation provided useful information to the SPIDERWG, simply adding the slides without the added information and benefit provided by the presenter lacks the full value presented and adds little to the guideline.	Suggest deleting Footnote 11 for the reasons provided.	Thank you for your comment. Removed footnote and moved it ot Appendix A with context.

Organization(s)	Page #	Line / Paragraph	Comment	Proposed Change	NERC Response
Edison Electric Institute	6 to 7	334 - 338	When reading this paragraph it seems to imply that the intent is to identify, with precision, specific DER(s) that might be prone to tripping. While this might be practical in the future, the SPIDERWG should be careful to not provide guidance that is not currently achievable. Instead, the guidance should aligns with what is currently possible with the tools and data available to the industry. However, if we have misinterpreted the intent, consideration should be given to adding addition clarity to what is written.	To address our concerns EEI suggests modifying the guidance to better align with the tools and data currently available to the industry or add additional clarity to what was intended in the last paragraph of the Steady State Power Flow Studies section. Alternatively, this issue could be solved by simply removing the following: "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, 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."	Thank you for your comment, added clarifying language to the section that the validation is not on individual DER devices but on the actual DER tripping as seen by the T-D Interface.
Edison Electric Institute	7	340 - 345	While this above back and forth process is uncommon, the~~se updates~~ **process and findings will overtime be most help if care is taken to** ~~should be well~~ document**ed** ~~**in the**~~ **the steps taken in the** contingency files and reviewed for their applicability **elsewhere** ~~**to changing study conditions**~~. TPs should **also consider validating their** model**s** ~~**its**~~ **of** expected steady-state DER tripping performance to ~~**known or assumed**~~ **actual** DER tripping **and align their studies accordingly** ~~**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.	EEI suggests edits in boldface. Point out the practical realities of the data currently available both now and the foreseeable future.	Thank you for your comment, changes made to the text based on the proposed edit.
Edison Electric Institute	8	372 - 373	EEI is unaware of any areas where DERs have actually displaced bulk-connected generation. If this is the case, a white paper describing and documenting this should be developed and published for industry review and comment. If there is no documentation of this occurring the following statement should be deleted. "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."	EEI suggested deleting the sentence that speaks to DERs displacing bulk-connected generation. However, if this is in fact happening the SPIDERWG should develop a white paper detailing where this has occurred and mitigations used to limit the impacts to BPS reliability.	Thank you for your comment. Changes made to the sentence to clarify intent and removal of the "displacement of bulk-connected generation" phrase.

Organization(s)	Page #	Line / Paragraph	Comment	Proposed Change	NERC Response
Edison Electric Institute	9	419 - 436	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~~ **the SPIDERWG believes that 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 findings. **While DER impacts are rarely impactful at low penetration levels, beginning the process of incorporating these resources into entity planning studies is a best practice that if employed could help to ensures that unexpected impacts are identified while developing improved planning skills and practices before those skill are needed.** ~~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.~~ **Moreover, at** low penetration levels, DER can reasonably be represented in transmission level studies using broad generalizations of DER behavior (assuming independent operation).	EEI suggested edits in boldface.	Thank you for your comment. Changes made based on the proposed edits to this section.
Edison Electric Institute	9	424, 528, 587, 619, 623, 626, 641, 901, 956, 1017, 1064,	Hyphen missing from steady-state.	Add hyphen to steady-state consistently.	Thank you for your comment. Changes made as proposed.
Edison Electric Institute	10	449 - 450	Suggest retitling Figure 2.1 as a Table and changing the title to DER Penetration Level Designations & Impacts.	Retitle to table.	Thank you for your comment. Redesigned and retitled the figure to be less like a table and more a priority order.
Edison Electric Institute	11 to 12	496 - 498	Thus, multiple base cases (peak net load, peak gross load, high DER output, etc.) ~~may need to be built to~~ **could be built to include the impact of DERs to assess their impact on BPS reliability.** ~~should be considered in order to ensure the impact of DERs is comprehensively evaluated in order to thoroughly assess their impacts on BPS reliability~~. ~~Concerning DER dispatch in the base case, the major assumptions that a~~ TP ~~should~~ **could consider** review**ing when assessing DER impacts could include the following** ~~are~~:	EEI suggests edits in boldface.	Thank you for your comment. Edits made based on the proposed change.
Edison Electric Institute	12	501	EEI questions whether a TP will actually have any meaningful insights into the DER control logic being used on either individual or aggregated DERs. To address this concern, we ask that additional clarity be provided at to the intent of Item 3 titled "DER control logic".	EEI asks for additional clarity.	Thank you for yoru comment. Based on this and other comments, clarity added for this item in the list.
Edison Electric Institute	13	509 - 518	EEI asks that the section titled Non-TPL-001 uses for Base Cases including Table 3.2 be deleted because it proposes additional assessments where no guidance is provided. Moreover, the guidance provided in this guideline would seem sufficient for now.	EEI suggests deleting this section.	Thank you for your comment, revised this section to add more context based on this comment.
Edison Electric Institute	15	558 - 559	EEI suggests modifying the following sentence as indicated in boldface: TPs **who decide to conduct DER impact studies** ~~should~~ **may want to consider adding the** ~~evaluate~~ following sensitivity cases and **possibly** develop**ing** ~~the appropriate~~ case(s) to ~~match~~ **identify** the expected reliability impacts associated with high DER penetrations:	EEI suggests the following edits in boldface.	Thank you for your comment. Changes made based on the proposed edits.
Edison Electric Institute	17	636	It is EEI's understanding that whether the "PQBRK" type parameter is accurate for load representation or not is somewhat irrelevant as long as the threshold is set reasonably below the voltage violation limit. In some instances, your choice is either a converged simulation that shows very low voltages, or a diverged simulation which shows you nothing. Even more, if the steady-state simulation shows voltages below this threshold, it almost certainly represents an event that will lead to DER tripping. Finally, since DERs are typically current limited devices, it's not even accurate to model them as constant MVA load to begin with. Disabling this kind of parameter for accuracy of DER modeling is unnecessary (again, assuming the parameter is set below the voltage violation limit) and likely incorrect.	EEI suggests removing the suggestion in the "Key Takeaway", describe how this type of assumption may not be accurate for DER, and recommend TPs be careful that this setting is reasonably below the lower voltage limit.	Thank you for your comment. The takeaway box has been removed and additional context has been added based on this comment.
Edison Electric Institute	17	645 - 658	The actions listed do not add value to the section and exclude nuance and detail. (1) only includes ride-through behavior, (2) is too direct and may not be necessary for TPs with low DER penetration, (3) is likely incorrect and unnecessary as described above, (4) is inconsistent ("possibly") with other wording in the document.	EEI suggests removing "Based on the above points, TPs should perform the following actions:" and the list of actions.	Thank you for your comment. Edits made based on this and other comment.
Edison Electric Institute	17	647	EEI suggests modifying Item 1 as indicated in boldface: ~~Accurately~~ **With available tools and resources, TPs should consider making best efforts to** represent low voltage and high voltage ~~ride-through~~ **performance** of DERs in their steady-state studies**, including their ability to ride through localized disturbances.**	EEI notes that TPs and PCs may not have accurate information on DER ride through capability, however, they should make reasonable efforts to represent the known capabilities of the resources.	Thank you for your comment. This bullet was removed in editing the section.

Organization(s)	Page #	Line / Paragraph	Comment	Proposed Change	NERC Response
Edison Electric Institute	17	650 - 651	Item 3 regarding what is intended with Item 3. Specifically, how is the TP expected to know with precision how specific DERs are going to react to during low voltage conditions and when it might be necessary to consult with their planning software vendor.	Please provide additional clarity to Item 3.	Thank you for your comment. Additional clarity added on TP actions.
Edison Electric Institute	17	657 - 658	Within action (4) there is a note that states "the intent is to not hold load and DER to different modeling fidelity". We understand this to be an important goal, even though it is not sufficiently identified as such in the reliability guideline.	Given the importance of the guidance, we believe this guidance should be more prominent place in this guideline. We also suggest that this issue be more thoroughly expanded upon so TPs and PCs are clear that efforts to improve DER modeling must coincide with efforts to improve load modeling if TPs and PCs are to achieve more accurate simulations. Moreover, tripping DER without considering load tripping may produce a worse outcome.	Thank you for your comment. SPIDERWG agrees this should be added to the Development of Credible Contingencies section. Text added to that section and recommendations section to elevate this concept.
Edison Electric Institute	17	674	It is EEI's understanding that DERs may be represented inside of some load models (e.g., CMLD). This is even shown in on page 5 (see figure 1.2) where R-DER is included in the load model.	To address this concern, we suggest deleting the statement "In transient dynamic assessments, aggregate DERs should be modeled explicitly and not netted with substation load."	Thank you for your comment. Added clarifying edits to state that explicit representations include integration with the load model.
Edison Electric Institute	18	682 - 683	Cloud cover is not a P3 contingency or a "modification" to a P3, it is a different event (and not a BES event). Moreover, reduced DER capacity as the initial condition is likely to improve stability.	EEI suggest removing the following statement "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."	Thank you for your comment. Clarifying changes made to remove cloud cover from the sentence. SPIDERWG requests EEI present on improved stability seen by reductions of DER in contingencies.
Edison Electric Institute	18	690 - 695	EEI suggests the following edits but also asks for additional clarity to the following: ~~When~~ **TPs considering** assessing dynamic analysis results, active and reactive power output of DERs, system bus voltages, and transmission line flows **should ~~be~~ also consider** monitored **available data** to compare the trajectory and calculate stability margins for a TPs system.	EEI assumes the guideline is suggesting that the planner monitor the DER outputs within the planning software in aggregate, noting that real time monitoring of DERs in general does not exist at this time.	Thank you for your comment. SPIDERWG agrees that the recommended practice here to monitor active and reactive power flows are at the T-D Interface and not real time monitoring of DERs which is not done in the planning domain. Clarity edits made based on this comment.
Edison Electric Institute	18	697 - 712	EEI suggests the following edits in boldface: Further, **TPs may also want to consider that including** small signal stability and low frequency inter-area oscillation analysis **of DERs could ~~be~~** enhance~~d to include the impact of DERs~~ **the fidelity of their planning studies**. At the Interconnection-wide study level, the inter-area oscillatory impact of DERs ~~should~~ **can enhance ~~be studied~~ studies to better** 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**ing the impact of high** penetrations of DERs **as they** grow. As such, the TP should **consider** perform**ing an** 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.	EEI suggest the edits in boldface.	Thank you for your comment. Changes made based on the proposed changes
Edison Electric Institute	18	715	EEI finds Item (1) in the list to be confusing, the CMLD load model can be applied to a load that includes netted DER. In fact, it may be that modeling the DER as a separate connection to the transmission system creates an inaccuracy in modeling since the related impacts of loads and DERs are not represented as well.	EEI suggests removing recommendation (1) or clarify this should be done.	Thank you for your comment. Clarifying edits made based on this comment.
Edison Electric Institute	19	717	The line starting with "Varying" appears to be a new list item, but it is not numbered.	Number the item starting with "Varying".	Thank you for your commnet. Change made as proposed

Organization(s)	Page #	Line / Paragraph	Comment	Proposed Change	NERC Response
Edison Electric Institute	19	718-720	The suggestion that "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." implies it is possible to accurately depict ride-through behavior for DERs in positive sequence tools for unbalanced events. EEI understands that this has been comprehensively demonstrated to be impossible. Beyond this, benchmarking DER in EMT models would require very large detailed EMT models with data TPs are unlikely to be able to acquire. Otherwise, TPs will just be benchmarking an assumed aggregate EMT model against an assumed aggregate positive sequence model.	EEI suggests removing: "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."	Thank you for your comment. Added footnote linking previous non-positive sequence efforts to validate DER tripping. These methods do not require the use of EMT studies to benchmark, but rather a version of a three phase model to compare against the positive sequence model to update the expected performance in the positive sequence domain.
Edison Electric Institute	19	728-730	TPs may choose to update steady-state contingencies based on stabilty study results, but this is not always practical or possible (see earlier comment). This guideline states this practice should be done or should possibly be done. Instead, we suggest that the guideline should recommend that TPs have a method to account for DER tripping in steady-state studies, which may include incorporating results from stability studies, or may be an alternative method that conservatively estimates lost DER.	To address our concerns we suggest removing "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."	Thank you for your comment. Edits made based on the proposed change.
Edison Electric Institute	20	760	EEI finds Item 3a to be confusing. Is the suggestion to disconnect BES connected generators because of the additional DER on the system? This would be inappropriate since there may be situations where DER is not dispatched and breaker sizing needs to consider that. Removing BES generators would lower fault current at BES buses and could lead to undersized breakers. This wording is also inconsistent with item 2 in the second list on page 20 where the TP is expected to compare full DER to no DER (this is more reasonable).	EEI suggests removing item 3a.	Thank you for your comment. Change made as requested. Other content deleted to clean the list up in addition to this comment.
Edison Electric Institute	21	805 - 833	While EEI agrees that credit should be given to ISO-NE for the lessons learned, the listed items should be written as generic recommendations rather than specific descriptions of ISO-NE activities.	EEI suggests generalizing items in the list. Using (4) as an example, change "ISO-NE used conversion software tools..." to "Utilize conversion software tools..."	Thank you for your comment. Based on the content provided SPIDERWG felt the continual reference to ISO-NE was warranted in review of their practices and lessons learned to not falsely attribute specific practices and lessons learned to a generic planning department. No change made.
Edison Electric Institute	21	812	Item 2 says that generic EMT models are better than netting DER with the load. 1) Its not clear how exactly these are alternatives, 2) this is an unjustified claim. Why is an inaccurate EMT model better?	EEI suggests removing "However, the use generic EMT representations and assumptions is better than netting DER with the load."	Thank you for your comment. No changes made based on this comment. Generation can either be negative load (netted), generically represented, or OEM-specific represented.
Edison Electric Institute	22	838 - 842	EEI suggests the following boldface edist and also asks that the incomplete thought shown in red be clarified and completed: 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**~~ **For this reason, it is important that planners considering** evaluat**ing** performance against a wide array of criteria **(review in their ???)** ~~**and**~~ **while recognizing that** not all criteria violations ~~**will**~~ **can** be mitigated by DER-specific ~~**Corrective Action Plans (CAPs)**~~ **mitigations**. This chapter details the stages of results comparison and development of ~~**corrective actions**~~ **mitigations**. It also summarizes the broad recommendations of the reliability guideline.	EEI suggests boldface edits and asks that the incomplete thought shown in red be completed and clarified.	Thank you for your comment. Clarity added to the sentence and edits made based on proposed changes.

Organization(s)	Page #	Line / Paragraph	Comment	Proposed Change	NERC Response
Edison Electric Institute	22	875	EEI does not support the use of Corrective Action Plans within Reliability Guidelines and offers the following edits to the following title (in boldface) Development of ~~**Corrective Action Plans**~~ **mitigations** related to DERs	EEI suggests edits to better align the language to a reliability guideline.	Thank you for your comment, title changed based on comment. SPIDERWG appreciates the concerns raised, but reiterates the document does not require CAPs. Rather, it provides specific considerations should a TP design a CAP relating to aggregate DER.
Edison Electric Institute	22 & 23	876 - 888	EEI suggests replacing CAPs with mitigations to better align text to a guideline.	EEI suggests edits to better align the language to a reliability guideline.	Thank you for your comment. No change made based on this comment
Edison Electric Institute	23	894 - 897	TPs and PCs should **consider** ~~**explicitly**~~ identify**ing** 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 **consider** review**ing** **Appendix A:** and ~~**incorporate**~~ **adopting** the study-dependent recommendations.	EEI suggests edits to better align the language to a reliability guideline.	Thank you for your comment. Changes made based on proposed edits
Edison Electric Institute	23	898 - 900	TPs and PCs should **consider** reflect**ing** expected dynamic reactive power performance of DER equipment in **their** stability simulations. Dynamic injection and withdrawal of reactive power by DER during system disturbances can ~~**significantly**~~ impact study results.	EEI suggests edits to better align the language to a reliability guideline.	Thank you for your comment. Changes made based on proposed edits
Edison Electric Institute	23	901 - 902	TPs and PCs should **consider beginning the process of** account**ing** for ~~**appropriate levels of**~~ DER tripping in their steady state contingency definitions and properly reflect expected DER trip characteristics in stability simulations **when such data is available**.	EEI suggests edits to better align the language to a reliability guideline.	Thank you for your comment. Changes made based on proposed edits
Edison Electric Institute	23	903 - 906	PCs should ~~**ensure**~~ **consider engaging** neighboring PCs **in order to develop a common** understand**ing of** ~~**the settings of**~~ DER **settings** (i.e. share appropriate DER models through interconnection wide case building processes) in their system **when available in order to better coordinate** ~~**when coordinating**~~ their planning assessments. PCs should also ~~**ensure**~~ **endeavor to document** ~~**that**~~ any DER related impact**(s) in their** ~~**is highlighted in this coordination of the**~~ planning assessment.	EEI suggests edits to better align the language to a reliability guideline.	Thank you for your comment. Changes made based on proposed edits
Edison Electric Institute	23	907 - 909	TPs ~~**should**~~ **could also begin the process of** document**ing** ~~**any**~~ **known** DER-related common mode of failure**s** in their set of contingencies applied to planning assessments. ~~**(e.g., cyberattack, cloud cover)**~~ TPs **may also want to** ~~**should seek**~~ to improve their understanding of **the impacts of** these common mode failures through **these** studies.	EEI suggests edits to better align the language to a reliability guideline.	Thank you for your comment. Changes made based on proposed edits
Edison Electric Institute	23	910 - 913	TPs and PCs **could** ~~**should**~~ **consider developing processes to** review their planning criteria to **more** ~~**ensure that it is**~~ accurately flag~~**ging**~~ areas of risk under increasing penetration of DERs. TPs and PCs ~~**should**~~ ~~**choose relevant**~~ **may also want to consider developing** criteria for their area and refine such criteria for the impact**s** of growing penetrations of DERs in their transmission simulations as found in the **Impacts from High Levels of DER on Transmission Studies** section.	EEI suggests edits to better align the language to a reliability guideline.	Thank you for your comment. Changes made based on proposed edits
Edison Electric Institute	23	914 - 915	~~**When**~~**TPs and PCs may want to consider** developing **mitigation** ~~**Corrective Action Plans**~~**.** TPs ~~**should ensure**~~ **may also want to engage system operators to obtain data that might help them better understand whether their** ~~**that the action**~~ **proposed mitigations** ~~**taken**~~ **address** ~~**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**~~.	EEI suggests edits to better align the language to a reliability guideline.	Thank you for your comment. Changes made based on the proposed edits. Added content for system operators based on comment.
Edison Electric Institute	24	930-954	This paragraph does not provide specific guidance, it just repeats high-level information from the main document.	EEI suggests removing the paragraph.	Thank you for your comment. Section removed as proposed.
Edison Electric Institute	24	959	While commonly used, +/- 0.95 is not technically accurate.	Suggest replacing "range of +/- 0.95" with "range of 0.95 leading to 0.95 lagging".	Thank you for your comment. No change made based on this comment.
Edison Electric Institute	24	918	This is a general comment for Appendix A. The Appendix includes a significant amount of material that is redundant with sections in the main document. Additionally, there are considerations listed in Appendix A which are probably better suited for the main document.	EEI suggests abbreviating Appendix A, removing redundancies with the main document, and putting the most important considerations into the main document.	Thank you for your comment. No change made based on this comment.

Organization(s)	Page #	Line / Paragraph	Comment	Proposed Change	NERC Response
Edison Electric Institute	27	1057-1059	The comment about voltage criteria under contingency may not reflect every entity's criteria (e.g., some require normal voltage range to be met even for N-1 conditions). Moreover, the comment isn't relevant to the "base case".	EEI suggests removing "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."	Thank you for your comment. Deletions made based on this comment.
Edison Electric Institute	27	1080	The first point under "Approach" says aggregate DERs should be modeled explicitly. It is unclear if this means apart from load, or in disaggregated form. Feeder impedance can make a great deal of difference in the voltages seen by DERs. Overall, the value of this recommendation is unclear.	Expand or clarify the point of the first recommendation under "Approach" and soften the language to better align with a guideline.	Thank you for your comment. Changes made to reflect the feeder impedance coupled with generator representation rather than with inside the load records.
Edison Electric Institute	28	1084	Cloud cover is not a P1 contingency, it is a different event (and not a BES event).	Recommend TPs consider wide-spread DER outages without equating them to P1 events.	Thank you for your comment. Changes made based on proposed edits.
Edison Electric Institute	28	1090-1092	List punctuation is incorrect.	Fix list punctuation.	Thank you for your comment. Changes made based on this comment.
Edison Electric Institute	29	1148-1149	The consideration of maintenance outages and variation of maintenance schedules is outside of the scope of this guideline.	EEI suggests removing "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."	Thank you for your comment. Changes made.
Edison Electric Institute	32	1255-1258	While almost the entire section on angular stability is redundant with material covered in the main document, the list of potential solutions for angular stability is outside of the scope of this guideline. There are far more ways to address angular instability, but this document should focus on DER specific issues. Thus, (3) is appropriate to include, while (1) and (2) are not.	EEI suggests removing items (1) and (2), and if appropriate, add additional DER related mitigations.	Thank you for your comment. Changes made based on this comment.
Edison Electric Institute	32	1262	FIDVR is driven more by load than by DERs. This is a good place to expound on the idea that accurately modeling load just as important as modeling DER (or more important, depending on penetration).	Suggest making it clearer to TPs and PCs that efforts to improve DER modeling should coincide with efforts to improve load modeling generally -- if TPs and PCs actually want more accurate simulations. Tripping DER without considering load tripping may produce a worse case, but is unlikely to be accurate.	Thank you for your comment. Added content as suggested
Edison Electric Institute	32	1272	Unclear wording: "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."	Replace with: "In general, if additional voltage sources ride-through the fault, the FIDVR conditions will improve."	Thank you for your comment. Change made as proposed
Edison Electric Institute	33	1297	It seems that most of the content under "Approach" is better suited for "Potential solutions"	Suggest moving the list of future setting assessments to Potential Solutions.	Thank you for your comment. Moved the content as propsoed.
Edison Electric Institute	33	1312	Capitalization error.	Suggest replacing "Potential solutions" with "Potential Solutions".	Thank you for your comment. Change made as proposed.
Edison Electric Institute	37	1461-1463	While the Motor Start Studies section includes information relevant to DERs, the listing of criteria is outside of the scope of this guideline.	Suggest removing the voltage sag and voltage magnitude criteria, allowing the section to focus on DER impacts.	Thank you for your comment. Change made as proposed.
ISO New England	vi	109	The words "overviewed better" are extraneous and should be deleted.	...use to study the bulk system impact of DERs. ~~overviewed better~~ The...	Thank you for your comment. Executive summary altered based on this and other comments
ISO New England	vi	121	The words "of focus" are extraneous and should be deleted.	The SPIDERWG has also identified that ~~of focus~~ transmission planning departments...	Thank you for your comment. Executive summary altered based on this and other comments

Organization(s)	Page #	Line / Paragraph	Comment	Proposed Change	NERC Response
ISO New England	7	343	Tripping of DER in the post-contingency operating state lends to a more conservative evaluation of expected performance. It is not always true that assuming DER tripping is more conservative. The sentence needs to be qualified.	Tripping of DER in the post-contingency operating state may lend~~s~~ to a more conservative evaluation of expected performance.	Thank you for your comment. Change made as proposed
ISO New England	7	361	The abbreviation for milliseconds should be "ms", rather than "mS".	Within 400 m~~S~~s,	Thank you for your comment. Change made as proposed
ISO New England	12	Bottom row of table, first line	Add a space between "DER" and "is"	to the area where DER is located	Thank you for your comment. Change made as proposed
ISO New England	11	482	Delete the extraneous "a".	Historically, ~~a~~ peak loading conditions	Thank you for your comment. Change made as
ISO New England	15	558	TPs should evaluate following sensitivity cases and develop the appropriate case(s) to match the expected reliability impacts associated with high DER penetrations. TPs are allowed to select sensitivity cases per the Standards. These should be considerations instead of stating that they specifically should be studied.	TPs should consider the following sensitivity cases and develop the appropriate case(s) to match the expected reliability impacts associated with high DER penetrations.	Thank you for your comment. Change made based on this and other comments for the same section.
ISO New England	15	564	Line 562 defines the case as high DER output, yet line 564 refers to "no solar". This seems to confict with other information in this paragraph. The reference to no solar should be deleted.	to a "High Solar" case in the summertime ~~or a "No Solar" case in the springtime~~	Thank you for your comment. Change made as
ISO New England	18	701	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. The TP should be given discretion to determine if eigenvalue analysis is appropriate.	As such, the TP should ~~perform~~ consider 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.	Thank you for your comment. Changes made based on this and other comment.s
ISO New England	19	755	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 The TP should be given discretion to determine if the proposed method should be adopted.	Further, the following should be ~~added~~ considered as a method to evaluate if the "correct" amount of generation is "online" (and thus able to provide its fault current) in the case	Thank you for your comment. Change made as proposed.
ISO New England	20	768	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 SPIDERWG50 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. ASPEN has indicated to us that the 1.0 pu voltage is appropriate for short-circuit studies.	Consider modifying language to address ASPEN consideration of 1.0 pu voltage for studies.	Thank you for your comment. Altered the statement to reflect the type of assumptions rather than specific assumptions.

Organization(s)	Page #	Line / Paragraph	Comment	Proposed Change	NERC Response
ISO New England	21	799	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. Further, ISO-NE gathers information about currently in-service DERs from a voluntary survey. 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	ISO-NE requires DERs of 1 MW or greater to notify ISO-NE that they are seeking to interconnect and to follow a ~~queue~~ study process similar to the bulk-connected side. Further, ISO-NE gathers information about currently in-service DERs from a voluntary survey. 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	Thank you for your comment. Change made as proposed.
ISO New England	23	879	When Transmission planners may need to evaluate equipment upgrades on the distribution system as a potential solution for criteria violations related to DERs. The wording above is not a sentence.	Revise this langauge to be a sentence.	Thank you for your comment. Sentence revised.
ISO New England	29	1137	Assumptions TPs should make the following generic assumptions when studying the thermal overload impact of high penetrations of DERs Change "make" to "consider"	Assumptions TPs should ~~make~~ consider the following generic assumptions when studying the thermal overload impact of high penetrations 1138 of DERs	Thank you for your comment. Change made as proposed. Changed make to consider for all assumptions headers.
ISO New England	29	1157	Approach TPs should use the following method when conducting a thermal assessment analyzing the thermal impact of high penetrations of DERs: Change "use" to "consider"	Approach TPs should ~~use~~ consider the following method when conducting a thermal assessment analyzing the thermal impact of high penetrations of DERs:	Thank you for your comment. Change made as proposed
ISO New England	35	1397	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. This may not require a formal study if ongoing discussions can be used to facilitate that determination	1. TPs and PCs should ~~perform~~ consider ~~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.	Thank you for your comment. Change made as proposed.
Manitoba Hydro	9	424 / Table 2.1	DER Model domain. The authors introduce "average domain", for example, which is mixing model type with the simulation domain. There are only two relevant simulation domains: Phasor domain and electromagnetic transient domain. Within phasor domain, a steady-state solution can be calculated and a transient solution can be calculated. DER models can created in varying levels of details. A DER EMT model could be based on a detailed equivalent circuit model representing each individual IGBT switch, or an average value model based on switching functions (harmonics represented) or a simplified average model (no harmonics represented). The simplified average model is most often used to model aggregate DER in planning studies.	Perhaps have a column titled "simulation domain" and a column titled "DER Model".	Thank you for your comment, changes made to help separate Table 1.1. for specific simulation domain and DER model
Manitoba Hydro	41	1547 - 1560	The specific metrics noted don't seem to be very useful in measuring the effectiveness of this guideline as they're more related to DER modelling and not related to the recommended types of planning studies that are needed. The metrics could be tied to the recommendations noted on page vi.	Suggest reviewing and revising the metrics.	Thank you for your comment, SPIDERWG reviewed and updated the metrics according to the comment to align more to studies and the recommendations of the guideline.

Organization(s)	Page #	Line / Paragraph	Comment	Proposed Change	NERC Response
PJM	Vi	109	Check wording: The NERC System Planning Impacts from Distributed Energy Resources Working Group (SPIDERWG) identified in this 104 reliability guideline a set of planning practice enhancements for Transmission Planners (TPs), Planning Coordinators 105 (PCs), and other relevant entities. With the growing penetration of distributed energy resources (DERs), the 106 SPIDERWG had previously focused its guidance on the aggregate modelling practice enhancements and the 107 procurement of data to parameterize and validate such models. Planning studies rely on accurate models, but also 108 need robust practices that guide their study choices. Growing DER penetrations in the NERC footprint indicate a 109 growing importance on the method TPs and PCs use to study the bulk system impact of DERs. overviewed better The 110 SPIDERWG identified an adaptable framework that a TP or PC can apply to their planning practices associated with 111 the TPL-001 standard to improve identification of potential reliability impacts of DER on the Bulk Electric System 112 (BES). There are recommendations for each stage of the framework, highlighted in the following steps common to 113 TPs and PCs:		Thank you for your comment. The text has been removed due to this and other comments that rewrote the executive summary.
PJM	8	396	Typo: conventional resources may not be dispatched at the time of high DER output or may even be retired . If		Thank you for your comment. Typo corrected.
PJM	11	482	Typo: Historically, a peak loading conditions have been assumed to present the most stressed system conditions to		Thank you for your comment. Typo corrected.
PJM	12	Table 3.1	Typo: Base Case Assumption Review TPs and PCs should pay close attention to the area where DERis located and how their control l		Thank you for your comment. Typo corrected.
PJM	13	Table 3.2	Footnote error - asterisk defined on subsequent page 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		Thank you for your comment. Deleted the rows that contanied the footnote.
PJM	14	516-517	Not sure of the logic behind the footnote? * 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 non517 TPL-001 uses of Interconnection-wide base cases.		Thank you for your comment. Deleted the rows that contanied the footnote.
PJM	16	629	Spelling: power-voltage (PV) and reactive power-volage (QV		Thank you for your comment. Spelling corrected.
PJM	18	709	Either mostly or most are: and thus there are a wide variety of schemes, most proprietary. However, many of the most common schemes are		Thank you for your comment. Change made based on comment.
PJM	20	789	Not a proper noun: Industry has not yet found a Brightline threshold for entities to begin including DER into EMT studies, but there are a		Thank you for your comment. Word changed to lowercase.
EPRI	1	Line #2 of Purpose Section	Not all the parameters can be adjusted or any adjustment may result in a wrong behavior of DER therefore if possible the model adjustment should done with the help of DPs.	A cautionary sentence telling that cautions should be taken while adjusting the model can be added.	Thank you for your comment. This section was updated with other comments to remove the adjustment piece of the statement. SPIDERWG agrees with the cuationary sentence, inserted as part of the below comment.
EPRI	3	Line 4 of Previous SPIDERWG Materials	*TPs and PCs need to adjust the model to ensure…* If possible this should be done with OEMs' input or DPs' input, this will make sure that the model is not adjusted just to meet study assumptions.		Thank you for your comment, altered the phrase to remove adjust and clarified the intended role of coordinating with OEM and DPs for this process..
EPRI	7	1	It's confusing whether to use EMT or PD tool for transient stability at this point in the document.	We can add See section Types of Studies Under Consideration on whther to use EMT tool or PD tool.	Thank you for your comment, changes made to help separate Table 1.1. for specific simulation domain and DER model

Organization(s)	Page #	Line / Paragraph	Comment	Proposed Change	NERC Response
EPRI	9	1	This is confusing to read and does not clearly differentiate between switched and average model in EMT studies.	Average and switched models are not differentiated based on control of IGBT but whether the inverter is represented by switches (switched model) or not (as an voltage dependent source, average model).	Thank you for your comment, changes made to help separate Table 1.1. for specific simulation domain and DER model
EPRI	17	3	It says 'As most software..', Although steady-state studies are done primarily using the phasor-domain softwares it is worth mentioning here or before that this relates to PD software (and not EMT software). In addition EMT softwares do not model DERs as a part of load record.	As most phasor-domain sofware adds DER as a part of load record..	Thank you for your comment. Change made as proposed.
EPRI	18	Paragraph 3	A transient dynamic assessment that captures this interaction may require a three-phase simulation, EMT analysis.	Can we use term such as advisable instead of saying 'may require': it is advisable to use EMT analysis?	Thank you for your comment. No changes made based on this comment.
EPRI	21	Point #3	*As the number of buses increases in an EMT simulation, the computational burden rises exponentially.'* Agree with computational burden, but saying it increases exponentially may deter planners to do an EMT study. Is there a reference that shows the burden is exponential?	Can we just say: 'As the number of buses increases in an EMT simulation, the computational burden increases.'	Thank you for your comment. Change made as proposed.
EPRI	21	Point #7	*but EMT studies are significantly more labor intensive than traditional stability studies to perform.'* Although EMT studies are more labor intensive and take longer times, this should not be seen as a drawback of EMT studies it is rather due to limitation of present computational infrastructure which can be improved in future.	Sentence is completed wiithout adding anything as: *Increasing expertise should provide some reduction in necessary man-hours over time.*	Thank you for your comment. Altered the sentence. Did not delete the phrase.
EPRI	21	Last line	*TPs and PCs should review the above lessons learned and adopt those practices that are relevant to their area.*	It can be worth mentioning that it is a good practice to ask for EMT models, irrespective of the size of DERs, from OEMs or DPs.	Thank you for your comment. No edits made based on this comment.
EPRI	36	Section: Potential solutions. Point #3	Requiring frequency droop control on DERs	Can be changed to: Requiring frequency droop control on DERs as per IEEE 1547-2018.	Thank you for your comment. Change made as proposed.
EPRI	vi	Line 7	.overviewed better The SPIDERWG	. The SPIDERWG	Thank you for your comment. Words deleted based on this and other comments.
EPRI	vi	Para2	The SPIDERWG has also identified that of focus transmission planning departments	The SPIDERWG has also identified that focus of transmission planning departments	Thank you for your comment. Sentence altered based on other comments.
EPRI	6	Steady state power flow studies	In document steady state and steady-state is used interchangbly		Thank you for your comment. "Steady state" altered to "Steady-state".
EPRI	14	Last line	following factors that can affect the performance of DER in simulation Should be considered:	following factors that can affect the performance of DER in simulation should be considered:	Thank you for your comment. Capitalization changed.
EPRI	15	Last line	more specific study methods are found in Error! Reference source not found..		Thank you for your comment. Link to Appendix A fixed.
EPRI	17	Point 4	missing closing)		Thank you for your comment. Typo corrected.
EPRI	17	Section: Stability Simulation, Line 1	are found in Error! Reference source not found..		Thank you for your comment. Link to Appendix A fixed.
EPRI	19	Line 1	Should be Point #2, instead of a paragraph		Thank you for your comment. Change made as comment suggests.
EPRI	19	Last Paragraph	In document short circuit and short-circuit is used interchangbly		Thank you for your comment. Short circuit changed to short-circuit.
EPRI	28	Poin #1	Modify shunt switching practices and adding more automatic functions where manual switching still exists/		Thank you for your comment. Typo corrected.

White Paper: Reducing DER Variability and Uncertainty Impacts on the Bulk Power System

Action

Approve

Summary

Large penetrations of distributed energy resources (DER) are significantly increasing variability and uncertainty within Bulk Electric System (BES) planning and operations. This uncertainty is largely driven by lack of knowledge of the quantity, location, and characteristics of DERs, especially as related to their impacts on the bulk power system (BPS). The need to reduce uncertainty about DER impacts has been made more urgent by the introduction of Federal Energy Regulatory Commission (FERC) Order 2222. This order introduced the concept of the DER Aggregator,[1] which allows multiple DERs to participate in wholesale markets. The System Planning Impacts from Distributed Energy Resources Working Group (SPIDERWG) recently published the *BPS Reliability Perspectives on the Introduction of the DER Aggregator*[2] white paper, which touches on the modeling, verification, study, and coordination of this new entity within the electric ecosystem. That paper assessed that the uncertainty and variability of DERs required further exploration. This paper documents the findings of such an exploration and identifies areas of improvement and technical considerations to account for reliability impacts associated with integrating DERs. This paper also identifies methods to improve data collection and data sharing between the applicable entities described below. The methods described in the paper are applicable not only to entities with deregulated market structures and DER Aggregators but also to vertically integrated utilities or any other entity that seeks to reduce uncertainty through collection and sharing of DER data.

This document includes the revisions from RSTC comments and requests for additional information.

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[1] Some abbreviate this term as DERA, and individual market terms have various ways to describe this same entity. This paper uses DER Aggregator for the abbreviation of Distributed Energy Resource Aggregator to help differentiate between the entity that aggregates DERs (i.e., DER Aggregator) and the aggregation of DERs in modeling.

[2] Available here: https://www.nerc.com/comm/RSTC_Reliability_Guidelines/SPIDERWG_White_Paper_-_BPS_Persepectives_on_DER_Aggregator_docx.pdf

Reducing DER Variability and Uncertainty Impacts on the Bulk Power System

DER Data Collection, Storage, and Sharing with DER Aggregators
SPIDERWG White Paper

Statement of Purpose

Large penetrations of distributed energy resources (DER) are significantly increasing variability and uncertainty within Bulk Electric System (BES) planning and operations. This uncertainty is largely driven by lack of knowledge of the quantity, location, and characteristics of DERs, especially as related to their impacts on the bulk power system (BPS). The need to reduce uncertainty about DER impacts has been made more urgent by the introduction of Federal Energy Regulatory Commission (FERC) Order 2222. This order introduced the concept of the DER Aggregator,[1] which allows multiple DERs to participate in wholesale markets. The System Planning Impacts from Distributed Energy Resources Working Group (SPIDERWG) recently published the *BPS Reliability Perspectives on the Introduction of the DER Aggregator*[2] white paper, which touches on the modeling, verification, study, and coordination of this new entity within the electric ecosystem. That paper assessed that the uncertainty and variability of DERs required further exploration. This paper documents the findings of such an exploration and identifies areas of improvement and technical considerations to account for reliability impacts associated with integrating DERs. This paper also identifies methods to improve data collection and data sharing between the applicable entities described below. The methods described in the paper are applicable not only to entities with deregulated market structures and DER Aggregators but also to vertically integrated utilities or any other entity that seeks to reduce uncertainty through collection and sharing of DER data.

Applicable Entities

DER Aggregators, Transmission Planners (TP), Distribution Planners, GIS Administrators, Regulators, and other entities that require knowledge of the size, location, and capabilities of DERs in aggregate for reliability-focused studies (e.g., Distribution Operators, Balancing Authorities (BA), Transmission Operators (TOP), and Reliability Coordinators (RC)) may find this paper useful to refine their internal practices and procedures.

SPIDERWG and the Operational Perspective

The SPIDERWG is composed of transmission and distribution entities but has historically been focused on planning. For this effort, since the SPIDERWG identified that operational time frame concerns may be more prevalent than planning, SPIDERWG members engaged with their TOPs, RCs, and distribution operators. Data for DERs, which is foundational for planning and modeling to support operational functions, remains a focus of this paper.

[1] Some abbreviate this term as DERA, and individual market terms have various ways to describe this same entity. This paper uses DER Aggregator for the abbreviation of Distributed Energy Resource Aggregator to help differentiate between the entity that aggregates DERs (i.e., DER Aggregator) and the aggregation of DERs in modeling.

[2] Available here: https://www.nerc.com/comm/RSTC_Reliability_Guidelines/SPIDERWG_White_Paper_-_BPS_Persepectives_on_DER_Aggregator_docx.pdf

Definitions and Clarifications

The SPIDERWG's definition of DER is a "Source of Electric Power located on the Electric system";[3] in many instances, the definition of "DER" varies depending on the context. This paper uses the SPIDERWG-preferred definition as the primary definition to focus on the reliability aspect of the conversation. The SPIDERWG definition includes only generation and storage devices on the distribution system and not flexible loads (i.e., demand response). Other definitions and clarifications for this paper are provided below:

FERC Definition of DER: "A distributed energy resource is any resource located on the distribution system, any subsystem thereof or behind a customer meter."[4] FERC states that these resources may include electric storage resources, distributed generation, demand response, energy efficiency, thermal storage, and electric vehicles and their supply equipment.[5]

Distributed Energy Resource Aggregator: "An entity that aggregates one or more distributed energy resources for purposes of participation in the capacity, energy and ancillary service markets of the regional transmission operators and independent system operators."[6]

DER Geographic Location: The physical address or geospatial coordinates that define where the DER is located.

DER Electric Location: The DER location on the electric network. The minimum required information to locate a DER on the distribution and transmission network is the meter identification and transmission point of interconnection. These two points allow the distribution utility to utilize its system knowledge to establish additional parameters, such as the feeder, substation, or portion of its system, and the Independent System Operator/Regional Transmission Organization (ISO/RTO) to use its system knowledge to establish parameters such as sub-node, node, or market regions.

Different organizations have varied DER definitions according to their focus. With Order 2222, FERC aimed to give distribution-connected resources access to the market. The SPIDERWG's definition focuses more specifically on reliability. The varying definitions create confusion in the industry without the above-established context. Adding to the set of definitions, Project 2022-02 is scoped to define DER in the *NERC Glossary of Terms*[7] and has proposed a definition that slightly differs from the SPIDERWG definition, although the spirit of the definitions is the same.[8]

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[3] The SPIDERWG has posted a document for definitions available here: https://www.nerc.com/comm/RSTC/SPIDERWG/SPIDERWG%20Terms%20and%20Definitions%20Working%20Document.pdf
[4] Part 35, Chapter I, Title 18, Code of Federal Regulations, § 35.28(b)(10).
[5] Federal Energy Regulatory Commission, Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Independent System Operators, Order No. 2222, 85 FR 67094 (Oct. 1, 2020), 172 FERC ¶ 61,247 ("Order No. 2222"), P. 114.
[5] Ibid., P. 114.
[6] FERC Order No. 2222, (September 17, 2020) P 85
[7] Available here: https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf
[8] Primarily, the SPIDERWG definition used nested terms to simplify the length of the DER definition while the project's term does not use nested definitions.

U-DER and R-DER Designations

Modeling designations in SPIDERWG documents may have caused some confusion about what DER is under the control of a DER Aggregator, specifically whether utility-scale DERs (U-DERs), retail-scale DERs (R-DERs), or both are included in the aggregation under the control of a DER Aggregator. As the R-DER and U-DER distinctions are primarily used for modeling purposes, both may be collected under a single DER aggregation. Since the installations are smaller and typically non-utility owned, it is more difficult to gather location-specific information (both geographic and electric network location) for R-DER. This is not a concern for populating aggregate models of this equipment since the aggregation is not specific to one location, and other SPIDERWG reliability guidelines, white papers, and technical reports have provided methods to model aggregate DER.[9]

One further distinction relative to U-DERs is that it can be large enough to require a dedicated facility from the distribution utility. Therefore, it is likely to have gone through a much more rigorous interconnection review than an R-DER, and the utility will have more detailed information on the assets being installed.

Survey Process

To best analyze the uncertainty and variability of DER Aggregators, the SPIDERWG asked its members to complete a voluntary survey. The survey process and aggregate answers are provided in **Appendix A** and **Appendix B**, respectively. However, the limited number of responses (6 received from over 100 sent) prevented the SPIDERWG from generalizing the results.

Variability and Uncertainty of DER on Electric Systems

NERC's *2023 Long-Term Reliability Assessment*[10] projected rapid growth of DERs with behind-the-meter solar photovoltaic (PV) projected to reach 90 GW of capacity by 2033. Key to this type of DER is that its output can rapidly increase and decrease with weather patterns and the daylight cycle. The ramp stemming from large amounts of distribution-connected PV resources can strain other grid resources. Other forms of DER technology, including battery energy storage systems, may not be as predictable through engineering judgment and weather conditions as the current solar PV dominant technology type. This introduction of variability and uncertainty can be influenced further by end-use customer choices and preferences, resulting in potentially even further operating characteristic uncertainty. Although DER forecasting tools have made significant progress in predicting DER output, the accuracy of such tools is entirely dependent on knowledge of the total amount of DERs and their characteristics as well as their mapping to the correct substation and bus within the power system model.

System operators and planners need information on the quantity of DERs and where they are connected to reliably operate and plan the system. This paper explores variability and uncertainty reduction in this data and identifies methods of gaining this information. With high DER penetration leading to high uncertainty, key entities may be prevented from planning and modeling the system appropriately. The same variability and uncertainty may not impact an entity in lower penetrations as greatly as those with higher penetrations; however, a common, clear, and consistent method for TPs to gather data reduces the impacts

[9] SPIDERWG reliability guidelines are available here: https://www.nerc.com/comm/Pages/Reliability-and-Security-Guidelines.aspx
[10] https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2023.pdf

of variability and uncertainty under both low and high penetrations. Over the past several years, NERC has published a variety of white papers that provide guidance on the data requirements and models for DERs necessary to reduce this variability and uncertainty. This paper further focuses the discussion to provide guidance on the types of DER data and the collection process in a manner that reduces uncertainty on this information critical for planning and modeling.

The SPIDERWG has found that the variability and uncertainty in system planning are reduced by data collection from distribution owners and DER Aggregators providing clear, reportable data fields to the TP and TOP. The Electric Power Research Institute (EPRI) has also undertaken work on DER Aggregator planning impacts, particularly in identifying key data exchanges needed in the long-term planning horizon.[11] This report confirms the findings from the SPIDERWG[12] and Security Integration and Technology Enablement Subcommittee (SITES) white papers[13] stating that the data reporting obligation for DER Aggregators facilitates an enforceable and reliability-focused reduction of risk to the planning of the future BPS. The data exchange process could be significantly enhanced with a single point of truth for DERs that allows data exchange based on the Common Information Model (CIM).

The DER Aggregator's Role

The DER Aggregator's role was defined in FERC Order 2222 and resulting clarifications by the Commission about the interactions of DER Aggregators, individual DERs, and ISO/RTOs. FERC stated that the DER Aggregator—not the individual DERs in the aggregation—is the single point of contact with the ISO/RTO, responsible for managing, dispatching, metering, and settling the individual DERs in its aggregation.[14] These statements in Order 2222 establish that the DER Aggregator is the entity that will interact with RTOs and ISOs and be responsible for the operation of the individual DERs within its control. The DER Aggregator will also be responsible for the collection of data on factors such as DER characteristics and location plus information on DER operation and measurement of DER participation.

FERC Order 2222 implementations across each jurisdictional area will define in more detail the interaction between the DER Aggregators, distribution system operators (DSO), TOs, and ISOs. Local implementations will also define the role of DER Aggregators in operating DERs, controlling setpoints, and adjusting inverter parameters. Each jurisdictional area may have multiple settings for inverter-based resources (IBR) across the geography of their system and may have multiple requirements for implementation of these operational parameters. It is anticipated that the DER Aggregator will be responsible for understanding these operational requirements and ensuring that individual DERs operate according to the guidance provided by the operational control authority.

Although the operational setpoint or day-to-day operational requirements may differ between utilities or ISOs/RTOs, the fundamental DER dataset required for all stakeholders to be able to appropriately plan,

[11] Available here: DER Aggregation Participation in Electricity Markets: EPRI Collaborative Forum Final Report and FERC Order 2222 Roadmap
[12] Available here: https://www.nerc.com/comm/RSTC_Reliability_Guidelines/SPIDERWG_White_Paper_-_BPS_Persepectives_on_DER_Aggregator_docx.pdf
[13] Available here: https://www.nerc.com/comm/RSTC_Reliability_Guidelines/White_Paper_Cybersecurity_for%20DERs_and_DER_Aggregators.pdf
[14] FERC Order No. 2222 (September 17, 2020), P 266.

model, and operate the electric system effectively will be consistent for everyone. The DER Aggregator will play an important role in the accuracy and currency of the individual DERs that they control and represent to the marketplace.

DER Data Collection, Storage, and Sharing Survey

The SPIDERWG conducted a voluntary survey of its own members to attain greater clarity regarding the interactions with the DER Aggregator and ways to reduce variability and uncertainty. As the survey received only a limited number of responses, the results are not conclusive of all industry examples but demonstrate the beginnings of specific trends important to consider for transmission planning and operations.

Survey Results

Six SPIDERWG members, including four ISO/RTOs, responded to the survey. Most companies that participated share different transmission functions (e.g., TOP, Resource Planner (RP), BA, TP, RC) with one of them being a distribution operator and two being distribution providers (DP). In terms of peak gross load, four members have over 20,000 MW with these four members' DER installed capacity ranging between 1,000MW and 5,000 MW. Even though these entities' roles, DER installed capacity, and peak loads vary widely, the survey would have benefited from more responses. Therefore, the SPIDERWG decided that the survey's results may not be conclusive but provide a landscape of different practices for DER Aggregator data exchange.

The SPIDERWG interpreted the survey results as showing that introducing the DER Aggregator in the planning realm may *reduce* variability and uncertainty. The survey also yielded recommendations for maintaining situational awareness (a key reliability aspect) in the operations time frame. However, these survey results only apply to DERs that are collected by DER Aggregators for aggregation to the ISO/RTO markets. DERs that are not aggregated will not have the benefit of a DER Aggregator verifying or keeping DER information current. It is important for all DERs, not just those with DER Aggregator participation, to be known and accounted for in planning and modeling processes.

DERs can be made up of a variety of resources that may not currently be included in the interconnection process, most notably electric vehicles. Consequently, it should be expected that a significant number of DERs will remain "unknown," especially when utilities rely solely on DER Aggregators to provide DER information.

Transmission planning to enable DER Aggregator market participation requires coordination[15] between the ISO/RTO, DER Aggregators, Transmission Owners/Utilities, Distribution Utilities, and Relevant Electric Retail Regulatory Authorities (RERRA). As the SPIDERWG survey results were not conclusive, the team looked to outside reports and frameworks to determine the coordination needed to reduce variability and uncertainty. One EPRI report[16] considers some long-term planning studies and key data exchange between DER Aggregators, DER owners, and the operations and planning staff, which includes the following:

[15] The SPIDERWG has published a paper describing the available coordination and communication strategies related to DERs. This is available here: TandDCoordinationDocument_draft_White_Paper (nerc.com)

[16] DER Aggregation Participation in Electricity Markets: EPRI Collaborative Forum Final Report and FERC Order 2222 Roadmap

1. **Ensuring Adequate Transmission Impact and Reliability Assessment Studies:** The upcoming participation of DER Aggregators in the wholesale market could necessitate assessing the potential impact of one or more DER aggregations on the transmission system.
2. **DER Modeling Methods in Long-Term Transmission Planning Studies:** In most cases, research has confirmed the adequacy of modeling methods such as the NERC *Reliability Guideline on Parameterization of the DER_A Model* to study bulk system voltage and frequency performance under high levels of DERs.[17] The industry continues to identify corner cases where more sophisticated modeling of individual DERs and DER Aggregations may be desired.
3. **Ensuring Adequate DER Capabilities, Performance, and Functional Settings:** The technical interconnection and interoperability requirements (TIIR) for DERs, including those that may choose to participate in the wholesale market through a DER Aggregator or a distribution system operator, are not subject to FERC jurisdiction. FERC recognized—and highlighted in Order 2222—the responsibilities of the RERRA to initiate and lead coordination between the stakeholders on each side of the transmission-distribution interface, including ISOs/RTOs, Distribution Utilities, and DER Aggregators.
4. **Key Data Needs, Exchanges, and Update Mechanisms:** Modeling of DER and DER Aggregators in transmission planning studies and technical reviews requires adequate and efficient collection of DER data and could become increasingly important as more DER Aggregators begin to participate in the wholesale market. Several key categories of data needs and exchanges discussed include management of DER functional settings, remote configurability, common file format for DER functional settings, and potential use of a DER settings database.

The above points from the EPRI report highlight the desire for a common, clear, and consistent method of exchanging both planning and operational datasets to identify important DER information that a DER Aggregator sends to the ISO/RTOs. Further, a common, clear, and consistent data exchange can be leveraged for utilities that require coordination between myriad DERs, even those not under a DER Aggregator. The benefits of reducing variability and uncertainty translate to more accurate studies and therefore clearer identification of potential reliability risk in the planning horizon. The SPIDERWG looked at the CIM as a method for reducing variability and uncertainty as a response to the key points from the EPRI report above.

Use of the Common Information Model for DER Data Exchange

Exchange of DER data among DER owners, DER Aggregators, and other entities, including distribution service providers (DSP), transmission service providers, and market operators, presents a unique challenge due to both the disparate nature of data and the fundamental differences in modeling practices by individual grid operators. The CIM is a semantic standard for consistent representation of power system data across the generation, transmission, distribution, market, and customer domains. It is an open-source information model that provides standardized definitions for common grid components and business procedures under an Apache 2.0 license (free to use and modify).

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[17] DER Modeling Guidelines for Transmission Planning Studies. 2019-2021 Summary. EPRI. Palo Alto, CA: September 2021. 3002019453. [Online] https://www.epri.com/research/products/000000003002019453.

As a semantic standard, the CIM provides the technical equivalent of an English dictionary of spelling and vocabulary for electric equipment. The CIM differs from more widely known communications standards (such as IEC 61850) in that it only specifies the agreed-upon names for various devices and their physical characteristics (e.g., that length of a wire should be written as "Conductor.length"). The semantic standard does not dictate how the data should be communicated but is critical for both parties to understand what is being sent and whether the data received has any meaning in the given context (e.g., the attribute of "length" makes no sense in describing market revenue paid to a DER). The CIM also maps to a set of corresponding International Electrotechnical Commission (IEC) standards that define usage of the information model and compliant data exchange mechanisms.

With the introduction of unbalanced distribution network modeling in version 17 of the Grid package of the CIM, it now stands as the only standard that offers a consistent method for representing power system equipment and utility business processes in both transmission and distribution. Detailed representations of grid-edge devices and further improvements to distribution network modeling will be released in version 18 of the CIM Grid package.

The CIM divides power system data into three domains. The first is the Asset model, which describes the characteristics of individual devices (such as nameplate data) and maps to the IEC 61968 series of standards. The second is the Grid model, which describes the role that a given asset (such as a breaker, switch, or power transformer) plays when connected to the electric system and maps to the IEC 61970 series of standards. The third is the Market model, which describes the behavior of assets (including aggregate behaviors of DERs through a DER Aggregator or virtual power plant) and maps to the IEC 62325 and IEC 62746 series of standards. Complete representation of DER consists of one or more ***asset*** records (derived from the Asset section of the CIM), one or more ***equipment*** records (derived from the Grid section of the CIM), and one or more ***resource*** records (derived from the Market section of the CIM).

Leveraging the CIM has two extremely powerful benefits, the first of which comes with adopting a standard and thereby creating a common understanding of the data being exchanged. The CIM is extremely well developed in this area not only because all data elements are defined in a single object model but also because the relationships among elements are established and documented. This means that information can be passed from one system to another by leveraging standard terminology, and the meaning of the data is understood equally on both ends. Data exchanges can be incorporated into larger databases because the relationships among elements are defined. This is not true of all standards, many of which merely define the exchanges without establishing a model vocabulary behind those exchanges.

Case Study: Enabling Interoperability with Europe's Common Grid Model Exchange Standard (CGMES). The CGMES effort established in Europe is the CIM's greatest success story. The European Network of Transmission System Operators (ENSTO-E) represents 40 electric transmission system operators (TSO) from 36 countries across Europe and led the development of a CIM standard for grid model data exchange. Not only were the standards developed and ratified by the IEC, but ENTSO-E also developed a conformity test process that currently lists 21 compliant products.[18] The CGMES process calls for each TSO to create so-called Individual Grid Models (IGM) of their systems both annually as a year-ahead projection as well as daily to capture short-term changes at different hours of each day. With a set of relevant IGMs in hand, each regional security coordinator (RSC) then assembles the models into a single common grid model (CGM). This CGM supports wide-area analysis processes and, when sent back to the individual TSOs, provides visibility into neighboring grids that would otherwise require highly manual processes.

The second benefit of using the CIM for DER data exchange is that the CIM is designed to reconcile the data with the representation of the electric power system. Not only can the CIM help to capture DER data in a standard way, but the data can also immediately be embedded into the models that are used for long-term planning, operational planning, and operations to manage the grid across time. While DER data is a relatively new addition to the CIM, mechanisms to update DERs follow the time-proven processes of any type of grid equipment, such as transmission lines, breakers, and transformers.

Case Study: Tracking Grid Changes with ERCOT's Network Model Management System (NMMS). As the electricity markets in Texas transitioned from zonal to nodal, the Texas market operator, ERCOT, realized the importance of an accurate grid model. Given its role as the operator, but not the owner, of the grid assets, ERCOT understood that the details needed to build a grid model must be collected from other entities, namely the Transmission Owners in Texas. As a result, the NMMS was implemented as the single point of entry and maintenance for the network model topology used by external ERCOT market participants. During the lifespan of the initial NMMS implementation, the system processed roughly 2 million grid model changes over the course of a decade. At the end of the period, less than half of the original data elements were untouched from the initial model from 2009.[19] However, the use of the CIM enabled a consistent workflow for handling these changes and maintenance of a single source of truth used for planning, operations, markets, asset management, and all other key business functions performed by ERCOT.

Use of the CIM facilitates mapping of DER data through use of a consistent set of data classes and attributes across all utility models by a consistent globally unique identifier that is invariant across all systems. Using the CIM, a single source-of-truth object can be created for each DER, along with one for the capabilities for every instance of its make and model, one for the unique data related to the asset that is installed and configured, one for the role that asset plays in the larger interconnected system of equipment, and one for its role in the market, often that of an aggregated resource. Exchange of such data can be facilitated by the creation of a shared CIM-based data exchange service that would eliminate the need to develop custom orchestration software to coordinate the data integration for every utility in a "one-off" manner. Using persistent identifiers, information can be shared regardless of the entity of origin using references that allow updates to be made across multiple systems maintained by multiple entities.

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[18] https://docstore.entsoe.eu/major-projects/common-information-model-cim/cim-for-grid-models-exchange/conformity-registry/Pages/default.aspx

[19] https://cimug.ucaiug.org/Meetings/eu2024/Arnhem%202024%20Presentations/CIM%20University/Track%202/CIMU%20T2%20S2a%20Moseley-ERCOT%20CIM.pdf

Figure 1 below shows some of the key entities involved in the exchange of DER data, including the customer, the distribution grid operator, and the regional TP. Each of these entities will use a different software system with a different database and a different naming convention. Even within a single utility entity, the same piece of equipment will have slightly different names between different departments. Consider the simple example of mapping a set of DERs to the correct feeder breakers and individual transmission/sub-transmission substations. Information detailing the various physical assets and power system network models will be located across multiple databases from multiple software systems. Some of the required data includes the capacity from the interconnection agreement, metering point from the customer billing database, feeder connection point from the geographic information system (GIS), substation breaker from a system one-line diagram, and transmission bus from the bus-branch planning model (or node-breaker energy management system (EMS) model). Without a standard representation of power system components, a series of data tables would need to be created for each representation. Even if each application uses the same "human-readable" name for a particular piece of equipment, the exact naming string, description, and set of properties modeled will vary by application. A mapping table is then required between each set of data tables to reconcile differences in identification and attributes of each asset. Although utilities have been able to manage this in the past, the vast increase in data quantity associated with DERs will make manual data mapping impossible.

However, the use of the CIM with a consistent class name and a persistent identifier for each DER and each associated data type solves this naming problem. The identifier needs to be created only once and then stored in an object registry as part of a set of a master list of identifiers for data import and export. The identifier does not have to be human-readable and is generally not intended to be displayed to the end users of advanced power applications. Rather, it is a machine-readable identifier that can be referenced across all databases and data exchanges between multiple entities. To ensure global uniqueness across all systems, the identifier should be a universally unique identifier (UUID), a 128-bit integer that is serialized as a 32-character hexadecimal string. For the DER-to-substation mapping example, the DER would be assigned a unique identifier when first created during the interconnection approval process, with the identifier stored in the object registry. That identifier would then be referenced by all other systems, such as the GIS model, customer billing database, and planning model. The data mapping process then becomes a simple table join query that gathers all references to the master identifier across each enterprise system and combines them into an aggregate representation that can be shared with the TP and other external entities. Further information on the use cases and core data classes used for data exchange by the CIM is available in a series of primer documents.[20,21,22]

[20] Enabling Data Exchange and Data Integration with Common Information Model. 2022, PNNL-32679. Richland, WA. [Online] https://www.pnnl.gov/main/publications/external/technical_reports/PNNL-32679.pdf

[21] A Power Application Developer's Guide to the Common Information Model, 2023, PNNL-3946, Richland, WA. https://www.pnnl.gov/main/publications/external/technical_reports/PNNL-34946.pdf

[22] Common Information Model Primer, Ninth Edition, 2023, EPRI, Palo Alto, CA. https://www.epri.com/research/programs/062333/results/3002026852

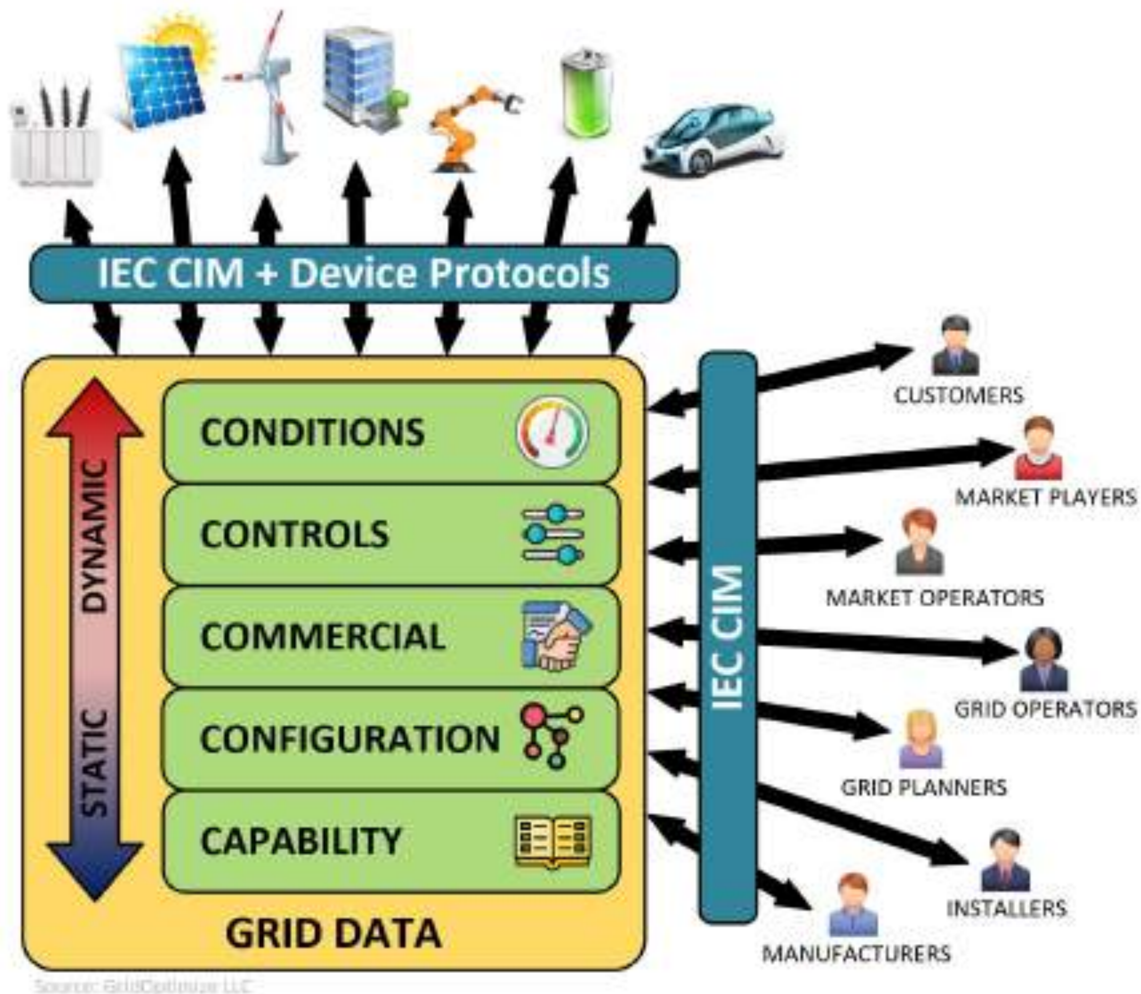

Figure 1: Visualization of Grid Data Types

Modeling DERs in CIM

The five distinct functions in the energy industry covered by DER data, as follows, will be defined in this section:

- Capability Data
- Configuration Data
- Commercial Data
- Controls Data
- Conditions Data

This data can be provided by multiple entities across the energy industry, including the manufacturer, owner, aggregator, and utility operator (see Error! Reference source not found.). Typically, each of these stakeholders use their own set of custom data formats, which are difficult to share and interpret. Since the

CIM is a high-level semantic model focused on enterprise-level data, it must be paired with lower-level, device-focused communications protocols (such as IEC 61850 or IEEE 2030.5) to enable real-time information gathering and ultimately device controls, as shown in **Figure 2**. This white paper focuses on the types of data needed to reduce variability and uncertainty in system planning, seen in the green semantic data layer of **Figure 2**.

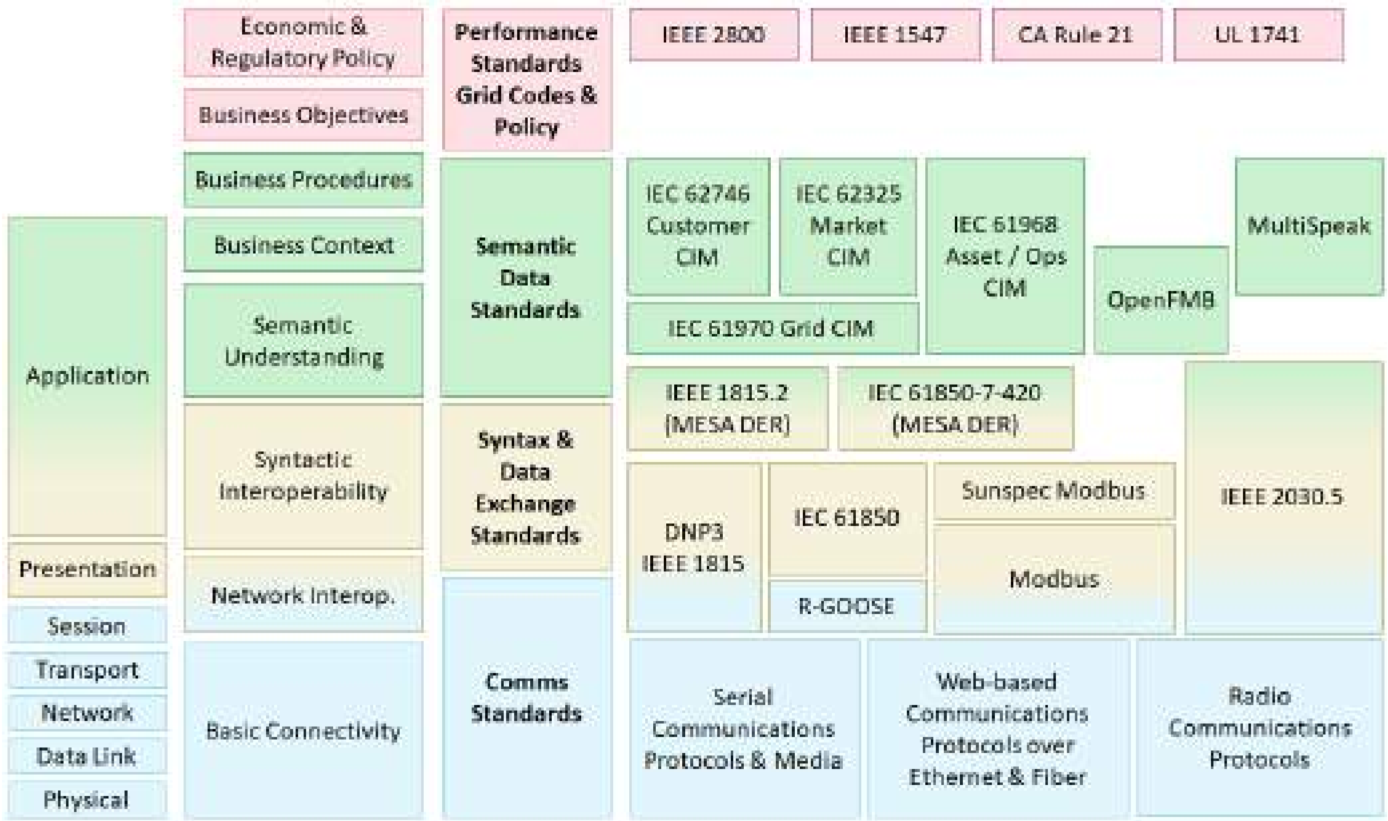

Figure 2: Standards Landscape for Exchange of DER Data

As DER penetration increases, all parties will need to be able to obtain data for decision-making and analysis. To this end, creation of a "single source of truth" for each DER is recommended to help eliminate confusion and incorrect DER models. Moreover, establishment of a master repository of DER data can make data management substantially less costly and challenging. The types of data to be included in such a repository are described below.

DER Capability Data

DER capability data describes the nameplate capabilities of the DER, which are generally identical for all instances of a particular make and model of battery, solar panel, or electric vehicle charger. In general, capability data is relatively static and is either provided by the manufacturer or determined by evaluation through testing labs. The data is tied to a particular make and model of DER and can be reused as each asset is produced along with its own unique data-like serial number or electronic address. The California Energy

Commission has the most complete set of capability data for DERs, available online.[23] Examples of DER capability data include the following:

- Make and model identifier
- Rated voltage
- Rated current
- Maximum apparent power output
- Maximum reactive power injection
- Reactive power absorption maximum
- Storage capacity (storage DERs only)
- Active power charge rate maximum (storage DERs only)
- List of IEEE 1547-2018 operational modes available

Detailed asset-based modeling with standardized data sheets for distribution equipment was added to the CIM such that common data could be defined unique to a particular make and model and simply referenced by each physical asset deployed on the grid. This approach for utility-owned grid equipment is being extended to cover DER datasheets and core modeling in version 18 of the CIM Grid package. The latest version of CIM packages (as well as the previous CIM17/CIM100 release) is available for download from the UCAiug CIM User Group website.[24]

Documenting datasheets to support DERs include two major subsets of data. The first set of data is the nameplate data and includes the rated voltage, maximum power capabilities, and full set of data elements inspired by the requirements published in IEEE 1547-2018.[25] The second set of data, also driven largely by requirements in IEEE 1547-2018, documents available operational modes and protection capabilities and is much more substantial. R-DER assets are expected to be primarily “off-the-shelf” equipment with datasheets consistent across any instance of that make and model. U-DER assets are expected to be “built-to-specification” equipment with datasheets unique to that installation. The modeling structures are identical regardless of the number of references to a DER datasheet (i.e., a single U-DER or thousands of R-DERs).

The process of collecting DER capability consists of two phases. First, the datasheet must be located. In the best case, the data can be found on the manufacturer’s website, embedded in datasheets, or in the user manuals. Second, the data must be converted from human-readable documents (such as PDFs and spreadsheets) to the proper data class fields in the CIM. This requires both knowledge of the CIM as well as training in electrical engineering to help ensure that data is properly converted. To avoid duplication of modeling efforts, it is possible to create a collaborative “single source of truth” data environment to provide

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[23] https://www.energy.ca.gov/programs-and-topics/programs/solar-equipment-lists
[24] The CIM Users Group has released CIM version 18 in early 2024. The latest is available here: https://cimug.ucaiug.org/CIM%20Model%20Releases/Forms/AllItems.aspx
[25] https://standards.ieee.org/ieee/1547/5915/

this information. The “single source of truth” environment would enable access to DER capability data to users through a graphical user interface (GUI) and application programming interface (API) access.

DER Configuration Data

DER configuration data describes how a particular asset is connected to the grid and how it is configured during installation. Much of this information is known by the installer and the distribution utility, typically published in a one-line electrical diagram and in GIS representations. Importantly, this modeling allows the utility to incorporate information about the DER into long-term planning studies and short-term operations planning studies.

Examples of DER configuration data include the following:

- Asset identifier
- Owner
- Geospatial location
- Electrical equipment settings (e.g., ride-through, frequency droop gain, return-to-service)
- Energization date
- Grid point-of-interconnection (POI), which is any/all of the following:
  - CIM connectivity node identifier
  - Feeder identifier
  - Substation identifier
  - POI for transmission-distribution interface

Interconnection agreements and permitting information for R-DERs can be stored in a variety of non-standard methods, including a spreadsheet, a customer billing system, a dedicated DER database, or a GIS system in which each R-DER is associated with the street address (or geospatial coordinate location) of the customer premises. Meanwhile, the data relating to the DER connection to the grid is typically contained within a GIS database. Finally, power flow models used for interconnection studies and system planning are most frequently described by proprietary data formats to support specific vendor tools. None of the typical sources of data (DER database, GIS, or modeling tools) use a standard format, naming, or structure, making collection and sharing of data extremely difficult. Furthermore, the tools and data listed above are nearly exclusive to distribution utilities; a transmission entity would likely struggle to open and parse any of the model files and data.

The CIM provides a better approach. DER configuration data is instantiated in two areas of the CIM. The first is the asset data, which documents the particular instance of a certain type of DER (in a manner similar to how distribution utilities perform asset management to track hundreds of instances of certain makes/models of pole-top transformers). The asset data consists of the serial number of the particular asset, who owns it, and where it is located. If local codes require constraints on the capability data (e.g., a certain operational mode required to be set during installation), this information is also captured and tracked with the asset information.

The second area of the CIM is the grid representation perspective, known within the CIM as equipment data. This data represents the role of the asset in the electric grid used for power flow studies and operations. The most important data to be collected is the POI data, which describes where the DER is connected in the distribution feeder and in the bulk transmission system. Although the POI can be estimated using geospatial techniques, the preferred approach would be for the utility to provide a reference to a persistent grid location identifier (such as the bus number or CIM connectivity node). Mapping U-DER and R-DER to the correct bus within the power system network model is a major milestone in the data collection process toward reducing uncertainty regarding DER impacts. This mapping creates an accurate topological model of individual resources in support of the implementation of existing SPIDERWG recommended modeling practices.

As the specific name, number, or other identifier for the grid POI likely varies across entities, careful internal database maintenance of DER connection points to the TP's desired representation at the grid POI is necessary to mitigate duplication or erasure of data. Data entry entities are likely not aware of the TP's internal nomenclature on this point. Further, operational configuration can alter the DER connection point through reconfiguration of the distribution system, meaning that, for operational purposes, some of these points may not be the same under all operating conditions. These discrepancies between entities highlight the importance of a "single source of truth" system of record, which is discussed below.

DER Aggregation Commercial Data

Aggregation commercial data in this context represents how the DER participates in any number of market opportunities, from local distribution utility programs to third-party energy retailer/aggregator programs to wholesale market service opportunities. A key point in commercial agreements, at least from the utility perspective, is if the DER is directly participating or is participating as part of an aggregation where some or all of the device-level details may be ignored. Examples of DER aggregation commercial data include the following:

- Resource identifier
- Aggregation identifier(s)
- Service qualifications (e.g., energy, ramping)
- Service start and end dates

Collecting and mapping this data is even more complicated and offers one of the strongest use cases for adoption of the CIM. Myriad data validation needs to be performed at this level, including the following:

- Is a given DER participating in the DER Aggregator's provided service?
- Is the DER in an aggregation already?
- If not full capacity, how much of the capacity is part of the aggregation?

- What are the extents (voltage, geography, etc.) of the aggregation?
- Are there rules for which opportunities can be supplied coincidently?
- If multiple services of the aggregation are offered to different entities, for example T and D, which takes precedence?

The parties to coordinate or perform these validations are yet to be determined. However, according to the processes currently defined by the ISO/RTO FERC Order 2222 compliance filings, the DER Aggregator will be responsible for understanding the market rules and the submittal/enrollment of an aggregation with appropriate parameters. By building the DER representation in the layered fashion provided by the CIM, there exists an opportunity to capture the more fluid aggregation dataset separately and link it to the less dynamic (sometimes static) DER capabilities and configuration data. As the roles and capabilities of each DER changes over time, this linkage of datasets can be updated in the “single source of truth” system of record.

In addition to providing data classes for the assets and topology of the power system, the CIM also provides a baseline from which DER aggregations can be formed. Aggregations can be formed based on power system topology, market structures, or control hierarchy. As markets evolve, planners and operators need sufficient information to study reliability impacts, especially in the case where DER Aggregators span multiple market nodes, which can translate to multiple BES substations. TPs can use the information contained within the aggregation to validate their case assumptions to determine how the DER and DER Aggregators interact in their simulations. TOPs may be able to use this data to supply their real-time assessment or other operational time frame analysis.

DER Controls Data

While all the prior datasets are focused on exchanges among systems, DER controls data explains the interactions between systems and devices. Since the CIM is primarily a system-to-system protocol, this often means incorporating a device-specific protocol between the utility and the devices that need to be issued control, such as with IEC 61850-7-402 (which has native integration) or with IEEE 2030.5, CTA-2045, or OpenADR (where mappings are possible).

DER controls data can be grouped into two broad categories: energy scheduling and operational modes. Energy scheduling is an optimization of the device’s behavior to maximize profits and/or grid reliability. The results multi-function optimization could be a schedule of production or consumption levels[26] that are communicated to the device. Today, these function optimizations are most commonly delivered to devices via the internal communication channels provided by the device manufacturers, but it is anticipated that the industry will need general protocols to allow easier scheduling in the future.

The second category of controls covers those of operational mode, such as switching an inverter from constant power factor to Volt-VAR mode. Closely tied to operational mode are protection settings, such as the time constants for voltage and frequency ride through. These controls are primarily reliability-based,

[26] This translates to real power scheduling. In some cases, reactive power is also scheduled.

and utilities will need a standard way to deliver these settings (or signals to switch to settings groups) using a standards protocol.

DER Conditions Data

Another significant challenge is the collection of real-time measurements for use by the distribution operators, and in aggregate, but the TOPs. At most substations shared between separate utilities, supervisory control and data acquisition (SCADA) data points for boundary equipment are obtained from dual-ported remote terminal units (RTU) and intelligent electronic devices (IED). The same set of measurements is sent across independent operational technology (OT) communications networks of the TOP and DSP. Only a minimal amount of data is exchanged through Inter-Control Center Communications Protocol (ICCP). Most control actions are coordinated by verbal communication between power system operators via telephone calls or scheduled in advance.

Most transmission utilities currently have no knowledge of total DER output from a set of feeders served by a given substation. Most EMSs only provide a display of the total real power and reactive power flow measured on each transformer winding. In regions with high penetrations of renewables where multiple distribution feeders push energy back into the transmission system, operators may only see a reversal in the power flow direction at the substation transformer with no further information on the amount of actual load and actual DER output.

Implementation of FERC Order 2222 will require significantly closer coordination and data exchange across the transmission-distribution (T-D) boundary. Like the network modeling problem, exchange of real-time data is also very difficult because existing data streams are highly siloed. Even if dual-metered advanced meter infrastructure (AMI) data is available (with separate metering of customer load and R-DER), this data is often not ingested and aggregated until the next business day. Use of data with such high latency would require recursive back-calculations and revision of market settlements for aggregate DERs to avoid double-counting of energy at the T-D interface. Furthermore, even if such data is available in real time, there are often no mechanisms except for ICCP by which the data can be aggregated and shared with transmission entities.

However, it is anticipated that low-latency DER data will become more readily available, either directly from the devices or through DER Aggregators using non-utility infrastructure. This potentially rich source of data introduces challenges in both the semantic realm (making sure translations are accurate between protocols) and the security realm (given that the primary communications mechanisms at the grid edge are not secured utility-managed infrastructure).

The CIM also provides the opportunity to transition to more efficient and automated reporting. Utilizing the allowable communications interfaces[27] for DERs, inverters could self-report to DSOs, TSOs, or ISO/RTOs when they disconnect or connect to the grid or when they enter into dead-band operation due to system

[27] Examples of these interfaces and allowable protocols can be found in Table 41 of IEEE 1547-2018. Additional proprietary protocols may also exist for communication to DERs.

voltage or frequency anomalies, significantly lowering the burden of grid operator reporting requirements while providing a robust dataset for post-event analysis.

Structurally, the CIM allows the power systems industry to deal effectively with the administrative functions of sharing DER and DER Aggregator data across all stakeholders. New tools and structures have been added to the CIM to support the operational and settlement aspects for DERs/DER Aggregators and are being demonstrated now. DERs and DER Aggregators present a new challenge to industry to effectively define a single point of truth for DERs and DER Aggregators (tens of millions over time) and share this information broadly across a wide range of stakeholders. An ad-hoc approach to DER and DER Aggregator data that cannot be collaboratively shared with all stakeholders will significantly undermine the industry's ability to utilize DERs and DER Aggregators for grid and market support. Utilizing the CIM as the foundation for this collaborative set of data will ensure the accuracy of the information for appropriate planning and modeling, dramatically reducing the IT costs over time and significantly reducing the time for the effective implementation of DERs and DER Aggregators into the grid and markets.

System of Record (Single Point of Truth)

With more than 3,000 utilities interacting with multiple ISOs/RTOs and market constructs, a DER can provide valuable services to both a utility retail program and a market product. To facilitate the effective implementation of FERC Order 2222 and make DERs broadly available to both utility retail programs and market products, a single point of truth or system of record can readily provide the capability and configuration data for the DER. Consistency of data input for aggregate DERs (through a DER Aggregator or other entity) is the key to ensure similar device-to-device treatment so that, when needed, the TP can pull the relevant information from the central repository and build a representative model of the aggregation. This improvement highlights the key nature of a single system of record for DER information and can readily reduce uncertainty between TPs and PCs.

Some entities that have implemented a system of record include the Australian Energy Market Operator,[28] EPRI,[29] the Vermont Electric Power Company,[30] and Collaborative Utility Solutions.[31] As these systems of record are typically not backwards-compatible to new or updated systems, element relationship definitions that were set on implementation may take a significant amount of time to update if they are not based on CIM data structures. Thus, TPs should ensure that the needed DER information can be made available through the single system of record, as having multiple systems to feed the data defeats the purpose of a common single system of record. In the ideal scenario, the system of record should do the following:

- Represent all the DER ***capability***, ***configuration***, ***commercial, conditions,*** and ***controls*** information through a robust set of parameters in the system of record
- Capture all the fields that a TP can translate into its software

[28] A report on CIM modeling is available at the Australian Renewable Energy Agency here: https://arena.gov.au/knowledge-bank/using-the-cim-for-electrical-network-model-exchange/
[29] Available here: https://www.epri.com/research/products/000000003002006001
[30] Initial architecture available here: https://www.vermontspc.com/sites/default/files/2024-01/VSPC_VXPlatformpresentation.pdf
[31] The library of resources for Collaborative Utility Solutions is available here: https://www.cusln.org/resources/Public%20Library

- Resolve TP-to-TP differences in modeling practices so that the data is communicable to neighboring TPs.

The breadth of industry stakeholders that require access to DER data (**Figure 3**) has expanded significantly when compared to the historical industry interactions with a single set of data. A single system of record ensures coordination across the necessary stakeholders. Collaboration among the necessary stakeholders that use this data reduces a DER Aggregator's variability and uncertainty impact. Entities seeking to implement a system of record should ideally ensure that the entities responsible for each function in the figure can leverage the system in order to reduce uncertainty and variability.

Figure 3: DER Data Uses

The potential for millions of DERs being connected to the grid provides unique opportunities for both the reliability and resiliency of the grid. Still, if there is no simple method to share DER data across the stakeholders in the energy value chain, it will be more difficult to effectively integrate, utilize, and ensure the reliability of the BPS with the growth of DER into the future.

The following barriers must be overcome when implementing CIM data to avoid disrupting utility practices:

- Stakeholders may need to be educated on the benefits of the CIM,[32] the update procedure, and the technical implementation of CIM profiles for DERs.
- Translation of CIM structure into proprietary software may require software vendors to update their code and release patches or versions to handle this syntax. For example, positive sequence load flow software already contains proprietary-to-proprietary file conversion support[33] (to communicate across other positive sequence load flow tools. Some software vendors may already have a CIM translation tool; however, those that do not may need code alterations to accept the way power flow and dynamic data is input to the program from CIM.
- As a subset of the translation barrier, planning practices may need updates to implement the CIM structure in procured proprietary software for use in transmission planning studies.
- Education on the methods to ensure a secure exchange of data among entities, which is separate from the CIM structure. For example, the CIM can be communicated across any file transfer protocol. Not all file transfer protocols are secure from malicious access. Entities may need education to establish good cyber posture and hygiene when implementing CIM (and other) data sharing mechanisms.
- Enhancements to standard-based data exchanges may be necessary. Currently, many of the NERC Reliability Standards require a mutually agreeable data format or provide an entity the full authority to require a specific data format. This may mean that entities could forbid data exchange in the CIM in lieu of proprietary protocols. Thus, a potential barrier to CIM implementation across the NERC footprint is a lack of incorporation by the entities into their standard practices that can be remedied by exposing such entities to the benefits of CIM per item 1 in this list.

[32] Such as materials using [insert items from footnote 21-23] for education.
[33] Such as the .raw file extension translation tools in positive sequence load flow software.

Appendix A: Detailed Survey Process with Questions

The SPIDERWG followed up its original modeling survey[34] with a set of questions that focused on the impacts of DER Aggregators and the responses to its original membership survey to track improvements. This survey was distributed to the SPIDERWG email distribution list, which has over 100 members, some of whom represent the same company. Six members, including four ISO/RTOs, responded. Most companies that participated in the survey share different transmission functions (e.g., TOP, RP, BA, TP, RC) with one of them being a distribution operator and two being DPs. In terms of peak gross load, four respondents have over 20,000 MW and these four stated having DER installed capacity in the range of 1,000–5,000 MW.

The following questions were asked in this survey:

1. What is your company's function?
    a. If you are a Reliability Coordinator (RC), do you have specifications for DER data when performing your OPAs, RTAs, or real-time monitoring?
        i. How periodically is that information submitted? (e.g., seasonally, monthly, weekly, daily)
        ii. Do DER Aggregators provide any of this data?
    b. What are the specifications for DER data when performing your planning assessments?
        i. How periodically is that information submitted? (e.g., seasonally, yearly)
        ii. Do DER Aggregators provide any of this data?
    c. If you are a Reliability Coordinator, Transmission Operator, or Balancing Authority, are there differing rules for T-side connected generation resources versus DER and DER Aggregators (i.e., sources of power located on the distribution system)?
        i. Can you explain any difference in treatment of the two categories of generation resources?
2. What is the peak gross load of your area [MW]?
3. What is the minimum gross load of your area [MW]?
4. What is the total capacity of DERs connected to your system [MW]?
5. How are DERs being aggregated in your system?
6. Have you observed widespread tripping of DERs due to faults in operations? If yes, how many DERs tripped [MW and count, if available]
7. Do you receive any DER operational data (e.g., active power output of DER or DER status)
8. How do you model DERs in load flow studies? (buckets altered to be specific as net load hanging off transmission bus, modeled on low end of T-D XFMR)
9. Which positive sequence DER model do you use in your dynamic studies?

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[34] Available here: https://www.nerc.com/comm/RSTC_Reliability_Guidelines/White_Paper_SPIDERWG_DER_Survey.pdf

   a. Do you use any non-positive sequence DER modeling for any transient dynamic study? (e.g., a generic EMT model for DER)

10. Which positive sequence load model do you use in your dynamic studies? (ZIP load, CLOD, cmpld, cmpld_der_a)
    a. Do you use any non-positive sequence load modeling for any transient dynamic study?
11. What offerings does the DER Aggregator have in your area?
    a. Is there an analogous entity for areas that are not ISO/RTOs that aggregate the response of generation-connected generation?
    b. How is the Demand Response program controlled in your area?
12. Does the DER Aggregator (or entity aggregating the DER in your area) have interconnection or participation requirements for participating DER? If yes, proceed to the following:
    a. Are those documented?
    b. Are those available to share for DPs?
    c. Are those available to share for transmission entities?
    d. How does Clause 10 of IEEE 1547-2018 play into account here?
    e. Are there additional technical requirements required for reliability from the ISO/RTO on participation? Are these publicly sharable? If so, please provide a link.
13. How and when do new DERs or existing DERs intended to increase the capacity signal to a DER Aggregator participate in that aggregation for your area?
    a. Does the DER Aggregator notify transmission entities of this new capacity for your area?
    b. Is this taken care of in the capacity review identified in FERC Order 2222, or is it a separate requirement of the ISO/RTO?
14. How do the distribution system operators and planners coordinate with the DER Aggregator for analysis of constraints on the distribution system?
    a. D-side constraints can have backup plans; how are those currently monitored?
    b. Are some of these schemes automated?
    c. What requires operator control and does that affect which T-D Interface a DER is pushing against?
15. If known, how does the DER Aggregator collect, store, and share the following:
    a. Planning data
    b. Operational data
    c. Short Circuit data
16. Does the DER Aggregator share resource type (PV, PV+BESS, Wind) information?

   a. Is this unit by unit, or lump sum?

17. Does the DER aggregator or entity supplying DER planning, operational, or short circuit data send notice to the transmission entity at the T-D Interface when DER device characteristics change?
    a. Is there a verification of capacity and control from that which is provided in the services to the information shared for planning?
    b. Is there a verification of capacity and control from that which is provided in the services to the information shared for operations?
    c. Is there a verification of capacity and control from that which is provided in the services to the information shared for protection relay coordination?
18. What set points or schedules does a DER Aggregator set on the DER it controls?
19. How is double counting or other duplication of generation accounted for?
    a. Is the DER Aggregator covering all of the T-D Interfaces?
20. What estimation techniques for DER Aggregator output are used to run a 15-minute ahead, 30-minute ahead, hour-ahead, and day-ahead analysis?
    a. Does the estimation spread across multiple load records?
    b. Does the estimation allow for creation of "new" generators in the model?
    c. Are predictions made on zones, substations, feeders? (select all that apply)
    d. How granular of a forecast is required?
    e. How does the forecast deal with uncertainty or error?
21. For your state estimator, how does the mismatch solution deal with negative records added to the load?
    a. Does an output negative load link with a DER generator dynamic model?
    b. How are mismatch loads dealt with in the OPA and RTA practices? Are they ignored, netted, or other?
22. Does your data quality checks or other operational assessment practices account for gross versus net loading at each T-D Interface?
    a. What metering supplies this gross versus net loading? (e.g., transformer-level, breaker-level, or DER device-level metering)
    b. Are these quality checks posted or otherwise available on request?
23. For information provided by the DER Aggregator, what telemetry granularity is the aggregator able to provide? (e.g., SCADA scans, Advanced Distribution Management System (ADMS), other time frame or framework)
    a. Do they disaggregate their load from active power producing generation resources?
    b. What metering is used or provided to telemeter the data for operational planning analysis?

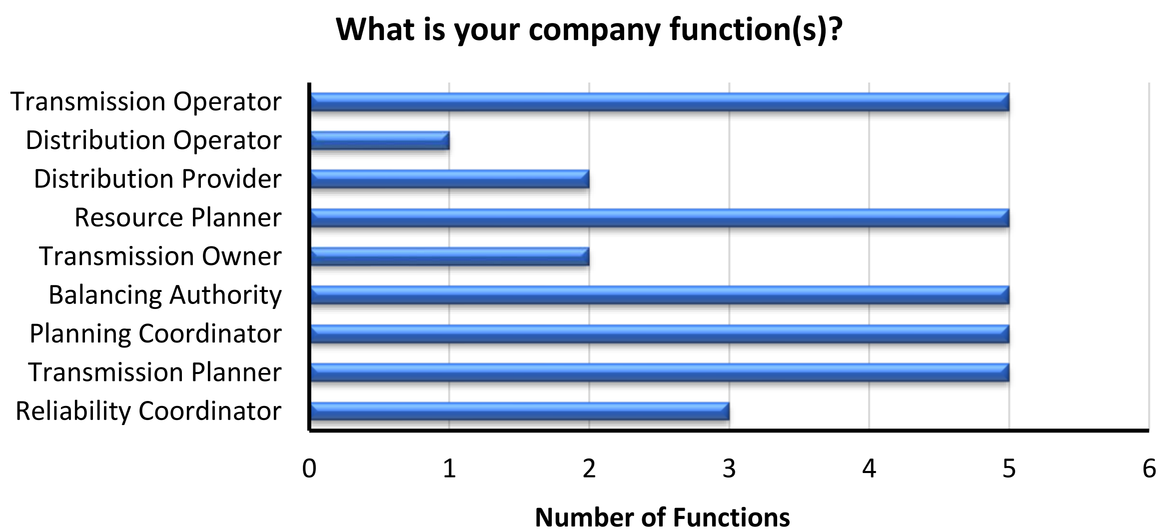
c. What metering is used or provided to telemeter the data for real-time analysis?

Appendix B: DER Aggregators Survey Responses

This appendix provides the aggregated responses from the survey as well as the key takeaways for each question asked. The values show the number of responses out of the total number of received surveys. The lack of survey participation should qualify the key takeaways as needing further investigation into other entity impacts.

Question 1

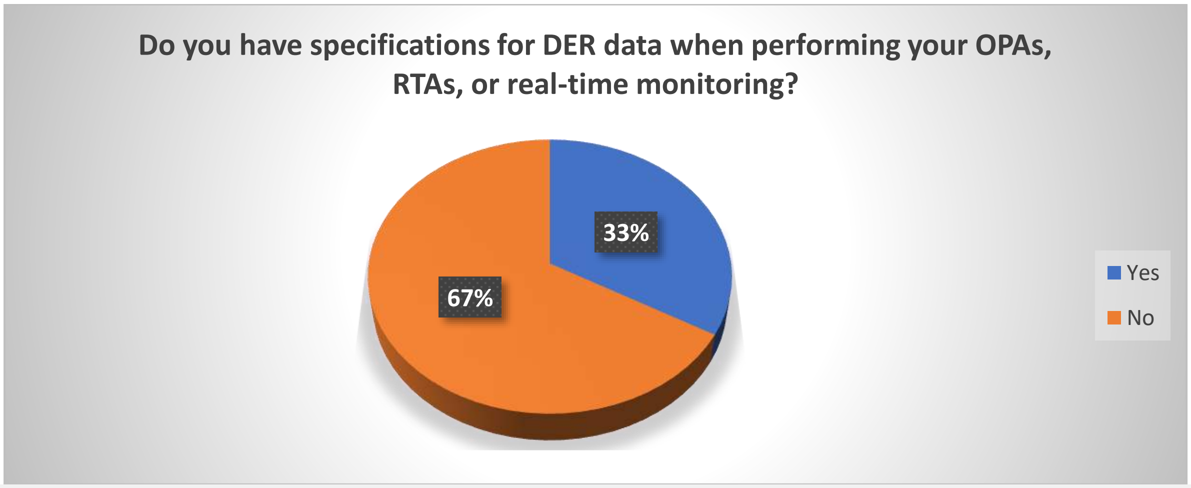
1. What is your company function(s)? (Select all that apply)



Key takeaway: Question 1
Most surveyed members represent multiple NERC entities simultaneously. Functional entities most represented among the surveyed members are TOs, RPs, BAs, PCs, and TPs.

Question 2

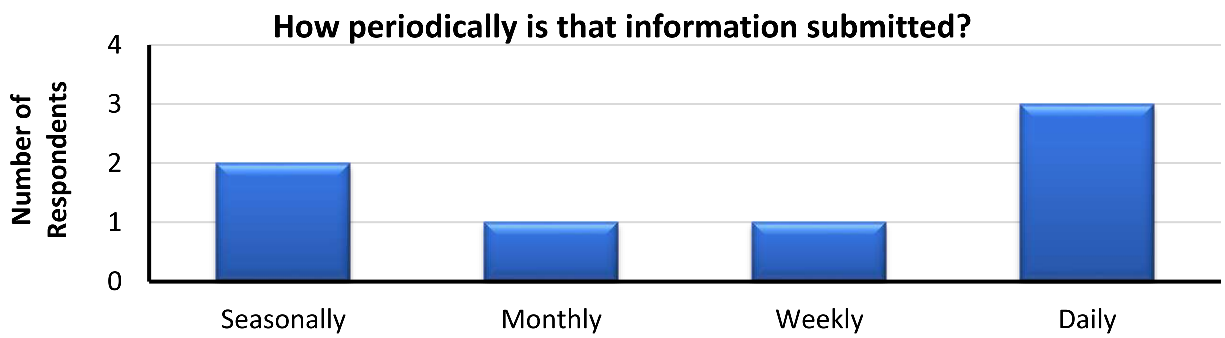
2. If you are a Reliability Coordinator (RC), do you have specifications for DER data when performing your Operating Planning Analysis (OPAs), Real-time assessment (RTAs), or real-time monitoring?



Key takeaway: Question 2
Only one surveyed member has specifications for DER data for OPAs, RTAs, or real-time monitoring.

Question 3

3. How periodically is that information submitted? (Select all that apply). Do DER Aggregators provide any of this data?



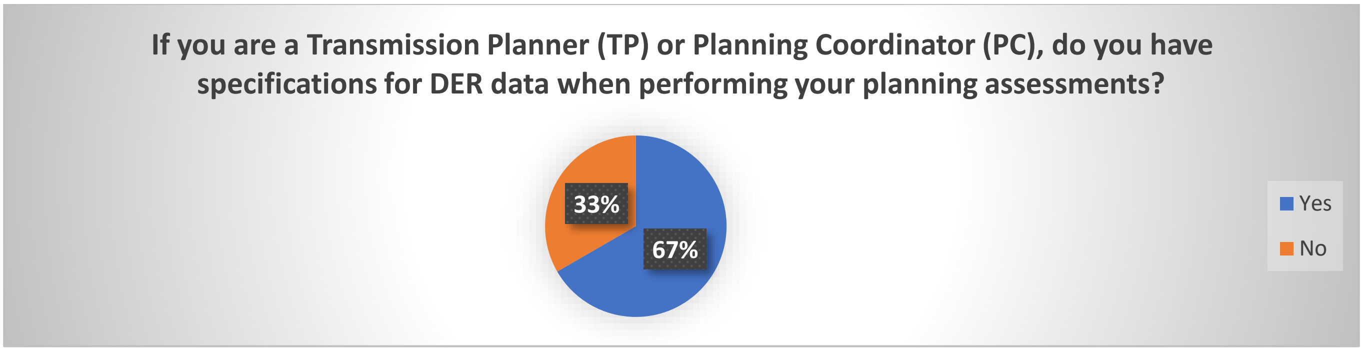
Key takeaway: Question 3
One entity emphasized that DER and DER aggregations registered for participation in the wholesale electric market provided data for a variety of assessments. Data is provided in a wide variety of time ranges with necessary modeling information (provided weekly), near-term reliability studies (hourly), and dispatch in real time (up to 2 seconds). Additionally, monthly updates are provided in terms of detailed distribution premises and devices that make aggregation. There is a need to identify how the OPA and RTA tools can capture a significantly growing set of data for the operational impact of DER Aggregators as these entities grow in their capacity and penetration.

According to another survey participant, data is provided via surveys submitted by the Transmission Owners in their company's footprint.

Most of the surveyed SPIDERWG members do not currently have DER Aggregators.

Question 4

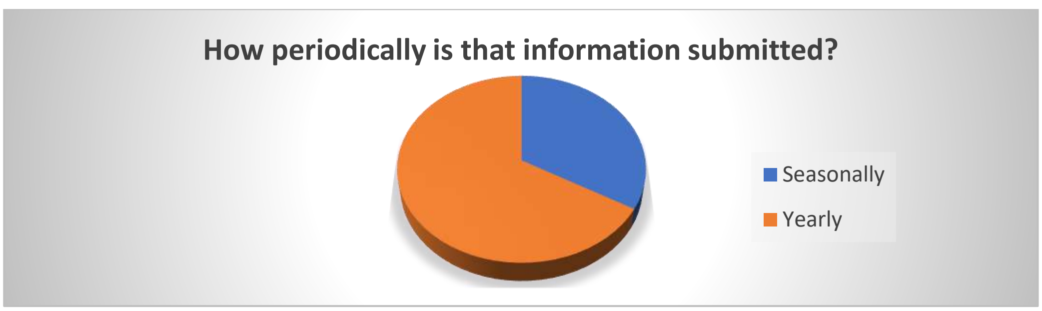
4. If you are a Transmission Planner (TP) or Planning Coordinator (PC), do you have specifications for DER data when performing your planning assessments?



Key takeaway: Question 4
The majority of survey participants (66%) stated that they have established specifications for DER data when performing planning assessments.

Question 5

5. How periodically is that information submitted? Do DER Aggregators provide any of this data?



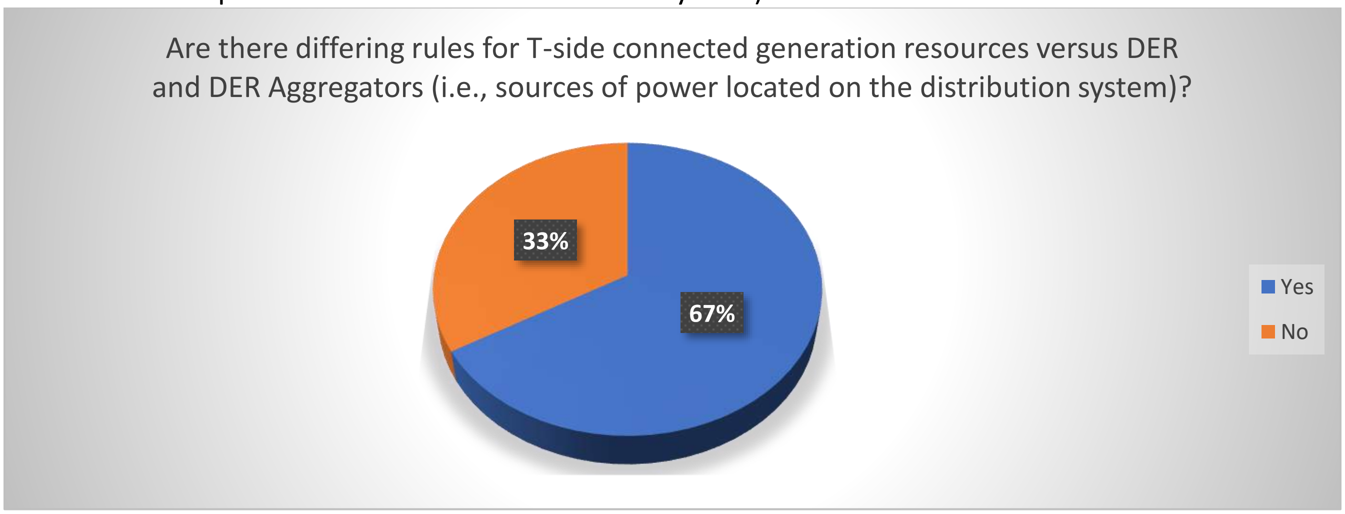
Key takeaway: Question 5
67% of surveyed entities stated that they do not have DER Aggregators connected to their system. However, their DER generation is based on forecast data that includes future and currently connected DER.

One entity claimed that DERs greater than 1 MW are required to register and provide data and are included in annual base-case development. Responses show that this data can be provided (or forecasted) seasonally or yearly.

According to another survey participant, data is provided via monthly surveys submitted by the Transmission Owners in their company's footprint.

Question 6

6. If you are a Reliability Coordinator, Transmission Operator, or Balancing Authority, are there differing rules for T-side connected generation resources versus DER and DER Aggregators (i.e., sources of power located on the distribution system)?



Can you explain any difference in treatment of the two categories of generation resources?

The SPIDERWG received the following open-ended responses to this question:

- DER has different requirements for ride-through. Reactive power capability and voltage control are generally specified by the distribution provider.
- Transmission: Have to hold voltage schedule. Require ride-through of transmission connected generation. Evaluate need for AGC capability.
- Distribution: must hold unity power factor. Ride-through not required on distribution connected DER.

Key takeaway: Question 6

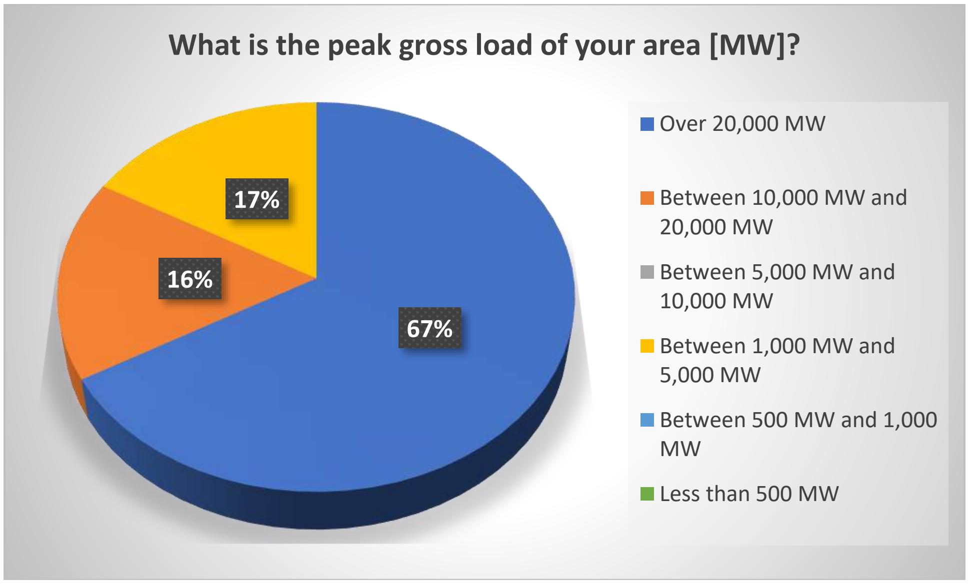
Two-thirds of surveyed SPIDERWG members showed that they have established specifications for DER data when performing planning assessments. As expected, members stated that there are different specifications for ride-through, voltage regulation, and other capabilities for resources connected to the transmission vs. distribution side and that DPs are responsible for specifying DER capabilities and performance.

Some survey participants shared that DERs enter the state interconnection process, whereas transmission-connected resources enter through ISO-NE's queue and the FERC interconnection process.

The SPIDERWG has published the Reliability Guideline Bulk Power System Reliability Perspectives on the Adoption of IEEE 1547-2018 to help RCs and BAs coordinate and specify DER functions that are key to ensure BPS reliability.

Question 7

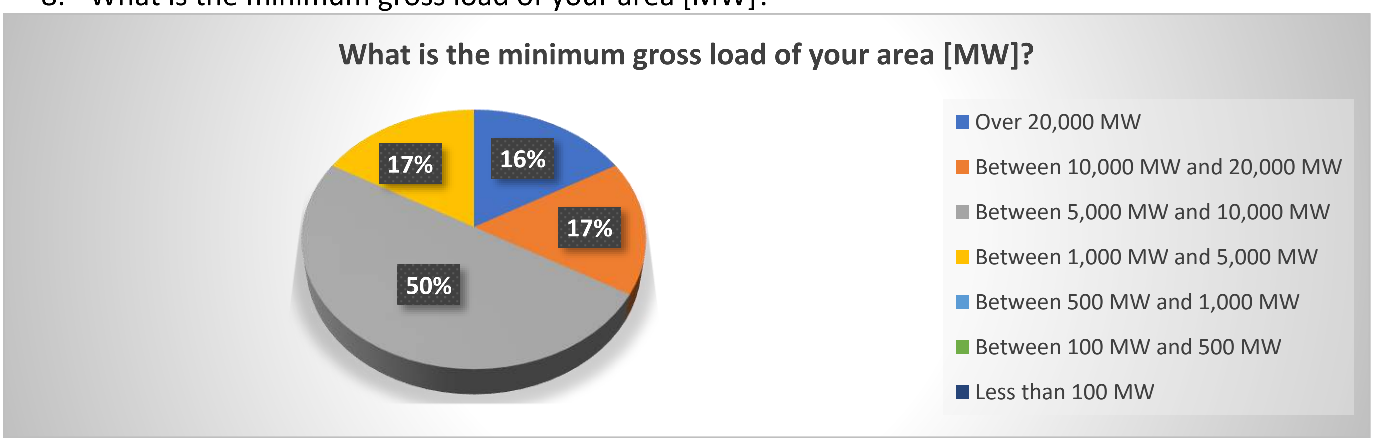
7. What is the peak gross load of your area [MW]?



Key takeaway: Question 7
The majority of surveyed members (75%) have over 20,000 MW peak gross load. The remaining two entities stated they have 1,000 MW–5,000 MW and 5,000–10,000 MW, respectively, of peak gross load.

Question 8

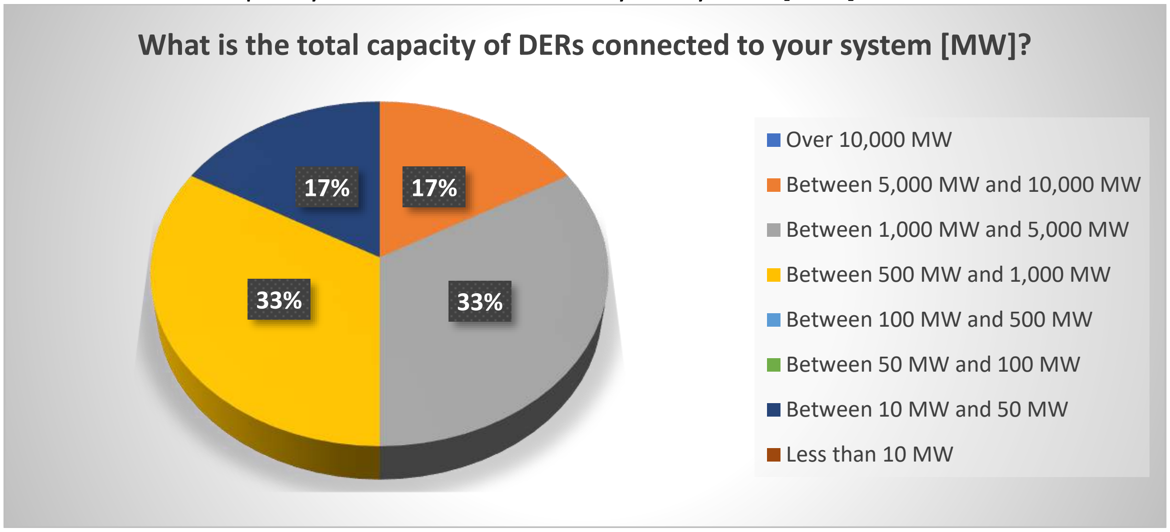
8. What is the minimum gross load of your area [MW]?



Key takeaway: Question 8
Minimum gross load among members ranges between 1,000 and over 20,000 MW

Question 9

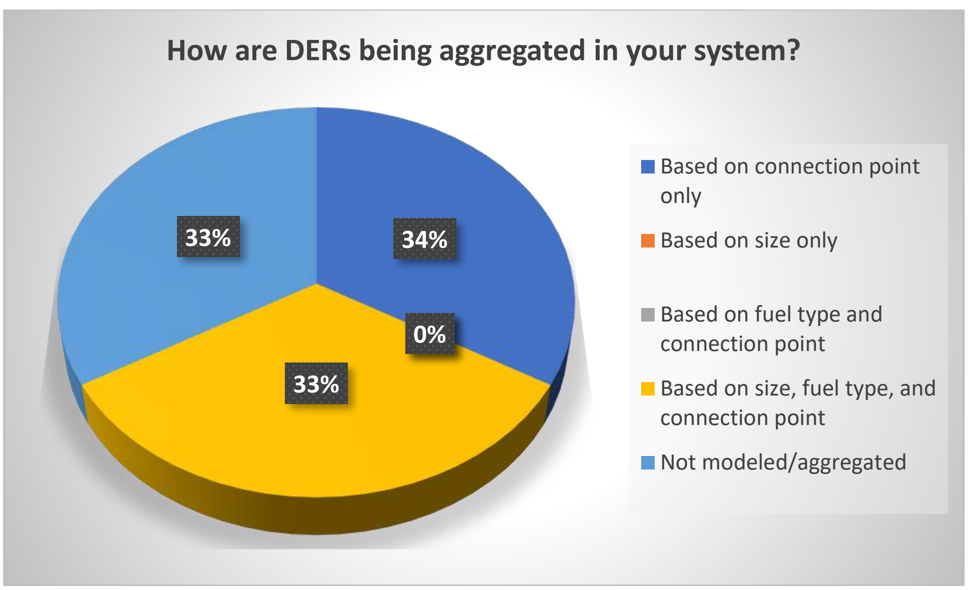
9. What is the total capacity of DERs connected to your system [MW]?



Key takeaway: Question 9
83% of members have significant DER capacity connected to their system that ranges between 500 and 5,000 MW. One entity has lower penetration ranging from between 10 and 50 MW.

Question 10

10. How are DERs being aggregated in your system?



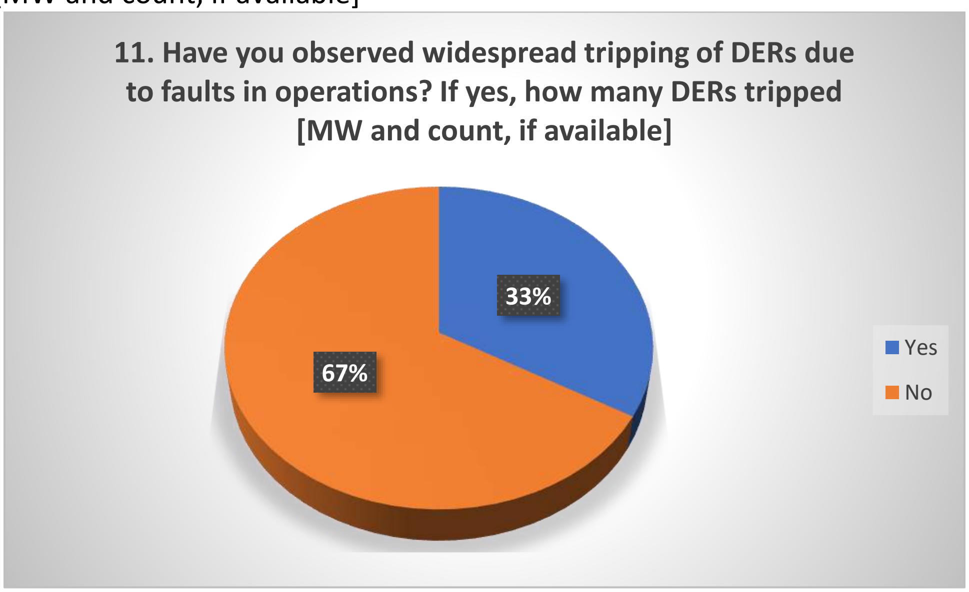
Key takeaway: Question 10
One-third of surveyed members stated that DER aggregations are performed based on size, fuel type, and connection points, while one entity mentioned that they are not being modeled/aggregated.

One entity mentioned that aggregation of DERs is performed according to their connection point and that devices or premises that make a DER Aggregator must individually have less than 1 MW of controllable capability. They are required to be within a single DSP and load zone but not behind the same connection point. Participation is not mandatory for DER over 1 MW, but, if they do participate, they must be registered separately.

The two surveyed companies with DER Aggregators in their footprint aggregate DERs based on point of connection.

Question 11

11. Have you observed widespread tripping of DERs due to faults in operations? If yes, how many DERs tripped [MW and count, if available]



Key takeaway: Question 11
Two entities observed DER tripping due to faults in operation without stating how many had tripped. DER capacities for each entity range between 1,000 and 5,000 MW and 5,000 and 10,000 MW, respectively.

Question 12

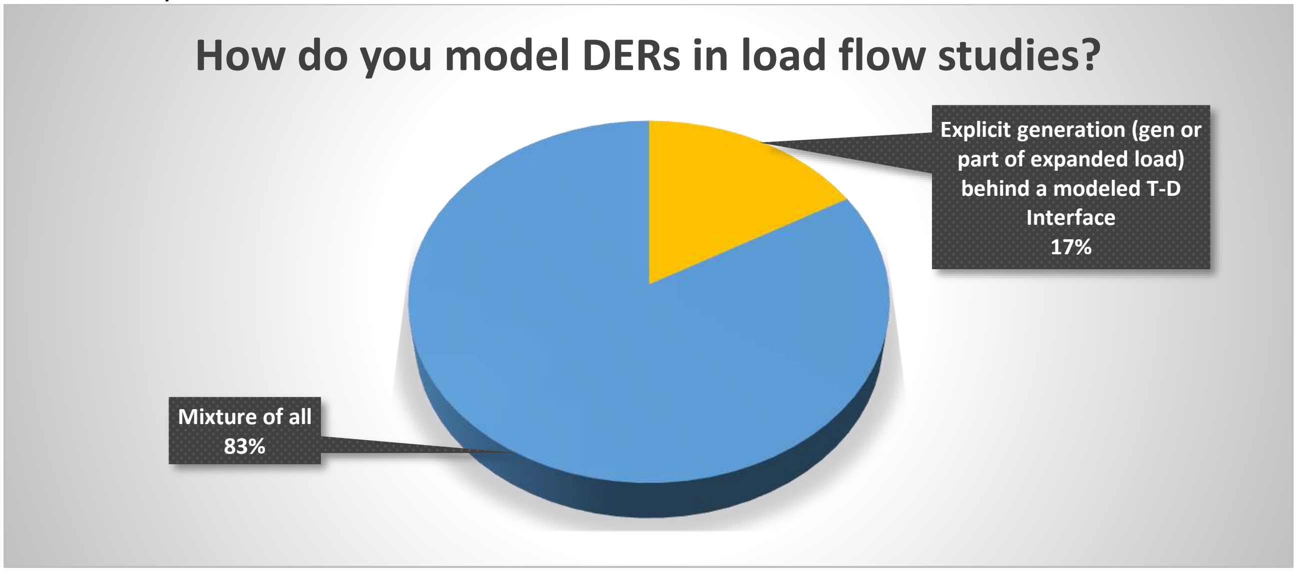
12. Do you receive any DER operational data? (e.g., active power output of DER or DER status)

Key takeaway: Question 12 (open-ended)
Most of the surveyed entities do not receive operational data from DERs. One entity requires data from DERs registered to the wholesale market, including power output, status, ramp rates, and operational limits. State of charge is also provided for some storage sites.

Two other entities shared that if the DERs participate in the market as a modeled generator, then they do provide operational data.

Question 13

13. How do you model DERs in load flow studies?



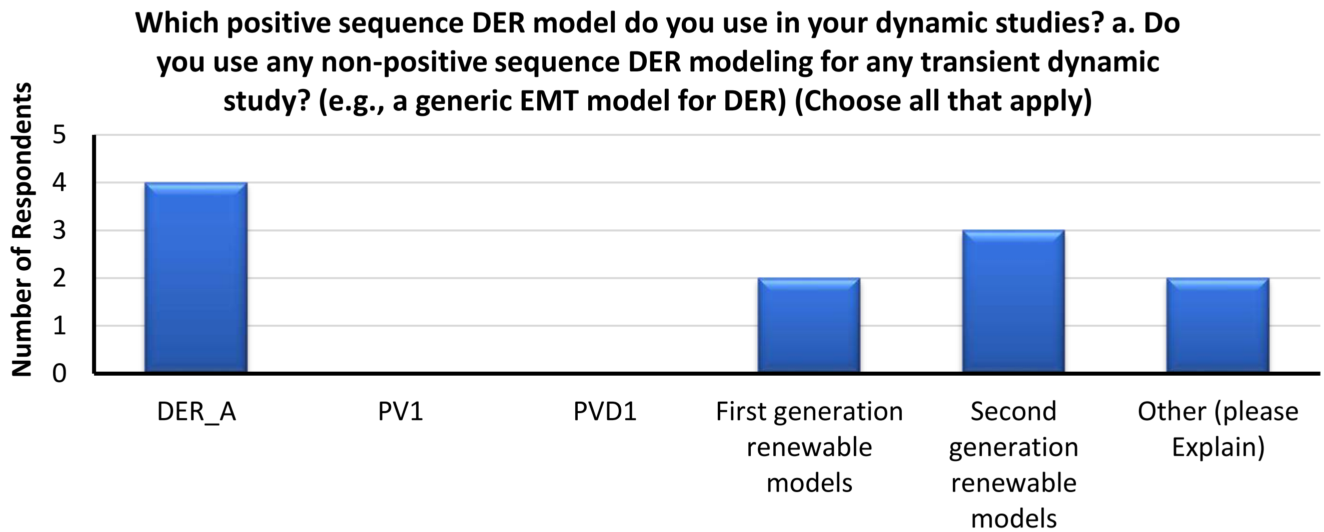
Key takeaway: Question 13
83% (5) of surveyed members model DERs with a mixture of the following: *a) negative load off the transmission bus b) negative load off an explicitly modeled T-D Interface c) explicit generation (gen or part of expanded load) hanging off the transmission bus d) explicit generation (gen or part of expanded load) behind a modeled T-D Interface.*

One of the entities stated that it models DER Aggregators like a controllable load resource and that they are seen as negative load. DERs over 1 MW are represented as generators mapped to a transmission bus and unregistered behind-the-meter units are netted with load.

One entity with the smallest amount of DER connected (10–50 MW) uses an explicit generator behind a modeled T-D Interface as a DER model.

Question 14

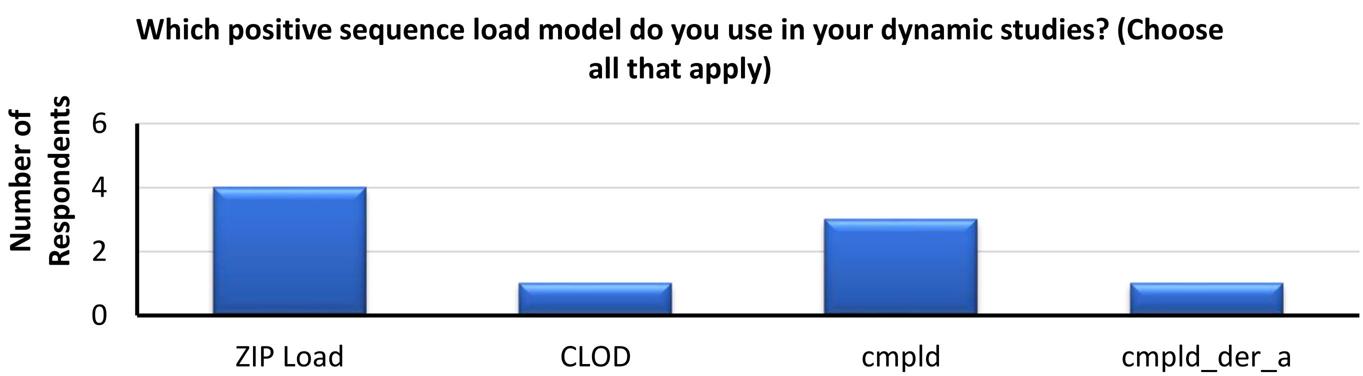
14. Which positive sequence DER model do you use in your dynamic studies? a. Do you use any non-positive sequence DER modeling for any transient dynamic study? (e.g., a generic EMT model for DER) (Choose all that apply)



Key takeaway: Question 14
Most of the surveyed participants use DER_A to perform dynamic studies. One entity separates inverter-based projects into two categories: projects less than 5 MW are modeled with DER_A and projects greater than 5 MW are modeled with second-generation renewable models. Synchronous generation is generally netted with the load, and no models are used unless they are greater than 5 MW, at which point they are modeled with explicit generator, exciter, and governor models.

Question 15

15. Which positive sequence load model do you use in your dynamic studies? (Choose all that apply)



Key takeaway: Question 15
The survey shows that different positive sequence models are used. ZIP load and cmpld models are used by the entity having DER aggregators.

Question 16

16. What offerings does the DER Aggregator have in your area? a. Is there an analogous entity for areas that are not ISO/RTOs that aggregate the response of distribution-connected generation? b. How is the Demand Response program controlled in your area?

Key takeaway: Question 16 (open-ended)
One entity allows DER aggregations to participate in its wholesale electric market. In general, the entity that represents a registered aggregator should also represent the load. Under the pilot for DER aggregations, they will be controlled through base point instruction produced using security-constrained economic dispatch.

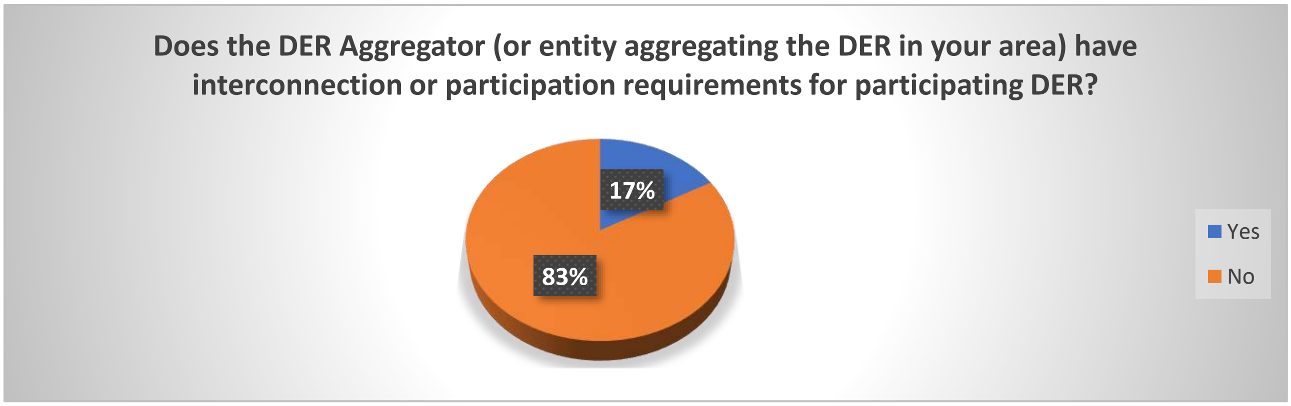
Another surveyed member responded that there is only one aggregator in their footprint, and the aggregator is simply a price taker in the respondent's market. The aggregator provides no services. For demand response, registration is performed under specific operating procedures.

For demand response, the standby generators and interruptible programs are controlled through the TCC (not by an aggregator).

Most surveyed entities mentioned that they do not have DER Aggregators or demand-response programs in their areas.

Question 17

17. Does the DER Aggregator (or entity aggregating the DER in your area) have interconnection or participation requirements for participating DER? If yes:
    a. Is there a verification of capacity and control from that which is provided in the services to the information shared for planning?
    b. Is there a verification of capacity and control from that which is provided in the services to the information shared for operations?
    c. Is there a verification of capacity and control from that which is provided in the services to the information shared for protection relay coordination?



Key takeaway: Question 17 (open-ended)
All participants responded that the DER Aggregator does not have participation requirements for participating DERs.

The entity with DER Aggregators claimed that the DSP has the interconnection requirements, not the DER aggregator. Specific rules for the DER aggregation pilot initiative are publicly available.

Another entity with DER Aggregators mentioned that rules for DER interconnection are required to meet UL certification 1741-SB and be compliant with IEEE 1547-2018, whereas transmission resources need to meet the requirements of the entity's planning and operating procedures. Also, DERs enter the state interconnection process, whereas transmission-connected resources enter through ISO-NE's queue and the FERC interconnection process. For DERs connected through an RTU to the ISO for modeled gens, 1547-2018 interoperability requirements do not apply.

Question 18

18. How and when does new DER, or existing DER wishing to increase its capacity, communicate to a DER Aggregator they wish to alter their equipment? a. Does the DER Aggregator notify transmission entities of this new capacity for your area? b. Is this taken care of in the capacity review identified in FERC Order 2222, or is this capacity review a separate requirement of the ISO/RTO?

Key takeaway: Question 18 (open-ended)
One entity shared changes to the aggregation, including monthly communications to detail changes to the premises/devices that make up the aggregation. These updates are provided to and require approval by the entity and the DSP before becoming effective. Transmission service providers are informed of changes in capacity but do not need to approve changes to the aggregation. Changes in capacity are a separate requirement from the O2222 review.

Most of the surveyed entities do not have DER aggregators or they do not act in that capacity.

Question 19

19. How do the distribution system operators and planners coordinate with the DER Aggregator for analysis of constraints on the distribution system? a. D side constraints can have backup plans; how are those currently monitored? b. Are some of these schemes automated? c. What requires operator control and does that affect which T-D Interface a DER is pushing against?

Key takeaway: Question 19 (open-ended)
One entity shared that, prior to allowing a premise or device to become part of an aggregation, the DSPs review the list of all proposed premises and devices and can either approve or reject each individual line item. This is the DSPs' first opportunity to head off potential concerns. Once the aggregators is in operation, the DSPs have the right to change how the aggregation is being managed should they see issues that they cannot otherwise easily manage. As this entity is managing the work in a pilot project, more formal procedures are under development to be developed. However, the entity stated they have no visibility of DSP procedures that may be in place to monitor and control reliability issues. To the degree an aggregator is limited by instructions from the DSP, the aggregator is required to reflect those limitations in the data provided (for example, as a reduction in available capacity reflected in real-time telemetry).

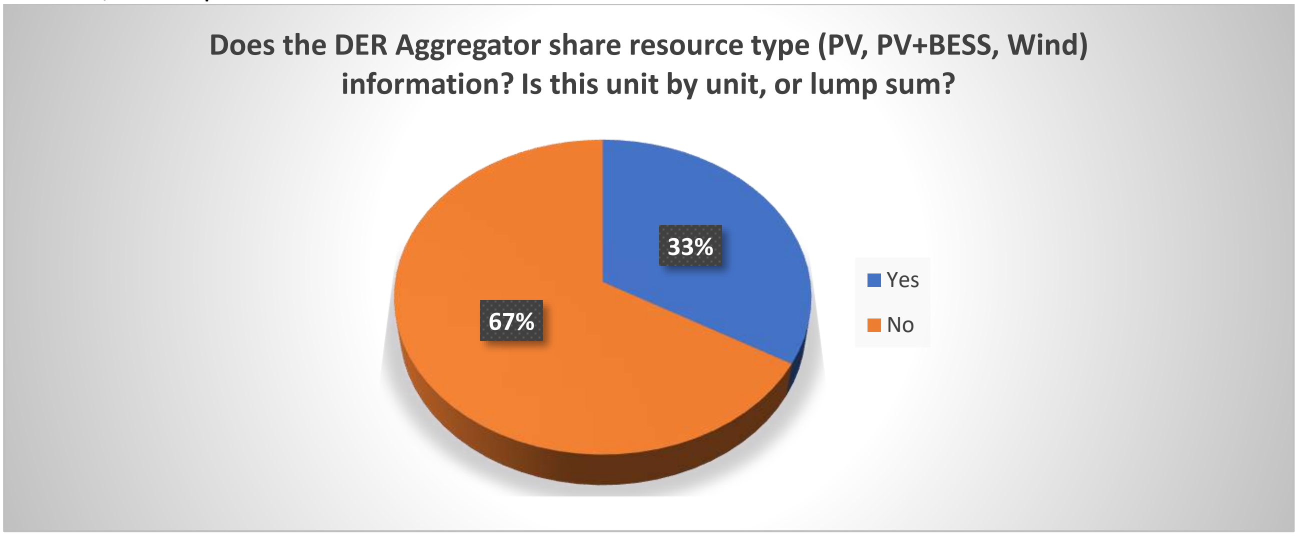
Question 20

20. If known, how does the DER Aggregator collect, store, and share (Planning Data, Operational Data, and Short Circuit Data)?

Key takeaway: Question 20 (open-ended)
From the survey responses, experiences from the one entity with DER Aggregators show that this task is left to the aggregators to organize. No rules are set on how to collect and store information. Only requirements on what information needs to be provided for studies and models have been specified.

Question 21

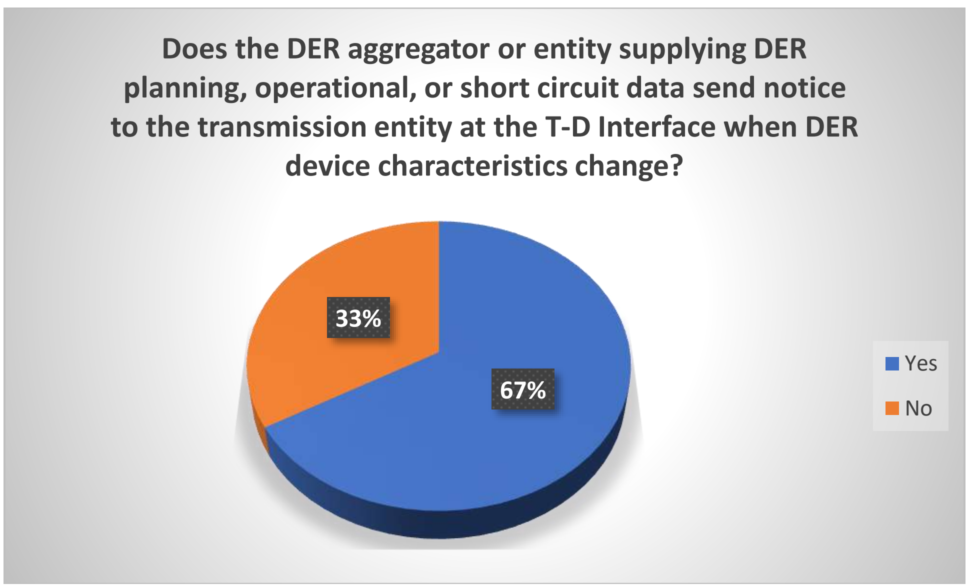
21. Does the DER Aggregator share resource type (PV, PV+BESS, Wind) information? Is this unit by unit, or lump sum?



Key takeaway: Question 21 (open-ended)
Entities with DER aggregators shared that real-time telemetry and near-term operational data (hours and days) are provided for the aggregation. Registration-type information is provided for each individual premise or device with this information updated monthly, following entity and DSP review.

Question 22

22. Does the DER aggregator or entity supplying DER planning, operational, or short circuit data send notice to the transmission entity at the T-D Interface when DER device characteristics change?
    a. Is there a verification of capacity and control from that which is provided in the services to the information shared for planning?
    b. Is there a verification of capacity and control from that which is provided in the services to the information shared for operations?
    c. Is there a verification of capacity and control from that which is provided in the services to the information shared for protection relay coordination?



Key takeaway: Question 22 (open-ended)
Only one entity responded that a DER aggregator or similar entity supplied DER planning, operational, or short-circuit data and sent notice to the transmission entity at the T-D Interface when DER device characteristics change. As shared in the previous question, entities with DER aggregators shared that real-time telemetry and near-term operational data (hours and days) are provided for the aggregation. Registration-type information is provided for each individual premise or device with this information updated monthly, following entity and DSP review. There is also a process to validate the real-time telemetry and operations performance of the aggregations.

The second entity with DER aggregators responded that if the capacity changes, then it is notified. Otherwise, it is not necessarily notified.

Most of surveyed member do not have aggregators within their area.

Question 23

23. How is double counting or other duplication of generation accounted for in DER Aggregators? Does this cover all T-D Interfaces? Explain.

Key takeaway: Question 23 (open-ended)
One entity responded: As part of the process for approving participation of an individual premise or device, validation is done to ensure that they are not also participating in another wholesale market program.

Another company records all DERs currently installed and planned and actively monitors for possible double-counting issues.

Question 24

24. How is double counting or other duplication of generation accounted for in resource plans? Does the DER Aggregator supply this information? Does the DER Aggregator cover all T-D Interfaces for these resource plans? Explain.

Key takeaway: Question 24 (open-ended)
One member responded that as part of the process for approving participation of an individual premise or device, validation is done to ensure that they are not also participating in another program, addressing duplication on the front end. Another entity responded that DER is typically handled in its load forecast as a load offset and not counted as generation.

Question 25

25. What estimation techniques for DER Aggregator output are used to run a 15-minute ahead, 30-minute ahead, hour-ahead, and day-ahead analysis?

a. Does the estimation spread across multiple load records?

b. Does the estimation allow for creation of "new" generators in the model?

c. Are predictions made on zones, substations, feeders? (please indicate all that apply)

d. How granular of a forecast is required?

e. How does the forecast deal with uncertainty or error?

Key takeaway: Question 25 (open-ended)
One entity with DER Aggregators stated that aggregators are required to provide hourly operational information. Maximum power consumption and low power consumption values for the aggregators for future hours are monitored.

Most of surveyed member do not have aggregators within their region.

Question 26

26. For your state estimator, how does the mismatch solution deal with negative records added to the load?

    a. Does an output negative load link with a DER generator dynamic model?

    b. How are mismatch loads dealt with in the OPA and RTA practices? Are they ignored, netted, or other?

Key takeaway: Question 26 (open-ended)
One surveyed member responded that a fake generator model is added to the state estimator to represent the DER behind the station. The size of this model is commensurate with the expected capacity and expected output of the DERs.

Question 27

27. Do your data quality checks or other operational assessment practices account for gross vs. net loading at each T-D Interface?

    a. What metering supplies this gross versus net loading? (e.g., transformer-level, breaker-level, or DER device-level metering)

    b. Are these quality checks posted or otherwise available on request?

Key takeaway: Question 27 (open-ended)
Entities with DER aggregators have gross 15-minute meter data available for validation in the first phase of the pilot project. Other approaches are likely be considered in future phases. Rules specific to the DER aggregation pilot are publicly available.

Most of the surveyed members do not have aggregators within their region.

Question 28

28. For information provided by the DER Aggregator, what telemetry granularity are they able to provide? (e.g., SCADA scans, Advanced Distribution Management System (ADMS), other time frame or framework)
    a. Do they disaggregate their load from active power producing generation resources?
    b. What metering is used or provided to telemeter the data for operational planning analysis. What metering is used or provided to telemeter the data for real-time analysis.

Key takeaway: Question 28 (open-ended)
For DER aggregators, one entity requires providing telemetry with granularity as low as 2 seconds, in alignment with requirements for other resource types. This includes the following:

a. Providing both options where either a device can be part of the aggregation or the whole premise can be part of the aggregation.
b. Operational planning analysis based on resource plan data provided for the aggregation. In general, these processes do not depend on meter data or telemetry.
c. 15-minute meter data is the data available for validation.

Most surveyed members do not have aggregators within their area.

Reducing Impacts on Bulk Power System Variability and Uncertainty

DER Data Collection, Storage, and Sharing with DER Aggregators

SPIDERWG White Paper

Statement of Purpose

Large penetrations of distributed energy resources (DERs) are significantly increasing variability and uncertainty within planning and operations of the Bulk Electric System (BES). This uncertainty is largely driven by lack of knowledge of the quantity, location, and characteristics of DERs, especially as related to their impacts on the bulk power system (BPS). The need for reducing uncertainty into impacts of DERs has been made more urgent by introduction of FERC Order 2222. FERC Order 2222 introduced the concept of the Distributed Energy Resource Aggregator (DER Aggregator)[1], which is an entity that allows multiple DERs to participate in wholesale markets. The System Planning Impacts from Distributed Energy Resources Working Group (SPIDERWG) recently published a white paper titled *BPS Reliability Perspectives on the Introduction of the DER Aggregator*[2] that touches on the modeling, verification, study, and coordination aspects of this new entity within the electrical ecosystem. In that paper, the uncertainty and variability of DERs was identified as an area that required further exploration. This paper documents the findings of such an exploration and seeks to identify areas of improvement and technical considerations to account for reliability impacts associated with integrating DER. This paper also identifies methods to improve data collection and data sharing between applicable entities described below. The methods described in the paper are applicable not only to entities with deregulated market structures and DER Aggregators, but also to vertically integrated utilities or any other entity that seeks to reduce uncertainty through collection and sharing of DER data.

Applicable Entities

The following entities may find this paper useful to refine their internal practices and procedures: DER Aggregators, Transmission Planners, Distribution Planners, GIS Administrators, Regulators, and other entities that require knowledge of the size, location, and capabilities of DERs in aggregate for reliability focused studies (e.g., Distribution Operator, Balancing Authority (BA), Transmission Operator (TOP), Reliability Coordinator (RC)).

SPIDERWG and the Operational Perspective

The SPIDERWG is composed of transmission and distribution entities; however, the focus of the group historically has been primarily planning. For this effort, SPIDERWG identified that operational time frame concerns may be more prevalent than planning and as such SPIDERWG members engaged with their TOPs,

[1] Some abbreviate this term as DERA, and individual market terms have various ways to describe this same entity. This paper uses DER Aggregator for the abbreviation of Distributed Energy Resource Aggregator to help differ between the entity that aggregates DER, i.e., DER Aggregator, and the aggregation of DERs in modeling.

[2] Available here: https://www.nerc.com/comm/RSTC_Reliability_Guidelines/SPIDERWG_White_Paper_-_BPS_Persepectives_on_DER_Aggregator_docx.pdf

RCs and distribution operators. Data for DERs is a foundational need for the planning and modeling to support the operational functions and remains a focus for this paper.

Definitions and Clarifications

The SPIDERWG's definition of DER is a "Source of Electric Power located on the Electric system",[3] and in many instances the definition of DER varies depending on the context. In this paper, the typical definition used is the SPIDERWG preferred definition to focus on the reliability aspect of the conversation. The SPIDERWG definition includes only generation and storage devices on the distribution system and not inclusive of flexible loads, i.e. Demand Response. Other definitions and clarifications for this paper are as below:

FERC definition of DER: "A distributed energy resource is any resource located on the distribution system, any subsystem thereof or behind a customer meter."[4] FERC states that these resources may include, but are not limited to, electric storage resources, distributed generation, demand response, energy efficiency, thermal storage, and electric vehicles and their supply equipment.[5]

Distributed Energy Resource Aggregator: "An entity that aggregates one or more distributed energy resources for purposes of participation in the capacity, energy and ancillary service markets of the regional transmission operators and independent system operators.[6]

DER Geographic Location – The physical address or geospatial coordinates that define where the DER is located.

DER Electric Location – The DER location on the electrical network. The minimum required information to locate a DER on the distribution and transmission network is the meter identification and transmission point of interconnection. These two points allow the distribution utility to utilize their system knowledge to establish additional parameters such as the feeder, substation, or portion of their system and the ISO/RTO to use their system knowledge to establish parameters such as sub-node, node or market regions.

It should be noted that different organizations define DER according to their focus. FERC's focus for Order 2222 was enabling distribution connected resources to have access to the market. NERC SPIDERWG's definition focuses more specifically on reliability. However, these definitions do create confusion in the industry without the above established context. Adding to the set of definitions, Project 2022-02 is currently

[3] SPIDERWG has posted a document for definitions available here: https://www.nerc.com/comm/RSTC/SPIDERWG/SPIDERWG%20Terms%20and%20Definitions%20Working%20Document.pdf
[4] Part 35, Chapter I, Title 18, Code of Federal Regulations, § 35.28(b)(10).
[5] Federal Energy Regulatory Commission, Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Independent System Operators, Order No. 2222, 85 FR 67094 (Oct. 1, 2020), 172 FERC ¶ 61,247 ("Order No. 2222"), P 114.
[5] ibid, P 114.
[6] FERC Order No. 2222, (September 17, 2020) P 85

scoped to define DER in the NERC Glossary of Terms,[7] and has proposed a slightly altered definition from the SPIDERWG one; however, the spirit of the definition is the same.[8]

U-DER and R-DER Designations

Modeling designations in SPIDERWG's documents have potentially caused some confusion on what DER is under control of a DER Aggregator; that is, if U-DERs, R-DERs, or both are included in the aggregation under the control of a DER Aggregator. The R-DER and U-DER distinctions are primarily for modeling purposes and as such both may be collected under a single DER aggregation. Data collection procedures for R-DER have greater difficulty in gathering location specific information (both geographic location and electric network location) as the installations are smaller, and typically non-utility owned. This is not a concern for populating aggregate models of this equipment (as the aggregation is not specific to one location) and other SPIDERWG reliability guidelines, white papers, and technical reports have given methods to model aggregate DER.[9]

One further distinction relative to U-DER is that it can be large enough to require a dedicated facility from the distribution utility. Therefore, it is likely to have gone through a much more rigorous interconnection review than a R-DER and the utility will have more detailed information on the assets being installed.

Survey Process

The SPIDERWG determined that the best way to analyze the uncertainty and variability of DER Aggregators from its membership was to directly ask the members via a voluntary survey. The survey process and aggregate answers are found in Appendix A and Appendix B, respectively. Based on the number of responses (~~five~~ six received from over 100 sent), however, the SPIDERWG could not generalize the results as a limited number of members responded to this voluntary survey.

Commented [AM1]: Later in the document, we say "six".

Commented [JS2R1]: Updated to correct for six. SPIDERWG had a late survey response)

Variability and Uncertainty of DER on Electric Systems

The *2023 NERC Long-Term Reliability Assessment*[10] projected a rapid growth of distributed energy resources, with behind-the-meter solar photovoltaic (PV) projected to reach 90 GW of capacity by 2033. A key characteristic of this type of DER is that its output can rapidly increase and decrease with weather patterns and the rising and setting of sun. With large amounts of distribution-connected PV resources, the resulting ramp can strain other grid resources. Other forms of DER technology, including battery energy storage systems, may not be as predictable through engineering judgement and weather conditions as the current solar PV dominant technology type. This introduction of variability and uncertainty can be influenced further by end-use customer choices and preferences, resulting in potentially even further uncertainty of operating characteristics. Although DER forecasting tools have made significant progress in predicting the output of DERs, the accuracy of such tools is entirely dependent on knowledge of the total amount of DER, their characteristics, and their mapping to the correct substation and bus within the power system model.

Commented [AM3]: Is this referring to traditional generation sources like, coal, gas, nuclear and hydro? I suggest being more explicit.

Commented [JS4R3]: Added clarity

[7] Available here: https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf

[8] Primarily, the SPIDERWG definition used nested terms to simplify the length of the DER definition while the Project's term does not use nested definitions.

[9] SPIDERWG reliability guidelines are available here: https://www.nerc.com/comm/Pages/Reliability-and-Security-Guidelines.aspx

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

System operators and planners need information on the quantity of DERs and where they are connected to reliably operate and plan the system. This paper helps explore variability and uncertainty reduction in this data and to identify methods of gaining this information. ~~Variability and uncertainty are created on the electric system when the operation control authorities lack knowledge of the quantity of DER and where they are located within the BES.~~ With high penetrations of DER with high uncertainty, key entities may not be able to plan and model the system appropriately. ~~With lower penetrations, the~~The same variability and uncertainty may not impact an entity in lower penetrations as greatly as those with higher penetrations; however, a common, clear, and consistent method to gather data by TPs reduce the impacts of variability and uncertainty under both low and high penetrations. Over the past several years, NERC has introduced a variety of white papers that provide guidance on the data requirements and models for DERs necessary to reduce this variability and uncertainty. This paper has further focused this discussion to provide guidance on the types of DER data and collection process in a manner that reduces uncertainty on this critical information for planning and modeling.

Commented [AM5]: I suggest a slight change to how we describe the problem statement and purpose of the paper. We can say something like… "To reliability operate and plan the system, system operators need information on where DERs are connected and the quantity that is connected. The purpose of this paper is to recommend an effective way of getting this information."

Commented [JS6R5]: JP note: I altered the paragraph to incorporate the idea

SPIDERWG has found in its discussions that the variability and uncertainty in system planning is reduced with data collection from distribution owners and DER Aggregators with clear, reportable data fields to the TP and TOP. EPRI has also undertaken work on the planning impacts from the DER Aggregators, particularly in identifying key data exchanges needed in the long-term planning horizon.[11] This report confirms the findings from the SPIDERWG White Paper[12] and SITES white paper[13] that the data reporting obligation for DER Aggregator enables an enforceable and reliability focused reduction of risk to the planning of the future BPS. The data exchange process could be significantly enhanced with a single point of truth for DERs that allows data exchange based on the Common Information Model (CIM).

The DER Aggregator's Role

The DER Aggregator's role was defined in FERC Order 2222 and resulting clarifications by the Commission pertaining to the interaction of the DER Aggregator, individual DER, and the ISO/RTOs. FERC stated that the DER Aggregator, not the individual distributed energy resources in the aggregation, is the single point of contact with the RTO/ISO, responsible for managing, dispatching, metering, and settling the individual distributed energy resources in its aggregation.[14] These statements in FERC Order 2222, establish that the DER Aggregator is the entity that will interact with RTOs and ISOs and will be responsible for the operation of the individual DERs within its control. Furthermore, the DER Aggregator will also be responsible for the collection of data on DER characteristics, location, etc. plus information on DER operation and measurement of DER participation.

FERC Order 2222 implementations across each jurisdictional area will define in more detail the interaction between the DER Aggregators, DSOs, TOs and ISOs. Local implementations will also define the role of DER Aggregators in operating DERs, controlling set points, and adjusting inverter parameters. Each jurisdictional

[11] Available here: DER Aggregation Participation in Electricity Markets: EPRI Collaborative Forum Final Report and FERC Order 2222 Roadmap

[12] Available here: https://www.nerc.com/comm/RSTC_Reliability_Guidelines/SPIDERWG_White_Paper_-_BPS_Persepectives_on_DER_Aggregator_docx.pdf

[13] Available here: https://www.nerc.com/comm/RSTC_Reliability_Guidelines/White_Paper_Cybersecurity_for%20DERs_and_DER_Aggregators.pdf

[14] FERC Order No. 2222 (September 17, 2020), P 266.

area may have multiple settings for inverter-based resources (IBRs) across the geography of their system and may have multiple requirements for implementation of these operational parameters. It is anticipated that the DER Aggregator will be responsible for understanding these operational requirements and ensuring that individual DERs operate according to the guidance provided by the operational control authority.

Although the operational setpoint or day-to-day operational requirements may differ between utilities or RTOs/ISOs, the fundamental DER dataset required for all stakeholders to be able to appropriately plan, model, and operate the electric system effectively will be consistent for everyone. The DER Aggregator will play an important role in the accuracy and currency of the individual DERs they control and represent to the marketplace.

DER Data Collection, Storage, and Sharing Survey

The NERC SPIDERWG conducted a voluntary survey of its own membership to attain greater clarity regarding the interactions with the DER Aggregator and ways to reduce variability and uncertainty. As a limited number of responses were gathered, the results are not conclusive of all industry examples but demonstrate the beginnings of specific trends important to consider for transmission planning and operations.

Survey Results

A total of six members sent their responses including four ISO/RTOs. Most companies that participated in the survey share different transmission functions (e.g., TOP, RP, BA, TP, RC, etc.) with one of them being a distribution operator and two being DPs. In terms of peak gross load, four members have over 20,000 MW with DER installed capacity in the range of 1,000 MW to 5,000 MW. Even though there is a wide spread of entities roles, DER installed capacity, and peak loads, the survey would have benefited from having more responses sent. Therefore, the SPIDERWG decided that the results from the survey may not be conclusive but provide a landscape of different practices for DER aggregators data exchange.

From the results, the SPIDERWG found that there is a potential to have a *reduction* of variability and uncertainty with the introduction of the DER Aggregator in the planning realm. The survey also yielded recommendations for maintaining situational awareness (a key reliability aspect) in the operations time frame. However, these survey results only apply to DERs that are collected by DER Aggregators for aggregation to the ISO/RTO markets. DERs that are not aggregated will not have the benefit of a DER Aggregator verifying or keeping DER information current. It will be important that all DERs, not just those participation with a DER Aggregators, are known and accounted for in our planning and modeling processes.

It should be noted that DERs can comprise a variety of resources that may not be included in the interconnection process currently, most notably electric vehicles. Consequently, it should be expected that there will be a significant number of DERs that remain ‘unknown’, especially in the scenario where utilities rely solely on DER Aggregators to provide DER information.

Transmission planning to enable DER Aggregator market participation requires coordination[15] between the RTO/ISO, DER Aggregators, Transmission Owners/Utilities, Distribution Utilities, and Relevant Electric Retail Regulatory Authorities (RERRAs). As the survey results from SPIDERWG were not conclusive, the team looked to outside reports and frameworks to determine the coordination needed to reduce variability and uncertainty. One EPRI report[16] considers some long-term planning studies and key data exchange between DER Aggregators, DER owners, and the operations and planning staff, which includes:

1. **Ensuring Adequate Transmission Impact and Reliability Assessment Studies:** The upcoming participation of DER aggregators in the wholesale market could bring the need of assessing the potential impact of one or more DER Aggregations on the transmission system.

2. **DER Modeling Methods in Long-term Transmission Planning Studies:** Research has confirmed, for most cases, the adequacy of modeling methods such as the NERC *Reliability Guideline on Parameterization of the DER_A Model* to study bulk system voltage and frequency performance under high levels of DERs.[17] The industry continues to identify corner cases where more sophisticated modeling of individual DER and DER Aggregations may be desired.

3. **Ensuring Adequate DER capabilities, Performance, and Functional Settings:** The technical interconnection and interoperability requirements (TIIRs) for DERs, including those that may choose to participate in the wholesale market through a DER Aggregator or a distribution system operator, are not subject to FERC jurisdiction. FERC recognized – and highlighted in the Order – the responsibilities of the RERRA to initiate and lead coordination between the stakeholders on each side of the transmission and distribution interface, including RTOs/ISOs, Distribution Utilities, and DER Aggregators.

4. **Key data needs, exchanges, and update mechanisms:** Modeling of DER and DERA in transmission planning studies and technical reviews requires adequate and efficient collection of DER data and could become increasingly important as more DERA begin to participate in the wholesale market. Several key categories of data needs and exchanges discussed include a) Management of DER functional settings b) Remote configurability c) Common file format for DER functional settings and d) potential use of a DER settings database.

The above points from the EPRI report indicate that a common, clear, and consistent way to exchange the planning and operational data sets is desirable so that the important information is identified about the DERs a DER Aggregator represents to the ISO/RTOs. Further, a common, clear, and consistent data exchange can be leveraged for utilities that require the sort of coordination between a myriad of DERs, even those not under a DER Aggregator. The benefits of reducing variability and uncertainty translate to more accurate studies and therefore clearer identification of potential reliability risk in the planning horizon. SPIDERWG looked at the Common Information Model (CIM) as a method for reducing variability and uncertainty as a response to the key points from the EPRI report above.

[15] SPIDERWG has published a paper describing the available coordination and communication strategies related to DERs. This is available here: [INSERT LINK WHEN PUBLISHED]

[16] DER Aggregation Participation in Electricity Markets: EPRI Collaborative Forum Final Report and FERC Order 2222 Roadmap

[17] DER Modeling Guidelines for Transmission Planning Studies. 2019-2021 Summary. EPRI. Palo Alto, CA: September 2021. 3002019453. [Online] https://www.epri.com/research/products/000000003002019453.

Use of the Common Information Model for DER Data Exchange

Exchange of DER data among DER owners, DER Aggregators and other entities including distribution service providers, transmission service providers, and market operators presents a unique challenge due to both the disparate nature of data and fundamental differences in modeling practices by individual grid operators. The CIM is a semantic standard for consistent representation of power system data across the generation, transmission, distribution, market, and customer domains. The CIM is an open-source information model that provides standardized definitions for common grid components and business procedures under an Apache 2.0 license (free to use and modify).

As a semantic standard, CIM provides the technical equivalent of an English dictionary of spelling and vocabulary for electrical equipment. CIM differs from more widely known communications standards (such as IEC 61850) in that it only specifies what are the agreed-upon names for various devices and their physical characteristics (e.g. that length of a wire should be written as "Conductor.length"). The semantic standard does not dictate how the data should be communicated but is critical for both parties to understand what is being sent and whether the data received has any meaning in the given context (e.g., the attribute of "length" makes no sense in describing market revenue paid to a DER). The CIM also maps to a set of corresponding International Electrotechnical Commission (IEC) standards that define usage of the information model and compliant data exchange mechanisms.

With the introduction of modeling of unbalanced distribution networks in ~~CIM~~ version 17 of the Grid package of CIM, it now stands as the only standard that offers a consistent method for representing power systems equipment and utility business processes in both transmission and distribution. Detailed representation of grid-edge devices and further improvements to modeling of distribution networks will be released in version 18 of the CIM Grid package ~~standard~~.

The CIM divides power system data into three domains: The first is the Asset model which describes the characteristics of individual devices (such as nameplate data) and maps to the IEC 61968 series of standards. The second is the Grid model, which describes the role a given asset plays when connected to the electrical system (an example of a role is a breaker or switch or power transformer) and maps to the IEC 61970 series of standards. The third is the Market model, which describes the behavior of assets (including aggregate behaviors of DERs through a DER Aggregator or Virtual Power Plant) and maps to the IEC 62325 and IEC 62746~~XXXXX~~ series of standards. Complete representation of DER consists of one or more ***asset*** records (derived from the Asset section of ~~the~~ CIM), one or more ***equipment*** records (derived from the Grid section of ~~the~~ CIM), and one or more ***resource*** records (derived from the Market section of ~~the~~ CIM).

Leveraging the CIM has two extremely powerful benefits. The first benefit comes with adopting a standard. This creates a common understanding of the data being exchanged. The CIM is extremely well-developed in this area not only because all data elements are ~~not only~~ defined in a single object model, but also because the relationships among elements are also established and documented. This means that information can be passed from one system to another leveraging standard terminology, and the meaning of the data is understood equally on both ends. Data exchanges can be incorporated into larger databases because the relationship among elements is defined. This is not true of all standards, many of which merely define the exchanges without establishing a model vocabulary behind those exchanges.

Case Study: Enabling interoperability with Europe's Common Grid Model Exchange Standard (CGMES). The CGMES effort established in Europe is the CIM's greatest success story. The European Network of Transmission System Operators (ENSTO-E) represents 40 electricity transmission system operators (TSOs) from 36 countries across Europe and led the development of a CIM standard for grid model data exchange. Not only were the standards developed and ratified by the IEC, but ENTSO-E also developed a conformity test process which currently lists 21 compliant products.[18] The CGMES process calls for each TSO to create so-called Individual Grid Models (IGMs) of their systems both annually as a year-ahead projection as well as daily to capture short-term changes at different hours of each day. With a set of relevant IGMs in hand, each Regional Security Coordinator (RSC) then assembles the models into a single Common Grid Model (CGM). This CGM supports wide-area analysis processes plus when sent back to the individual TSOs, gives visibility into neighboring grid that would otherwise need to be collected via highly manual processes.

The second benefit of using CIM for DER data exchange is that CIM is designed to be able to reconcile the data with the representation of the electrical power system. Not only can CIM help to capture DER data in a standard way, but the data can also immediately be embedded into the models which are used for long-term planning, operational planning, and operations to manage the grid across time. While DER data is a relatively new addition to the CIM, mechanisms to update DERs follow the time-proven processes of any type of grid equipment such as transmission ~~like~~ line~~r~~s, breakers, and transformers.

Case Study: Tracking grid changes with ERCOT's Network Model Management System (NMMS). As the electricity markets in Texas transitioned from zonal to nodal, the market operator in Texas, ERCOT, realized the importance of having an accurate grid model. And as the operator, but not owner, of the grid assets, ERCOT also understood that the details that are needed to build a grid model must be collected from other entities, namely the transmission owners ~~providers~~ in Texas. Thus, the NMMS was implemented as the single point of entry and maintenance for the

network model topology used by external ERCOT market participants. During the lifespan of the initial NMMS implementation ~~lasting almost a decade~~, the system processed roughly two million grid model changes over the course of a decade. The ~~,~~ resulting ~~in a~~ model at the end of the period had ~~which~~ less than half of the original data elements untouched from the initial model from 2009.[19] However, the use of CIM enabled a consistent workflow for handling these changes and maintenance of a single-source-of-truth used for planning, operations, markets, asset management, and all other key business functions performed by ERCOT.

[18] https://docstore.entsoe.eu/major-projects/common-information-model-cim/cim-for-grid-models-exchange/conformity-registry/Pages/default.aspx

[19] https://cimug.ucaiug.org/Meetings/eu2024/Arnhem%202024%20Presentations/CIM%20University/Track%202/CIMU%20T2%20S2a%20Moseley-ERCOT%20CIM.pdf

Use of the CIM facilitates mapping of DER data through use of a consistent set of classes and attributes across all utility models through the use of a consistent globally unique ~~master resource~~ identifier ~~(mRID)~~ that is unique and invariant across all systems. Using CIM, a single source-of-truth object can be created for each DER, along with one for the capabilities for every instance of its make and model, one for the unique data related to the asset that is installed and configured, one for the role that asset plays in the larger interconnected system of equipment, and one for its role in the market often that of an aggregated resource. Exchange of such data can be facilitated by creation of a shared CIM-based data exchange service that would eliminate the need to develop custom orchestration software to coordinate the data integration for every utility in a "one-off" manner. Using persistent ~~mRIDs~~identifiers, information can be shared regardless of the entity-of-origin using references that allow updates to be made across multiple systems maintained by multiple entities. ~~(Alex to use PNNL example language – Substitute UUID vs mRID)~~

Commented [AM7]: I suggest providing an example to further explain the benefits of mRIDs.

Commented [JS8R7]: added

Figure 1 below shows some of the key entities involved in exchange of DER data, including the customer, the distribution grid operator, and regional transmission planner. Each of these entities will use a different software system with a different database and a different naming convention. Even within a single utility entity, the same piece of equipment will have slightly different names between different departments. Consider the simple example of mapping a set of DERs to the correct feeder breakers and individual transmission / sub-transmission substations. Information detailing the various physical assets and power system network models will be located across multiple databases from multiple software systems. Some of the required data includes the capacity from the interconnection agreement, metering point from the customer billing database, feeder connection point from the geographic information system (GIS), substation breaker from a system one-line diagram, and transmission bus from the bus-branch planning model (or node-breaker EMS model). Without a standard representation of power system components, a series of data tables would need to be created for each representation. Even if each application uses the same "human-readable" name for a particular piece of equipment, the exact naming string, description, and set of properties modeled will vary by application. A mapping table is then required between each set of data tables to reconcile differences in identification and attributes of each asset. Although utilities have been able to manage this in the past, the vast increase in quantity of data associated with DERs will make manual data mapping insurmountable.

However, the use of CIM with a consistent class name and a persistent identifier for each DER and each associated datatype solves this naming problem. The identifier needs to be created only once, and then stored in an object registry as part of a set of a master list of identifiers for data import and export. The identifier does not have to be human-readable and is generally not intended to be displayed to end-users of advanced power applications. Rather, it is a machine-readable identifier that can be referenced across all databases and data exchanges between multiple entities. To ensure global uniqueness across all systems, it is recommended that the identifier be a universally unique identifier (UUID), which is a 128-bit integer that is serialized as a 32-character hexadecimal string. For the DER to substation mapping example, the DER would be assigned a unique identifier when first created during the interconnection approval process and stored in the object registry. That identifier would then be referenced by all other systems, such as the GIS model, customer billing database, and planning model. The data mapping then becomes a simple table join query that gathers all references to the master identifier across each enterprise system and combines them into an aggregate representation that can be shared with the transmission planner and other external entities. Further information on the use cases and core data classes used for data exchange by CIM are available in a series of primer documents[20],[21],[22].

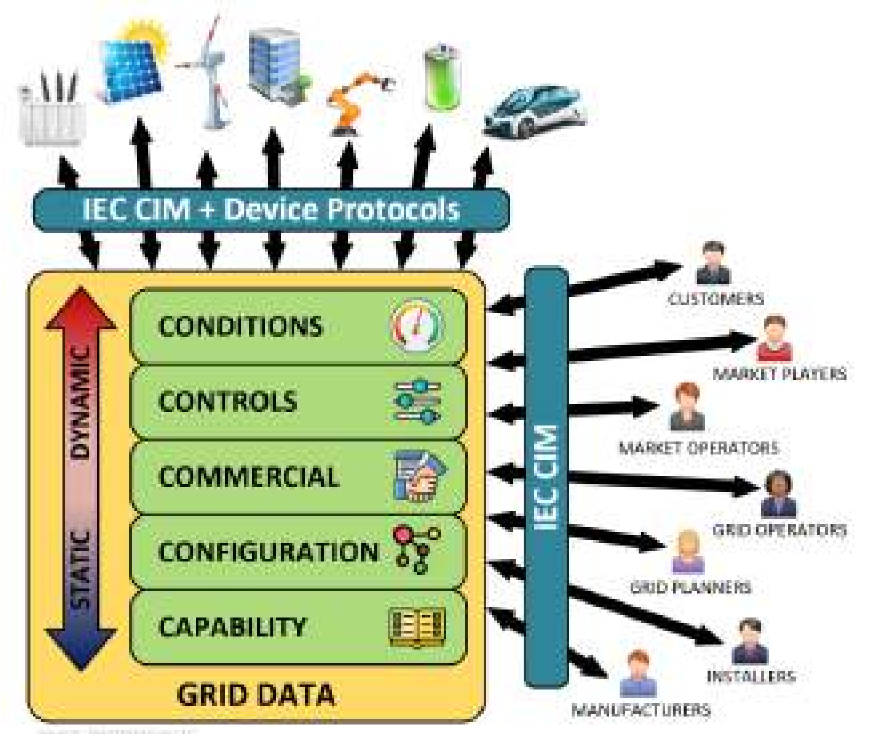


Figure 1: Visualization of Grid Data Types

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Modeling DERs in CIM

DER Data covers ~~four~~ five distinct functions in the energy industry, which will be defined in this section.

- Capability Data,
- Configuration Data,

[20] Enabling Data Exchange and Data Integration with Common Information Model. 2022, PNNL-32679. Richland, WA. [Online] https://www.pnnl.gov/main/publications/external/technical_reports/PNNL-32679.pdf

[21] A Power Application Developer's Guide to the Common Information Model, 2023, PNNL-3946, Richland, WA. https://www.pnnl.gov/main/publications/external/technical_reports/PNNL-34946.pdf

[22] Common Information Model Primer, Ninth Edition, 2023, EPRI, Palo Alto, CA. https://www.epri.com/research/programs/062333/results/3002026852

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- ~~Aggregation~~ Commercial Data,
- Controls Data, and
- Conditions~~ & Control~~ Data

This data can be provided by multiple entities across the energy industry, including the manufacturer, owner, aggregator, and utility operator (see Error! Reference source not found.~~**Figure 1**~~). Typically, each of these stakeholders all use their own set of custom data formats, which are difficult to share and interpret. Additionally, over time communication with the distribution-connected devices will be possible. Since the CIM is ~~primarily~~ a high-level semantic~~communication~~ model focused on enterprise-level data, it is necessary to pair it~~ing~~ with lower-level, device-focused communications protocols (such as IEC 61850 or IEEE 2030.5) ~~is expected~~ to enable ~~more~~ real-time information gathering and ultimately device controls, as shown in Figure 2. The focus of this whitepaper will on the types of data needed for reducing variability and uncertainty in system planning, which reside in the green semantic data layer of Figure 2.

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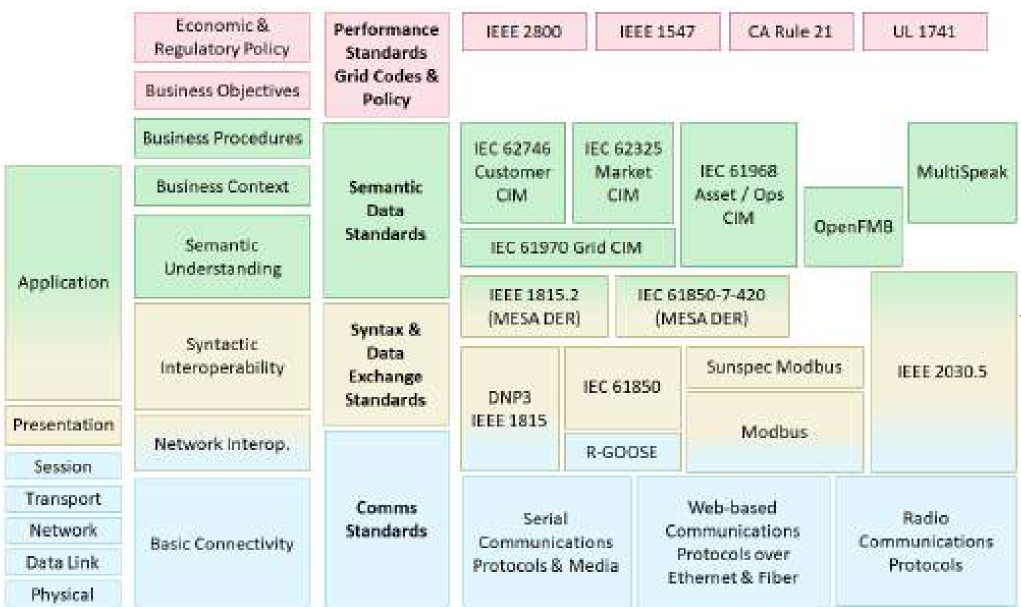

Figure 2: Standards Landscape for Exchange of DER Data

As the penetration of DERs increases, it will be essential for all parties to be able to obtain data needed for decision-making and analysis. To this end, creation of a "single source of truth" for each DER is recommended to help eliminate confusion and incorrect models for DERs. Moreover, establishment of a master repository of DER data can make data management substantially less costly and challenging. The types of data to be included in such a repository are described below.

DER Capability Data

DER Capability Data describe the nameplate capabilities of the DER, which are generally identical for all instances of a particular make and model of battery, solar panel, or electric vehicle charger. In general, capability data is relatively static. It is either provided by the manufacturer or determined by evaluation through testing labs. These data are tied to a particular make and model of DER and can be reused as each asset is produced along with its own unique data like serial number or electronic address. The California Energy Commission currently has the most complete set of capability data for DERs, which is available online[23]. Examples of DER Capability Data include the

- Make & model identifier
- Rated voltage
- Rated current
- Maximum apparent power output
- Maximum reactive power injection
- Reactive power absorption maximum
- Storage capacity (storage DERs only)
- Active power charge rate maximum (storage DERs only)
- List of IEEE 1547-2018 operational modes available

Detailed asset-based modeling with standardized data sheets for distribution equipment was added to the CIM such that a common data could be defined unique to a particular make and model and simply referenced by each physical asset deployed on the grid. This approach for utility-owned grid equipment is currently being extended to cover DER datasheets and core modelling ~~will be released~~ in ~~CIM~~ version 18 of the CIM Grid package. The latest version of CIM packages (as well as previous CIM17 / CIM100 release) are available for download from the UCAiug CIM User Group website.[24]

Commented [AM10]: General Question: Is the approach presented in this paper for sharing data ready to be implemented today? Statements like this makes me think that the standards are not yet ready.

Commented [JS11R10]: The standards are ready but certain aspects are in update. Added footnote and link to get the UML Model files.

Documenting datasheets to support DERs include two major subsets of data. The first set of data is the nameplate data and includes the rated voltage, maximum power capabilities, and full set of data elements inspired by the requirements published in IEEE 1547-2018[25]. The second set of data, also driven in large part by requirements in IEEE 1547-2018, documents available operational modes and protection capabilities and is substantially more voluminous. R-DER assets are expected to be primarily “off-the-shelf” equipment with datasheets consistent across any instance of that make and model. U-DER assets are

[23] https://www.energy.ca.gov/programs-and-topics/programs/solar-equipment-lists
[24] The CIM Users Group has released CIM version 18 in early 2024. The latest is available here: https://cimug.ucaiug.org/CIM%20Model%20Releases/Forms/AllItems.aspx
[25] https://standards.ieee.org/ieee/1547/5915/

expected to be "built-to-specification" equipment with datasheets unique to that particular installation. Regardless of the number of references to a DER datasheet, i.e. a single U-DER or thousands of R-DERs, the modeling structures are identical.

The process of collecting DER Capability consists of two phases. First, datasheet must be located. In the best case, these data can be found on the manufacturer's website, embedded in datasheets, or in the user manuals. Second, the data must be converted from human-readable documents (such as PDFs and spreadsheets) to the proper data class fields in the CIM. This requires both knowledge of the CIM as well as training in electrical engineering to help ensure that data is properly converted. To avoid duplication of modeling efforts, it is possible to create a collaborative "single source of truth" data environment to provide this information. The "single source of truth" environment would enable access to DER capability data to users through a graphical user interface (GUI) and application programming interface (API) access.

DER Configuration Data

DER Configuration Data describes how a particular asset is connected into the grid and how it is configured during installation. Much of this information is known by the installer and the distribution utility, typically published in a one-line electrical diagram and in geographic information system (GIS). Importantly, this modeling allows the utility to incorporate information about the DER into long-term planning studies and short-term operations planning studies.

Examples of DER Configuration data:

- Asset identifier
- Owner
- Geospatial location
- Electrical equipment settings (e.g., ride-through, frequency droop gain, return-to-service)
- Energization date
- Grid Point-of-Interconnection (POI), which is any/all of:
  - CIM Connectivity Node Identifier
  - Feeder Identifier
  - Substation Identifier
  - POI for Transmission-Distribution interface

Interconnection agreements and permitting information for R-DERs can be stored in a variety of non-standard methods today. Common methods include a spreadsheet, a customer billing system, a dedicated DER database, or a GIS system in which each R-DER is associated with the street address (or geospatial coordinate location) of the customer premises. Meanwhile, the data relating the DER connection to the grid is typically contained within a GIS database. Finally, power flow models used for interconnection studies and system planning are most frequently described by proprietary data formats to support specific vendor tools. None of the typical sources of data (DER database, GIS, or modelling tools) use a standard format, naming, or structure, which makes collection and sharing of data extremely difficult. Furthermore, the tools and data listed above are nearly exclusive to distribution utilities; a transmission entity would likely struggle to open and parse any of the model files and data.

The CIM provides a better approach. DER Configuration Data is instantiated in two areas of the CIM. The first is the Asset Data, which documents the particular instance of a certain type of DER (in a manner similar to the way distribution utilities perform asset management to track hundreds of instances of certain make/model of pole-top transformer). The asset data comprises the serial number of the particular asset, who owns it, and where it is located. If local codes require constraints on the Capability data (e.g., a certain operational mode should be set during installation), this information is also captured and tracked with the asset information.

The second area of the CIM is the grid representation perspective, known internally within the CIM as Equipment Data. These data represent the role of the asset in the electrical grid used for power flow studies and operations. The most important data to be collected is the Point-of-Interconnection (POI) data. This data describes where the DER is connected in the distribution feeder and in the bulk transmission system. Although the POI can be estimated using geospatial techniques, the preferred approach would be for the utility to provide a reference to a persistent grid location identifier (such as the bus number or CIM Connectivity Node). Mapping U-DER and R-DER to the correct bus within the power system network model is a major milestone in the data collection process towards reducing uncertainty regarding impacts of DERs. This mapping creates an accurate topological model of individual resources in support of implementation of existing NERC SPIDERWG recommended modeling practices.

As the specific name, number, or other identifier for the grid point-of-interconnection point is likely different across entities, careful internal database maintenance of DER connection points to the TP's desired representation at the grid POI is necessary to mitigate duplication or erasure of data. Data entry entities are likely not aware of the TP's internal nomenclature for this point. Further, operational configuration can alter the DER connection point through reconfiguration of the distribution system, meaning that for operational purposes some of these points may not be the same under all operating conditions. These discrepancies between entities highlight the importance of a "single source of truth" System of Record, which is discussed below.

DER Aggregation Commercial Data

Aggregation~~-~~ c~~C~~ommercial data in this context represents how the DER participates in any number of market opportunities, from local distribution utility programs to third-party energy retailer / aggregator programs to wholesale market service opportunities. One of the key elements of commercial agreements, at least from the utility perspective, is if the DER is directly participating or is participating as part of an aggregation where some or all of the device-level details may be ignored. Examples of DER Aggregation ~~C~~commercial data include:

- Resource identifier
- Aggregation identifier(s)

- Service qualifications, e.g. Energy, Ramping
- Service Start and end dates

Collection and mapping of this data is even more complicated and offers one of the strongest use cases for adoption of the CIM. There exists a myriad of data validation which needs to be performed at this level, including:

- Is a given DER participating in the DER Aggregator's provided service?
- Is the DER in an aggregation already?
- If not full capacity, how much of the capacity is part of the aggregation?
- What are the extents (voltage, geography, etc.) of the aggregation?
- Are there rules for which opportunities can be supplied coincidently?
- If multiple services of the aggregation are offered to different entities, for example T and D, which takes precedence?

It is yet to be determined who will coordinate or perform these validations. However, according to the processes currently defined by the ISO/RTO FERC Order 2222 compliance filings, the DER Aggregator will be responsible for understanding the market rules and the submittal/enrollment of an aggregation with appropriate parameters. By building the DER representation in the layered fashion provided by the CIM, there exists an opportunity to capture the more fluid aggregation dataset separately and link it to the less dynamic (sometimes static) DER Capabilities and Configuration Data. As the roles and capabilities of each DER changes over time, this linkage of datasets can be updated in the "single source of truth" System of Record.

In addition to providing data classes for the assets and topology of the power system, the CIM also provides a baseline from which DER aggregations can be formed. Aggregations can be performed based on power system topology, market structures, or control hierarchy. As markets evolve, planners and operators may need to have sufficient information reflected to their models and systems to study any reliability impacts. This is prevalent when DER Aggregators span multiple market nodes, which can translate to multiple BES substations. Transmission Planners can use the information contained within the aggregation to validate their case assumptions to determine how the DER and DER Aggregators interact in their simulations. Transmission Operators may be able to use this data to supply their real-time assessment or other operational time frame analysis.

Commented [JS12]: Added based on 8/22/24 discussion of reflecting practices to reliability, which is covered elsewhere.

DER Controls Data

While all of the prior data sets are focused between exchanges among systems, DER controls data ~~involve~~explains the interactions between systems and devices. Since the CIM is primarily a system-to-system protocol, this often means incorporating a device-specific protocol between the utility and the devices which need to be issued control, such as with IEC 61850-7-402 which has native integration or with IEEE 2030.5, CTA-2045, or OpenADR where mappings are possible.

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DER controls data may be grouped into two broad categories: energy scheduling and operational modes. Energy schedule is an optimization of the devices behavior to either maximize profits and/or grid reliability. The results of what can be a multi-function optimization is a schedule of production or consumption levels or real and potentially reactive power that are communicated to the device. Today these are mostly commonly delivered to devices via the internal communication channels provided by the device manufacturers, but in the future, it is anticipated the industry will need general protocols to allow easier scheduling.

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The second category of controls are those of operational mode, such as switching an inverter from constant power factor to Volt-VAR~~r~~ mode. Closely tied to operational mode are protection settings, for example the time constants for voltage and frequency ride through. These controls are primarily reliability-based and utilities will need a standard way to deliver these settings (or signals to switch to settings groups) using a standards protocol.

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DER Conditions ~~& Controls~~ Data

Another significant challenge is the ~~exchange~~ collection of real-time measurements a~~nd net aggregate data from both SCADA and AMI across the Transmission-Distribution boundary~~for use by the distribution operators, and in aggregate, but the transmission operators. At most substations shared between separate utilities, SCADA datapoints for boundary equipment are obtained from dual-ported remote terminal units (RTUs) and intelligent electronic devices (IEDs). The same set of measurements are sent across independent OT communications networks of the transmission operator and distribution service provider. Only a minimal amount of data is exchanged through Inter-control Center Communications Protocol (ICCP). Most control actions are coordinated through verbal communication between power system operators via telephone calls or scheduled in advance.

Currently, most transmission utilities have no knowledge of total output of DER from a set of feeders served by a given substation. Most EMS systems only provide a display of the total real power and reactive power flow measured on each transformer winding. In regions with high penetrations of renewables ~~and~~ where multiple distribution feeders ~~backfeeding~~ push energy back into the transmission system, operators may only see a reversal in the power flow direction at the substation transformer, with no further information of the amount of actual load and actual DER output.

Implementation of FERC Order 2222 will require significantly closer coordination and higher amounts of data exchanged across the T-D boundary. Similar to the network modeling problem, exchange of real-time data is also very difficult due to the highly siloed nature of existing data streams. Even if dual-metered AMI data is available (with separate metering of customer load and R-DER), this data is often not ingested and aggregated until the next business day. Use of data with such high latency would require recursive back-calculations and revision of market settlements for aggregate DERs to avoid double-counting of energy at the T-D interface. Furthermore, even if such data is available in real-time, there often does not exist any mechanisms except for ICCP by which the data can be aggregated and shared with transmission entities currently.

However, it is anticipated that low-latency DER data will become more readily available, either directly from the devices or through DER Aggregators using non-utility infrastructure. This potentially rich source of data introduces challenge in both the semantic realm (making sure translations are accurate between protocols) and the security realm (given the primary communications mechanisms at the grid-edge are not secured utility-managed infrastructure).

~~Use of CIM for DER data offers a combination of solutions to solve the semantic challenge. The first is the set of eXtensible Schema Definition (XSD) messages defined by the IEC 61968 family of standards. This format is increasingly supported by metering vendors and provides a standardized format for delivery of meter messages which can be understood by any vendor system and by open data-integration platforms. The second is introduction of the IEEE P2030.103 Universal Utility Data Exchange (UUDEX) protocol, which combines CIM semantic structures with ICCP-based messaging and a simple syntax structure based on JavaScript Object Notation (JSON). Use of UUDEX messages against a shared CIM power system model could greatly simplify the mechanisms for exchanging real-time data between transmission entities, distribution service providers, and DER aggregators, a concept that showing promise through demonstration projects.~~

~~The third is introduction of an OT data / control bus~~[26] ~~based on the IEC 61968-1 Interface Reference Model. All incoming SCADA, AMI, and DER data for a control area would be published onto the message bus as CIM-based messages. A set of shared services subscribe to the incoming messages, aggregate the data from incoming messages, map the results to associated aggregate DER objects, and publish the results for each DER aggregate back onto the message bus. The structure can be implemented in a centralized or hierarchical manner. A hierarchical / distributed implementation offers several advantages, including scalability, compartmentalization of data, and reduction of cyber-attack surfaces for each distributed instance. Within a hierarchical architecture, layered messages bus would be created, starting with the regional ISO or market operator and working downwards with a message bus for data aggregation created for each DP, substation, and DER aggregator. Each data aggregation service would be responsible for ingesting measurements from devices at its level as well as aggregate data published upwards from downstream message buses.~~

CIM also provides the opportunity to transition to more efficient and automated reporting. Utilizing the allowable communications interfaces[27] for DERs, inverters could self-report to DSO, TSO, RTO/ISO when they disconnect or connect to the grid or when they enter into dead-band operation due to system voltage or frequency anomalies, significantly lowering the burden of grid operator reporting requirements while providing a robust data set for post-event analysis.

Commented [CH13]: We removed the speculation and focused on what is available now. While it is interesting to monitor, we felt we should not include speculative information that doesn't provide direct context in this paper - so rewrote to what is available now, published and working.

Commented [AM14]: Please see my previous comment on whether or not the standards and data sharing approaches recommended in this paper are ready to be implemented today.

Commented [JS15R14]: Footnote was added above. Demonstration projects however include a multitude of ISO-RTO work.

Note to SPIDERWG: Can we link an ISO-RTO proof of concept here?

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[26] The concept of separating the OT data bus from the IT enterprise message bus is introduced in https://www.osti.gov/servlets/purl/1813936

[27] Examples of these interfaces and allowable protocols can be found in Table 41 of IEEE 1547-2018. Additional proprietary protocols may also exist for communication to DERs.

Structurally, CIM provides the ability for the power systems industry to deal effectively with the administrative functions of sharing DER and DERA data across all stakeholders today. New tools and structures have been added to CIM to support the operational and settlement aspects for DERs / DERAs and are being demonstrated now. DERs and DERAs present a new challenge to industry to effectively define a single-point of truth for DERs and DERAs (tens of millions over time) and share this information broadly across a wide range of stakeholders. An ad-hoc approach to DER and DERA data that cannot be collaboratively shared with all stakeholders will significantly undermine the industry's ability to utilize DERs and DERAs for grid and market support. Utilizing CIM as the foundation for this collaborative set of data will ensure the accuracy of the information for appropriate planning and modeling, dramatically reducing the information technology costs over time and significantly reducing the time for the effective implementation of DERs and DERAs into the grid and markets.

System of Record (Single Point of Truth)

With more than 3,000 utilities interacting with multiple RTOs/ISOs and market constructs, it is possible for a DER to provide valuable services to both a utility retail program and a market product. To facilitate the effective implementation of FERC Order 2222 and make DERs broadly available to both utility retail programs and market products, a single point of truth or system of record can readily provide the capability and configuration data for the DER. Consistency of data input for aggregate DERs (through a DER Aggregator or other entity) is the key to ensure similar device to device treatment so that, when needed, the TP can pull the relevant information from the central repository and build a representative model of the aggregation. This improvement highlights the key nature of a single system of record for DER information and can readily reduce uncertainty between TPs and PCs.

Some examples to investigate the data specifications that have implemented a system of record include the Australian Energy Market Operator,[28] EPRI,[29] Vermont Electric Power Company[30], and Collaborative Utility Solutions.[31] These examples are typically not backwards compatible to a new or updated system as the element relationship definitions were set with the data fields chosen, and updates to the fields can take a significant amount of development time if they are not based on CIM data structures. Thus, TPs should ensure that the DER information needed can be made available through the single system or record as having multiple systems to feed the data defeats the purpose of a common single system or record. In the ideal scenario, the system of record should:

1. Represent all the DER ***capability***, ***configuration***, ***~~aggregation~~commercial***, ***conditions,*** and ***controls*** information through a robust set of parameters in the system of record,
2. Capture all of the fields a TP can translate into their software, and
3. Resolve TP to TP differences in their modelling practices so that the data are communicable to neighboring TPs.

Commented [JS16]: Algin with title change above.

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[28] A report on CIM modeling is available at the Australian Renewable Energy Agency here: https://arena.gov.au/knowledge-bank/using-the-cim-for-electrical-network-model-exchange/

[29] Available here: https://www.epri.com/research/products/000000003002006001

[30] Initial architecture available here: https://www.vermontspc.com/sites/default/files/2024-01/VSPC_VXPlatformpresentation.pdf

[31] The library of resources for Collaborative Utility Solutions is available here: https://www.cusln.org/resources/Public%20Library

The breadth of industry stakeholders that require access to DER data (Figure 2~~Figure 2~~) is significantly broader than historical industry interactions with single set of data. A single system of record ~~-~~ensures coordination across the necessary stakeholders. Collaboration among the necessary stakeholders that use this data reduce the variability and uncertainty impact a DER Aggregator can have. Entities seeking to implement a system of record ideally should ensure the entities responsible for each function in the figure can leverage the system in order to reduce uncertainty and variability.

Figure 2: DER Data Uses

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The potential for millions of DERs being connected to the grid provides unique opportunities for both the reliability and resiliency of the grid. Still, if there is a not a simple method to share DER data across the stakeholders in the energy value chain, it will be more difficult to effectively integrate, utilize, and ensure reliability of the BPS with the growth of DER into the future. ~~future~~.

Implementing CIM data exchange has some barriers to not disrupt utility practices. These are:

1) Education of stakeholders on the benefits of CIM,[32] the update procedure, and the technical implementation of CIM profiles for DERs.
2) Translation of CIM structure into proprietary software may require software vendors to update their code and release patches or versions to handle this syntax. For example, positive sequence load flow software already proprietary-to-proprietary file conversion support (such as for the .raw file extension) to communicate across other positive sequence load flow tools. Some software vendors may already have a CIM translation tool; however, those that do not may need code alterations to accept the way powerflow and dynamic data is input to the program from CIM.
    a. As a subset of this barrier, there are instances where the planning practices may need updates to further use this CIM structure in procured proprietary software for use in their studies.
3) Education on the methods to ensure a secure exchange of data among entities, which is separate from the CIM structure. For example, CIM can be communicated across any file transfer protocol. Not all file transfer protocols are secure from malicious access. Entities may need education to establish good cyber posture and hygiene when implementing CIM (and other) data sharing mechanisms.
4) Enhancements to standard-based data exchanges may be necessary. Currently, many of the NERC Reliability Standards require a mutually agreeable data format or provide an entity the full authority to require specific data format. This may mean that entities could forbid data exchange in CIM in lieu of proprietary protocols. Thus, a potential barrier to CIM implementation across the NERC footprint is a lack of entity incorporation into their standard practices that can be remedied by exposing such entities to the benefits of CIM per item 1) in this list.

[32] Such as materials using [insert items from footnote 21-23] for education.

Commented [AM17]: Would it be possible to include in the Appendix how DER *capability, configuration, aggregation, conditions,* and *controls* information is represented in CIM?

Commented [CH18R17]: We have spent the last couple of weeks trying to find a way to represent this so that it would help versus create more confusion but the reality of CIM is that it is unique and the vast majority of folks would just be confused with any form of representation we put in. We have added all of the links and references for people familiar with CIM to get the current models but feel adding this, in any form, into the paper would create confusion vs clarity so feel it is best to keep the paper at a higher level and let the experts get the model from the references.

Commented [AM19]: Can we conclude this paper with some thoughts on barriers that may exist to implementing the approaches recommended in this paper? For example, I assume this approach would not work if a CIM representation of the power system is not available. Have all of the required standards been developed and tested?

Can we also conclude with some thoughts on next steps for implementing this approach?

Commented [JS20R19]: Implementation barriors include education of various stakeholders, exposure of CIM to areas that have not historically performed CIM work or tried to implement this.

DER CIM as a subset of all CIM model changes can be discussed. This is not a DER specific benefit potentially.

Commented [JS21R19]: Adress the ability to move the planning models into CIM is worthwhile. Address the concept/perspective of the MWG here: https://www.nerc.com/comm/PC/Model%20Validation%20Working%20Group%20MVWG%202013/NERC%20Standardized%20Component%20Model%20Manual.pdf

Work in ISOs have updated this and the interface is now updated for effective integration. This is likely both scalable and portable.

Commented [JS22R19]: Need to discuss: is security a barrier or a needed inclusion in this? Could be good to have cybersecurity inclusions here in the implementation piece. @alex/@chris

Commented [CH23R19]: We discussed the concept of security here and everything we could write is effectively covered in other NERC work product. People involved in security understand that CIM enhances and enable security in new and unique ways, as does any standard, but ultimately the security concept is founded in encryption (wrapping and unwrapping) the data and how secure the transfer medium is. We can discuss more but do not feel this would be an addition to this paper.

Commented [JS24]: Zakia to help get VELCO specific implementation work.

Commented [JS25]: 8/13/24 - Implementation barrier on the CIM is current structures are in place. Current procedures may be beholden to vendor specific implementation. Vendor support and needs to revise entity programs/procedure/data services are contingent on the software vendors implementing this function.

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Appendix A: Detailed Survey Process with Questions

SPIDERWG followed up its original modeling survey[33] with a set of questions that focused on the impacts of DER Aggregators and original responses to its original survey of membership to track improvements. This survey was distributed to the SPIDERWG e-mail distribution list, containing over 100 members with some members representing the same company. A total of six members sent their responses including four ISO/RTOs. Most companies that participated in the survey share different transmission functions (e.g., TOP, RP, BA, TP, RC, etc.) with one of them being a distribution operator and two being DPs. In terms of peak gross load, four respondents have over 20,000 MW and four of them stated having DER installed capacity in the range of 1,000 MW to 5,000 MW.

The following questions were asked in this survey:

4. What is your company function?
    a. If you are a Reliability Coordinator (RC), do you have specifications for DER data when performing your OPAs, RTAs, or real-time monitoring?
        i. How periodically is that information submitted? (e.g., seasonally, monthly, weekly, daily)
        ii. Do DER Aggregators provide any of this data?
    b. specifications for DER data when performing your planning assessments?
        i. How periodically is that information submitted? (e.g., seasonally, yearly)
        ii. Do DER Aggregators provide any of this data?
    c. If you are a Reliability Coordinator, Transmission Operator, or Balancing Authority, are there differing rules for T-side connected generation resources versus DER and DER Aggregators (i.e., sources of power located on the distribution system)?
        i. Can you explain any difference in treatment of the two categories of generation resources?
5. What is the peak gross load of your area [MW]? (same buckets)
6. What is the minimum gross load of your area [MW]? (same buckets)
7. What is the total capacity of DERs connected to your system [MW]? (same buckets, but with an option for over 10GW and 5GW – 10GW)
8. How are DERs being aggregated in your system? (same buckets)
9. Have you observed widespread tripping of DERs due to faults in operations? If yes, how many DERs tripped [MW and count, if available]
10. Do you receive any DER operational data (e.g., active power output of DER or DER status)
11. How do you model DERs in load flow studies? (buckets altered to be specific as net load hanging off transmission bus, modeled on low end of T-D XFMR)

[33] Available here: https://www.nerc.com/comm/RSTC_Reliability_Guidelines/White_Paper_SPIDERWG_DER_Survey.pdf

Commented [AM26]: I scanned through the Appendices. I suggest replacing the Appendices with a couple of pages on the key points that you took away from the survey results. I believe that would be more useful that reading through each question.

Commented [JS27R26]: Thank you for your comment. These appendices help to demonstrate the SPIDERWG survey effort and to compare to the previous modeling survey it took in 2019-2020.

Commented [AM28]: Numbering is off

Commented [JS29R28]: Corrected

12. Which positive sequence DER model do you use in your dynamic studies? (same buckets)
    a. Do you use any non-positive sequence DER modeling for any transient dynamic study? (e.g., a generic EMT model for DER)
13. Which positive sequence load model do you use in your dynamic studies? (ZIP load, CLOD, cmpld, cmpld_der_a)
    a. Do you use any non-positive sequence load modeling for any transient dynamic study?
14. What offerings does the DER Aggregator play in your area?
    a. Is there an analogous entity for areas that are not ISO/RTOs that aggregate the response of generation-connected generation?
    b. How is the Demand Response program (not DER, but is part of the DER Aggregator control?) controlled in the area?
15. Does the DER Aggregator (or entity aggregating the DER in your area) have interconnection or participation requirements for participating DER? If yes,
    a. Are those documented?
    b. Are those available to share for DPs?
    c. Are those available to share for transmission entities?
    d. How does Clause 10 of IEEE 1547-2018 play into account here?
    e. Are there additional technical requirements required for reliability from the ISO/RTO on participation? Are these publically sharable? If so, please provide a link.
16. How and when does new DER or existing DER wishing to increase its capacity signal to a DER Aggregator they wish to participate in that aggregation for your area?
    a. Does the DER Aggregator notify transmission entities of this new capacity for your area?
    b. Is this taken care of in the capacity review identified in FERC Order 2222, or is a separate requirement of the ISO/RTO?
17. How does the distribution system operators and planners coordinate with the DER Aggregator for analysis of constraints on the distribution system?
    a. D side constraints can have backup plans; how are those currently monitored?
    b. Are some of these schemes automated?
    c. What requires operator control and does that affect which T-D interface a DER is pushing against?
18. If known, how does the DER Aggregator collect, store, and share
    a. Planning data
    b. Operational data

   c. Short Circuit data

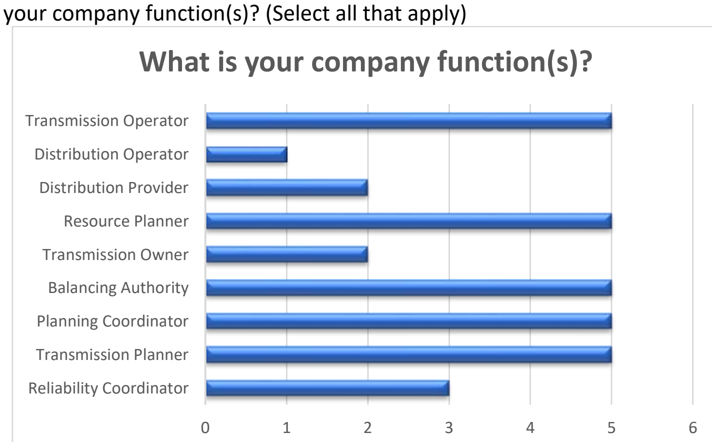
19. Does the DER Aggregator share resource type (PV, PV+BESS, Wind) information?
    a. Is this unit by unit, or lump sum?
20. Does the DER aggregator or entity supplying DER planning, operational, or short circuit data send notice to the transmission entity at the T-D Interface when DER device characteristics change?
    a. Is there a verification of capacity and control from that which is provided in the services to the information shared for planning?
    b. Is there a verification of capacity and control from that which is provided in the services to the information shared for operations?
    c. Is there a verification of capacity and control from that which is provided in the services to the information shared for protection relay coordination?
21. What set points or schedules does a DER Aggregator set on the DER it controls?
22. How is double counting or other duplication of generation accounted for?
    a. Is the DER Aggregator covering all of the T-D Interfaces?
23. What estimation techniques for DER Aggregator output are used to run a 15 minute ahead, 30 minute ahead, hour ahead, and day ahead analysis?
    a. Does the estimation spread across multiple load records?
    b. Does the estimation allow for creation of “new” generators in the model?
    c. Are predictions made on zones, substations, feeders? (select all that apply)
    d. How granular of a forecast is required?
    e. How does the forecast deal with uncertainty or error?
24. For your state estimator, how does the mismatch solution deal with negative records added to the load?
    a. Does an output negative load link with a DER generator dynamic model?
    b. How are mismatch loads dealt with in the OPA and RTA practices? Are they ignored, netted, or other?
25. Does your data quality checks or other operational assessment practices account for gross versus net loading at each T-D Interface?
    a. What metering supplies this gross versus net loading? (e.g., transformer-level, breaker-level, or DER device-level metering)
    b. Are these quality checks posted or otherwise available on request?
26. For information provided by the DER Aggregator, what telemetry granularity are they able to provide? (e.g., SCADA scans, Advanced Distribution Management System (ADMS), other time frame or framework)

a. Do they disaggregate their load from active power producing generation resources?
b. What metering is used or provided to telemeter the data for operational planning analysis
c. What metering is used or provided to telemeter the data for real-time analysis

Appendix B: DER Aggregators Survey Responses

This appendix provides the aggregated responses from the survey as well as the key takeaways for each question asked. The values show the number of responses out of the total number of received surveys. The lack of survey participants should qualify the key takeaways as needing further investigation into other entity impacts.

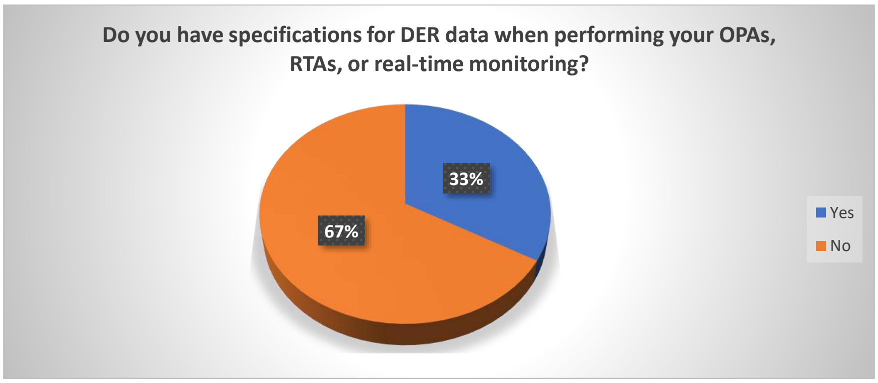
1. What is your company function(s)? (Select all that apply)



Key takeaway: question 1

Most surveyed members represent multiple NERC entities at the same time. Functional entities most represented among the surveyed members are TO, RP, BA, PC, and TPs.

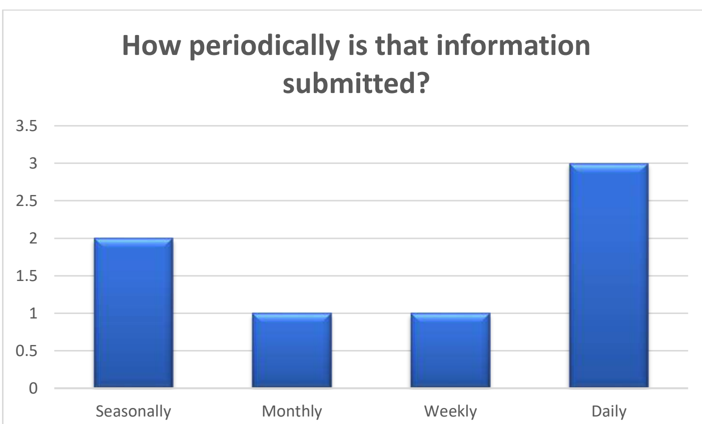
2. If you are a Reliability Coordinator (RC), do you have specifications for DER data when performing your Operating Planning Analysis (OPAs), Real-time assessment (RTAs), or real-time monitoring?



Key takeaway: question 2

Only one surveyed ~~memberSurveyed members with DER aggregators in their region hasve~~member has specifications for DER data for OPAs, RTAs, or real-time monitoring.

3. How periodically is that information submitted? (Select all that apply) Do DER Aggregators provide any of this data?



Key takeaway: question 3

One entity emphasized that DER and DER aggregations registered for participation in the wholesale electric market provided data for a variety of assessments. Data is provided in wide variety of time ranges with necessary modeling information (provided weekly), near-term reliability studies (hourly), and dispatch in real-time (up to 2 seconds). Additionally, monthly updates are provided in terms of detailed distribution premises and devices that make aggregation. There is a need to identify how the Operational Planning Assessment (OPA) and Real-Time Assessment (RTA) tools can capture a significantly growing set of data for the operational impact of DER Aggregators ~~with~~ as these entities grow in their capacity and penetration.~~greater participation.~~

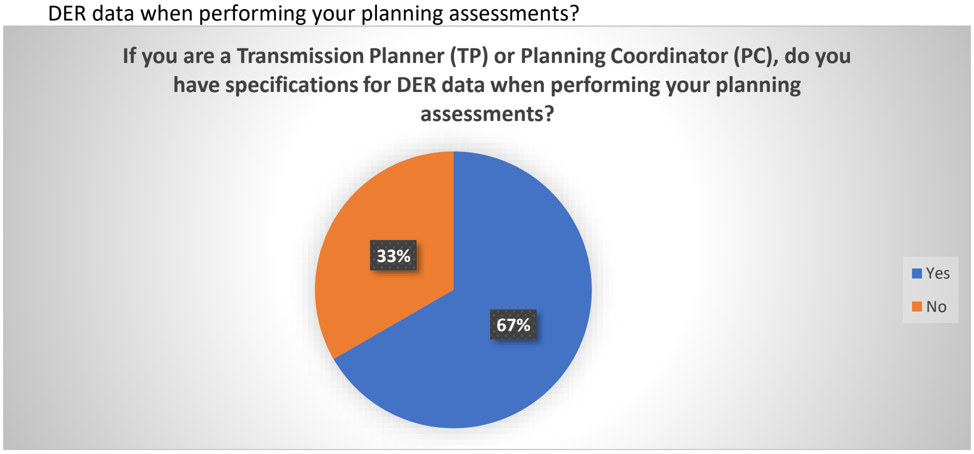
According to another survey participant, data is provided via surveys submitted by the transmission owners in their company's footprint.

Most of the surveyed SPIDERWG members do not have DER aggregators currently.

Commented [AM30]: I didn't follow the last sentence in the first paragraph.

Commented [JS31R30]: Altered sentence to reflect the need on ability to handle larger data sets in the OPA and RTA process as the DER Aggregator entity participation grows.

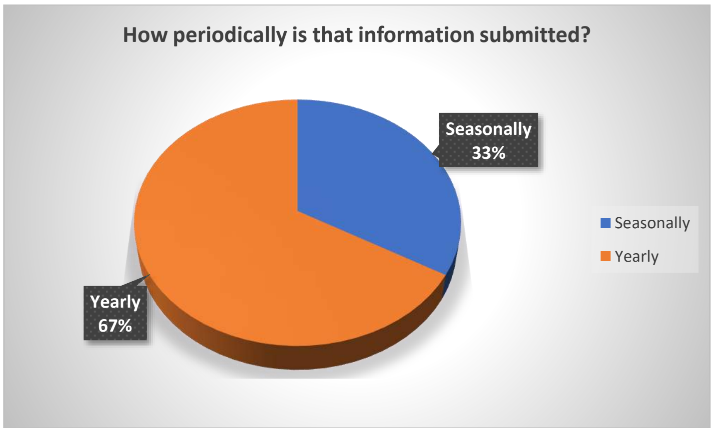
4. If you are a Transmission Planner (TP) or Planning Coordinator (PC), do you have specifications for DER data when performing your planning assessments?



Key takeaway: question 4

The majority of survey participants~~Half Majority ofof survey participantsed SPIDERWG~~ (66%) showed that they have established specifications for DER data when performing planning assessments.

5. How periodically is that information submitted? Do DER Aggregators provide any of this data?



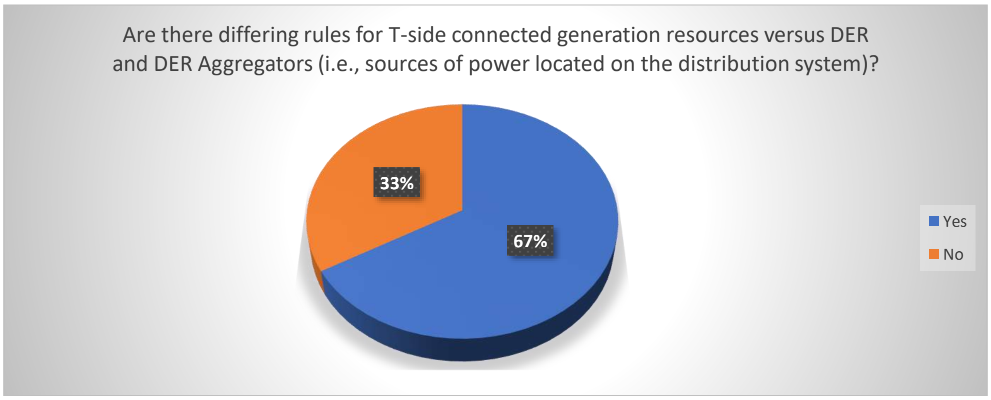
Key takeaway: question 5

67% of surveyed entities stated that they do not have DER aggregators connected to their system. However, their DER generation is based on forecast data which includes future and currently connected DER.

One entity claimed that DER greater than 1 MW are required to register and provide data and is included in annual base case development. Responses show that this data can be provided (or forecasted) seasonally or yearly.

According to another survey participant, data is provided via monthly surveys submitted by the transmission owners in their company's footprint.

6. If you are a Reliability Coordinator, Transmission Operator, or Balancing Authority, are there differing rules for T-side connected generation resources versus DER and DER Aggregators (i.e., sources of power located on the distribution system)?



Can you explain any difference in treatment of the two categories of generation resources?
The SPIDERWG received the following open ended responses to this question:

- DER has different requirements for ride-through. Reactive power capability and voltage control is generally specified by the distribution provider.
- Transmission – Have to hold voltage schedule. Require ride-through of transmission connected generation. Evaluate need for AGC capability. Distribution – must hold unity power factor. Ride-through not required on distribution connected DER.

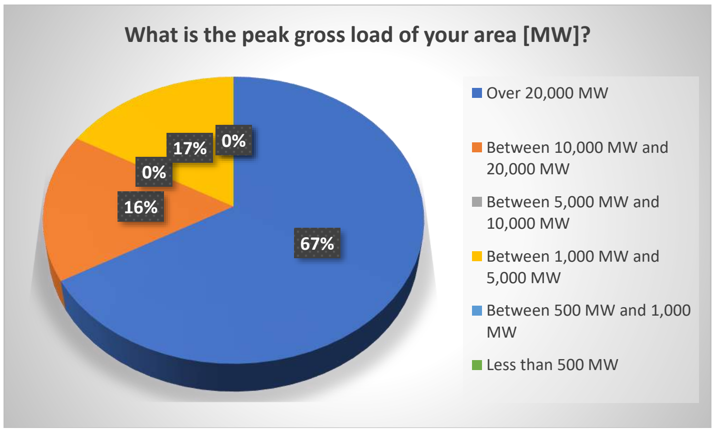
Key takeaway: question 6

~~Half~~ Two-thirds of surveyed SPIDERWG members showed that they have established specifications for DER data when performing planning assessments. As expected, members state that there are different specifications for ride-through, voltage regulation and other capabilities for ~~connected~~ resources connected to the transmission versus~~and~~ distribution side and that DPs are the responsible to specify DER capabilities and performance.

Some survey participants shared that DERs enter the state interconnection process whereas transmission connected resources enter through ISO-NE's queue and FERC interconnection process.

SPIDERWG has published a [Reliability Guideline Bulk Power System Reliability Perspectives on the Adoption of IEEE 1547-2018] to help RCs and BAs coordinate and specify DER functions that are key to ensure BPS reliability.

7. What is the peak gross load of your area [MW]?



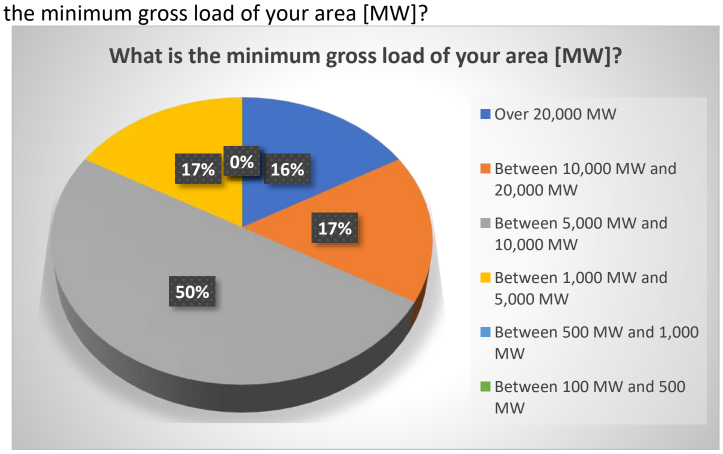
Key takeaway: question 7

Majority of surveyed members (~~67~~75%) have over 20,000 MW gross peak load. The r~~One entityR~~emaining two entities stated they have between 1,000 MW to 5,000 MW and 5,000 MW and 10,00 MW respectively of peak gross load.

Commented [AM32]: Check the percentage – typo

Commented [JS33R32]: @Jose, please confirm. I think the second set of numbers is the right one

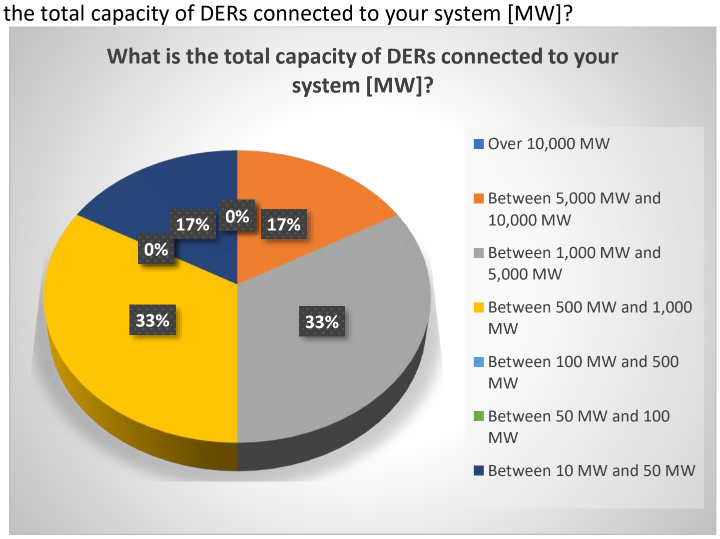
8. What is the minimum gross load of your area [MW]?



Key takeaway: question 8

Minimum gross load among members range between 1,000 MW to over 20,000 MW

9. What is the total capacity of DERs connected to your system [MW]?



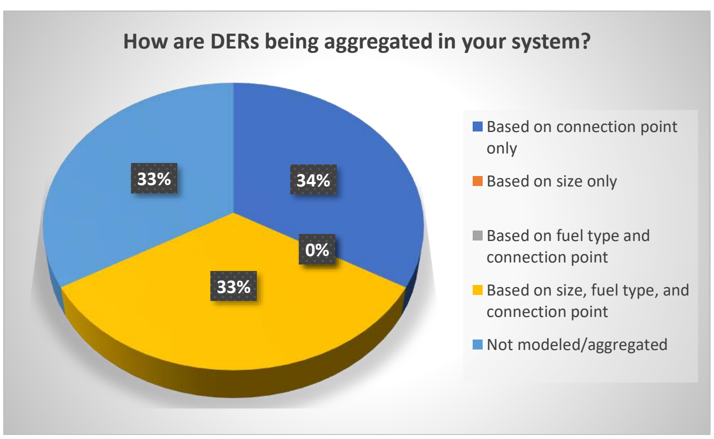
Key takeaway: question 9

~~75~~83% of members have significant DER capacity connected to their system that ranges between 500 MW to 5,000 MW. One entity has lower penetration ranging from between 10 MW to 50 MW.

Commented [AM34]: Check the percentage (typo)

Commented [JS35R34]: @Jose, same.

10. How are DERs being aggregated in your system?



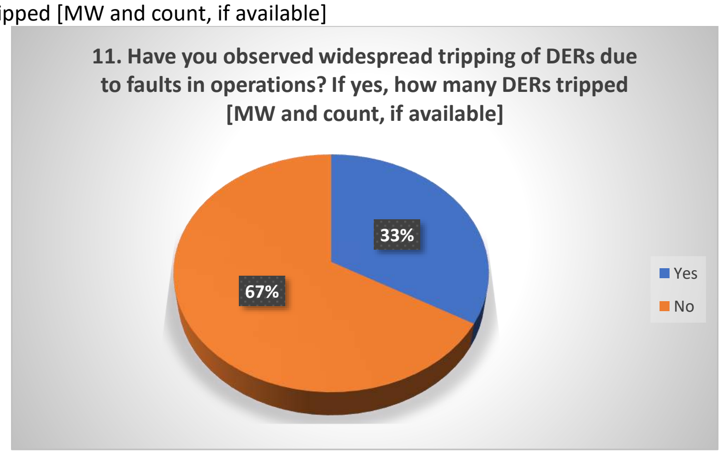
Key takeaway: question 10

~~Half of surveyed~~One-third of surveyed members stated that DER aggregations are performed based on size, fuel type, and connection points while one entity mentions that they are not being modeled/aggregated.

One entity mentioned that aggregation of DERs is performed according to their connection point and that devices or premises that make a DER Aggregator must individually have less than 1 MW of controllable capability. They are required to be within a single DSP and Load Zone, but not behind the same connection point. For DER over 1 MW, participation is not mandatory but if they do participate, they must be registered separately.

The two surveyed companies with DER aggregators in their footprint aggregate DERs based on point of connection.

11. Have you observed widespread tripping of DERs due to faults in operations? If yes, how many DERs tripped [MW and count, if available]



Key takeaway: question 11

~~One entity~~Two entities observed DER tripping due to faults in operation without stating how many had tripped. DER capacity for this each entity ranges between 1,000 MW to 5,000 MW and 5,000 MW to 10,000 MW respectively.

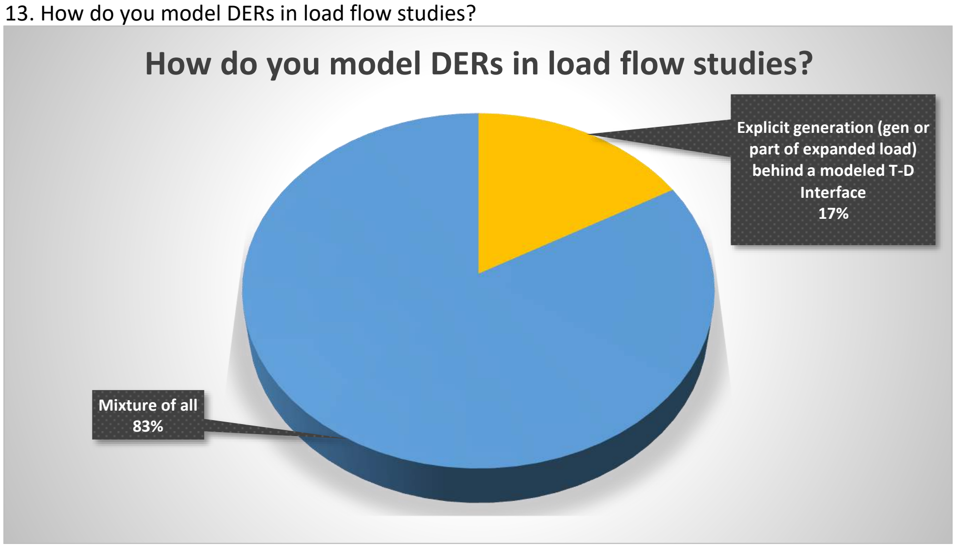
12. Do you receive any DER operational data (e.g., active power output of DER or DER status)

Key takeaway: question 12 (open ended)

Most of the ~~Half of~~ surveyed entities do not receive operational data from DERs. One entity requires data from DERs registered to the wholesale market which include power output, status, ramp rates, and operational limits. State of charge is also provided for some storage sites.

Two other entities shared that if the DER participates in the market as a modeled generator, then they do provide operational data.

13. How do you model DERs in load flow studies?



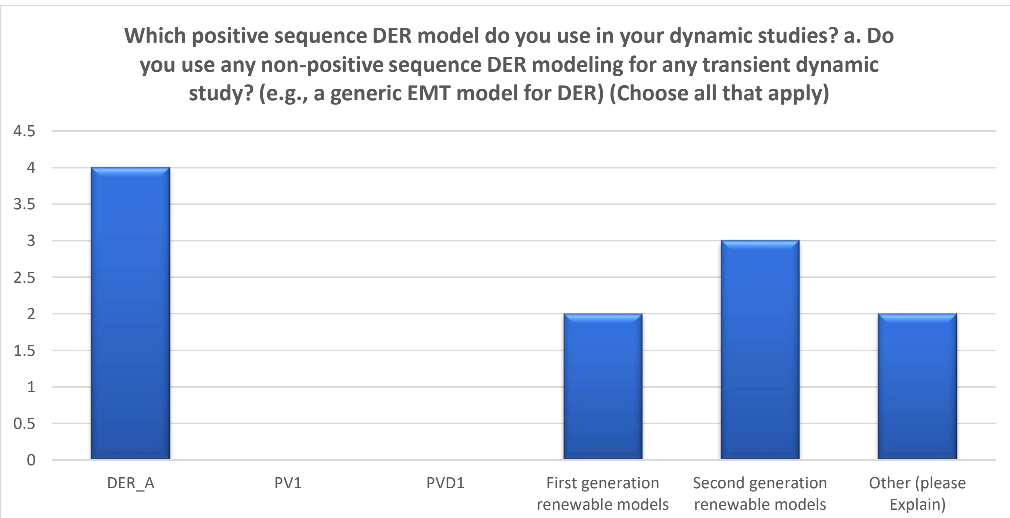
Key takeaway: question 13

83% (5) of surveyed members model DERs with a mixture of the following: *a) negative load off the transmission bus b) Negative load off an explicitly modeled T-D Interface c) explicit generation (gen or part of expanded load) hanging off the transmission bus d) explicit generation (gen or part of expanded load) behind a modeled T-D Interface.*

One of the entities stated that they model DER aggregators like a controllable load resource and it is seen as negative load. DERs over 1 MW are represented as generators mapped to a transmission bus and unregistered behind-the-meter units are netted with load.

One entity with the smallest amount of DER connected (10 MW to 50 MW) uses an explicit generator~~ion~~ behind a modeled T-D Interface as a DER model.

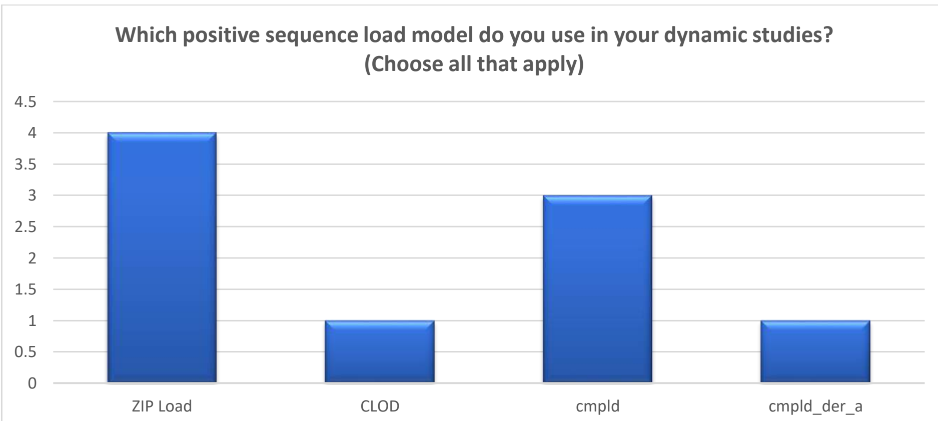
14. Which positive sequence DER model do you use in your dynamic studies? a. Do you use any non-positive sequence DER modeling for any transient dynamic study? (e.g., a generic EMT model for DER) (Choose all that apply)



Key takeaway: question 14

Most of the surveyed participants use DER_A to perform dynamic studies. One entity separates inverter-based projects into two categories: projects less than 5MW are modeled with DER_A and projects greater than 5MW are modeled with second generation renewable models. Synchronous generation is generally netted with the load and no models are used unless they are greater than 5MW, then they are modeled with explicit generator, e~~E~~xciter, and g~~G~~overnor models.

15. Which positive sequence load model do you use in your dynamic studies? (Choose all that apply)



Key takeaway: question 15

Survey shows that different positive sequence models are used. ZIP load and cmpld models are used by the entity having DER aggregators.

16. What offerings does the DER Aggregator play in your area? a. Is there an analogous entity for areas that are not ISO/RTOs that aggregate the response of distribution-connected generation? b. How is the Demand Response program controlled in the area?

Key takeaway: question 16 (open ended)

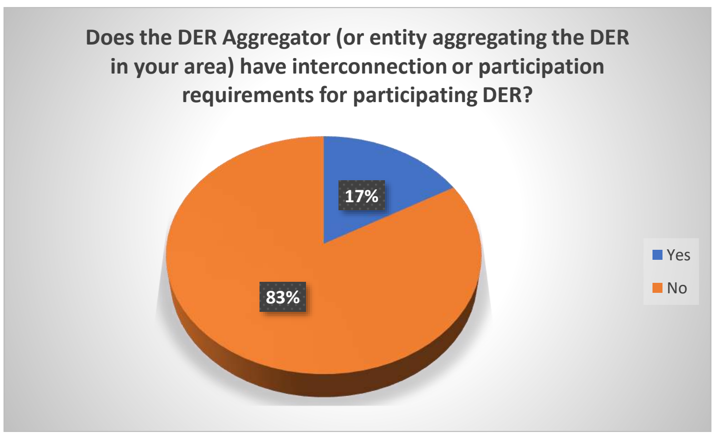
One entity allows DER aggregations to participate in their wholesale electric market. In general, the entity that represent a registered aggregator should also represent the load. Under the pilot for DER aggregations, they will be controlled through base point instruction produced using security-constrained economic dispatch.

Another surveyed member mentioned that there is only one aggregator in their footprint, and they are simply a price taker in the markets, there are no other services provided. For Demand response, registration is performed under specific operating procedures.

For demand response, the Standby Generators and Interruptible programs are controlled through the TCC (not by an aggregator).

Most surveyed entities mentioned they do not have DER aggregators or demand response programs in their regions.

17. Does the DER Aggregator (or entity aggregating the DER in your area) have interconnection or participation requirements for participating DER? If yes,
    a. Is there a verification of capacity and control from that which is provided in the services to the information shared for planning?
    b. Is there a verification of capacity and control from that which is provided in the services to the information shared for operations?
    c. Is there a verification of capacity and control from that which is provided in the services to the information shared for protection relay coordination?



Key takeaway: question 17 (open ended)

All participants responded that the DER aggregator does not have participation requirements for participating DER.

The entity with DER aggregators claimed that it is the DSP that has the interconnection requirements, not the DER aggregator. Specific rules to the DER aggregation pilot initiative are publicly available.

Another entity with DER aggregators mentioned rules for DER interconnection are required to meet UL certification 1741-SB and be compliant with IEEE 1547-2018 whereas transmission Resources need to meet the requirements of our Planning Procedures and Operating Procedures. Also, DERs enter the state interconnection process whereas transmission connected resources enter through ISO-NE's queue and FERC interconnection process. For DERs connected through an RTU to the ISO for modeled gens, 1547-2018 interoperability requirements do not apply.

18. How and when does new DER, or existing DER wishing to increase its capacity, communicate to a DER Aggregator they wish to alter their equipment? a. Does the DER Aggregator notify

transmission entities of this new capacity for your area? b. Is this taken care of in the capacity review identified in FERC Order 2222, or is a separate requirement of the ISO/RTO?

Key takeaway: question 18 (open ended)

One entity shared changes to the aggregation, including changes to the premises/devices that make up the aggregation are communicated monthly. These updates are provided to and require approval by the entity and the distribution service provider before becoming effective. Transmission service providers are informed of changes in capacity but do not need to approve changes to the aggregation. Changes in capacity are a separate requirement from the O2222 review.

Most of the surveyed entities do not have DER aggregators or they do not act in that capacity.

19. How does the distribution system operators and planners coordinate with the DER Aggregator for analysis of constraints on the distribution system? a. D side constraints can have backup plans; how are those currently monitored? b. Are some of these schemes automated? c. What requires operator control and does that affect which T-D interface a DER is pushing against?

Key takeaway: question 19 (open ended)

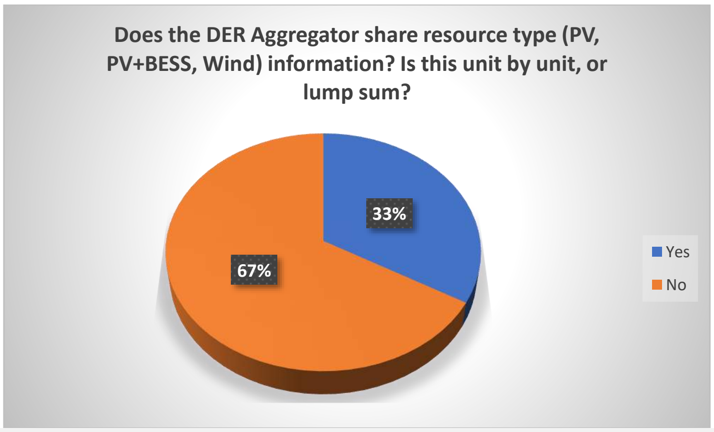
One entity shared that prior to allowing a premise or device to become part of an aggregation, the distribution service providers review the list of all proposed premises and devices and can either approve or reject each individual line item. This is their first opportunity to head off potential concerns. Once they are in operation, the distribution service providers ~~that~~ have the right to change how the aggregation is being managed should they see issues that they cannot otherwise easily manage. As this entity is in a pilot project, more formal procedures will have to be developed, but have no visibility of DSP procedures that may have in place to monitor and control these issues. To the degree an aggregator is limited by instructions from the DSP, they are required to reflect those limitations in the data provided. For example, as a reduction in available capacity reflected in real-time telemetry.

20. If known, how does the DER Aggregator collect, store, and share (Planning Data, Operational Data, and Short Circuit Data).

Key takeaway: question 20 (open ended)

From the survey responses, experiences from the one entity with DER aggregators show that this task is left to the aggregators to organize. No rules are set on how to collect and store information. Only requirements on what information needs to be provided for studies and models has been specified.

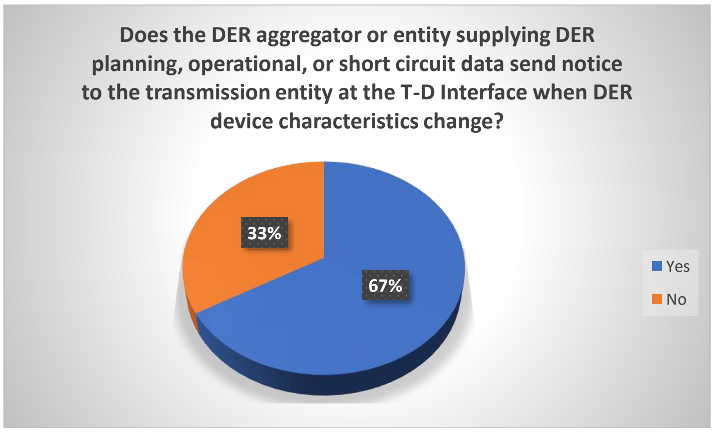
21. Does the DER Aggregator share resource type (PV, PV+BESS, Wind) information? Is this unit by unit, or lump sum?



Key takeaway: question 21 (open ended)

Entity with DER aggregators shared that real-time telemetry and near-term operational data (hours and days) is provided for the aggregation. Registration-type information is provided for each individual premise or device with this information updated monthly, following entities and distribution service provider review.

22. Does the DER aggregator or entity supplying DER planning, operational, or short circuit data send notice to the transmission entity at the T-D Interface when DER device characteristics change?
    a. Is there a verification of capacity and control from that which is provided in the services to the information shared for planning?
    b. Is there a verification of capacity and control from that which is provided in the services to the information shared for operations?
    c. Is there a verification of capacity and control from that which is provided in the services to the information shared for protection relay coordination?



Key takeaway: question 22 (open ended)

Only one entity responded that DER aggregator or entity supplying DER planning, operational, or short circuit data send notice to the transmission entity at the T-D Interface when DER device characteristics change. As shared in previous question, entity with DER aggregators shared that real-time telemetry and near-term operational data (hours and days) is provided for the aggregation. Registration-type information is provided for each individual premise or device with this information updated monthly, following entity and distribution service provider review. Also, there is a process to validate the real-time telemetry and operations performance of the aggregations.

The second entity with DER aggregators responded that if the capacity changes, then it is notified. Otherwise, not necessarily.

Most of surveyed member do not have aggregator within their region.

23. How is double counting or other duplication of generation accounted for in DER Aggregators? Does this cover all T-D Interfaces? Explain.

Key takeaway: question 23 (open ended)

One entity responded: as part of the process for approving participation of an individual premise or device, validation is done to ensure that they are not also participating in another wholesale market program.

Another company records all DERs currently installed and planned, and actively monitors for possible double counting issues.

24. How is double counting or other duplication of generation accounted for in resource plans? Does the DER Aggregator supply this information? Does the DER Aggregator cover all T-D Interfaces for these resource plans? Explain.

Key takeaway: question 24 (open ended)

One member responded that a part of the process for approving participation of an individual premise or device, validation is done to ensure that they are not also participating in another program, addressing duplication on the front end.
Another entity responded DER is typically handled in their load forecast as a load offset and not counted as generation.

25. What estimation techniques for DER Aggregator output are used to run a 15 minute ahead, 30 minute ahead, hour ahead, and day ahead analysis?
    a. Does the estimation spread across multiple load records?
    b. Does the estimation allow for creation of "new" generators in the model?
    c. Are predictions made on zones, substations, feeders? (please indicate all that apply)
    d. How granular of a forecast is required?
    e. How does the forecast deal with uncertainty or error?

Key takeaway: question 25 (open ended)

One entity with DER aggregators stated that aggregators are required to provide hourly COP information. Maximum Power Consumption and Low Power Consumption values for the aggregators for future hours are monitored.

Most of surveyed member do not have aggregator within their region.

26. For your state estimator, how does the mismatch solution deal with negative records added to the load?
    a. Does an output negative load link with a DER generator dynamic model?
    b. How are mismatch loads dealt with in the OPA and RTA practices? Are they ignored, netted, or other?

Key takeaway: question 26 (open ended)

One surveyed member responded that a fake generator model is added to the state estimator to represent the DER behind the station. The size of it is commensurate with the expected capacity and expected output of the DERs.

27. Does your data quality checks or other operational assessment practices account for gross versus net loading at each T-D Interface?
    a. What metering supplies this gross versus net loading? (e.g., transformer-level, breaker-level, or DER device-level metering)
    b. Are these quality checks posted or otherwise available on request?

Key takeaway: question 27 (open ended)

Entity with DER aggregators has gross 15-minute meter data available for validation in the first phase of the pilot project. Other approaches are likely be considered in future phases. Rules specific to the DER aggregation pilot are publicly available.

Most of surveyed member do not have aggregator within their region.

28. For information provided by the DER Aggregator, what telemetry granularity are they able to provide? (e.g., SCADA scans, Advanced Distribution Management System (ADMS), other time frame or framework)
    a. Do they disaggregate their load from active power producing generation resources?
    b. What metering is used or provided to telemeter the data for operational planning analysis. What metering is used or provided to telemeter the data for real-time analysis.

Key takeaway: question 28 (open ended)

For DER aggregators, one entity requires providing telemetry with granularity as low as 2 seconds, in alignment with requirements for other resource types. This includes:

a. providing both options where either a device can be part of the aggregation or the whole premise can be part of the aggregation.
b. Operational planning analysis based on resource plan data provided for the aggregation. In general, these processes do not depend on meter data or telemetry.
c. 15-minute meter data is the data available for validation.

Most of surveyed member do not have aggregator within their region.

SAR: EOP-005 Accounting for DER in Blackstart Plans

Action
Endorse

Summary
The purpose of the SAR is to revise the TOP's Operating Process in EOP-005 such that TOPs consider the automatic response of DERs in addition to Load during system restoration. DERs are inherently on the distribution provider's system[1] and as such may impact the variability seen during system restoration.[2] This Project aims to alter the requirements for TOP Operating Processes to account for known DER impacts during system restoration and to require the SDT to determine appropriate standard revisions such that the TOP considers DER automatic response during system restoration.

This SAR has been reviewed by and endorsed by the RTOS. This SAR has included a formal comment period and the response to those comments was also included collaboration with the RTOS.

[1] Note that not all distribution systems contain a Distribution Provider Registered Entity.
[2] In contrast, the Blackstart Resources connected through transmission or sub-transmission already have a known topology and model representation due to other NERC Reliability Standards.

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:	Accounting for DER in Blackstart Plans – EOP-005		
Date Submitted:	MM/DD/2022		
SAR Requester			
Name:	Shayan Rizvi, NPCC (NERC SPIDERWG Chair) John Schmall , ERCOT (NERC SPIDERWG Vice-Chair)		
Organization:	The NERC System Planning Impacts of DER Working Group (SPIDERWG)		
Telephone:	Shayan – 212-840-1070 John – 512-248-4243	Email:	Shayan – srizvi@nppc.org John – john.schmall@ercot.com
SAR Type (Check as many as apply)			
☐ New Standard ☒ Revision to Existing Standard ☐ Add, Modify or Retire a Glossary Term ☐ Withdraw/retire an Existing Standard		☐ Imminent Action/ Confidential Issue (SPM Section 10) ☐ Variance development or revision ☐ Other (Please specify)	
Justification for this proposed standard development project (Check all that apply to help NERC prioritize development)			
☐ Regulatory Initiation ☐ Emerging Risk (Reliability Issues Steering Committee) Identified ☐ Reliability Standard Development Plan		☒ NERC Standing Committee Identified ☐ Enhanced Periodic Review Initiated ☒ Industry Stakeholder Identified	
Industry Need (What Bulk Electric System (BES) reliability benefit does the proposed project provide?):			
In order to “ensure plans, Facilities, and personnel are prepared to enable System restoration from Blackstart Resources to ensure reliability is maintained during restoration”[1], clarity is needed for how to account for DER in EOP-005. If DER[2] are chosen as “Blackstart Resources” and part of a TOP’s system restoration plan, then there is a need to study the Cranking Path[3] from the new Blackstart Resources connected through the distribution system in order to accomplish the TOP’s system restoration objective. Even if DER are not chosen as a “Blackstart Resource”, accounting for DER automatic response to			

[1] Taken from EOP-005-3. Available: https://www.nerc.com/pa/Stand/Reliability%20Standards/EOP-005-3.pdf
[2] SPIDERWG uses the definition of DER as “any Source of Electric Power located on the Distribution System.” Taken from: https://www.nerc.com/comm/RSTC/SPIDERWG/SPIDERWG%20Terms%20and%20Definitions%20Working%20Document.pdf. Project 2022-02 currently is scoped to define DER.
[3] Sometimes this is called a “switching path”.

Requested information
energization of distribution equipment is necessary to ensure the reliable operation of the bulk system during system restoration activities. Particularly important is the careful study of automatic response when restoring lost service to transmission to distribution interfaces (T-D Interfaces) as they can contain automatic response of motor load, electronic load, and DERs.
Purpose or Goal (How does this proposed project provide the reliability-related benefit described above?):
The purpose of the SAR is to revise the TOP's Operating Process in EOP-005 such that TOPs consider the automatic response of DERs in addition to Load during system restoration. DERs are inherently on the distribution provider's system[4] and as such may impact the variability seen during system restoration.[5] This Project aims to alter the requirements for TOP Operating Processes to account for known DER impacts during system restoration and to require the SDT to determine appropriate standard revisions such that the TOP considers DER automatic response during system restoration.
Project Scope (Define the parameters of the proposed project):
Modify EOP-005 to account for the following: 1) Require the TOP to consider the automatic response of DERs (in addition to the Load response) when performing load pickup[6] of distribution equipment. The SDT should ensure the Operating Processes in R1.7 and R1.8 include the automatic response of such Load and generation assets when energizing a T-D Interface and for the duration of the system restoration plan. 2) Require the TOP to specify model requirements and distribute those specifications to appropriate entities in R6 for DER data to perform the scope item 1. The SDT can look at TOP-003 specifications to ensure clarity for DER data needed to perform scope item 1 rather than adding requirements in EOP-005 for this scope item. 3) As an alternative path to scope items 1 and 2, revise the EOP-005 requirements to allow a pathway such that the DP isolates sufficient[7] aggregate DERs during system restoration until directed and allowed to reconnect by the appropriate entity. The SDT should consider requirements to have the DP declare their pathway to the appropriate entities and require the TOP to include the DP's declared path in their Operating Processes to develop and implement their restoration plan.

[4] Note that not all distribution systems contain a Distribution Provider Registered Entity.
[5] In contrast, the Blackstart Resources connected through transmission or sub-transmission already have a known topology and model representation due to other NERC Reliability Standards.
[6] The SPIDERWG identifies that the automatic response of Load is well understood during these studies, and identifies that DER automatic response would be needed akin to the understanding of load per the SPIDERWG white paper. The duration of system restoration activities can be lengthy (i.e., hours-long) and the automatic responses of DERs may change during this time.
[7] Sufficient in this context is the amount required for the success of the TOP's system restoration plan rather than a standard, uniform amount for all plans.

Requested information
Detailed Description (Describe the proposed deliverable(s) with sufficient detail for a drafting team to execute the project. If you propose a new or substantially revised Reliability Standard or definition, provide: (1) a technical justification[8] which includes a discussion of the reliability-related benefits of developing a new or revised Reliability Standard or definition, and (2) a technical foundation document (*e.g.,* research paper) to guide development of the Standard or definition):
Under the current applicability section of EOP-005-3, the requirements for resource integration into system restoration plans in most cases fall to the TOP. Typically, these entities receive only load data from the DP and not the operating characteristics of underlying resource control systems; however, there are instances where the underlying controls are not known for DERs and Load control. Primarily, the concern is that the automatic return-to-service characteristics of the underlying resource control systems are not well known to the TOP for their effect during system restoration. The TOP is therefore frequently unable to confidently predict resource response to system conditions. TOPs have the ability to specify data gathering for their Operating Processes, yet some information may be needed from DERs and Load and is handled by the Distribution Provider. In some instances, there is no Distribution Provider Registered Entity for data sharing to submit the known automatic response of DERs or Load in their system. The SDT is scoped to ensure that TOPs have the necessary data to accomplish their Operating Processes. Historical events[9] have shown that the lack of data and modeling from distribution systems has resulted in potential for inaccurate assessments of transmission system performance and contingency responses. (Scope Item 2) On energization DERs will respond to the recovered voltage, potentially creating adverse conditions during system restoration if not accounted for in the TOP system restoration plan. Without access to modeling data and operating characteristics for modeling the DERs in these instances, the studies, such as steady-state or dynamic simulations, required to build a system restoration plan under EOP-005-3 would provide only an inaccurate estimate of the distribution system response to an event. Currently, the Requirement text for EOP-005 indicates that the TOP is responsible to contain Operating Processes to restore, among other things, "Load needed to stabilize generation and frequency, and provide voltage control." In this connection, should DER exist (and operate per its automatic response to re-energization) and not be studied as part of the Operating Processes, there exists uncertainty in the ability for the degraded system to stabilize. Further, the proposed DER definition from Project 2022-02 and SPIDERWG are technology agnostic. This means that the automatic response may differ between TOPs depending on the composition of the Load and DER when re-energizing a bus. The alternative is to ensure that DPs disconnect DERs, where possible, during system restoration and do so until an appropriate entity directs

[8] 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.

[9] In particular, the *Lessons Learned: DER Performance During a Disturbance* (available here: https://www.nerc.com/pa/rrm/ea/Lessons%20Learned%20Document%20Library/LL20220401_DER_Performance_During_a_Disturbance.pdf) highlighting the potential for the devices to react on system energization and the Palmdale Roost and Angeles Forest disturbances (available here: https://www.nerc.com/pa/rrm/ea/April_May_2018_Fault_Induced_Solar_PV_Resource_Int/April_May_2018_Solar_PV_Disturbance_Report.pdf)

Requested information
the DP to reconnect the DER as part of the system restoration or when returning to a normal operating state. Further, understanding a resource's expected response is particularly important in the early stages of restoration when the transmission system is weak and frequency and voltage control can be challenging for system operations with frequency and voltage excursions beyond the normal range. Current equipment standards like IEEE 1547-2018 include anti-island and other ride-through capability that can impact their automatic re-energization to the grid. As IEEE 1547 allows a range of settings, the specific settings chosen dictate the automatic re-energization response of DER during load pickup. Clear identification of roles among the DP, TOP, and the GOP of Blackstart Resources in a TOP's system restoration plan is necessary to properly ensure frequency and voltage excursions and automatic equipment response (including automatic response of DERs and Load) seen during the early stages of system restoration is well understood and actions taken in a system restoration plan are effective.
Cost Impact Assessment, if known (Provide a paragraph describing the potential cost impacts associated with the proposed project):
Material cost impacts are unknown. Clarity enhancements are not anticipated to have a significant cost and the extra time spent on studying the Cranking Path may have an extra cost to evaluate and develop a reliability-focused Cranking Path. It should be noted that blackstart is a topic whose cost to benefit calculations are fairly skewed towards spending to ensure reliability.
Please describe any unique characteristics of the BES facilities that may be impacted by this proposed standard development project (*e.g.*, Dispersed Generation Resources):
None anticipated. However, if a DER is selected as a Blackstart Resource, they become a BES Facility per Inclusion 3 to deliver the power as part of a Cranking Path and are no longer non-BES equipment. However, such a Blackstart Resource is connected through a distribution system, which is inherently non-BES.
To assist the NERC Standards Committee in appointing a drafting team with the appropriate members, please indicate to which Functional Entities the proposed standard(s) should apply (*e.g.*, Transmission Operator, Reliability Coordinator, etc. See the most recent version of the NERC Functional Model for definitions):
Distribution Provider (DP), Transmission Operator (TOP), Transmission Owner (TO), and Generation Operator (GOP).

Requested information
Do you know of any consensus building activities[10] in connection with this SAR? If so, please provide any recommendations or findings resulting from the consensus building activity.
This SAR has been submitted through the RSTC and has been vetted by the SPIDERWG membership. The SPIDERWG membership includes BAs, RCs, TOs, TPs, TOPs, PCs, and DPs. The SPIDERWG documented this work in the SPIDERWG white paper *NERC Reliability Standards Review,*[11] where the SPIDERWG recommended this standard be revised. The SAR was also circulated to the Real-Time Operating Subcommittee and the Event Analysis Subcommittee and their comments and edits are incorporated in language.
Are there any related standards or SARs that should be assessed for impact as a result of this proposed project? If so, which standard(s) or project number(s)?
There are no other standards projects or anticipated SARs that will address the study of DER in blackstart restoration plans. However, Project 2022-02 currently has scoped the definition of DER in its project and this SAR is impacted by the exact definition. In addition, TOP-003 is an impacted standard for data requirements for its analysis, including the studies performed under EOP-005 R6 if using the same data.
Are there alternatives (e.g., guidelines, white paper, alerts, etc.) that have been considered or could meet the objectives? If so, please list the alternatives.
The SPIDERWG considered Standards revisions alongside compliance implementation guidance and reliability guidelines. The SPIDERWG identified that specific standards revisions are necessary to ensure the reliable operation of the system during system restoration. A reliability guideline is useful in identifying and recommending best practices for sharing aggregate DER information[12] (inclusive of expected dispatch and updated capacity information at the bulk system bus) as well as best practices highlighting a procedure using this information in the development of a system restoration plan. The SPIDERWG looked at compliance implementation guidance,[13] and found that compliance implementation guidance was not suited to address the identified reliability gap. A reliability guideline or compliance implementation guidance could not address the reliability need for the TOP to capture DER and Load automatic response to load pickup actions taken in a system restoration plan such that the plan is successful. Thus, the SPIDERWG recommended Standards revisions due to the limitation of reliability guidelines or compliance implementation guidance to address the identified gap.

[10] 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.
[11] Available here: https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Whitepaper_SPIDERWG_Standards_Review.pdf
[12] The SPIDERWG in their white paper recommended a reliability guideline to cover the data sharing between the TOP and DP for system restoration plans. This is in addition to other operational data sharing guidelines listed in the paper as a procedure to share information.
[13] Compliance implementation guidance information can be found here: https://www.nerc.com/pa/comp/guidance/Pages/default.aspx.

Requested information
To be clear, the reliability gap this SAR is scoped to address is not in how the data sharing or procedures are performed but that there is ambiguity on the treatment of a T-D interface such that automatic response of DERs and Load are not accounted for in a system restoration plan.

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

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

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

For Use by NERC Only

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

Version History

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

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NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standard Authorization Request (SAR)

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

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

Requested information			
SAR Title:	~~Inclusion~~ Accounting for~~of~~ DER in Blackstart Plans – EOP-005		
Date Submitted:	MM/DD/2022		
SAR Requester			
Name:	Shayan Rizvi, NPCC (NERC SPIDERWG Chair) John Schmall , ERCOT (NERC SPIDERWG Vice-Chair)		
Organization:	The ~~NREC~~ NERC System Planning Impacts of DER Working Group (SPIDERWG)		
Telephone:	Shayan – 212-840-1070 John – 512-248-4243	Email:	Shayan – srizvi@nppc.org John – john.schmall@ercot.com
SAR Type (Check as many as apply)			
☐ New Standard ☒ Revision to Existing Standard ☐ Add, Modify or Retire a Glossary Term ☐ Withdraw/retire an Existing Standard		☐ Imminent Action/ Confidential Issue (SPM Section 10) ☐ Variance development or revision ☐ Other (Please specify)	
Justification for this proposed standard development project (Check all that apply to help NERC prioritize development)			
☐ Regulatory Initiation ☐ Emerging Risk (Reliability Issues Steering Committee) Identified ☐ Reliability Standard Development Plan		☒ NERC Standing Committee Identified ☐ Enhanced Periodic Review Initiated ☒ Industry Stakeholder Identified	
Industry Need (What Bulk Electric System (BES) reliability benefit does the proposed project provide?):			
In order to "ensure plans, Facilities, and personnel are prepared to enable System restoration from Blackstart Resources to ensure reliability is maintained during restoration"[1], clarity is needed for how to account for DER in EOP-005. If DER[2] are ~~considered~~ chosen as "Blackstart Resources" and part of a TOP's system restoration plan, then there is a need to study the Cranking Path~~switching path~~[3] from the ~~DER~~ new Blackstart ~~unit~~Resources connected through the distribution system ~~to the BPS system restoration plan objective~~in order to accomplish the TOP's system restoration objective~~ensure reliability during these~~			

[1] Taken from EOP-005-3. Available: https://www.nerc.com/pa/Stand/Reliability%20Standards/EOP-005-3.pdf
[2] SPIDERWG uses the definition of DER as "any Source of Electric Power located on the Distribution System." Taken from: https://www.nerc.com/comm/RSTC/SPIDERWG/SPIDERWG%20Terms%20and%20Definitions%20Working%20Document.pdf. Project 2022-02 currently is scoped to define DER.
[3] Sometimes this is called a "switching path~~cranking path~~".

Requested information
~~time periods~~. Even if DER are ~~not part of the~~not chosen as a “Blackstart Resource~~s~~”, accounting for DER automatic response to energization of distribution equipment is necessary to ensure the reliable operation of the bulk system during ~~S~~system restoration activities. Particularly important is the careful study of automatic response when restoring lost service to transmission to distribution interfaces (T-D Interfaces) as they can contain automatic response of motor load, electronic load, and DERs.
Purpose or Goal (How does this proposed project provide the reliability-related benefit described above?):
The purpose of the SAR is to revise the ~~EOP-005 to include DER data in Requirements R1.4, R6, R7, and R11ensure clarity for how DER impact a~~ TOP’s Operating Process in ~~the~~ EOP-005 ~~requirements~~such that TOPs consider the automatic response of DERs in addition to Load during system restoration~~– andin addition to scoped sections to ensure additional factors needed for DER to be included as a Blackstart Resource or to disallow DERs from designation as Blackstart Resources~~. DERs are inherently on the d~~D~~istribution p~~P~~rovider’s system[4] and as such may ~~require additional information~~impact the variability seen during system restoration ~~about such distribution system[5] in order to study and produce an effective restoration planin comparison to bulk connected devices~~.[6] This Project aims to ~~first bring clarity to~~alter the ~~required~~requirements for TOP Operating ~~Procedures~~Processes ~~and secondarily provide clarity on DER-specific nuances~~to account for known DER impacts ~~associated~~during ~~with being included in Blackstart Plans~~system restoration and to require the SDT to determine appropriate standard revisions such that~~to require~~ the TOP ~~to consider~~considers DER automatic response during system restoration~~-~~. ~~to allow for the TOP to account for DER in their system restoration plan as well as account for DER in the Blackstart Resource Agreements with the TOP’s respective GOPs.~~
Project Scope (Define the parameters of the proposed project):
Modify EOP-005 to account for the following: - ~~Update the EOP-005 requirements to reflect additional required~~ distribution system ~~information[7] and telemetry needs for~~ DERs ~~for when~~ if ~~a DER is selected as a Blackstart Resource~~when ~~Blackstart Resources are connected through a distribution system to the remainder of the Bulk~~

[4] Note that not all distribution systems contain a Distribution Provider Registered Entity.

~~[5] Note that in the Project Scope section the SDT is given the scope to determine if such additional information and coordination is too burdensome or a reliability risk and as suchto disallows DER from being Blackstart Resources in their deliberations.~~

[6] In contrast, the Blackstart ~~units~~Resources connected through transmission or sub-transmission already ha~~s~~ve a known topology and model representation due to other NERC Reliability Standards.

~~[7] In the SPIDERWG white paper *NERC Reliability Standards Review,* (https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Whitepaper_SPIDERWG_Standards_Review.pdf) it was discussed that the switching path tofrom the DERsBlackstart Resources connected to the distribution system (i.e., those DERs that provide Blackstart and are no longer DERs) andto remainder of the BPSBES would be required to be fully understood as part of DERs accepted in blackstart plans. The SDT should consider the technology and equipment standards for those resources connected to the distribution system in this evaluation consider starting with those parameters as well as the required data gathering on such a system to ensure proper collection mechanisms exist for the TOP..~~

Commented [A1]: Needs to be revised. Cranking path is not a BES only. As such, the clarity edits and nuance the scope section in 1) are not needed should the cranking path be subject to EOP-005.

The effectiveness of having DER as a Blackstart may be state dependent, cautioning detail in standard.

Commented [A2]: Company who owns a Cranking Path or a portion of a Cranking Path needs to be a registered Entity (DP, GO, or TO) – Brad Woods

Commented [A3R2]: RTOS - is this always the case?

Commented [A4]: facilities that may have previously been considered DER but are Blackstart resources in scope of the NERC Glossary, ROP per Inclusion I3.

Requested information
~~Electric System (BES). The SDT should particularly consider that while DER under a Blackstart Resource Agreement are BES Blackstart Resources connected through the distribution system have data and telemetry requirements, the path to connect such units the DER to the remainder of the bulk system is a distribution system that may not have widespread telemetry or switching controlmay not be BES[8] and ensure the additional information is included in the EOP-005 requirements.~~ ~~1)~~ ~~Blackstart units connected through the distribution system.~~ ~~2)~~1) Require the TOP to ~~capture~~ consider the automatic response of DERs (in addition to the Load response) when performing load pickup[9] of distribution equipment. The SDT ~~in particular should~~should ~~particularly~~ ensure the Operating Processes in R1.7 and R1.8 include the automatic response of such Load and generation assets when energizing a T-D Interface and for the duration of the system restoration plan. 2) Require the TOP to specify model requirements and distribute those specifications to appropriate entities in R6 ~~DP to provide~~for DER data ~~to the TOP~~ to ~~perform the study in~~perform the ~~-~~scope ~~i~~Item ~~2~~1. The SDT can look at TOP-003 specifications to ensure clarity for DER data needed to perform scope item ~~2~~1 rather than adding requirements in EOP-005 for this scope item. 3) ~~Or, a~~As an alternative path to scope items ~~2~~1 and ~~3~~2, revise the EOP-005 requirements to ~~requirein lieu of datathe data and study require~~allow a pathway such that the DP ~~to isolate~~isolates sufficient[10] aggregate DERs during system restoration until directed and allowed to ~~interconnect~~reconnect ~~it~~ by the appropriate entity. The SDT should consider requirements to have the DP declare their pathway to the appropriate entities and require the TOP to include the DP's declared path in their Operating Processes to develop and implement their restoration plan. ~~Require the TOP to establish test established telemetry and communication requirements as part of their studies to ensure the success of their System restoration plans.~~ ~~4)~~

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[8] ~~In particular, the SDT should look at I3 as it pertains to resources connected to the distribution system in this evaluation. The SDT should consider potentially excluding such resourcesDERs from Blackstart Resource plans based on their findings.~~

[9] The SPIDERWG identifies that the automatic response of Load is well understood during these studies, and identifies that DER automatic response ~~is similar~~would be needed akin to the understanding of load ~~in nature~~ per the SPIDERWG white paper. The duration of system restoration activities can be lengthy (i.e., hours-long) and the automatic responses of DERs may change during this time.

[10] Sufficient in this context is the amount required for the success of the TOP's system restoration plan rather than a standard, uniform amount for all plans.

Requested information

Detailed Description (Describe the proposed deliverable(s) with sufficient detail for a drafting team to execute the project. If you propose a new or substantially revised Reliability Standard or definition, provide: (1) a technical justification[11] which includes a discussion of the reliability-related benefits of developing a new or revised Reliability Standard or definition, and (2) a technical foundation document (*e.g.,* research paper) to guide development of the Standard or definition):

Under the current applicability section of EOP-005-3, the requirements for resource integration into ~~the~~ system restoration plans~~plan,~~ in most cases~~,~~ fall to the TOP~~ or the TO~~. ~~Typically~~Typically, these entities receive only load data from the DP and~~,~~ not the operating characteristics of underlying resource control systems; however, there are instances where the underlying controls are not known for DERs and Load control. Primarily, the concern is that the automatic return-to-service characteristics of the underlying resource control systems are not well known to the TOP for their effect during system restoration. The TOP ~~or TO are~~is therefore frequently unable to confidently predict resource response to system conditions. TOPs have the ability to specify data gathering for their Operating Processes, yet some information ~~that~~ may be needed from DERs and Load ~~lies~~and is handled by~~ to~~ the Distribution Provider. In some instances, there is no Distribution Provider Registered Entity for data sharing to submit the known automatic response of DERs or Load in their system. The SDT is scoped to ensure that TOPs have the necessary data ~~in order to~~to accomplish their Operating Processes. Historical events[12] have shown that the lack of data and modeling from distribution systems has resulted in potential for inaccurate assessments of transmission system performance and contingency responses. (Scope Item 2)~~If DERs are to be accepted to participate as blackstart resources in a system restoration plan and thus become Blackstart unitsResources connected through a distribution system in a system restoration plan, there will be a need to study the switching path from the DER to the BPS system restoration plan objective that is being supported. As such, standard revisions should provide flexibility to ensure reliability is maintained during system restoration should DERs be accepted as blackstart resourceswith Blackstart unitsResources connected through distribution systems to participate in restoration plans.~~

~~Regardless of whether DERs are blackstart resources,~~On energization DERs will respond to ~~energization of distribution substations in load pickupsystem restoration~~the recovered voltage, potentially creating adverse conditions during system restoration if not accounted for in the TOP system restoration plan. Without access to modeling data and operating characteristics for modeling the DERs in these instances, the studies, such as steady-state or dynamic simulations, required to build a system restoration plan under EOP-005-3 would provide only an ~~weak~~inaccurate estimate of the distribution system response to an event~~, such as in steady-state and dynamic simulations~~. Currently, the Requirement text for EOP-005 indicates that the TOP is responsible to contain Operating Processes to restore, among other things, “Load

[11] 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.

[12] In particular, the *Lessons Learned: DER Performance During a Disturbance* (available here: https://www.nerc.com/pa/rrm/ea/Lessons%20Learned%20Document%20Library/LL20220401_DER_Performance_During_a_Disturbance.pdf) highlighting the potential for the devices to react on system energization and the Palmdale Roost and Angeles Forest disturbances (available here: https://www.nerc.com/pa/rrm/ea/April_May_2018_Fault_Induced_Solar_PV_Resource_Int/April_May_2018_Solar_PV_Disturbance_Report.pdf)

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needed to stabilize generation and frequency, and provide voltage control." In this connection, should DER exist (and operate per its automatic response to re-energization) and not be studied as part of the Operating Processes, there exists uncertainty in the ability for the degraded system to stabilize. Further, the proposed~~as~~ DER ~~per the~~ definition from~~of~~ Project 2022-02 and~~or~~ SPIDERWG are technology agnostic. This means that~~,~~ the automatic response may differ between TOPs depending on the composition of the Load and DER when re-energizing a bus. The alternative is to ensure that DPs disconnect DERs, where possible, ~~-~~during system restoration and do so until an appropriate entity directs the DP to reconnect the DER as part of the system restoration or when returning to a normal operating state. ~~The ability to obtain this distribution system or DER information in a vertically integrated environment may not present challenges, but Regional Trade Transmission Organizations (RTOs) /Independent System Operators (ISO)/TOP's past experience has shown difficulty in obtaining new technology or resource mix data and operating characteristics when not enforceable under a standard in market environments. Integration of demand response (DR) in the forward capacity market is an example. DR resides on the distribution system and causes data concerns for the RTOegional Trade Organization/ISO or /TOP around potential real-time dispatch of DR on the wrong side of a constraint. The potential data gathering challenges described here bring into question the accuracy of the studies. Historical events[13] have shown that the lack of data and modeling from distribution systems has resulted in potential for inaccurate assessments of transmission system performance and contingency responses.~~ ~~Some contributing factors to events were a lack of visibility and understanding of the distribution system resource controls responses to transmission system contingencies. With the integrationAny integration of DER as a blackstart resource in a system restoration plan makes it critical to evaluate the transmission system contingency response prior to accepting the resource into the system restoration plan. The SDT should carefully weigh the current lack of visibility and understanding of the distribution system interactions in system restoration in their discussions for additional data requirements should DER be a Blackstart Resource in item 1) of the Project Scope. in~~ Further, ~~U~~understanding ~~the~~ a resource's expected response is particularly important in the early stages of restoration when the transmission system is weak and frequency and voltage control can be challenging for system operations with frequency and voltage excursions beyond the normal range. ~~This is true regardless of if a DER is identified as a "Blackstart Resource" or if the DERaggregate DER is reacting to load energization.~~ Current equipment standards like IEEE 1547-2018 include anti-island and other ride-through ~~settings~~capability that can impact their automatic re-energization to the grid. As IEEE 1547 allows a range of settings, the specific settings chosen ~~information highly~~ dictate the automatic re-energization response of DER during load pickup. ~~Coordination~~ Clear identification of roles among the DP, TOP, and

~~[13] In particular, the *Lessons Learned: DER Performance During a Disturbance* (available here: https://www.nerc.com/pa/rrm/ea/Lessons%20Learned%20Document%20Library/LL20220401_DER_Performance_During_a_Disturbance.pdf) highlighting the potential for the devices to react on system energization and the Palmdale Roost and Angeles Forest disturbances (available here: https://www.nerc.com/pa/rrm/ea/April_May_2018_Fault_Induced_Solar_PV_Resource_Int/April_May_2018_Solar_PV_Disturbance_Report.pdf)~~

Commented [A5]: See comment above related to Cranking Path. This scope and section goes away if crossing distribution system.

Requested information
the GOP of Blackstart Resources in a TOP's system restoration plan is necessary to properly ~~study~~ ensure frequency and voltage ~~response~~ excursions and automatic equipment response (including automatic response of DERs and Load) seen during the early stages of system restoration is well understood~~are stable~~ and ~~lead~~actions taken in a system restoration plan are~~to an~~ effective~~ Operating Plan for system restoration~~. ~~These findings are documented in the SPIDERWG white paper *NERC Reliability Standards Review*[14].~~
Cost Impact Assessment, if known (Provide a paragraph describing the potential cost impacts associated with the proposed project):
Material cost impacts are unknown. Clarity enhancements are not anticipated to have a significant cost and the extra time spent on studying the C~~c~~ranking P~~p~~ath may have an ~~needed~~ extra cost to evaluate and develop a reliability-focused C~~c~~ranking P~~p~~ath. ~~In addition, should additional telemetry and monitoring of distribution equipment status be required (as for DER selected as Blackstart), such infrastructure is a cost burden to entities.~~ It should be noted that blackstart is a topic whose cost to benefit calculations are fairly skewed towards spending to ensure reliability~~ in this regard~~.
Please describe any unique characteristics of the BES facilities that may be impacted by this proposed standard development project (*e.g.*, Dispersed Generation Resources):
None anticipated. However, if a DER is selected as a Blackstart Resource, they become a BES F~~f~~acility~~ in effect~~ per Inclusion 3 to deliver the power as part of a C~~c~~ranking P~~p~~ath and are no longer non-BES equipment. However, such a Blackstart Resource is connected through a distribution system, which is inherently non-BES.
To assist the NERC Standards Committee in appointing a drafting team with the appropriate members, please indicate to which Functional Entities the proposed standard(s) should apply (*e.g.*, Transmission Operator, Reliability Coordinator, etc. See the most recent version of the NERC Functional Model for definitions):
Distribution Provider (DP), Transmission Operator (TOP), Transmission Owner (TO), and Generation Operator (GOP).
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.

~~[14] Available here: https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Whitepaper_SPIDERWG_Standards_Review.pdf~~

[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
This SAR has been submitted through the RSTC and has been vetted by the SPIDERWG membership. The SPIDERWG membership includes BAs, RCs, TOs, TPs, TOPs, PCs, and DPs. The SPIDERWG documented this work in the SPIDERWG white paper *NERC Reliability Standards Review,*[16] where ~~T~~the SPIDERWG recommended this standard be revised~~ in *White Paper: SPIDERWG NERC Reliability Standards Review*~~. The SAR was also circulated to the Real-Time Operating Subcommittee and the Event Analysis Subcommittee and their comments and edits are incorporated in language.
Are there any related standards or SARs that should be assessed for impact as a result of this proposed project? If so, which standard(s) or project number(s)?
There are no other standards projects or anticipated SARs that will address the study of DER in blackstart restoration plans~~ or account for the nuances of a DER being selected for a Blackstart Resource~~. However, Project 2022-02 currently has scoped the definition of DER in its project and this SAR is impacted by the exact definition. In addition, TOP-003 is an impacted standard for data requirements for its analysis, including the studies performed under EOP-005 R6 if using the same data.
Are there alternatives (e.g., guidelines, white paper, alerts, etc.) that have been considered or could meet the objectives? If so, please list the alternatives.
The SPIDERWG considered Standards revisions alongside compliance implementation guidance and reliability guidelines. The SPIDERWG identified that specific standards revisions are necessary to ensure the reliable operation of the system during system restoration. A reliability guideline is useful in identifying and recommending best practices for sharing aggregate DER information[17] (inclusive of expected dispatch and updated capacity information at the bulk system bus) ~~and~~as well as best practices highlighting a procedure using this information ~~for~~in the development of a system restoration plan. The SPIDERWG looked at compliance implementation guidance,[18] and found that ~~presenting~~ compliance implementation guidance was not suited to address the identified reliability gap. ~~These objectives~~A reliability guideline or compliance implementation guidance could not~~ do, but not~~ ~~in~~ addressing~~ing~~ the ~~critical~~ reliability need ~~to~~ for the TOP to capture DER and Load automatic response to ~~actions~~ load pickup actions taken in a system restoration plan such that the plan is successful. Thus, the SPIDERWG recommended Standards revisions due to the limitation of reliability guidelines or compliance implementation guidance to address the identified gap. ~~The SPIDERWG in theire white paper recommended a reliability guideline to cover the data sharing between the TOP and DP for system restoration plans. This is in addition to other operational data sharing guidelines listed in the paper as a procedure to share information but will be insufficient to address the process clarity requirements needed to reliably capture the energization of a T-D Interface during system restoration. This SAR and SPIDERWG also note that per inclusion 3, once a DER is chosen as a Blackstart~~

[16] Available here: https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Whitepaper_SPIDERWG_Standards_Review.pdf
[17] The SPIDERWG in their white paper recommended a reliability guideline to cover the data sharing between the TOP and DP for system restoration plans. This is in addition to other operational data sharing guidelines listed in the paper as a procedure to share information.
[18] Compliance implementation guidance information can be found here: https://www.nerc.com/pa/comp/guidance/Pages/default.aspx.

Commented [A6]: Walk through the I3 discussion/review here at a high level. Gives us credibility on the outcome of scoped language here.

Commented [A7]: Less focus directly on DER. More focus on objective of the TOP here.

RG should be covering the hows

Standards cover the reliability objectives. (whats)

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Requested information
~~Resource, then it no longer is a DER and has BES obligations. That scenario is not identified by SPIDERWG to need guidance.~~ To be clear, the reliability gap this SAR is scoped to address is not in how the data sharing or procedures are performed but that there is ambiguity on the treatment of a T-D interface such that automatic response of DERs and ~~L~~load are not accounted for in a system restoration plan.

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

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

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

For Use by NERC Only

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

Version History

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

SAR	Inclusion of DER in Blackstart Plans – EOP-005
Instructions	**Please use this form to submit comments on the SAR. Comments must be submitted within the review period below to NERC (John.Skeath@nerc.net) with the words "SAR Inclusion of DER in Blackstart Plans – EOP-005" in the subject line. Only comments submitted in this Microsoft Excel format will be accepted. Both general and specific comments should be provided within this form. Red-line document changes, PDF versions of this document, or email comments will NOT be accepted.** Comments may be submitted by individuals or organizations. Please provide the requested information in Row 6. If comments are submitted on behalf of multiple organizations, list all organizations in Row 6. Please provide the Industry Segment and Region (if applicable) in Rows 7 and 8 and provide the requested contact information in Rows 9 and 10. If you have any questions regarding this process, please contact John Skeath (John.Skeath@nerc.net)
Review Period	Jun 15, 2023 – July 15, 2023

Organization(s)	Page #	Line / Paragraph	Comment	Proposed Change	NERC Response
Advanced Energy United, David Lemmons submitter			Advanced Energy United is a national association of businesses that are making the energy we use secure, clean and affordable. Advanced Energy United is the only industry association in the United States that represents the full range of advanced energy technologies and services, both grid-scale and distributed. Advanced energy includes energy efficiency, demand response, energy storage, wind, solar, hydro, nuclear, electric vehicles, and more. The comments expressed in this filing represent the position of Advanced Energy United but may not represent the views of any particular member. In general, Advanced Energy United does not support this SAR. As written, the current standard addresses all areas needing to be addressed without reference to the technology/primary driver of the Blackstart Resources. If modifications to the standard are needed to address DER, similar modifications must be made to address the use of any technology, whether Gas, Diesel, IBR or DER resource as the TOP's Blackstart Resource.	Rather than address the concerns raised in this SAR related to modeling information only for this small subset of data needed for studies, it is recommended that a broader approach be used to address the data needs of the BA, TOP, RC and any other registered entity all at once rather than having these slow, detailed discussions over and over. Otherwise, the proposed changes to EOP-005 related to DERs will also raise the need to address similar issues for all other Blackstart Resources. Without addressing all resources, modifications to the standard will likely cause more confusion. As an example, if specifics are added to Requirement R6 related to DERs, does that mean a TOP that uses a diesel unit does not need to model DER impacts to the restoration plan? We fail to see how the Blackstart Resource used impacts the need to accurately model DER impacts when performing load pickup. It is also not clear from this SAR how the issue of appropriately modeling DER impacts during load restoration is not already required. If they are not part of the study the TOP is very likely to not be able to implement the plan successfully.	Thank you for your comment. Revised project scope to inlude an alternative to data specification in R6 of EOP-005. Further clarified the type of information and analysis throughout the SAR being on the TOP Operating plan rather than on Blackstart Resource used in system restoration.

Organization(s)	Page #	Line / Paragraph	Comment	Proposed Change	NERC Response
Advanced Energy United, David Lemmons submitter	1	12	While we agree with the intent of the SAR, we do not see how the need to study the switching path differs between technologies currently in use and DERs. As currently written, the standard requires these identified issues be part of the TOP's plan regardless of technology used as the Blackstart Resource. We believe this is appropriate and sufficient.		Thank you for your comment. Edits added to the detailed scope section as well as the Project Scope section. Text also added to clarify that DER are not limited in technology type per SPIDERWG or Project 2022-02 definition.
Advanced Energy United, David Lemmons submitter	2	14	The identified Requirements (R1.4, R6 and R7) require the TOP to account for the use of any resource as a Blackstart Resource. In these identified requirements, adding specific requirements for DER wil also necessitate adding specifics for any other technology. As written, the standard requires a TOP to have a plan that works. We believe this is appropriate and sufficient. Using a DER as a Blackstart Resource in no way changes the requirements listed.		Thank you for your comment. Updated Project scope section based on this comment.
Advanced Energy United, David Lemmons submitter	2	18	We agree with the data concerns raised in this section. However, it is expected that these issues impact more study areas than Blackstart. Rather than developing extremely piecemeal standards, a more complete structure should be used. This will eleminate multiple efforts to essentially make simliar changes multiple times across the NERC standards.		Thank you for your comment. Added link to Project 2022-02 and to TOP-003 that houses other data requirements to related standards or SARs based on this and other comments. Further enhanced scope section for SDT to consider TOP-003 as part of meeting the SAR's scope objectives.
Advanced Energy United, David Lemmons submitter	4	21	As a point of clarification, under Inclusion I3, if a DER is the Blackstart Resource, that DER becomes subject to all NERC Standards currently in effect for GOs and GOPs. Therefore, the data gathering concern related to DERs providing Blackstart service should be mostly addressed if a DER is providing the service.		Thank you for your comment. The SAR's scope has been removed related to the comment as part of this and other comments.
Georgia Transmission Corporation	N/A	N/A	GTC is of the opinion that a reliability guideline should be created on this topic prior to the submission of a SAR that will give industry opportunity to better understand and agree to the issue being presented in the SAR and to evaluate/modify current processes prior to a reliability standard being modified. The referenced whitepaper actually recommends a reliability guideline.	The SAR should be rescinded and efforts should be focused on the development of a Reliability Guideline to identify where industry guidance is needed.	Thank you for your comment. Additional clarifying text on the differences in scope between the proposed reliabiltiy guidleine and the standard revisions from the white paper added to the alternatives section.

Organization(s)	Page #	Line / Paragraph	Comment	Proposed Change	NERC Response
Georgia Transmission Corporation	1	12	The SAR states that clarity is needed to account for DER as a Blackstart Resource. If a DER resource is identified as a Blackstart Resource, it should fall under the current requirements of EOP-005-3.	Specify what clarity is needed as well as the gaps for EOP-005-3 for identification of Blackstart Resources.	Thank you for your comment. The SAR's scope has been removed related to the comment as part of this and other comments.
Georgia Transmission Corporation	2	14	Additional information is needed on what information is needed by the TOP to account for DER in a blackstart plan. The current requirements in EOP-005-3 are general enough to specify the intent in developing a blackstart plan. There is no evidence presented in the SAR to suggest that TOP's do not have the appropriate information to study DER as part of their blackstart plan should a DER resource be identified as a Blackstart Resource.	Additional information is needed on what information is needed by the TOP to account for DER in a blackstart plan.	Thank you for your comment. The SAR's scope has been revised related to the comment as part of this and other comments.
Georgia Transmission Corporation	2	18	Historical events have shown that the lack of data and modeling from distribution systems has resulted in inaccurate assessments of transmission system performance and contingency responses.	Please identify and provide links to the referenced events that justify the need to modify EOP-005-3.	Thank you for your comment. Text changes altered to cited text and added links to sources.
Georgia Transmission Corporation	3	19	If telemetry and communications are needed to DER resources, then this cost is significant.	Update cost impact to reflect typical cost to add telemetry and communications to a DER Resource.	Thank you for your comment. Cost Impact Assessment updated to reflect comment in additon to Project Scope.
Georgia Transmission Corporation	4	29	The SAR discusses that a Reliability Guideline can provide best practices but fails to identify why a Reliability Guideline could not be used to capture DER response to actions in a system restoration plan.	The section should be revised to clarify why a Reliability Guideline could not be used to capture DER response to actions in a system restoration plan.	Thank you for your comment. Updated alternatives section with clarity on the separation of SPIDERWG's recommended guideline versus the SAR.
NAGF			The NAGF does not support this SAR. There is not enough information currently available on how DER resources operate in Blackstart scenarios. Furthermore, it is unclear as to the capability of DER resources to provide Blackstart services. This lack of information should delay the development of this SAR until such time that it becomes available.	Withdraw the SAR.	Thank you for your comment. The comment mentions that there is not enough information available for how a DER operates in Blackstart scenarios, which is the concern the SPIDERWG has that a TOP may have a plan that does not account for automatic equipment response in a system restoration scenario. No changes made to the SAR based on this comment.
NAGF			The NAGF notes that registered entities will need to gather information from non-registered DERs. These non-registered entities may have no statutory obligation to provide the information necessary for compliance to a NERC registered entity that may still be required to provide such information.	Revise the SARs language to remove requirements that may force registered entities to report on information that may only be obtainable from non-registered entities that may have no obligation or ability to provide the needed information.	Thank you for your comment. Clarity on data gathering mechanisms the TOP has in TOP-003 were added to the SAR.

Organization(s)	Page #	Line / Paragraph	Comment	Proposed Change	NERC Response
Edison Electric Institute	N/A	N/A	General Comment: EEI appreciates the opportunity to provide comments on this draft SAR. While we support NERC efforts to be proactive in addressing emerging BES/BPS Reliability issues, we do not support this SAR at this time. While there may be a small number of utilities, due to the rapid expansion of DERs within their service territory, who are assessing how they might be able to utilize DERs for system restoration after a widespread loss of power that impacts the BES, this SAR is premature. These efforts to assess DERs for system restoration should provide valuable insights for the industry broadly and are best done at a grass roots level utilizing pilot projects to validate potential solutions. We also support efforts by National Laboratory and industry R&D organizations, such as EPRI, who are investigating DERs for Blackstart. However, until this necessary work is done, and such learnings are shared broadly with the industry, modifications to the Reliability Standards that promote unproven methods and processes within enforceable Reliability Standards are premature.	As stated in our general comments, EEI recognizes that a small number of utilities are at this time assessing how they might be able to utilize DERs for system restoration. We noted that those efforts remain small and under development. Such efforts are laudable and we hope will be a useful roadmap in the future for utilities broadly as the resource mix changes. While we support those efforts, such efforts are not yet proven or ready for integration into NERC Reliability Standards. For these reasons, we ask that this SAR not be approved.	Thank you for your comment. Project Scope and detailed description updated to incorporate this comment.
David Jacobson	1	5	NREC is mispelled	change to NERC	Change made as proposed
David Jacobson	2	12	Has any entity in North America proposed or is planning to consider DER as a "blackstart resource"? Most DERs that comply with IEEE-1547-2018 don't have the attributes necessary to be considered a black start resource as far as I'm aware. Most have anti-islanding protection that prevent micrograms from forming. Very little research work has been done to show that a stable microgrid can be a blackstart resource for the main grid.	Suggest that an industry survey be taken to determine the potential need for industry using DER as a blackstart resource.	Thank you for your comment. Current protection and automatic response of DERs is scoped to be considered by the SDT when forming standard language changes. Project scope clarified based on this comment.

Organization(s)	Page #	Line / Paragraph	Comment	Proposed Change	NERC Response
David Jacobson	2	12	The scope of the EOP-005 SAR also wants to account for the DER automatic response to energization of distribution equipment. Most DERs have anti-islanding protection and will be offline when the distribution feeder is energized and cold load is picked up. Once the voltage is healthy, the DER may autorestart. It's not clear what reliability issues modifications to EOP-005 will uncover. Loss of distribution feeders occur regularly and restoration of the feeder and DER is not known to cause reliability problems.	Perhaps a reliability guideline or other technical reference is needed first to demonstrate potential technical issues that might result to help justify the need for EOP-005 and to help a potential drafting team with future standard development language.	Thank you for your comment. Text added to reference 1547 equipment standards at play in the detailed description and their relationship to DER response.
Arizona Public Service - Marcus Bortman	n/a	n/a	AZPS agrees with EEI's comments no supporting this SAR at this time. The technical and regulatory challenges that need to be overcome prevent the addition of DER inclusion in Blackstart plans.		Thank you for your comment. See repsonse to EEI comments for this comment's response
ITC Holdings			General Comment: ITC agrees with EEI and NSRF's comments and rationale for recommending not moving forward with this SAR at this time.		Thank you for your comment. See response to EEI and NSRF comments for this comment's response
Minnesota Power			Minnesota Power supports all of MRO's NERC Standards Review Forum's (NSRF) comments.		Thank you for your comment. See response to NSRF's comments for this comment's response
Oncor Electric	2	1	DERs generally should not be considered blackstart resources. There may be limited exceptions in some operating areas where this is warranted. Those cases should be treated with significant scrutiny. Instead of requiring DER modeling characteristics, DER contribution by feeder, granular DER data and high levels of telemetry for small resources, as proposed in the EOP-005 SAR as well as in the MOD-032-2 standard, the SDT should consider making recommendations to require DERs to isolate from the grid in blackstart scenarios until directed to interconnect by the appropriate entity.		Thank you for your comment. Project scope section expanded to allow flexibility to the SDT to codify this comment.

Organization(s)	Page #	Line / Paragraph	Comment	Proposed Change	NERC Response
WEC Energy Group (Kane, Christine; Beilfuss, Matthew; Zellmer, Clarice; Boeshaar, David)			WEC Energy Group supports the comments submitted by EEI which state: "EEI appreciates the opportunity to provide comments on this draft SAR. While we support NERC efforts to be proactive in addressing emerging BES/BPS Reliability issues, we do not support this SAR at this time. While there may be a small number of utilities, due to the rapid expansion of DERs within their service territory, who are assessing how they might be able to utilize DERs for system restoration after a widespread loss of power that impacts the BES, this SAR is premature. These efforts to assess DERs for system restoration should provide valuable insights for the industry broadly and are best done at a grass roots level utilizing pilot projects to validate potential solutions. We also support efforts by National Laboratory and industry R&D organizations, such as EPRI, who are investigating DERs for Blackstart. However, until this necessary work is done, and such learnings are shared broadly with the industry, modifications to the Reliability Standards that promote unproven methods and processes within enforceable Reliability Standards are premature."		Thank you for your comment. See response to EEI comments for this comment's response.
Southern Company Services, Inc.	4	27	Southern believes that the proposed requirement in the EOP-005 SAR “to capture the automatic response of DER when performing load pickup of distribution equipment” is unnecessary. The existing standard [R6] already requires the TOP to verify that its restoration plan accomplishes its intended function (through steady state and dynamic simulations, if required). The current standard does not explicitly discuss any other aspects of loads or generation, and therefore any addition to the standard to add unique granularity for DERs should not be done.	Require the TOP to capture the automatic response of DER when performing load pickup of distribution equipment.	Thank you for your comment. Project Scope clarified based on this and other comments.

Organization(s)	Page #	Line / Paragraph	Comment	Proposed Change	NERC Response
Southern Company Services, Inc.	2	16	Southern feels that adding a requirement for entities to require DER Data to perform studies to capture the automatic response of DER when performing load pickup of distribution equipment" would create inconsistencies and is a duplication of other standards. The current EOP-005 standard does not explicitly require data to be provided from Generator Operators and Distribution Providers for other load and generation data that is needed for blackstart/restoration. Additionally, the TOP can get all data it needs through the current TOP-003 Data Specification standard and adding additional requirements for specifying data needs from other Registered Entities is needed.	Require the DP to provide DER data to the TOP to perform the study in Item 2.	Thank you for your comment. Changes made to Project Scope and related standards section based on this comment and similar comments.
Southern Company Services, Inc.	2	16	Southern believes that adding a requirement to establish telemetry and communications as part of their restoration studies to ensure the success of their System restoration plans" should only be limited to DERs designated as a blackstart resource	Require the TOP to establish telemetry and communication requirements as part of their studies to ensure the success of their System restoration plans.	Thank you for your comment. The SAR's scope has been removed related to the comment as part of this and other comments.

Organization(s)	Page #	Line / Paragraph	Comment	Proposed Change	NERC Response
Ann Carey-FirstEnergy	N/A	N/A	FirstEnergy supports EEI's comments, which state: EEI appreciates the opportunity to provide comments on this draft SAR. While we support NERC efforts to be proactive in addressing emerging BES/BPS Reliability issues, we do not support this SAR at this time. While there may be a small number of utilities, due to the rapid expansion of DERs within their service territory, who are assessing how they might be able to utilize DERs for system restoration after a widespread loss of power that impacts the BES, this SAR is premature. These efforts to assess DERs for system restoration should provide valuable insights for the industry broadly and are best done at a grass roots level utilizing pilot projects to validate potential solutions. We also support efforts by National Laboratory and industry R&D organizations, such as EPRI, who are investigating DERs for Blackstart. However, until this necessary work is done, and such learnings are shared broadly with the industry, modifications to the Reliability Standards that promote unproven methods and processes within enforceable Reliability Standards are premature.		Thank you for your comment. See response to EEI's comment for this comment's response
Evergy			Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI), MRO NSRF and NAGF for the draft EOP-005 SAR.		Thank you for your comment. See response to EEI's comment, NSRF's comments, and the NAGF's comments for this comments response.
Daniel Gacek on behalf of Exelon	General Comment		Exelon supports the use of DER within system restoration plans, the project however should be postponed until changes are made to the MOD-032 standard to clarify the aggregate DER data entities are required to maintain, and until the registation requirements for owners and operators of Inverter-Based Resources are determined.		Thank you for your comment. Added link to Project 2022-02 to related standards or SARs based on this and other comments.

Organization(s)	Page #	Line / Paragraph	Comment	Proposed Change	NERC Response
ISO/RTO Council Standards Review Committee (IRC SRC) (CAISO, ERCOT, IESO, ISO-NE, MISO, NYISO, PJM, and SPP)	All	All	Relying on distribution-level resources as Blackstart Resources would likely present a reliability risk due to the weakness of their ability to energize load or other Resources and the duration-limited nature of the output that some DERs can provide. The behavior of DERs in blackstart scenarios is best addressed through local rules rather than through NERC Reliability Standards. Consequently, if the SAR moves forward it should be revised to clarify that any resulting Reliability Standard revisions should not require that DERs be used as Blackstart Resources. Instead, any Reliability Standard revisions that result from the SAR should be limited to addressing the study of the behavior of DERs in a blackstart scenario and should recognize that the RC or BA should have the ultimate authority over whether and when DERs come online in a blackstart scenario.	Consider using an approach other than a Reliability Standard revision, such as a stakeholder working group or technical conference, to facilitate study and discussion of DER behavior in blackstart scenarios.	Thank you for your comment. A portion of the SAR's scope has been removed related to the comment as part of this and other comments. Further, the SAR's scope has expanded to cover delegation of authority to reconnect in the new scope item number 3.
ISO/RTO Council Standards Review Committee (IRC SRC) (CAISO, ERCOT, IESO, ISO-NE, MISO, NYISO, PJM, and SPP)	2	14	Relying on distribution-level resources as Blackstart Resources would likely present a reliability risk due to the weakness of their ability to energize load or other Resources and the duration-limited nature of the output that some DERs can provide. Consequently, if the SAR moves forward it should be revised to clarify that any resulting Reliability Standard revisions should not require that DERs be used as Blackstart Resources.	The purpose statement should be updated to require that any revisions to address DERs should be placed in new, DER-specific requirements rather than being placed in existing requirements that address Blackstart Resources.	Thank you for your comment. Project Scope and purpose sections revised based on this and other comments.
ISO/RTO Council Standards Review Committee (IRC SRC) (CAISO, ERCOT, IESO, ISO-NE, MISO, NYISO, PJM, and SPP)	2	16	Relying on distribution-level resources as Blackstart Resources would likely present a reliability risk due to the weakness of their ability to energize load or other Resources and the duration-limited nature of the output that some DERs can provide. Consequently, if the SAR moves forward it should be revised to clarify that any resulting Reliability Standard revisions should not require that DERs be used as Blackstart Resources.	Either delete bullet point 1), or revise it by replacing "when" with "if"	Thank you for your comment. Change made as proposed.
ISO/RTO Council Standards Review Committee (IRC SRC) (CAISO, ERCOT, IESO, ISO-NE, MISO, NYISO, PJM, and SPP)	2	18	The intended meaning of the term Regional Trade Organization is unclear.	Clarify the intended meaning of Regional Trade Organization or revise the term to Regional Transmission Organization.	Change made to Regional Transmission Organization as proposed.

Organization(s)	Page #	Line / Paragraph	Comment	Proposed Change	NERC Response
Southern Indiana Gas & Electric Company d/b/a CenterPoint Energy Indiana South (SIGE)	1	Line/Paragraph 12	DER Blackstart Resources must follow the same requirements as Blackstart Resources.		Thank you for your comment. Changes to Project Scope made based on this and other comments.
Southern Indiana Gas & Electric Company d/b/a CenterPoint Energy Indiana South (SIGE)	2	Line/Paragraph 18	The Blackstart plan should take into account the protections that the DPs have in place to prevent a distribution-level Resource from affecting the restoration plan. Blackstart restoration process requires a careful balance of load addition in order to stabilize the online units. At that point automatic DER energization would likely jeopardize the island. Therefore, it is more than likely that the DP would have to put protection in place to prevent automatic energization. EOP-005 should address this type of scenario and consider the inclusion of operating agreements between the DER, DP, and TOP to coordinate this effort.		Thank you for your comment. Changes made based on this and other comments to the Project Scope.
MRO NSRF	-	-	General Comment: MRO NSRF does not currently support this specific SAR, nor does it endorse the development of standards aimed at addressing the incorporation of DERs in Blackstart restoration plans at this time. This position is due to the limited availability of comprehensive information regarding the response(s) of DERs during blackstart scenarios. This lack of necessary information should delay the development of these standards until such time that it becomes available. Given the ongoing efforts being undertaken by various organizations to investigate the usage of DERs in Blackstart applications, MRO NSRF recommends that NERC waits for the distribution and industry-wide consideration of the findings from these endeavors before initiating the Standard development process.	Withdrawal of the SAR at this time. The MRO NSRF recommends a study be completed on DER in Blackstart restoration plans.	Thank you for your comment. Changes made to the Project Scope section based on this and other comments.

Organization(s)	Page #	Line / Paragraph	Comment	Proposed Change	NERC Response
MRO NSRF	-	-	General Comment: MRO NSRF does not support the development of standards that may result in a mandatory and enforceable reporting requirement applicable to a NERC registered entity for which some portion of the information that is necessary for compliance with the requirement must be obtained from non-registered entities. These non-registered entities may have no statutory obligation to provide the information necessary for compliance to a NERC registered entity that may still be required to provide such information.	Ensure that language with in SARs would not lead standard drafting teams to requirements that may force registered entities to report on information that may only be obtainable from non-registered entities that may have no obligation or ability to provide the needed information.	Thank you for your comment. Project Scope section updated based on this and other comments.
CenterPoint Energy Houston Electric, LLC (CEHE)	1	Line/Paragraph 12	DER Blackstart Resources must follow the same requirements as Blackstart Resources, or discuss what distribution equipment that DER would be able to energize during the Blackstart restoration.		Thank you for your comment. Changes to Project Scope made based on this and other comments.
CenterPoint Energy Houston Electric, LLC (CEHE)	2	Line/Paragraph 14	DER Blackstart Resources must follow the same requirements as Blackstart Resources. Additional clarification is needed as to the meaning of this sentence "account for DER in agreement with TOP's GOP."		Thank you for your comment. Purpose section updated and the phrase no longer exists in the updated SAR.
CenterPoint Energy Houston Electric, LLC (CEHE)	2	Line/Paragraph 16	DER Blackstart Resources must follow the same requirements as Blackstart Resources.		Thank you for your comment. Updated Project scope section based on this and other comments.

Organization(s)	Page #	Line / Paragraph	Comment	Proposed Change	NERC Response
CenterPoint Energy Houston Electric, LLC (CEHE)	2	Line/Paragraph 18	All Blackstart Resources should have the same requirements regardless of interconnection voltage level. DER Blackstart Resources must follow the same requirements as Blackstart Resources, or DER allowed to energize distribution equipment must have documented plans with the TOP and/or DP in order to protect the TOP's restoration plan. The Blackstart plan should take into account the protections that the DSPs have in place to prevent a distribution-level Resource from affecting the restoration plan. As is well known, the Blackstart restoration process requires a careful balance of load addition in order to stabilize the online units. At that point automatic DER energization would likely jeopardize the island. Therefore, it is more than likely that the DP would have to put protection in place to prevent automatic energization either by physical isolation via pole top switches or remote transfer trip. This scenario should be documented in the plan to ensure that the action is performed.		Thank you for your comment. Updates to Project Scope section made based on this and other comments.

Reliability Guideline: Recommended Practices for Performing EMT System Studies for Inverter-Based Resources

Action
Approve

Background
NERC EMT Modeling Task Force (EMTTF) has been developing the Reliability Guideline: Recommended Practices for Performing EMT System Studies for Inverter-Based Resources. This guideline is intended to equip transmission planning engineers and other industry engineers with the necessary knowledge to begin screening for and studying, when necessary, the impact of IBRs on the BPS. The primary goal of this guideline is to enable TPs and PCs to perform applicable system studies in EMT domain during interconnection study process and to perform high-fidelity event analysis. Utilization of the recommendations and best practices within this guideline should support TPs and PCs in effectively conducting high quality studies to identify and better mitigate emerging reliability risks. The guideline will also support EMT SAR Project 2022-04 EMT Modeling and will also serve as a foundation for future EMT modeling related activities of IRPS and EMTTF.

This draft guideline was created by a diverse team of EMTTF members with input from the IRPS throughout the process.

Summary
This guideline has been posted for the 45-day public comment and has been updated in response to the comments received during the public comment period. IRPS is seeking RSTC approval.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Reliability Guideline

Recommended Practices for Performing EMT System Studies for Inverter-Based Resources

December 2024

DRAFT

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 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 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 made with consideration of system design, configuration, and business practices.

Executive Summary

Accelerating changes in the BPS' resource mix, increasing penetrations of inverter-based resources (IBR) and their documented reliability challenges, and the added complexity of IBR controls and IBR plant configurations necessitate leveraging advanced electromagnetic transient (EMT) modeling and simulation tools to adequately assess reliability risks. These EMT models and simulations should utilize manufacturer-specific control logic and code in the form of equipment-specific models (ESM), allow for the modeling of communication delays and protocols, and have the ability to capture high-resolution study results not possible in other simulation domains.

The Inverter-Based Resource Performance Subcommittee (IRPS) previously published *Reliability Guideline: Electromagnetic Transient Modeling for BPS-Connected IBRs—Recommended Model Requirements and Verification Practices*, which provides foundational knowledge to facilitate effective system impact assessments of IBRs using highly accurate EMT models. This reliability guideline expands on the previous document and provides recommended EMT modeling practices for establishing screening criteria to determine if an EMT study is needed, study area selection, appropriate modeling of the study area and the surrounding network to balance the overall accuracy of the study result and the computational and human resource burden, and general best practices for selection of EMT studies.

The focus of this reliability guideline is within the generator interconnection studies process, primarily system impact studies, and not conventional EMT studies, such as insulation coordination. The goal is to equip transmission planning engineers and other industry engineers with the necessary knowledge to begin screening for and studying the impact of IBRs on the BPS with detailed equipment-specific EMT models within the EMT simulation domain.

Recommendations

This reliability guideline provides recommendations for Transmission Planners (TP), Planning Coordinators (PC), Generator Owners (GO), equipment manufacturers, and consultants for conducting EMT modeling and studies for interconnection of IBRs; NERC strongly encourages these entities to adopt all of the recommendations throughout this guideline and are summarized in **Table ES.1**.

Table ES.1: Recommendations and Applicability	
Recommendations	**Applicability**
Reiterating the Need for Resourcing: TPs and PCs should prepare for the growing need for EMT modeling and studies related to the reliable interconnection of IBRs in the near future by taking action now to develop their workforce. As the penetration of IBRs grows, the need for EMT studies to adequately ensure reliable operation of the BPS becomes more pressing. This may require upskilling existing staff as well as acquiring new talent and resources in this area. A robust understanding of the EMT simulation environment, IBR controls and behavior, and general power system analysis fundamentals is an important basis for conducting EMT analysis.	TPs and PCs
Modeling Data Quality and Consistency: TPs and PCs should enhance their modeling data management processes for improved quality and consistency between different modeling platforms, which helps streamline the development of corresponding EMT network models from the existing modeling data sources.	TPs and PCs
Screening for the Need for EMT Studies: TPs and PCs should develop, document, and maintain clear methods and criteria to determine when EMT studies are necessary in the interconnection study process. No single metric should rule *out* the EMT study need. While certain metrics have been known to be inadequate in predicting control instability and therefore determining the need for EMT studies, they can still be useful to "rule in" the need for EMT studies. For example, while high short-circuit current level alone should not rule out EMT study need, low short-circuit current level may be a trigger for conducting an EMT study. See **Chapter 1**.	TPs and PCs
EMT Study Area Selection: TPs and PCs should leverage the recommendations herein to develop, document, and maintain clear methods and criteria to ensure that the EMT study area is adequately "sized" such that correct system behavior and potential interactions between various dynamic devices can be captured. See **Chapter 2**.	TPs and PCs
Modeling of EMT Study Area and Rest of System: TPs and PCs should consider the recommended modeling methods herein for representing the study area and the rest of the system in EMT. See **Chapter 3**.	TPs and PCs
Consideration for Study Scenarios: TPs and PCs should consider the most critical contingencies and worst-case credible operating conditions where fewer grid-stabilizing characteristics, such as system strength, inertia, and damping, are available. See **Chapter 5**.	TPs and PCs
Cross-Platform System Model Benchmarking: TPs and PCs should establish modeling practices to ensure that EMT and positive-sequence system models are benchmarked against each other such that responses are consistent, considering modeling and simulation platform limitations. As the consistency of system models are dependent on the consistency of IBRs models, TPs and PCs should require GOs to provide properly benchmarked models as recommended in the Reliability Guideline: EMT Modeling for BPS-Connected IBRs – Recommended Model Requirements and Verification Practices and NERC Dynamic Modeling Recommendations. See **Chapter 4**.	TPs and PCs
Performing EMT Analysis: TPs and PCs should consider the analysis methods recommended herein when assessing dynamic system impact, resonances, and transmission system protection. TPs and PCs should also consider the quantitative post-processing methods recommended herein to narrow down the results to identify issues quickly. See **Chapter 6**.	TPs and PCs
Addressing the EMT Analysis Results: When addressing criteria violations/performance concerns (such as instability and ride-through issues) observed during the EMT analysis, any control tuning as part of mitigation should be performed by the original equipment manufacturer (OEM) or with direct permission/instruction from the OEM as other parties do not know the full implications of individual parameter changes and should not take responsibility for these changes. Control tuning done outside of the purview of the OEM should be considered investigative only. See **Chapter 6**.	TPs, PCs, and GOs

Chapter 1: When to Perform EMT Studies

Introduction

This guideline provides guidance on when and how to conduct select EMT studies, including how to scope and model the study area, the system external to the study area, and legacy IBR plants.

Although EMT modeling allows for highly accurate and detailed models, not all EMT models are inherently accurate. The accuracy and fidelity of a given EMT model depends on the model development process, the modeling requirements for which it was developed, and assumptions made by model developers. All models, both EMT and positive sequence phasor-domain (PSPD), have inherent limitations that should be understood by engineers carrying out modeling studies. Having thoroughly vetted models is a prerequisite to an accurate modeling study as the results of the study depend on the study inputs. The comprehensive model requirements and model quality verification practices recommended in the previous guideline[1] should be followed.

The following is a summary of this guideline's chapters:

- **Chapter 1** provides recommended considerations for when EMT studies should be conducted.
- **Chapter 2** covers how to scope an EMT study by selecting an appropriate study area to be modeled in detail.
- **Chapter 3** covers how to model the selected study area and the rest of the BPS external to the study area.
- **Chapter 4** touches on the importance of system model validation and recommendations to ensure a certain level of confidence in the base-case model before proceeding with dynamic studies.
- **Chapter 5** provides guidance on preparing study cases and consideration for contingencies to be studied.
- **Chapter 6** provides methodologies for three select types of EMT studies—dynamic system impact assessment, subsynchronous oscillation, and transmission system protection validation.
- **Chapter 7** expands on the previous guideline[1] with additional guidance on modeling legacy IBR plants.
- **Chapter 8** discusses how to accelerate EMT simulations.
- Additional materials on legacy plant modeling are covered in **Appendix A**.
- Additional examples and exploratory discussion on EMT analysis in operations are provided in **Appendix B** and **Appendix C**.

The flow chart below illustrates how contents in different chapters tie together in an EMT study process.

[1] Reliability Guideline: Electromagnetic Transient Modeling for BPS-Connected Inverter-Based Resources—Recommended Model Requirements and Verification Practices, March 2023

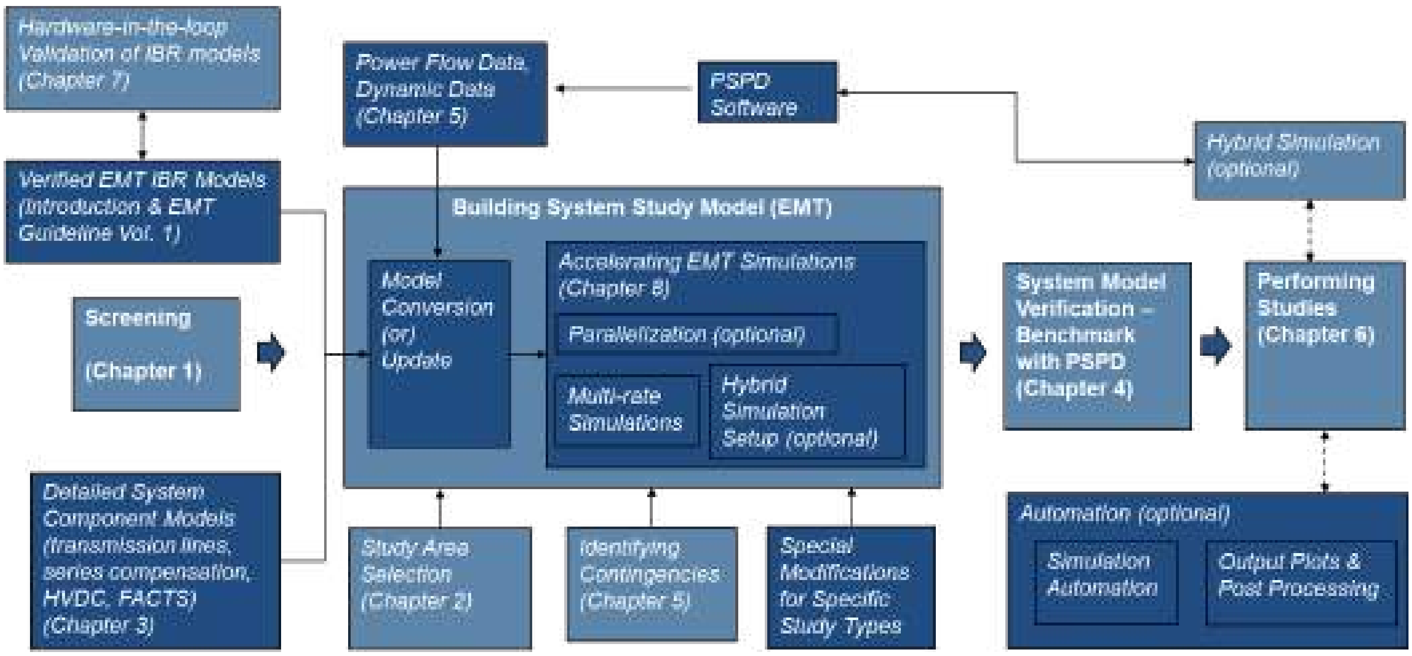


Figure 1.1: Overview of an EMT Study Process

This guideline provides recommended study practices for the following types of EMT studies:

- Dynamic system impact assessment related to interconnection of IBRs
- Subsynchronous oscillation
- Transmission protection system validation

Of interest to be evaluated in these studies are aspects related to control stability; interactions between IBRs and other dynamic devices such as FACTS, HVDC and synchronous condensers; and transmission protection system settings and schemes, such as remedial action schemes (RAS). While a detailed EMT study can provide valuable insight into these phenomena, the computational and human resource burden associated with carrying out such a study necessitates careful screening to identify the need for one. This chapter provides recommended considerations for deciding when to perform those EMT studies.

If any one of the situations detailed below applies, EMT studies should be considered.

Low System Strength

With the increasing penetration of IBRs and retirement of synchronous generators, specific areas of the BPS may experience reduced system strength (also known as voltage stiffness). Various steady-state system-strength metrics can approximate the strength of an area, mostly documented in the International Council on Large Electric Systems (CIGRE) WG B4.62 *Connection of Wind Farms to Weak AC Networks* technical brochure.[2],[3] These metrics are, however, based on the steady-state network topology and power flow across the network and do not consider the impact of the control system design and its parameterization. Nevertheless, a combination of these metrics can be

[2] https://www.e-cigre.org/publications/detail/671-connection-of-wind-farms-to-weak-ac-networks.html
[3] NERC White Paper "Short-Circuit Modeling and System Strength," February 2018

used to broadly determine whether an area of interest is "weak." There are also tools available that use those metrics to screen for weak areas.[4]

TP and PCs are encouraged to understand the strength of their footprint and adopt or develop system strength metrics and criteria to determine weak areas for which EMT studies may be required. Importantly, having a high level of system strength alone should not rule out the need for EMT studies without evaluating for the rest of the recommended considerations presented in this chapter. It is further important to note that the applicability of these system strength metrics may vary with specific footprints under consideration. Generalizing justifications across footprints is not recommended.

Stability Criteria

If transient stability studies performed in positive-sequence, phasor-domain root mean square (RMS) tools indicate any poor performance with respect to the stability criteria set forth by TPs and PCs, EMT studies can be considered to double-check those results[5]. If numerical instability is suspected in positive-sequence, phasor-domain RMS simulations, it is recommended that TPs and PCs first verify if the positive-sequence, phasor-domain RMS models have been constructed in a robust manner. The presence of numerical instability by itself is not necessarily indicative of the need for an EMT study. If numerical instability persists after the robustness and quality of the model are verified, it is recommended that the scenarios be further studied in EMT tools. It is important to ensure that all credible scenarios and contingencies are considered in positive-sequence, phasor-domain studies (e.g., minimum synchronous generation dispatch).

Small-signal stability can be assessed with analytical methods, such as either impedance scanning methods or Eigen value analysis and can provide insight into the possibility of control interactions, resonance, and/or instability in the small-signal realm. These analytical methods can help further refine the necessity for an EMT study. Analytical methods can also be used to evaluate the fault ride-through ability of IBRs based on known limits and gain insight into the maximum duration of fault that the IBR can withstand, which can also be compared with the operation time of protection within the area[6].

As positive-sequence models are an approximation and may not have sufficient details to represent all relevant dynamics of actual equipment, false stable or unstable results in positive-sequence stability studies are likely to be seen in some cases. For example, a Hawaiian island system performed stably in positive-sequence transient stability studies but showed instability in small-signal stability[7] and EMT studies. Therefore, TPs and PCs should consider adding some stability margins in their positive-sequence transient stability criteria to account for the lack of details in positive-sequence models. For example, if an area has 3% damping criteria based on positive-sequence simulations, then with decreasing system strength, increasing the threshold (screening criteria) to 5% based on positive-sequence simulations could indicate the need for an EMT simulation. This should not, however, imply that the mere presence of an EMT study automatically implies accuracy. If appropriate EMT models and simulation techniques are not used, EMT studies can show false results that can consume significant amounts of engineer time.

System Topology or Conditions with Stability Risks

TPs and PCs should consider the need for EMT studies in areas with any of the following characteristics:

- Pre-existing oscillation or oscillatory modes

[4] Example: EPRI's system strength assessment tool - https://www.epri.com/research/products/000000003002027116

[5] "Power System Dynamic Modelling and Analysis in Evolving Networks (CIGRE Green Book)", Editors: Babak Badrzadeh, Zia Emin, Springer, 2024

[6] S. Thakar, S. Konstantinopoulos, V. Verma, D. Ramasubramanian, M. Bello, J. Xu, W. Zhou, J. Mesbah, W. Zhou, and B. Bahrani (2024) Topic 2 – Analytical methods for determination of stable operation of IBRs in a future power system. CSIRO, Australia.

[7] Small-signal stability study was based on more detailed EMT models.

- Presence of the following devices nearby:[8]
  - Series-compensated lines
  - Flexible ac transmission system (FACTS) devices
  - HVdc lines
  - Other IBRs
- High IBR penetration level
- Presence of any specialized protection schemes, such as RASs
- Presence of transmission lines protected by distance relays and declining fault current levels
- Areas seeing a trend of decreasing system strength
  - TPs and PCs should monitor the system strength trend as it indirectly impacts the small- and large-signal stability of the system.
- Areas where there is a trend of increasing rate of change of frequency (RoCoF) or decreasing inertia
  - Increase in RoCoF due to decreasing system inertia could lead to delayed or non-operation of protective relays and jeopardize system integrity.

[8] See Chapter 3: Study Area

EMT Studies Following System Events

In addition to the system planning horizon, conducting an EMT study is also necessary during the operation time horizon, particularly following a system event. When an event occurs and the observed phenomena cannot be accurately replicated through simulation using a positive-sequence model (or if it significantly deviates from the behavior and performance results from the past EMT simulations), a new EMT study is needed. This is required to correct any potential errors in existing EMT models and verify the quality of the simulation base case and is an important feedback loop introduced between the reality and simulation study. By replicating the results of the event, the study ensures the accuracy of the simulation and lays the groundwork for validating proposed mitigations. This step is crucial to preventing the introduction of unintentional or unacceptable reliability risks to the BPS and requires coordination and cooperation among GOs, TOPs, RCs, PCs, TPs and other relevant stakeholders. It is important to acknowledge that replication of system events in simulation requires verified and validated models of all dynamic elements in the power system.

Chapter 2: How to Select Study Area to Be Modeled

It is not always practical or necessary to directly represent an entire interconnected power system (e.g., Eastern Interconnection wide database) in EMT tools. In EMT studies, a study area is a portion of the larger interconnected power system and the steady-state and/or dynamic contributions of the rest of the power system (external system) are represented as an equivalent (discussed in **Chapter 3**). Typically, only the equipment within the study area is represented explicitly. Some techniques, such as the use of hybrid simulation tools, allow the co-simulation of EMT tools and phasor-domain simulation tools simultaneously. However, even for these simulations, the study engineer needs to determine how much of the system needs to be modeled in the EMT domain. For studies intended to analyze the behavior, impact, or potential interaction between various IBRs, synchronous machines, and power electronic devices, it is important to ensure that the study area is adequately "sized" such that necessary system characteristics and potential interactions between various dynamic devices can be captured. This chapter will discuss the impacts of the timescale of power system dynamic phenomena on study area selection as well as methods for determining which dynamic devices should be included within a study area.

Study Area Selection

The goal of system modeling is to represent the associated equipment accurately for the phenomena of interest. As such, the system modeling techniques and simulation timestep should be selected according to the phenomena under evaluation, as illustrated in **Figure 2.1**.

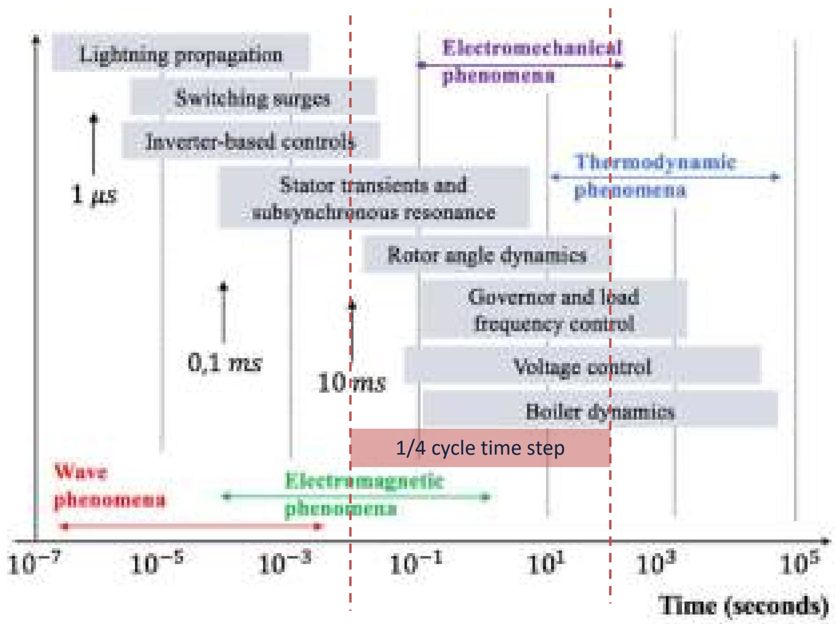


Figure 2.1: Timescales of Power System Phenomena ["Definition and Classification of Power System Stability–Revisited & Extended"; IEEE Transactions on Power Systems, July 2021]

The power system phenomena of primary interest for typical EMT simulations are as follows [Institute of Electrical and Electronics Engineers (IEEE) Std. C62.82.2-2022 and International Electrotechnical Commission (IEC) 60071-2 ED5]:

- **EMT System Impact Assessment Studies:** A Few Hz–2 kHz
  - This is the primary focus of this guideline. Phenomena of interest include evaluation of controls interactions, fault ride-through performance issues, and weak grid stability issues.

- Typically, the study area will be selected to provide adequate electromagnetic and electromechanical performance.

- **Temporary Overvoltage (TOV) Studies**: Up to 1 kHz
  - TOVs can be caused by fault initiation and clearing, grounding effectiveness, load rejection, resonance conditions, or system non-linearities.
  - The study area will be selected to provide adequate electromagnetic performance and, if necessary, electromechanical performance.
  - The modeling and analysis techniques discussed in this document are applicable to modeling for TOV studies.
- **Slow-Front Transients**: Up to 20 kHz
  - Slow-front transients are primarily caused by switching events, such as capacitor bank switching, transmission line switching, transformer switching, and fault initiation and clearing.
  - The study area will be selected to provide adequate electromagnetic performance and traveling wave behavior.
  - This is provided for information only. Study area selection for this phenomenon is outside the scope of this document.
- **Fast-Front Transients:** 10 kHz–1 MHz
  - Fast-front transients are primarily caused by high-frequency phenomena, such as lightning strikes.
  - The study area will be selected to provide adequate electromagnetic performance and traveling wave behavior.
  - This is provided for information only. Study area selection for this phenomenon is outside the scope of this document.

As the frequency of the phenomena under study increases, the size of the study area (e.g., electrical distance from the bus of interest) decreases and the level of modeling detail for equipment will increase. For example, when performing an EMT system impact assessment, it is acceptable to neglect the impedance of bus-work within a substation. However, for a fast-front transients study, the individual sections of bus-work down to the exact meter of bus-work length become important. Figure 2.2 illustrates study area size for different types of EMT studies. In this context, study area size represents the electrical impedance between the study bus and the boundary equivalents representing the system beyond the study area.

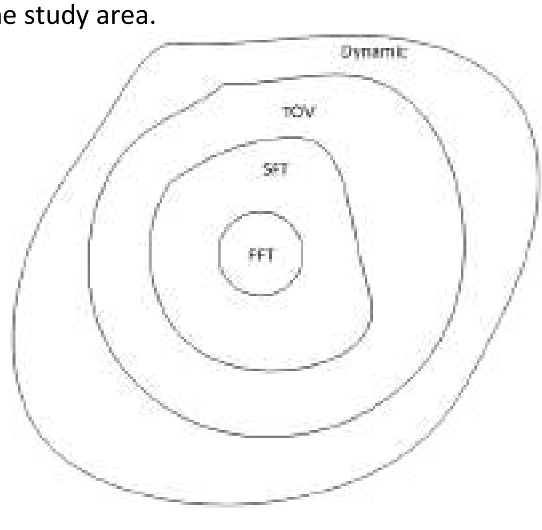


Figure 2.2: Study Area Size for Different Types of EMT Studies

For electromagnetic phenomena, because of the relatively high frequencies under study, the frequency-dependent nature of inductance ($X_L = 2\pi fL$) and capacitances ($X_C = 1/2\pi fC$) will dominate the relative impedance between nodes within a system. At higher frequencies (>10 kHz), the series inductance of the electrical system as well as frequency-dependent resistance from conductors due to skin effect will dominate and result in such transients becoming a more local phenomenon. When performing EMT studies for IBRs, it is necessary to ensure adequate system representation for the phenomena of interest at a given bus or between buses. The different methods to accomplish this will be discussed in this chapter. However, conceptually, the process of scoping the appropriate system area for EMT studies would involve quantifying the frequency-dependent impedance at a given bus within the power system considering progressively larger portion of the system. For example, calculate the harmonic impedance at a given bus for a system including the study bus and all buses within a given N number of buses from the study bus then iteratively increase the study area until further increases in the size of the modeled system negligibly impact the system frequency response.

Figure 2.3 provides an illustration of the determination of the size of the EMT study area. In **Figure 2.3**, the frequency-dependent impedance (Z) of three different system models is provided with the study area increasing in size by including all equipment within 6, 9, and 10 buses out from the study bus. There is a significant difference between the 6-bus out and 9-bus out models, especially around 800–1,100 Hz. However, the additional impact of going from a 9-bus out to a 10-bus out model is much smaller and perhaps negligible compared to the increased model size and solution time required for the wider model.

In performing this process, the study engineer must consider the following critical items:

- Throughout this discussion, the word “buses” has been used as a proxy to represent “electrical impedance.” Practically, when performing study area selection, the goal is to ensure that sufficient electrical impedance exists between the study bus or buses and the boundary equivalents representing the system outside of the study area. Improper study area selection can result in incorrect study conclusions, such as indication of false system resonance points or failure to identify system operating conditions of concern.
- **Figure 2.3** provides a very simplified study area selection process. In practice, the study engineer should be performing verification work to confirm that the boundary does not introduce inaccuracies within the frequency range of interest. The process could be iterative in nature.

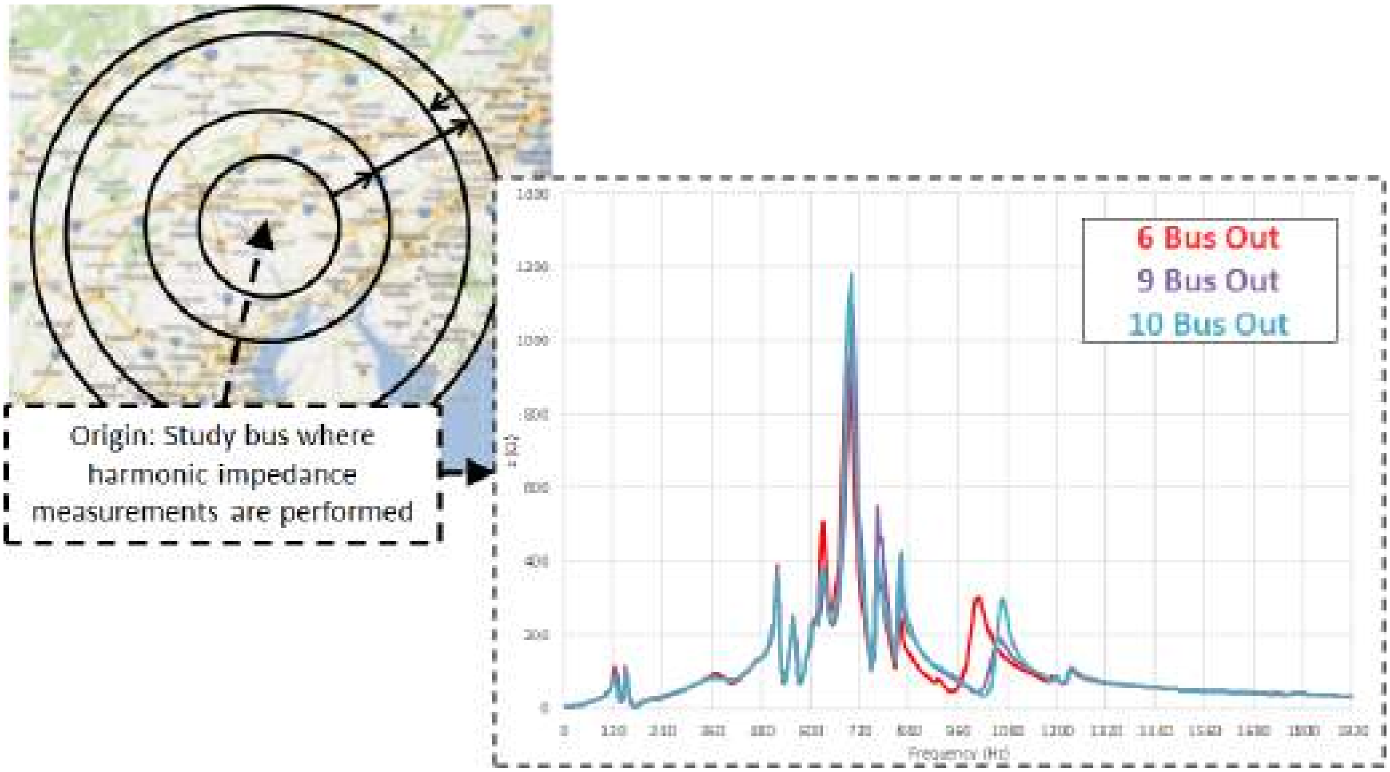


Figure 2.3: Concept of Iterative Approach to Sizing an EMT Study Area

For studies analyzing IBRs, the impacts on electromechanical phenomena, such as interactions with existing turbine generators and their excitation or governor control systems, typically need to be considered. It is also important to ensure that the developed EMT model is adequate to represent key electromechanical modes of oscillation. This can be accomplished through including dynamic representations of power electronic devices, IBRs, turbine generators, and loads within the developed EMT model or through more advanced techniques, such as hybrid simulation or electromechanical dynamic network equivalents, which will be discussed in **Chapter 3** of this guide. **Figure 2.4** illustrates benchmarking for a developed EMT model. This example shows the RMS voltage response for both an EMT (**black**) and phasor-domain (**red**) simulation tool at a given bus for a three-phase grounded fault.

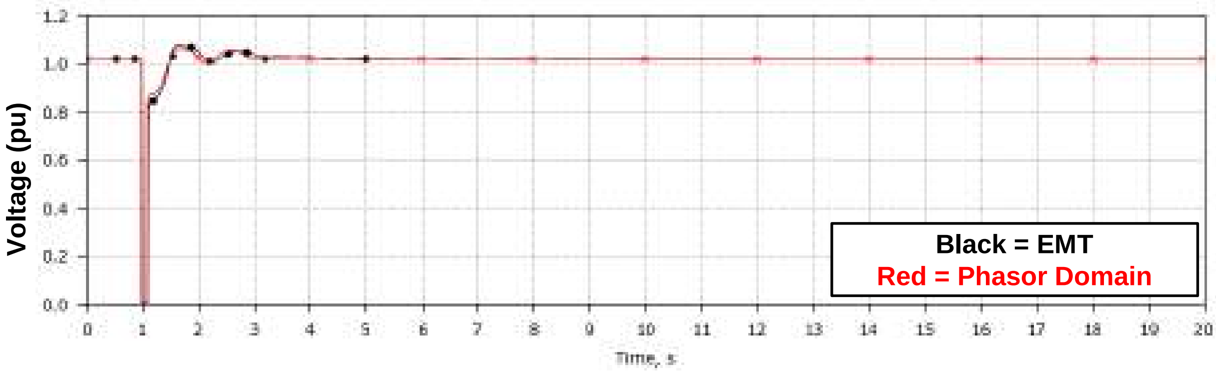


Figure 2.4: Comparison of RMS Voltage Response for a Given Fault Event Between EMT and Phasor-Domain Simulation Tools

Determining Which Dynamic Devices to Include in the Study Area

Beyond the techniques for determining the extent of the EMT domain study area previously outlined, there are techniques that can be used by study engineers to assist in determining which dynamic devices need to be explicitly modeled within the EMT study area. If a dynamic device, such as an IBR plant or FACTS device, is omitted from the study area, then its dynamic behavior will be omitted from the study and could introduce inaccuracies in the overall dynamic response of the system, thus preventing the observation of potential interactions that may actually occur between dynamic devices or other adverse reliability impacts. The following are examples of methods for determining which equipment should be included in the study area when performing EMT studies for IBRs:

- **Engineer Experience**
  - For study engineers performing EMT studies in a system in which they have already performed EMT studies or detailed screening assessments, their experience with the system can be used to determine which dynamic devices need to be included within the study area. New engineers may not have sufficient experience to understand all nuances related to study processes and phenomena and engineering judgement should be built over time through discussion with engineering mentors and technical experts.
  - For additional confidence, the experience with the system under study can also be coupled with system measurements and event analysis—such as gaining an understanding about the phenomenon or a type of system event being studied; observing voltage and frequency magnitude before, during, and after the event if the phase measurement unit (PMU), digital fault recorder (DFR), or supervisory control and data acquisition (SCADA) data is available; or noting how fast or slow and how deep the oscillations penetrate into the system.
- **Voltage Interaction Assessment**
  - One potential method to assist in choosing which dynamic devices need to be included within the study area is to use indices that offer insight into the electrical proximity between two buses within the system.

Multi-infeed interaction factor (MIIF),[9] improved/weighted MIIF,[10] multi-infeed voltage interaction factor (MVIF),[11] other indices as introduced in CIGRE, IEEE, and other publications aid engineers in studying and assessing potential interaction levels between two devices connected to the system at specific buses. These indices can be calculated using dynamic simulation tools and essentially serve as indicators of the ac voltage variation at one bus in response to a minor ac voltage change at another bus. They offer valuable insights into the extent of potential interactions between dynamic devices.

- The voltage interaction method provides a high-level assessment of potential interactions between devices at two points in a system.

- **Short-Circuit-Based Assessment**
  - Short-circuit-based assessments are typically used to indicate if a single facility or cluster of facilities requires further, more detailed analysis. Short-circuit current-based methods include available fault level, weighted short-circuit ratio, and composite short-circuit ratio.[12]
  - If a short-circuit-based assessment was used to determine if a single facility or cluster of facilities requires detailed EMT studies, then the facilities considered should be included within the study area. Additionally, the system operating conditions (e.g., generation dispatch and system outage conditions) that led to the need for a detailed EMT study should be considered when creating the study area. For example, if a certain line or generation outage leads to a system condition necessitating detailed study, then the study area should allow such an event to be simulated dynamically by including this equipment.

Typically, study area selection and dynamic device inclusion for EMT studies is an iterative approach. For example, the study engineer may notice that the dynamic response of their developed EMT model is not a good match when compared to the reference phasor-domain database. This type of mismatch may be caused by the omission of the dynamic behavior of a key generator, IBR facility, or power electronic device close to the study area. Additionally, it may be necessary to use some combination techniques when determining the EMT study area. Ultimately, the choice of the EMT study area should consider specific system characteristics, the phenomenon under study, findings from past studies, and engineering judgment.

[9] CIGRE Technical Brochure 364: *Systems with Multiple DC Infeed*

[10] CIGRE Technical Brochure 881: *Electromagnetic transient simulation models for large-scale system impact studies in power systems having a high penetration of inverter-connected generation*

[11] Hao Xiao; Yinhong Li, "Multi-Infeed Voltage Interaction Factor: A Unified Measure of Inter-Inverter Interactions in Hybrid Multi-Infeed HVDC Systems," IEEE Transactions on Power Delivery, Vol. 35, Issue 4 August 2020)

[12] https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Item_4a._Integrating%20_Inverter-Based_Resources_into_Low_Short_Circuit_Strength_Systems_-_2017-11-08-FINAL.pdf

Chapter 3: How to Model Systems

EMT simulations are computationally intensive, making it challenging to simulate an entire large-scale electrical system in an EMT environment. Additionally, the influence of electrically distant areas becomes less pronounced on disturbances within the study area due to high electrical impedance. Because of these factors, study engineers commonly model the study area in full detail in an EMT environment while employing an equivalent representation for the rest of the system, which has less impact on the study outcomes.

However, two important questions arise:

- How to define "electrically distant" areas? Or, in other words, where to stop the detailed model and start employing an electrical equivalent for the rest of the system?
- How to represent the rest of the system external to the study area using an electrical equivalent?

These questions will be discussed in the following sections.

Modeling of Study Area

The power system equipment within the study area should be modeled to the level of detail necessary for the power system dynamic phenomena under evaluation. With EMT studies, there is not always a one-size-fits-all representation for modeling power system equipment. Many of the commercially available tools used for automated creation of EMT models have a default method of modeling equipment and will generate a usable model. For example, these tools will typically import steady-state and dynamics data from a phasor-domain tool and will generate an EMT model that can run time domain simulations at a given simulation timestep. However, because of limitations in data available in the source databases, such models will not include many system modeling details that are typically important for EMT level simulation, such as the following:

- Correct zero sequence impedance of transmission lines or cables
- Frequency-dependent impedance of transmission lines or cables
- Mutual coupling between transmission lines
- Transformer winding configuration and grounding information
- Transformer saturation characteristics
- Custom or user-defined representation for load or generation
- Lack of representation of some system elements, such as surge arresters and grounding transformers, in the phasor-domain tools
- Inability to import all dynamic models from the phasor-domain tools; for example, newly added standard library models in phasor-domain programs may not be immediately available or some models, such as HVdc and FACTS, may not be properly exported

It is necessary for the study engineer to ensure that power system equipment is modeled appropriately for the phenomena of interest under evaluation. Providing a complete and detailed discussion on power system modeling for EMT is outside the scope of this document.

It is recommended that dynamic devices within the study area, especially power electronic devices and IBR plants, be represented by using EMT models, provided by a manufacturer, of the device/plant for the phenomena under study. A recreation of a WECC generic renewable model in an EMT tool can provide correct dynamic response for events that are within the models' bandwidth. However, such a model will not provide additional information beyond that captured in a phasor-domain tool. Ideally, within the study area, the power electronic devices and IBR plants under study should be represented with validated equipment specific models. However, it is not always possible to obtain these models for existing plants. It may be necessary to use simplified models for legacy plants. **Chapter 7** provides further guidance on how to model legacy plants. **Chapter 8** provides guidance on modeling plants with detailed plant-specific models.

In practice, the effort used to develop a model for a given "study area" can be used in future studies that are similar in scope and type. The process is slightly different depending on the specific EMT tool. However, these detailed models for dynamic devices and power system equipment should be maintained for future use. It is recommended that entities performing these studies begin to curate and maintain validated equipment model libraries.

Modeling of External System

Static Voltage Source

In this approach, the external system is represented as a fixed voltage source behind an equivalent impedance, which is obtained through the application of admittance matrix reduction techniques. This is the simplest technique for representing boundaries and is the approach employed by most software packages. However, it has the disadvantage that using a "fixed" voltage source can generate fictitious active/reactive powers during power imbalance conditions, potentially leading to inaccurate results as it masks the contributions provided by local generation within the study area. For the above reasons, it is recommended to use static voltage representation only when the boundary buses are located far from the study area.

A generator-trip study conducted in the Australian National Electricity Market (NEM) network (CIGRE TB 881 Section 4.1.7) demonstrated the drawbacks of employing a static voltage source equivalent to represent the boundary network. When the equivalent sources are positioned extremely close to the study area, the constant voltage source equivalent supplied a substantial amount of MW in response to the initial frequency dip following the loss-of-generation event. This action not only immediately restored the network frequency but also prevented real generator governors from increasing their power output to compensate for the generation loss in the area.

Dynamic Voltage Source

To overcome the drawbacks of the previous representation, a controlled voltage source is sometimes used instead of a fixed voltage source. The internal voltage magnitude and phase angle of the equivalent voltage source are controlled to sustain the pre-disturbance active and reactive power injections from the external system. Not only may this approach fail to fully capture the dynamic interactions between the study system and the external system, but it may also introduce false dynamics due to the equivalent sources attempting to maintain pre-disturbance power flow conditions.

To avoid this drawback, some independent system operators (ISO) (like Ontario's IESO) have chosen to represent the external system using equivalent synchronous machines with simplistic exciter and governor models. The parameters of these dynamic models are optimized to ensure that they maintain the response of the original external system. Additionally, constraints can be added to the optimization problem to preserve parameters, such as equivalent system inertia and short-circuit level at the boundary buses. Then, the developed, reduced model can be exported into an EMT program. This approach is labor intensive but can provide more accurate results as depicted below.

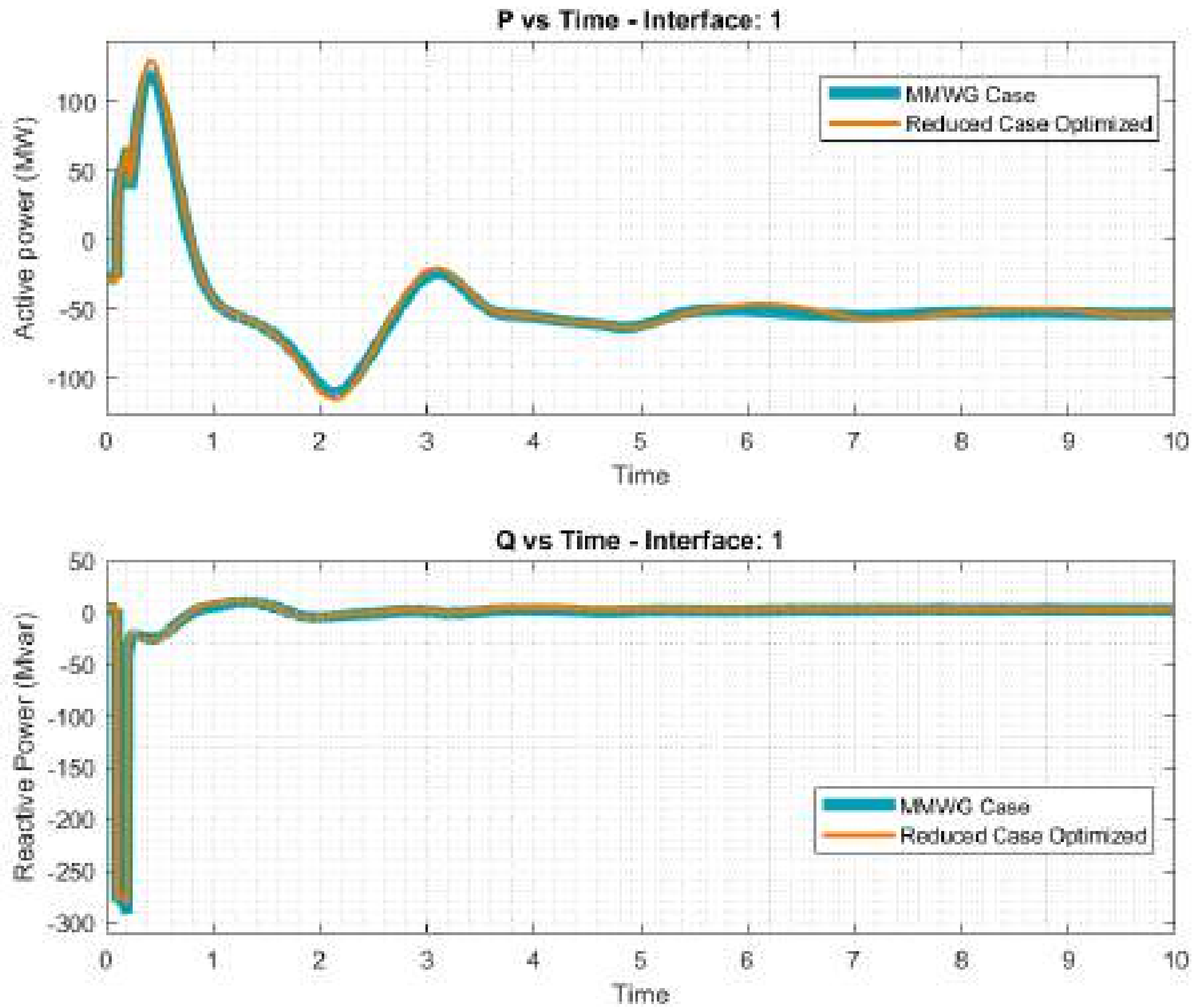


Figure 3.1: Full System vs. Reduced System Response with Equivalent Machines

Another approach to developing a reduced dynamic model that can capture a particular dynamic behavior at low frequencies is to utilize the available network reduction techniques in transient stability domain.[13,14,15,16] For example, coherency-based methods can be employed to identify a group of generators that oscillate together and replace them with an aggregated unit that can mimic the same behavior. Then, the reduced model can be imported into an EMT program while preserving the same low-frequency dynamic behaviors that will occur due to the interactions between the units in the study area and the external system. The network reduction in positive-sequence phasor-domain tool can result in artifacts, such as negative resistance produced from the network reduction in an equivalent branch connecting two buses of different voltage levels through a line instead of transformer.

[13] J. P. Yang, G. H. Cheng and Z. Xu, "Dynamic reduction of large power system in PSS/E," 2005 IEEE/PES Transmission & Distribution Conference & Exposition: Asia and Pacific, Dalian, China, 2005, pp. 1-4, doi: 10.1109/TDC.2005.1546815

[14] F. Ma, X. Luo and V. Vittal, "Application of dynamic equivalencing in large-scale power systems," 2011 IEEE Power and Energy Society General Meeting, Detroit, MI, USA, 2011, pp. 1-10, doi: 10.1109/PES.2011.6039372

[15] Kai, S., Che, Y., Zhang, F., Wu, G., Zhou, Z., Huang, P.: "A review of power system dynamic equivalents for transient stability studies." J. Eng. 2022, 761–772 (2022). https://doi.org/10.1049/tje2.12157

[16] M. Matar, N. Fernandopulle, and A. Maria, "Dynamic model reduction of large power systems based on coherency aggregation techniques and black-box optimization" International Conference on Power Systems Transients (IPST2013) in Vancouver, Canada July 18–20, 2013

Hybrid Simulation (Positive-Sequence Phasor Domain + EMT)

The requirements for dynamic analysis in power systems are significantly changing due to shifts in generation and load characteristics. A considerable portion of newly interconnected generation resources, along with various loads, now connect to the grid through power electronic (PE) converters. Transient stability (TS) simulation tools are inherently limited in adequately representing PE devices, especially during fault periods. These modeling deficiencies may lead to either an overestimation or underestimation of the system's reliable operation boundary and stability limits. Consequently, this can result in systems operating under heightened risk or less efficient conditions.

Conversely, EMT simulation tools can provide detailed representations of PE and single-phase devices. However, the portion of the system required to be modeled in detail in an EMT tool ("study area") has increased significantly due to high penetration of IBRs. Such EMT simulations with larger study area may result in requiring higher computational resources. To address these challenges, various simulation methods have been proposed, including parallel processing by breaking up a large network into smaller, decoupled networks; EMT-TS hybrid/co-simulation; frequency-dependent network equivalents; and dynamic phasor-based approaches. Among these, the hybrid simulation approach has garnered significant attention from both industry and academia due to multiple use cases. Some of the major use cases are detailed below:

- **High path flows through EMT study area**: When there is a high-power flow path through the selected study area (i.e., study area is in the middle of a transmission corridor), the post-contingency power flow solution (mainly voltage magnitudes and angles) will be less accurate at the boundaries with fixed-source equivalents.
- **Inter-area machine dynamics**: If there is a known inter-area oscillation (i.e., areas swinging against each other), it will not be visible with fixed-source boundary equivalents.
- **Interaction of power electronics components with system frequency**: In the case of interaction of PE components with system frequency, it will be important to model a wider power grid. In such cases, EMT models of PE components and the local regions are developed with the wider power grid being represented in the TS model (phasor-domain).[17] Example use cases are grid fault response from PV plants and the corresponding impact on the power grid as well as HVdc system fast control in low system strength regions to provide reliability to the power grid.

Note: There are no standard techniques that determine the size of the "study area" in EMT in hybrid EMT-TS simulations. One of the techniques used in literature employs a reactive power injection to understand the area in which voltage is affected.[18] Another technique used in literature is based on the sensitivity of the size of the "study area" in EMT such that the smallest-sized study area matching the results from the larger-sized study area is used in EMT simulations.

Caution

- Care must be taken to place boundaries at locations where voltages and currents do not have dynamic content with a period lower than five cycles (i.e., high-frequency oscillations/dynamics should not be visible at the boundary bus).
- Care must be taken to place boundaries at locations where voltages and currents do not have significant unbalance since the TS simulation is mainly positive sequence.

[17] ORNL, SCE, FPL/NextEra, Pennsylvania State University, CAISO, Suman Debnath, et. al., "Library of Advanced Models of large-scale PV (LAMP) (Final Technical Report)", ORNL Technical Report, 2023. [Online] Available: https://www.osti.gov/biblio/2345308.

[18] Y. Liu et al., "Hybrid EMT-TS Simulation Strategies to Study High Bandwidth MMC-Based HVdc Systems," 2020 IEEE Power & Energy Society General Meeting (PESGM), Montreal, QC, Canada, 2020, pp. 1–5.

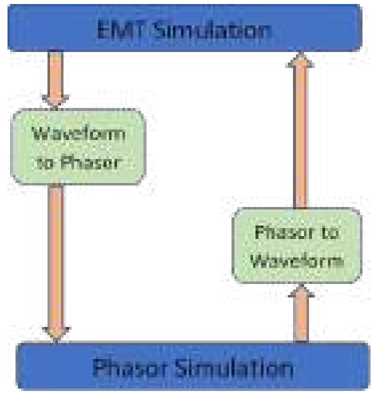


Figure 3.2: Communication Between EMT and Phasor Simulations

Chapter 4: System Base-Case Model Benchmarking

Before starting EMT studies, it is important to verify that the system model is a reasonably accurate representation of the actual system. Past and current industry practice on large-scale system-level studies have traditionally been centered around using a validated phasor-domain system model. Consequently, validated phasor-domain system models serve as the starting point for building an EMT model for TPs and PCs. While the process of benchmarking EMT models ensures consistency with the phasor-domain models across power flow, dynamic studies, and short circuit studies, care needs to be taken when extending such an approach, especially when there is significant planned IBR integration into the system and even more so when dealing with weak system conditions. Such scenarios could present cases in which the results of phasor-domain models deviate from actual system behaviors, and it could be misleading to try and benchmark EMT models against phasor models. The following sections explain the benchmarking process and the possible reasons for any discrepancies that may arise.

System Model Benchmarking

The primary means of benchmarking is to verify that the EMT model can simulate the dynamic response of the power system with reasonable accuracy when compared to the validated positive-sequence dynamic model and/or an actual system dynamic event. The comparison also identifies errors and parameters that cause mismatches. These errors and parameters can then be corrected or adjusted so that the EMT model emulates the actual conditions.

The system model can be developed by utilizing conversion or import tools to convert the validated positive-sequence dynamic model into the EMT model. The development and benchmarking of the EMT system model should consider both positive-sequence dynamic modeling data, short-circuit modeling data, and/or field measurement data. Figure 4.1 shows an example of the system model benchmarking process. Engineering judgement is needed to determine the acceptable accuracy.

It should be noted that a system model is a culmination of individual equipment models and as such the validation of the equipment model is the underlying foundation to system model accuracy.

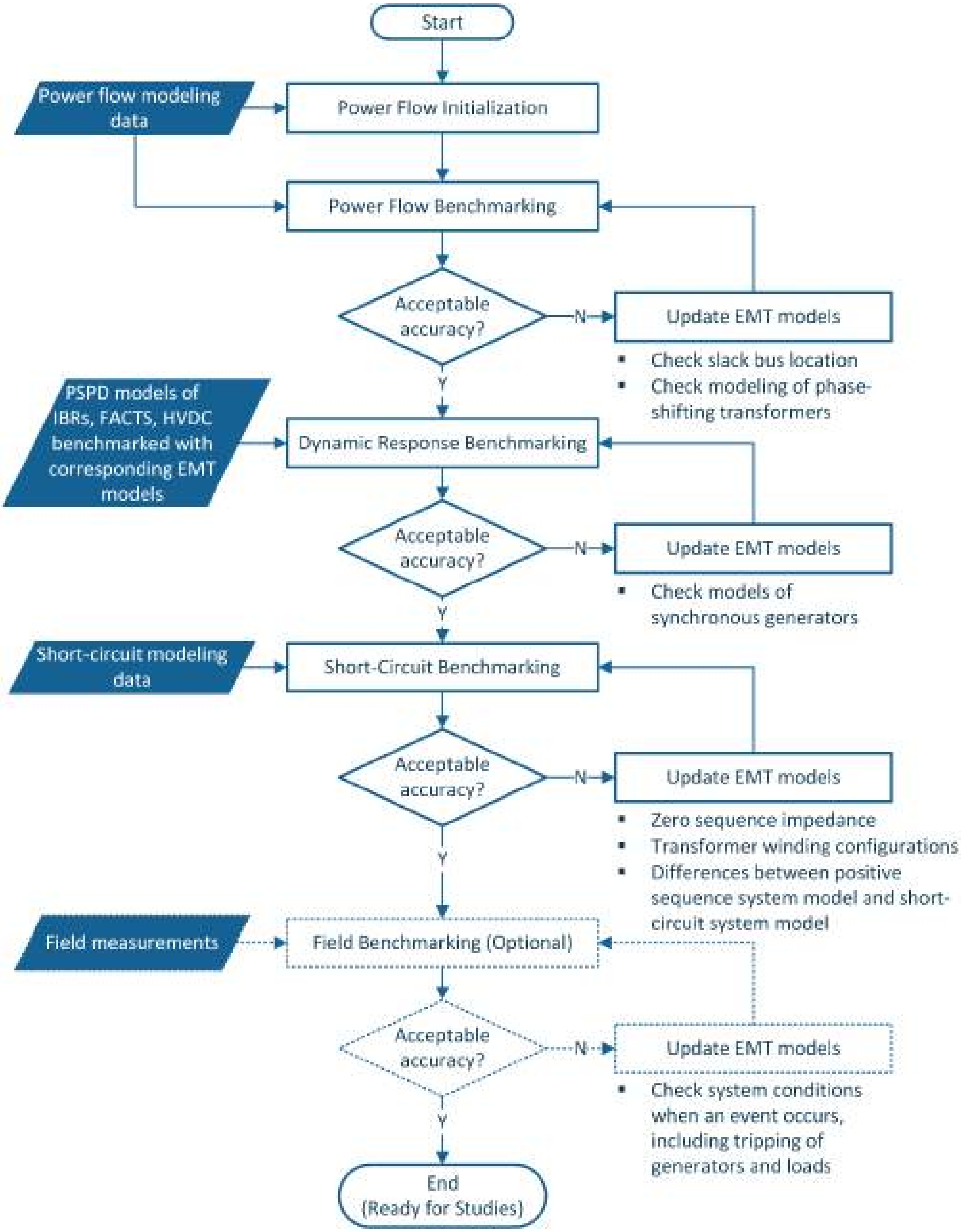


Figure 4.1: Example of System Model Benchmarking Process

The following benchmarking should be considered:

- Power flow benchmarking by comparing the EMT model against the positive-sequence dynamic model
- Fault current benchmarking by comparing the EMT model against the short-circuit model for balanced and unbalanced faults
- Dynamic response benchmarking by comparing the EMT models against the positive-sequence dynamic model
- Field benchmarking by comparing the EMT models against recorded data from actual system events

Power Flow Validation

The EMT model should be benchmarked against the positive-sequence dynamic model for power flow results by comparing each branch's real and reactive power flow.

Typically, an EMT model is a reduced network model derived from the positive-sequence dynamic model of the entire power system. There is a possibility that the swing buses in the EMT model and the positive-sequence dynamic model do not match, leading to the discrepancy in the power flow. The phase-shifting transformers can have significant impact on the power flow distribution. However, the EMT conversion tools may use regular transformers to model the phase-shifting transformers, resulting in a discrepancy in power flow comparison. The modeling of phase-shifting transformers in the EMT system model should be verified.

Fault Current Validation

The EMT model should be benchmarked against the short-circuit model for balanced and unbalanced faults by comparing the bus fault currents. Since short-circuit tools give steady-state fault currents in a numerical format, the RMS value of steady-state currents in the EMT simulation should be recorded for comparison. The fault duration in an EMT simulation should be set to a long enough period to obtain a steady-state fault current, and the last 10–20 cycles of the fault current can be used for calculating the RMS value. The generators should run at a fixed rotor speed ("locked") to obtain steady-state fault currents. Figure 4.2 shows an example of recorded fault current in the EMT simulation and the data for RMS value.

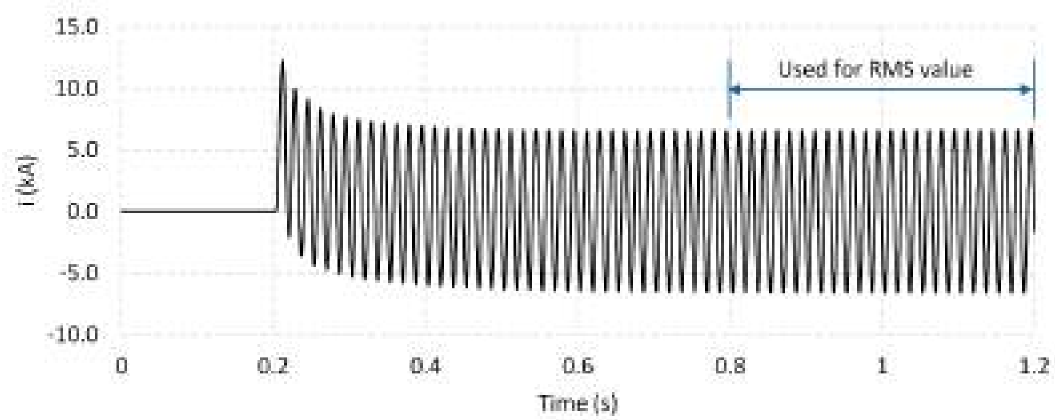


Figure 4.2: Example of Steady-State Fault Current

The discrepancy in fault current comparison can be caused by several factors, such as the following:

- The IBR models in the EMT model and the short-circuit model are different. The collected IBR models may not have been accurately modeled in the short-circuit model.
- The zero-sequence impedances in the EMT model and short-circuit model are different. The conversion or import tools typically use the positive-sequence dynamic model. If the zero-sequence data is unavailable, these tools will estimate the zero-sequence impedance based on positive-sequence impedance. This estimation causes the

difference in unbalanced fault current between these models. The zero-sequence impedance from the short-circuit modeling data should be used in this step to update the EMT model.

- The transformer winding configurations in the EMT model and the short-circuit model are different, leading to the discrepancy in unbalanced fault currents between these models. The transformer winding configurations from the short-circuit modeling data should be used to update the EMT model.

Updating the EMT model with the short-circuit modeling data will improve the accuracy of the EMT model. Since the EMT model is developed based on the positive-sequence dynamic model, this task can be challenging if the naming convention in positive-sequence dynamic model and short-circuit model is different or there are differences between the two models.

Dynamic Response Benchmarking

The EMT model should be benchmarked against the positive-sequence dynamic model for dynamic response under disturbances. The discrepancy in dynamic response between the EMT model and the positive-sequence dynamic model can be caused by differences in the modeling of generation, including exciters and governors, and dynamic devices. The response of the generators can be used for comparison. The typical quantities used to check for comparison include the output real and reactive power, generator speed, terminal voltage, and output current.

Figure 4.3 shows an example of dynamic response benchmarking for a 350-bus power system by comparing the real and reactive power output, the generator speed, and the terminal voltage in the EMT model and the positive-sequence dynamic model. Engineering judgement is needed to determine the acceptable accuracy of dynamic response benchmarking results.

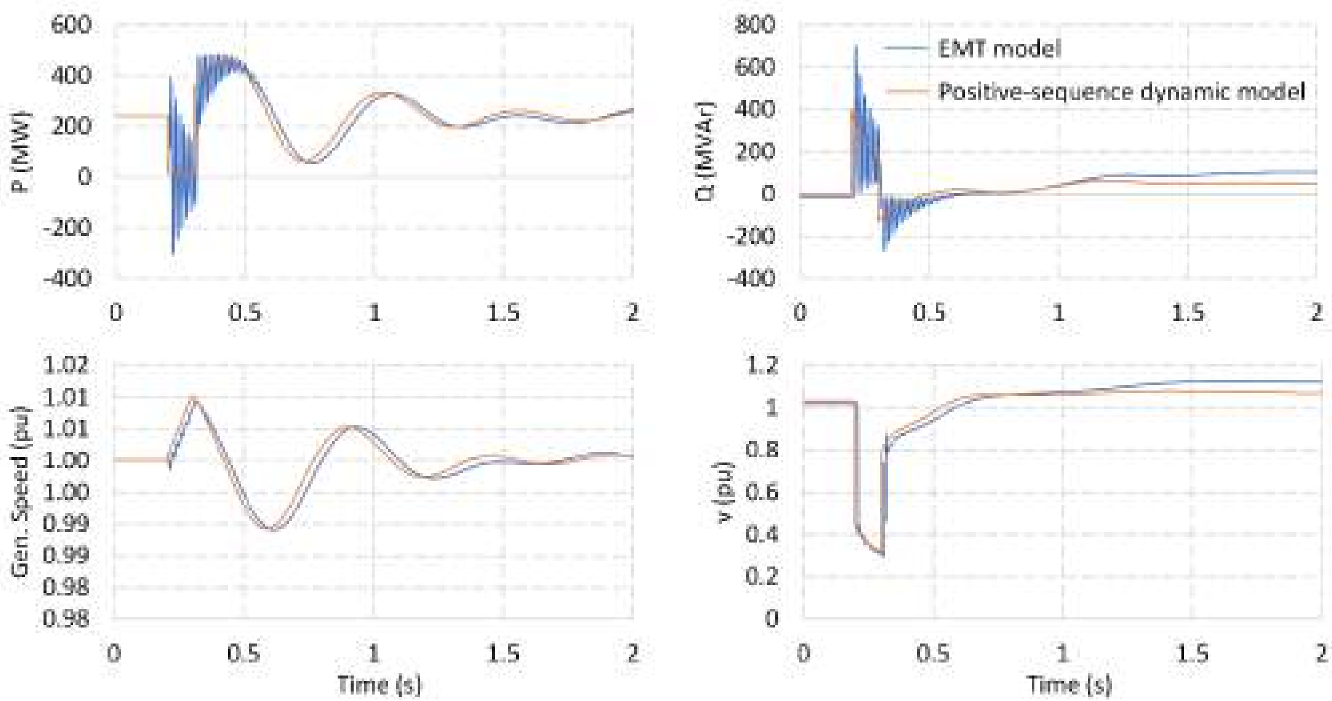


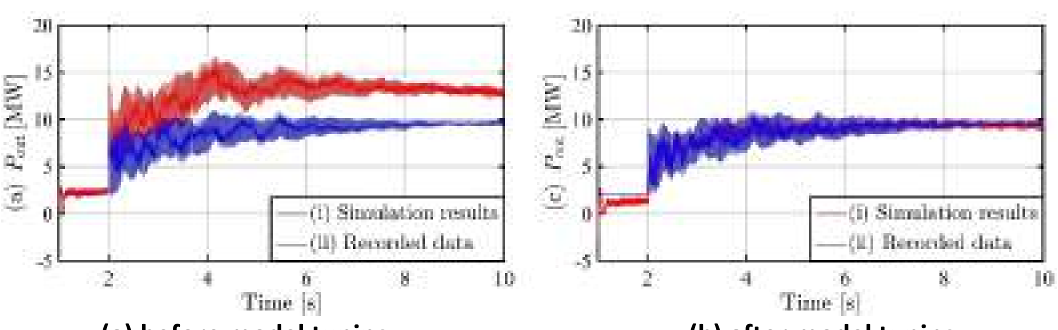
Figure 4.3: Example of Dynamic Response Validation for a 350-Bus System Model

Field Benchmarking

From the perspective of model fidelity, a carefully built and validated EMT model of the system is expected to reflect real-world system behavior across a range of broad use cases if it sufficiently captures the behavior of controls and protection elements. While previous processes of benchmarking EMT models ensure consistency with positive-sequence dynamic models and short-circuit model, care needs to be taken when extending such an approach, especially when the system is slated for significant planned IBR integration and even more so when dealing with weak system conditions. Such scenarios could present cases in which the results of phasor-domain models deviate from actual system behaviors, and it could be misleading to try and validate system-level EMT models only against previously validated phasor models without performing adequate validation and model fine-tuning based on field measurements.

The current recommended practice is to ensure that vendor- and plant-specific IBR plant models are thoroughly validated with various types of test case scenarios before commissioning using lab tests or during commissioning with appropriate tests. These validated, vendor- and plant-specific IBR plant models are then integrated into existing system-level EMT models that are then benchmarked against phasor-domain models. While this assumption of composing the system-level EMT models from a set of validated plant-level EMT models and previously validated phasor models is reasonable given practical constraints, lack of field measurement data to perform the necessary model validation in the EMT domain could result in inaccurate predictions about system behavior during disturbances. Several recent disturbance reports from NERC have shown that even validated system-level phasor models have failed to replicate real-world system behavior, especially pertaining to issues like IBR plant tripping, highlighting potential gaps in system-level validation and underlining the need for a systematic and recurring model validation in the EMT domain with high-resolution field measurement data in order to maintain their usefulness in predicting real-world behavior for possible future disturbances. Therefore, it is essential to include efforts that collect field test data periodically from available system resources to continuously validate system-level EMT models against real-world behaviors.

Figure 4.4 shows a case study from Hawaii that compares the results from a system-level EMT model with a vendor-provided IBR model against recorded field data.[19] Differences were visible initially. In order to resolve the differences, a single-inverter infinite bus system with recorded three-phase voltage waveforms was used to observe the simulated and recorded real and reactive power outputs while control parameters were tuned. The tuning of parameters was done with appropriate vendor/OEM guidance to understand which parameters can be tuned and which ones should not be modified. In order to fix the mismatches in steady-state active power the real-power/frequency droop constant(s) were tuned. Even with this, there were some mismatches during the transients, which were resolved by tuning the current loop parameters. After the model was carefully tuned, the system-level EMT model was able to match the recorded field test data, uncovering potential issues with settings and parameters in the model and thereby exemplifying the importance of IBR model true-up during commissioning and periodically validating system-level EMT models with either hardware-in-the-loop or field test data. This also highlights the importance of model true-up during commissioning.

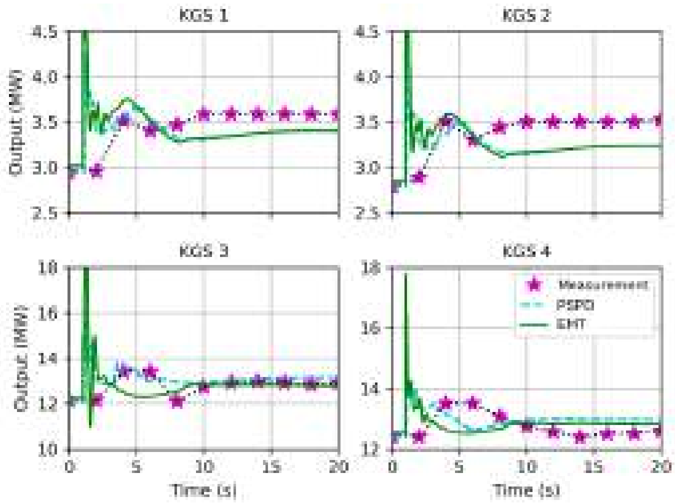


(a) before model tuning **(b) after model tuning**

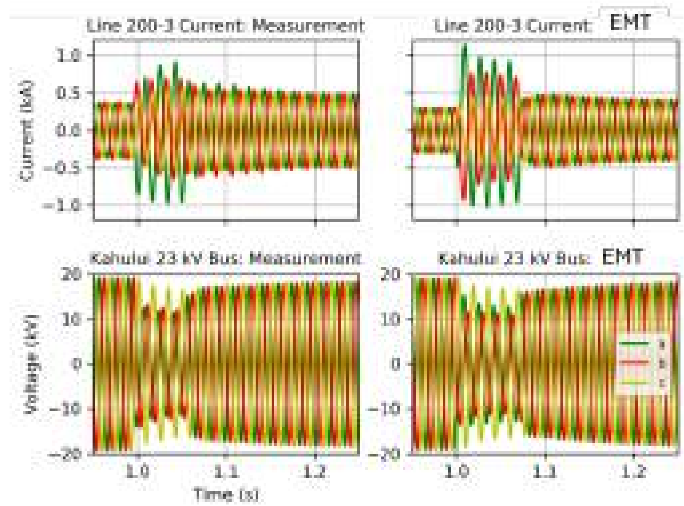
Figure 4.4: EMT-Domain Simulation (Red Line) and Field-Testing Data (Blue Line) of Vendor-Provided IBR EMT Model

[19] Tan, Jin, Dong, Shuan, and Hoke, Andy. Island Power Systems with High Levels of Inverter-Based Resources: Stability and Reliability Challenges. United States: N. p., 2023. Web.

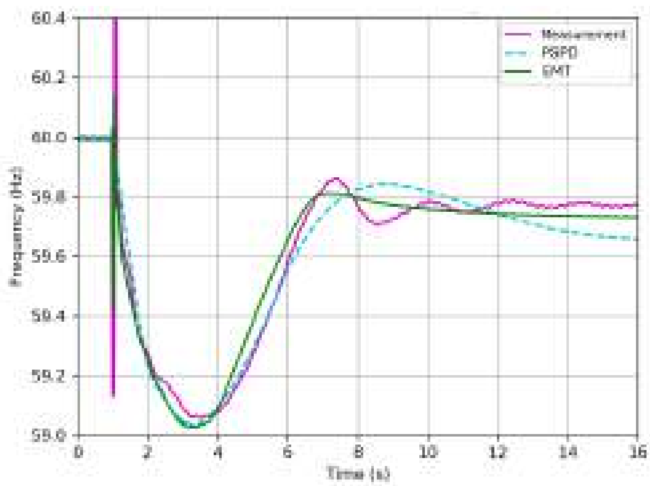
Figure 4.5 shows the validation of the Maui EMT model against the utility's PSPD model and field data for an event that consisted of a single-phase fault followed by a generation trip.[20] The available monitoring data included SCADA data with a two-second sampling rate for the utility-generating units and three-phase current and voltage measurements for the unit that experienced the disturbance. Additionally, high-resolution frequency data was also obtained from the Kahului generating station.



(a) Kahului generation station unit outputs from measurement data and simulated responses



(b) Kahului generation station main bus three-phase voltages and tie line currents; measured and EMT simulation results



(c) Kahului generating station frequency following the fault and generation trip

Figure 4.5: Field Validation of the EMT Models

TPs and PCs should ensure the consistency of the naming convention in positive-sequence dynamic models and short-circuit models. For example, the bus names and bus numbers in the positive-sequence dynamic model and the short-circuit model should match or easily correlate. By maintaining this consistency, the short-circuit modeling data can be easily utilized when updating the EMT model.

[20] R. W. Kenyon, B. Wang, A. Hoke, J. Tan, C. Antonio and B. -M. Hodge, "Validation of Maui PSCAD Model: Motivation, Methodology, and Lessons Learned," 2020 52nd North American Power Symposium (NAPS), Tempe, AZ, USA, 2021, pp. 1–6, doi: 10.1109/NAPS50074.2021.9449773.

TPs and PCs should ensure that vendor- and plant-specific IBR plant models are thoroughly validated with various test-case scenarios before commissioning using lab tests or during commissioning with appropriate tests.

Chapter 5: Study Scenarios

This chapter provides an overview of how the study scenarios should be selected and prepared. The first step in developing a base case is to select an appropriate study area, the size of which depends on the type of study performed. For example, the study area for a subsynchronous oscillation (SSO) or dynamic system impact assessment study differs from that of an insulation coordination study. For dynamic system impact assessment study, the study area is generally selected to include the major transmission corridor, major loads, and nearby generation (synchronous machine or other IBRs). Study area selection is further detailed in **Chapter 3**.

As described in **Chapter 4**, once the study area is selected and EMT model has been built, the EMT model must first be initialized to given operating conditions considering base cases for network power flow conditions (including generation mix) and prior outages. This step ensures that the EMT study case has correct initial conditions. In addition, to capture the worst-case scenarios, the dispatch levels for an interconnecting IBR can be selected to include operation under Pmax/Qmin, Pmax/Qmax, Pmin/Qmin, and Pmin/Qmax conditions. The initial active power condition can be considered for battery energy storage systems (BESS).

Contingencies to be Considered

The most critical contingencies, including tripping a transmission corridor, large load, or a generation plant as well as different fault scenarios, must be considered to capture the worst stress on IBR performance. Information from system operators, such as on a known oscillation in a specific network topology, and PSPD transient stability study results are useful in the process.

When simulating contingencies, the following aspects should be considered:

- Fault at POI (bolted) and X-buses away from POC (different retained/residual voltage seen at POI)
- Different types of faults: L-L-L-G, L-G, L-L, L-L-G
- Fault on the line side of the breaker so that it clears
- Breaker arrangement from utility, also considering RAS
- Transmission protection clearing times (local and remote clearing times)
- Normally cleared, breaker failure (backup protection), auto-reclose (successful and unsuccessful)
- Protection relay logic is not modeled. Only operating times are used (underlying assumption protection will operate as designed).
- Switching with no faults: transmission lines, transformers, large loads, large generators, etc.

Unsymmetrical faults are the most common faults to occur in transmission power systems. Line-to-ground faults (L-G) are the most common compared to other faults and represent 65–80% of all faults in transmission lines. Issues like lightning and vegetation can cause these types of faults when the conductor contacts the ground.

L-L-G faults, which cause two conductors to contact the ground, and L-L faults in transmission lines are largely caused by heavy winds.

Three-phase or symmetrical faults, which give rise to balanced currents displaced 120 degrees to each other, are the least common of all faults and may provide the highest available fault current.

All fault cases cause voltage and current to deviate from their nominal values. These faults are primarily caused by storms that collapse transmission towers or human error.

Selecting Study Scenarios

Performing studies for all possible options can result in an exhaustive list of scenarios and require significant engineering hours to perform the simulation and collect and analyze the results. Therefore, due diligence must be taken when selecting the scenarios to capture the worst-case conditions. Table 5.1 provides an example of the total number of simulation scenarios that can be considered for all possible options. Table 5.2 provides an example of the total number of simulation scenarios that can be considered to capture the worst-case conditions. Information from system operators, such as a known oscillation in a specific network topology, and PSPD transient stability study results are useful in narrowing down the study scenarios.

Table 5.1: An Example of Exhaustive List of Study Scenarios for All Possible Options	
Number of network power flow cases	6
Number of IBRs dispatch	8
Number of contingencies	50
Total number of scenarios	6x8x50 = 2400
Average number of hours to simulate each scenario	45 min[21]
Total number of hours to simulate (assuming 4 cases at once)	45 x (2400/4) = 27,000 min = 450 hrs

Table 5.2: An Example of Reduced List of Study Scenarios Based on Capturing Worst-Case Conditions

Base Case	**Contingency**														
A	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**
B	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x
C	x														
D			x		x		x					x			
E	x							x		x				x	x
F	x		x			x				x		x		x	
G			x			x			x						
H	x														

Table 5.3 provides an example estimate of less computing time necessary to simulate only the worst-case conditions.

[21] The time depends on the size of the network, number of PE devices (detailed or average model), simulation timestep, simulation time, and the performance of the PC used for the study.

Table 5.3: Computing Time Estimate	
Total number of scenarios	40
Average number of hours to simulate each scenario	45 min
Total number of hours to simulate (assuming 4 cases at once)	45 x (40/4) = 450 min = 7.5 hrs

When selecting contingencies to be studied in the EMT domain, the screening and ranking can be carried out using analytical methods and RMS domain runs. Common mode outages should be considered.

Notes on Initialization

EMT simulations should first be initialized to achieve desired power flow scenarios. Depending on the EMT software being used and the capabilities of the models within the software, a flat start may not be possible at the first run. As a result, if the EMT simulation is to start from a point away from the steady-state pre-disturbance operating point, care must be taken to ensure an appropriate ramp to steady state. Here, the presence of deadbands in control loops can be impactful. Since the EMT simulation can have a transient state before it achieves pre-disturbance steady state, the deadband may result in a pre-disturbance steady-state value that can be different from the power flow solution. As a result, a comparison between a study done in RMS simulation versus one in EMT simulation could result in mismatches.

The behavior of loads should also be considered. If motor load models are used in a study, then the reactive power consumed by the motor loads can be different in the EMT domain when compared to the power flow solution in the RMS domain because of the nuances associated with the method of initialization of motor loads in the RMS domain.

Chapter 6: Performing EMT Studies

The study methodologies for the following common types of EMT studies are discussed in this chapter:

- Dynamic system impact assessment studies
- SSO studies
- Transmission protection system validation studies

The first two are commonly conducted during the generator interconnection process as part of system impact studies. Not included in the scope of this guideline are traditional EMT studies, such as those for substation/line design (transient overvoltage, surge arrester and Basic Insulation Level (BIL) rating (insulation coordination), current limiting reactor (CLR) rating, Transient Recovery Voltage (TRV) (breaker rating), induced overvoltage due to mutual coupling from improper transposed or un-transposed lines, and secondary arc current (double-circuit line - induced current in opened line).

Dynamic System Impact Assessment Studies

EMT dynamic performance studies are system-level studies (beyond Single Machine Infinite Bus (SMIB) tests) that seek to evaluate the performance of an IBR plant or group of IBR plants against applicable performance criteria with aggregate[22] or partially aggregate plant models. The performance of the system included in the EMT model can also be evaluated against applicable criteria to the greatest possible extent. Steady-state and positive sequence phasor-domain (PSPD) transient stability analysis should be performed before the EMT analysis if possible, and the system model used in the EMT analysis should include all upgrades/mitigations deemed necessary in those studies. However, EMT dynamic performance studies typically take much longer than steady-state and PSPD transient stability analysis, potentially making it necessary to perform preliminary modeling and analysis in parallel with steady-state and transient stability analysis.

EMT Analysis

It is typically more challenging to analyze EMT study results than phasor-domain study results due to the increased complexity of the device models (real code, black boxed) and the inherent simulation differences (e.g., phase quantities vs. RMS, zero and negative sequence, small timestep). A robust understanding of the EMT simulation environment, IBR controls and behavior, and general power system analysis fundamentals should be considered prerequisites to performing EMT dynamic performance studies. Many aspects of EMT dynamic performance analysis, such as IBR balanced fault-ride-through performance/recovery and oscillation damping and voltage recovery, should also be checked in PSPD transient stability analysis.

The following sections highlight additional performance aspects that should be considered in EMT dynamic performance studies. Criteria violations/performance concerns (such as instability and ride-through issues) observed during the analysis are typically addressed by the plant developers/owners. Some issues may be mitigated by control tuning of participating devices. Any control tuning should be performed by the OEM or with direct permission/instruction from the OEM as other parties are not aware of the full implications of individual parameter changes and should not take responsibility for these changes. Control tuning done outside of the purview of the OEM should be considered investigative only.[23]

[22] A disaggregated plant model may produce a different result than an aggregate plant model for some events, such as differences in how fast transients propagate throughout a long collector system. However, the current practice is to model plants as plant models are typically a single aggregate generator or a few partially aggregate generator models for dynamic system impact studies as the computational and engineering resource requirements associated with developing and simulating one or multiple fully disaggregated plant model are prohibitive within the schedule constraints of most interconnection studies.

[23] There are some exceptions to this, such as when the model for a legacy plant that no longer has OEM support is tuned to match behavior observed in operation.

Stability

Assessing the stability of IBRs is typically a primary objective of EMT dynamic performance studies. Annex C of IEEE 2800-2022 *Inverter stability and system strength* thoroughly describes IBR stability concerns, including screening methods, examples, and mitigation. Stability in EMT dynamic performance typically concerns the following:

- **Oscillations:** Oscillations can occur over a wide frequency range in an EMT dynamic performance study due to the wide frequency range over which the model is valid (a few Hz to several kHz). Oscillations may occur at integer harmonics, subsynchronous, or super-synchronous frequencies and have many possible root causes that may involve natural system resonance and control-driven device characteristics. The ESIG "Diagnosis and Mitigation of Observed Oscillations in IBR-Dominant Power Systems"[24] guide and the CIGRE "Guidelines for Subsynchronous Oscillation Studies in Power Electronics Dominated Power Systems"[25] brochure are good resources on this topic.

- **Control Mode Cycling/Chattering:** EMT analysis of IBRs may result in interactions among IBRs or between IBRs and the system that are cyclic but not sinusoidal in nature. These kinds of interactions are often referred to as "control mode cycling" or "chattering," as they involve controllers repeatedly toggling between control modes. While mode cycling is possible in phasor-domain simulation, it is more commonly observed in EMT simulation due to the detailed modeling of plant- and inverter-level control loops/thresholds and the possibility of poor transitions between these controllers. One example of mode cycling is when an IBR with a slow reactive power controller attempts to ramp up active power after a fault into a weak system. As the active power ramps up, system voltage drops and the reactive power from the IBR is too slow to avoid the voltage dropping to a low-voltage-ride-through (LVRT) threshold. Once the threshold is hit, the LVRT controls cause the active power to drop quickly and then begin ramping again, repeating the process. Another example is an IBR with a terminal voltage that is at the edge of an LVRT threshold after fault recovery. If the plant controller is slow to change the reactive power command and was perhaps requesting the inverters to absorb reactive power before the fault, the inverter controls may repeatedly toggle between the power plant controller (PPC) commands and the inverter-level LVRT commands (which would be requiring the inverter to inject reactive power). **Figure 6.1** shows an example of a plant that enters this type of mode cycling for several seconds following a three-phase fault and loss of line. The plant controller eventually increases the reactive power reference to allow the plant to recover. This behavior may repeat for much longer depending on the speed of the plant controller and the magnitude of the post-fault undervoltage. This type of response is typically not accepted as a stable response, however the severity and duration of oscillation, as well as the potential system impact, should be taken into consideration when making such assessments.

The possibility of any of the above cyclical/periodic, sinusoidal, or non-sinusoidal/non-linear behavior (or a combination thereof) can result in a somewhat arbitrary response shape that may not lend itself to be quantified with traditional criteria, such as damping ratio. Alternative quantitative metrics, such as minimum recovery time, settling time, and settling bands, may be more appropriate[26], but these should be applied in conjunction with engineering judgment that considers the equipment and wider-grid implications of the response.

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[24] ESIG Stability Task Force "Diagnosis and Mitigation of Observed Oscillations in IBR-Dominant Power Systems", https://www.esig.energy/wp-content/uploads/2024/08/ESIG-Oscillations-Guide-2024.pdf, August 2024

[25] JWG C4/B4.52 "Guidelines for Subsynchronous Oscillation Studies in Power Electronics Dominated Power Systems", TB 909, 2023 , https://www.e-cigre.org/publications/detail/909-guidelines-for-subsynchronous-oscillation-studies-in-power-electronics-dominated-power-systems.html

[26] For example, see IEEE 2800-2022.

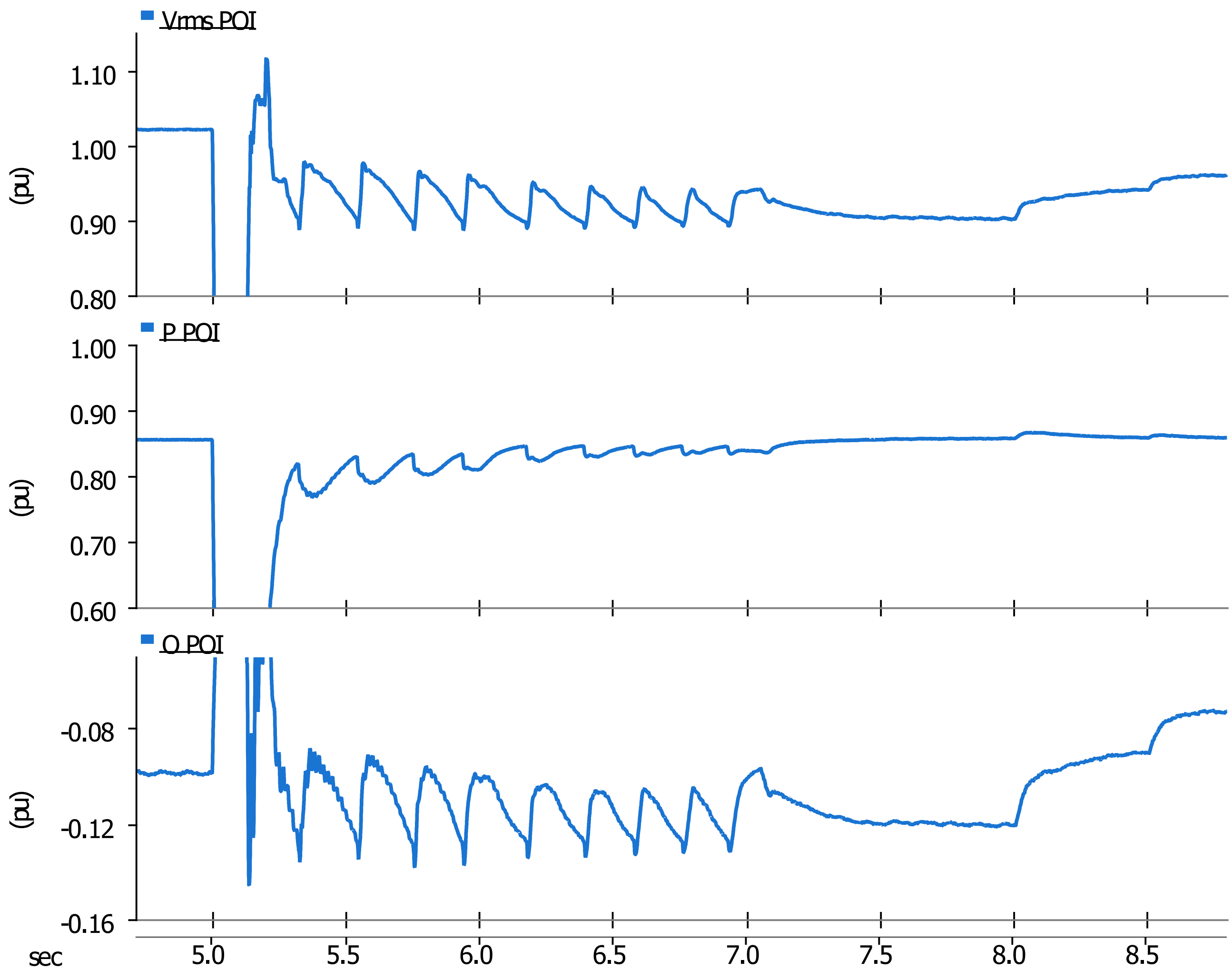


Figure 6.1: Reactive Power Mode Cycling Example (Courtesy of American Transmission Company)

Ride-Through and Post-Disturbance Performance

Another primary objective of EMT dynamic performance studies is to assess fault ride-through performance of a device or group of devices. IEEE 2800-2022 includes minimum capability requirements for IBR plants in response to abnormal events occurring on the transmission system and is a good reference for analyzing performance in EMT dynamic performance studies. The ride-through performance is typically assessed in the following terms and in the following order (IEEE 2800-2022 Chapter 4.7):

1. **Self-Protection:**[27] Do the devices remain connected throughout the disturbance or do a breaker or control signal cause devices to trip or self-protect for disturbances in which the system voltage and frequency remain within the applicable ride-through envelopes? (PRC-024-02, IEEE 2800-2022 Chapter 7.2.2.1, IEEE 2800-2022 Chapter 7.3.2.1)

[27] Aggregate models cannot represent partial tripping where a portion of the inverters in the IBR tripped in response to contingencies., however, they are considered useful for gaining understanding of overall plant ride-through performance, where the majority of inverters could be subject to tripping.

2. **Post-Event Recovery**: For energy resources, does the active power settle to an expected level (i.e., close to pre-fault conditions) after the disturbance? (IEEE 2800-2022 Chapter 7.2.2.2)
3. **Current Injection:** Do the devices provide adequate levels of positive-sequence real and reactive current injection (typically reactive current is priority, but not always) and negative-sequence current during the fault (IEEE 2800-2022 Chapter 7.2.2.3.4), and is the current injected in a fast and stable manner? (IEEE 2800-2022 Chapter 7.2.2.3.5)
4. **Post-Event Grid Support:** Do the devices control system voltage (IEEE 2800-2022 Chapter 5) and frequency (IEEE 2800-2022 Chapter 6) with reasonable responsiveness and stability?

Figure 6.2 shows an example of a plant responding to an event that reduced the point of interconnection (POI) voltage from 1.01 to 0.95 pu at 5 s. The plant does not begin responding to the undervoltage until 700 ms post-fault, which is slower than the 200 mS reaction time required in Table 5 of IEEE 2800-2022. The plant has a response time of around 15 seconds for this event, which is within the typical range of 1–30 seconds indicated in Table 5 of IEEE 2800-2022. The damping ratio requirement of 0.3 or higher is also met by this response.

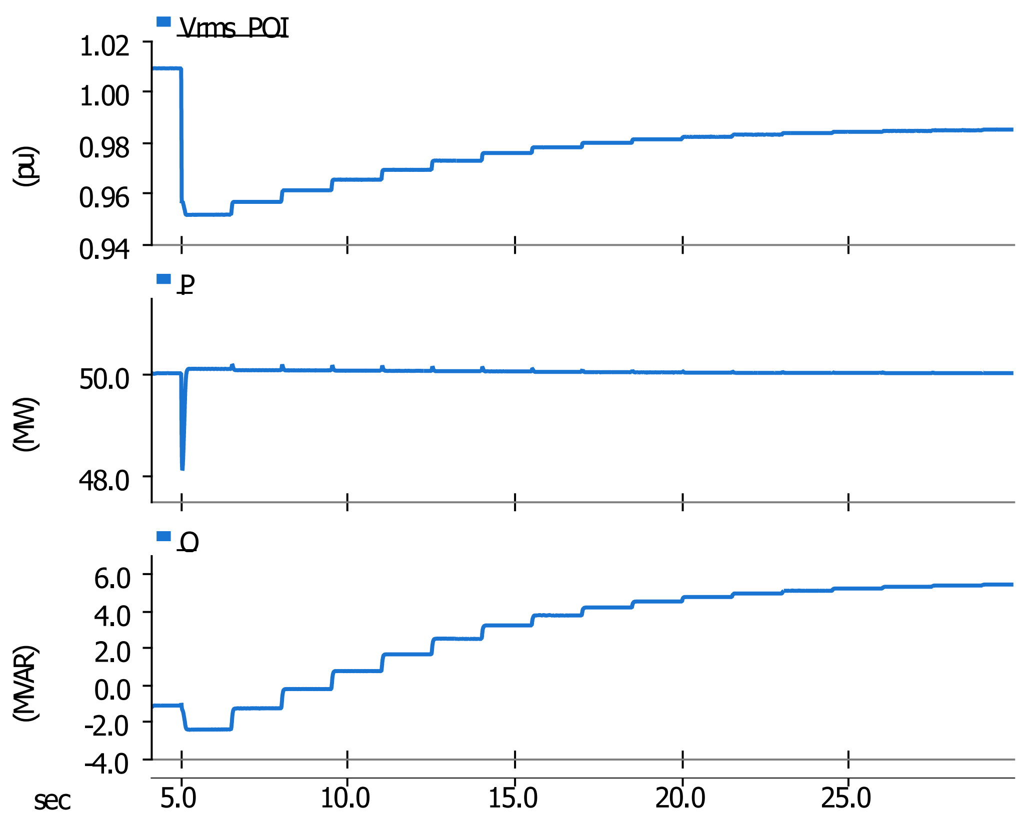


Figure 6.2: Plant Post-Event Voltage Support Example (Courtesy of American Transmission Company)

Harmonic Distortion/Flicker

Harmonic distortion and flicker can be observed in EMT studies as many detailed load and generation models are sources and/or sinks of harmonic content. The distortion levels can be quantified from the instantaneous voltage and current waveforms (measured at relevant locations) and compared against applicable criteria, such as those listed in IEEE 519 and IEEE 2800-2022 in Chapter 8. Additionally, large voltage distortions at inverter terminals may lead to instantaneous or RMS overvoltage tripping as these are superimposed on the fundamental frequency voltage. If such a result is observed, the study engineer should investigate whether the simulation model has sufficient details to be reasonably accurate at the distortion frequencies before taking further action. This could be investigated through discussion with GOs (and in turn, device OEMs) and by verifying that the system model is appropriate (as outlined in **Chapter 2** and **Chapter 3**).

Transient Overvoltage and Overcurrent

Transient overvoltages may occur in EMT simulation due to switching events and are often observed at fault clearing. These overvoltages may originate at the system level and propagate to inverter terminals or may originate at inverter terminals and propagate into the system. These over voltages may be observed at terminals of all or some inverters. Investigating inverter tripping due to a transient overvoltage requires observation of the instantaneous inverter terminal voltages as the overvoltage is often too brief to be fully visible in RMS measurements. Observation of overvoltage at levels at which surge arrestors begin conducting (e.g., around 1.7 pu) is an indicator that including surge arrestors in the simulation model may impact results. Observation of high and long overvoltage (e.g. >1.4 pu for longer than ½ cycle) at inverter terminals that does not cause the inverters to trip may require confirming that the EMT model has correctly modeled the overvoltage protection of the actual equipment. Likewise, observing a large instantaneous current at inverter terminals that appears to go well beyond (e.g. >1.5 pu) the inverter's rated continuous current limit for more than a few cycles but does not result in a trip indicates that the model current limits and/or overcurrent protection should be verified against equipment capability. **Figure 6.3** shows an example of an inverter responding to an unbalanced fault, during which the inverter produces an overcurrent of nearly 3 per unit on a single phase for a number of cycles. This level of overcurrent maybe unrealistic due to the thermal constraints of switching devices in modern inverter equipment and therefore requires further investigation of the model quality.

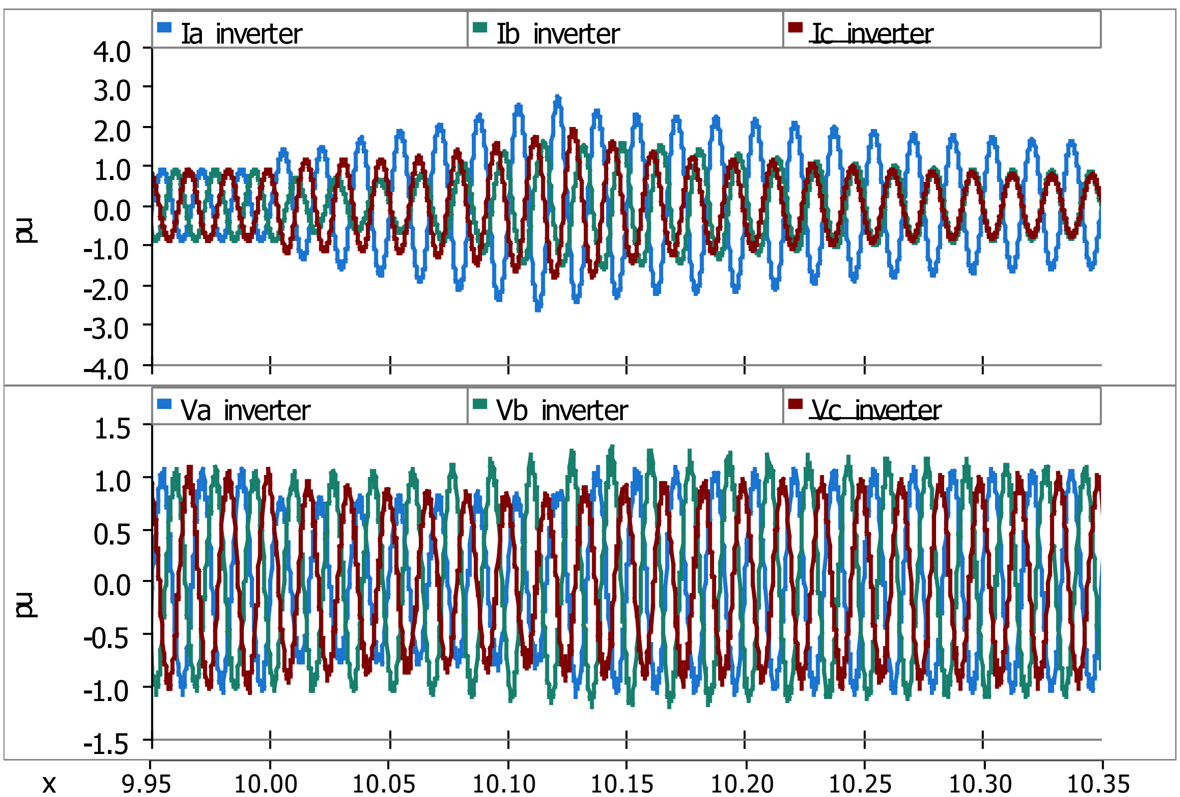


Figure 6.3: Example of Unrealistic Overcurrent Output at Inverter Terminals

Simulation Quantities to Monitor

Simulation quantities that are typically monitored to assess the dynamic performance of specific devices and the system include the following:

- **At the device terminals as well as at the reference point of applicability (e.g., POI):** Terminal instantaneous voltage and current, RMS voltage and P/Q output should be monitored. System frequency[28] at the reference point of applicability may also be of interest. Additional quantities (e.g., real and reactive components of current, sequence components of voltage and current) may also be of interest and can be derived from the instantaneous phase voltages and currents. Analysis of these quantities can be used to verify the ride-through and post-disturbance performance requirements applicable to the plant(s) under study. The study engineer may need to look at the results with a narrow time-axis aperture (e.g., less than 1–2 seconds) to perform a thorough analysis, specifically for transients occurring at fault initiation and fault clearing.
- **Control signals exchanged between plant and inverter-level controllers:** The commands sent from the plant controller to the inverters (typically P and Q commands) can be very informative in explaining plant behavior, particularly for diagnosing which controller is involved in unexpected behavior (i.e., when the plant trips or fails to meet plant-level voltage/frequency control objectives). For example, if the active power unexpectedly reduces after the event, the study engineer can quickly determine if the reduction is caused by the plant controller or by an inverter-level control by observing the active power command sent from the plant controller. Note that the plant controllers and inverter controllers may exchange many more control signals, such as power availability and information about terminal conditions sent from inverter to the plant controller, or voltage/frequency setpoints rather than P/Q setpoint from the plant controller to the inverter controller.
- **Device trip/ride-through mode flags:** These are outputs of internal quantities produced by the device model and are useful for diagnosing reasons for tripping and explaining device behavior (as the user cannot have full access to internal variables of the black-boxed EMT model). In the example plots shown in **Figure 6.5** , the LVRT and high-voltage-ride-through (HVRT) mode flags indicate that the inverters have stopped responding to the plant controller commands and are instead responding according to the LVRT and HVRT control algorithms implemented at the inverter level.
- **Internal control signal outputs:** Internal control signals, such as measured phase-locked loop (PLL) frequency/tracking error, measured RMS voltage, and measured real and reactive current, can be useful in assessing device performance during and after faults, although in many models these control signals are not externalized or very selectively externalized and typically do not have in-depth explanations provided due to OEM intellectual property concerns.
- **System instantaneous voltage, RMS voltage, and P/Q flows**: These should be monitored for buses and branches of interest, as needed to assess applicable system performance criteria.

Figure 6.4 and **Figure 6.5** show example plots of typical POI and inverter-level simulation quantities. The inverter-level plot is zoomed in to show the behavior of the IBR during and after the fault. The inverter-level plot includes the inverter HVRT and LVRT mode flags as well as several flags indicating the activation of self-protection mechanisms.

[28] Some frequency measurement methods (possibly even those that are embedded in EMT simulation tools) are prone to producing erroneous frequency measurements, such as spikes during transients or errors in steady-state measurement.

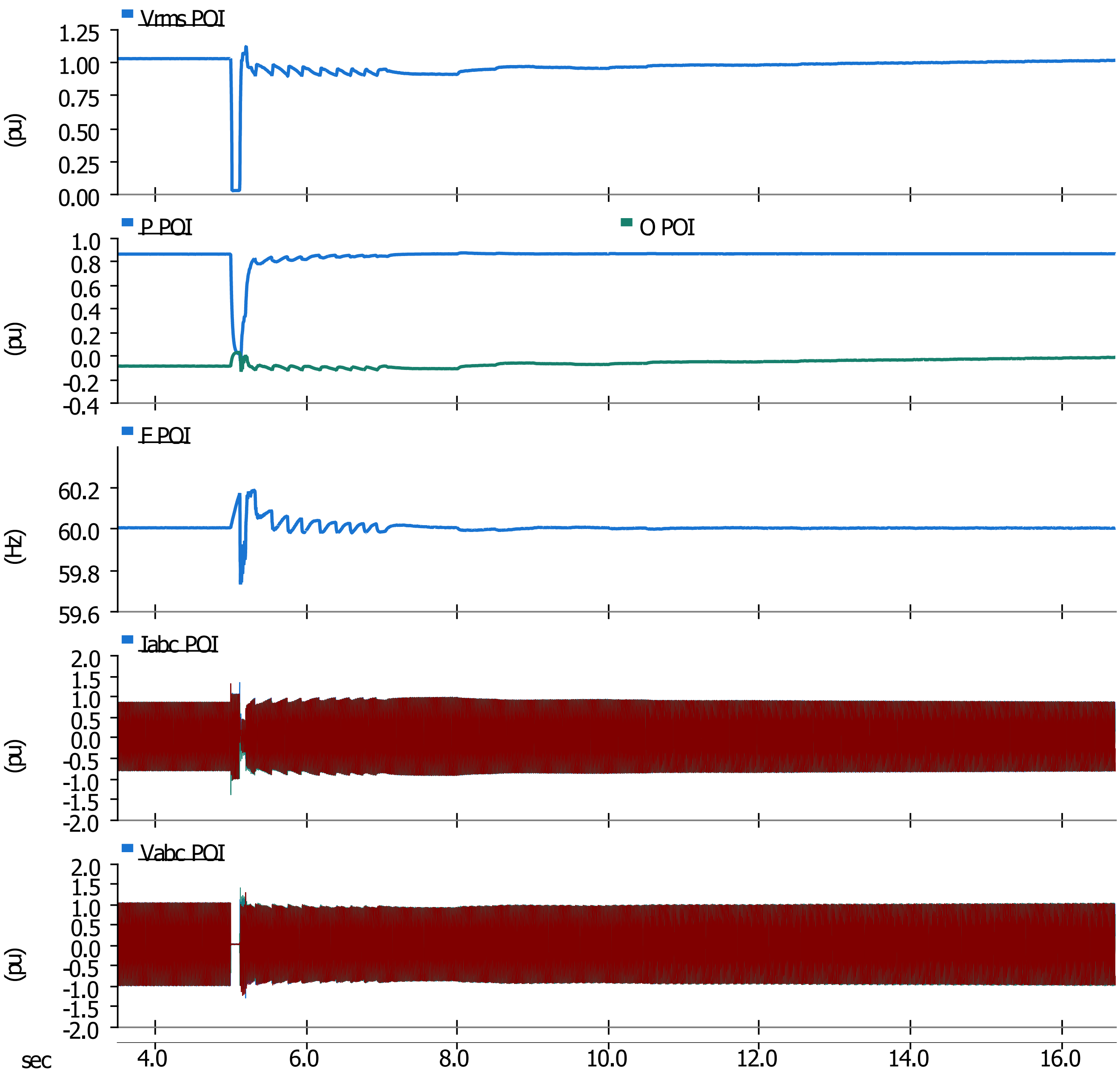


Figure 6.4: Example Plot of Typical IBR Plant POI Quantities (Courtesy of American Transmission Company)

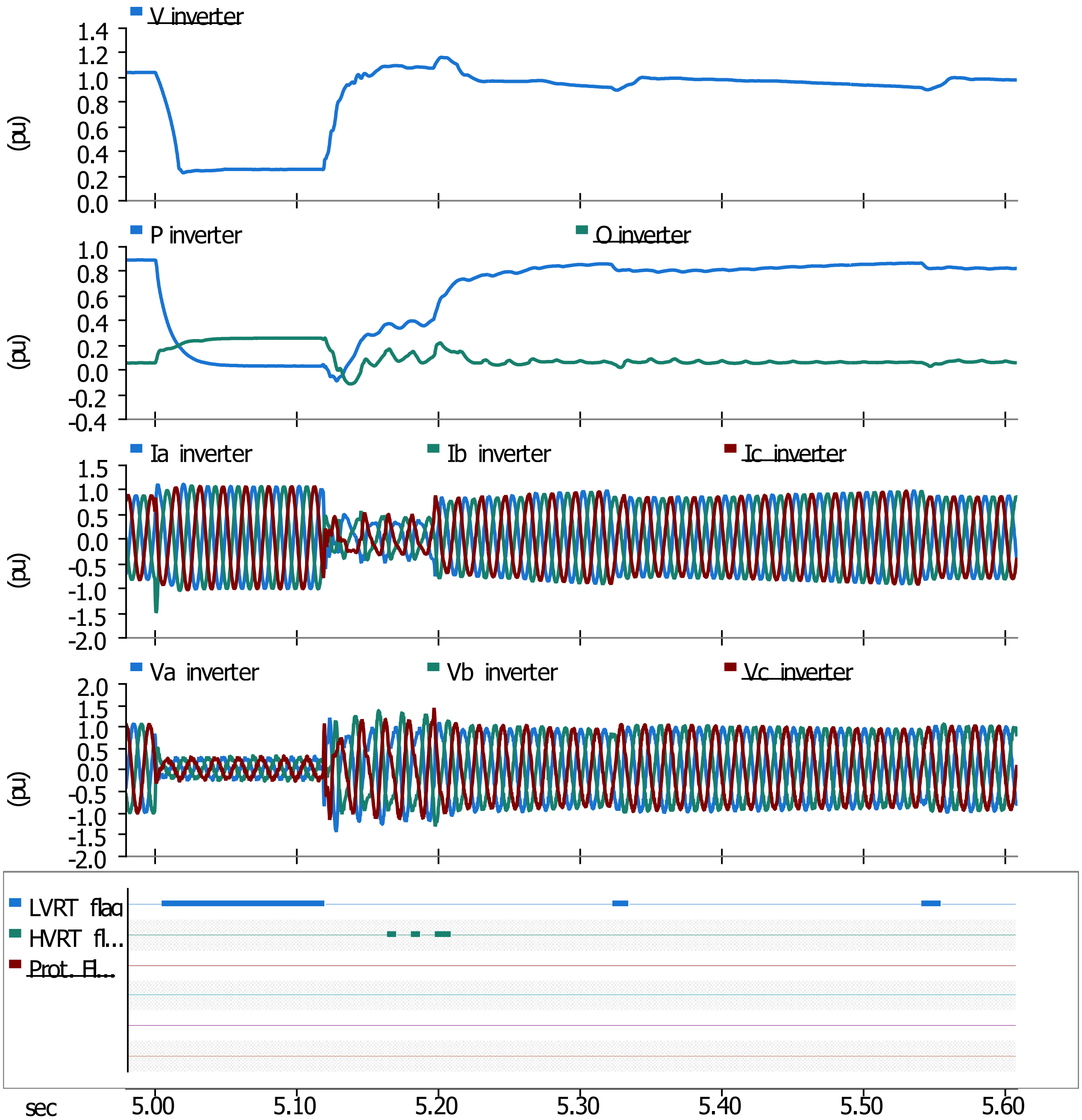


Figure 6.5: Example Plot of Typical IBR Inverter Quantities (Courtesy of American Transmission Company)

Processing Results

Depending on the size of the study, there may be several hundred pages of simulation results to analyze. The results may be screened by using a post-processing method that sets quantitative thresholds that are set conservatively such that only the very well performing results pass. This helps the study engineer focus on poor performance, although all result traces should still be reviewed with good engineering judgment.

Comparison to PSPD Study Results

RMS results from the EMT dynamic study may be compared to PSPD results with the objective of either benchmarking the phasor-domain model against the EMT model (i.e., substantial differences may be a result of modeling mistakes or inadequate study area selection) or identifying deficiencies in PSPD models (i.e., how much is missed in PSPD studies). This should be done with the understanding that there will be differences between results because there are inherent differences between the tools, because many PSPD models may not have been benchmarked thoroughly against corresponding EMT models and because the EMT system model is typically a subset of the PSPD system model and because load model dynamics are usually static in system wide EMT studies.

Subsynchronous Oscillation Studies

SSO is an electric power system condition in which the electric network exchanges significant energy with the generator at frequencies below the rated system frequency following a disturbance from the equilibrium.[29] Depending on the involved power system components, SSO is further classified into subsynchronous resonance (SSR), subsynchronous torsional interaction (SSTI), subsynchronous control interaction (SSCI) and subsynchronous ferroresonance (SSFR)[30].

SSR includes three phenomena – torsional interaction, induction generator effect and transient torque. SSCI is caused by the interaction between power electronics of IBRs and series-compensated lines or weak grid conditions. Thus, with the increasing penetration of IBRs on the BPS, there is an increased likelihood of encountering SSOs, which are detrimental for power systems since they may cause power quality issues or power outages, or damage power system components.

The ferroresonance phenomenon largely arises from the interaction between a capacitance (e.g., series-capacitor compensated lines) and a non-linear inductance (e.g., non-linear saturation of transformers), accompanied by minimal resistance. When the capacitance moves through a non-linear inductance region, ferroresonance is typically observed. Ferroresonance primarily happens due to the presence of components with non-linear properties, such as capacitance and inductance, within the network. This interaction typically leads to a non-linear relationship between voltage and current levels and distorts waveforms, causing them to deviate from their usual sinusoidal shape. Consequently, it is crucial to analyze this phenomenon in the time domain by accurately modeling the non-linear impedances in the system using EMT simulations, including the detailed saturation characteristics of power transformers.

Figure 6.6 summarizes the various types of subsychronous oscillations. For example, SSR is prevalent between series compensation and mechanical components of Type 3 WTGs.

[29] I. S. R. W. Group et al., "Terms, definitions and symbols for subsynchronous oscillations," IEEE Transactions on Power Apparatus and Systems, vol. 104, no. 6, pp. 1326–1334, 1985.

[30] K. Gauthier, M. Alawie, "A special case of Ferroresonance involving a series compensated line," (2017)

	IBR Components		
	Mechanical Components	Converter Control / Power Electronics	Power Transformer
Series Capacitor (Susceptibility)	SSR (Type I, II, III WTGs)	SSCI (All IBRs)	SSFR (All IBRs)
Gas Turbines (Susceptibility)	-	SSTI (All IBRs)	-
Converter Control / Power Electronics (Susceptibility)	-	Control Interaction (All IBRs)	-

Figure 6.6: Various Types of SSO and Control Interaction involving IBRs

The following sections describe the key differences between full converter systems, such as PV, BESS and Type 4 wind turbines, and doubly-fed induction generator (DFIG) wind turbines, also known as Type 3 machines, regarding their susceptibility to subsynchronous phenomena.

Full Converter Systems (PV, BESS, Type 4 WTG)

PV and BESS resources employ inverters which are also known as full converter systems. These power electronic converters can interact with network resonances causing SSCI-related issues.

Similarly, Type 4 wind turbines employ full converter systems which might completely isolate the turbine's mechanical parts from the grid's electrical resonances, depending on the control strategy utilized, therefore, making them inherently immune to SSR. These turbines can operate optimally across various wind conditions because their operational speed is not influenced by grid frequency, promoting efficiency and reducing mechanical stress. However, Type 4 WTGs are still susceptible to SSCI and SSFR due to interaction between the converter control and network resonances.

Doubly-Fed Induction Generator (DFIG) Turbines

DFIGs have a direct connection to the grid via the stator with the rotor connected through converters that handle a portion of the power. This setup partially exposes DFIGs mechanical system to grid conditions and disturbances. DFIGs' partial grid connection exposes them to SSR risks like induction generator effect and torsional interaction in particular, necessitating the implementation of specific control measures and possibly additional hardware to manage SSR effectively. DFIGs are economically favorable for variable speed operations due to the smaller size of the converters required compared to Type 4 WTG. However, this cost benefit comes with the increased complexity of managing potential SSR issues. Regardless of the converter topology, both technologies can be susceptible to SSFR and SSCI.

Subsynchronous Control Interaction

SSCI phenomena are frequently observed between Type 3 wind turbine generators (WTG) and weak, series-compensated grid lines. Figure 6.7 (top) and (bottom) illustrates a typical setup of a wind farm connected to a series-compensated line and the configuration of a Type 3 wind turbine. The control scheme of a DFIG-based wind turbine can result in a negative equivalent resistance at SSCI frequencies, potentially leading to grid instability and introducing the risk of the SSCI phenomenon.

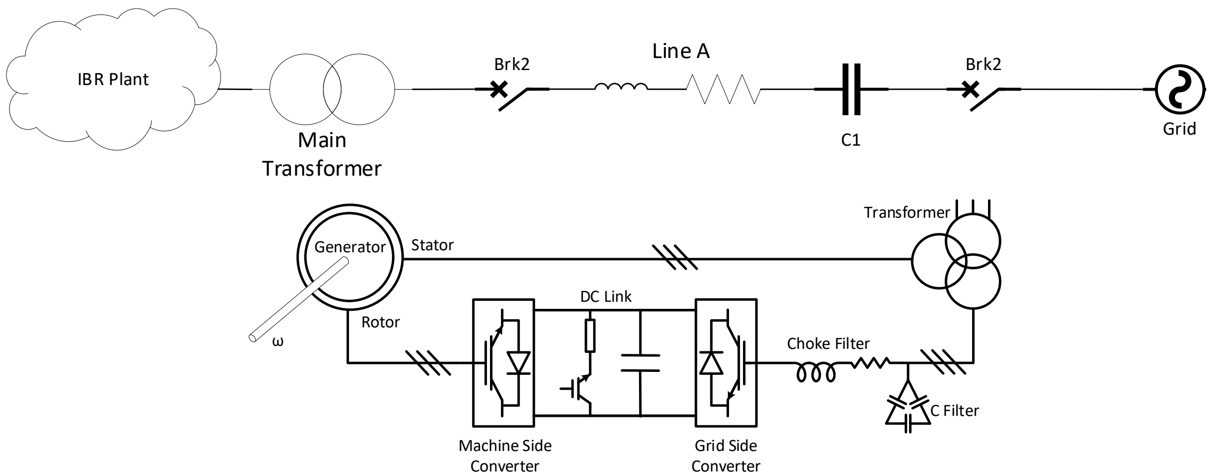


Figure 6.7: General Diagram of a Wind Farm-Connected Series Compensated Network (Top), a DFIG-Based WTG Configuration (Bottom)

The interaction between the grid impedance and the WTG impedance may cause an unstable operation condition and may also influence the control performance of the turbine. To determine the equivalent impedance of the IBR plant, adopt a simple and pragmatic analytical approach. At the POI of a wind farm, small voltage harmonics are superimposed on the fundamental waveform across various subsynchronous frequencies as shown in **Figure 6.8**. The currents at these frequencies entering the wind plant are monitored. Extract the magnitudes and phases of all relevant subsynchronous voltages and currents with a discrete Fourier transform algorithm. From these measurements, compute the resistance and reactance at each subsynchronous frequency at the wind plant's terminals with the initial harmonic perturbations. Use this resistance to estimate the damping effects attributable to the plant.

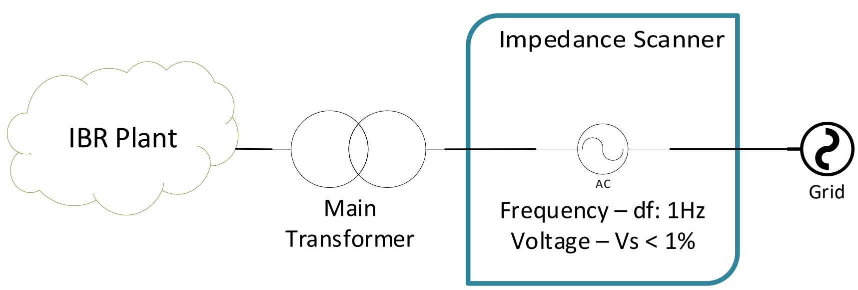


Figure 6.8: Single-Line Diagram of Impedance Scanner

The process in **Figure 6.8** should be simulated with time-domain simulation tools to accurately capture the currents and voltages over time. This detailed temporal data is crucial for further analysis, allowing for the conversion of these measurements into equivalent impedance values that can be expressed in either polar or rectangular format. This method ensures a comprehensive understanding of the system's dynamic responses and facilitates precise impedance characterization. Once the simulation data is obtained, a Fast Fourier Transform (FFT) analysis must be conducted to obtain the equivalent impedance.

As observed in **Figure 6.9**, the real part of the impedance of various IBR plants is analyzed to evaluate their susceptibility to SSCI. Type 3 wind turbines without SSCI mitigation display significant negative resistance, which can predispose them to stability issues. When the control systems of these Type 3 turbines are enhanced to include active frequency scanning and damping, their resistance becomes markedly less negative, improving their operational stability. In contrast, Type 4 turbines exhibit positive resistance, rendering them less vulnerable to SSCI compared to their Type 3 counterparts. Type 4 turbines and other full converter systems (PV and BESS) are still susceptible to SSCI if interconnected in areas with series compensation or weak grid conditions.

These insights are only obtainable through post-processing accurate EMT models, which are essential for analyzing the detailed control interactions of IBRs. This analysis highlights the critical role of advanced control mechanisms and high-fidelity modeling in mitigating SSCI risks and enhancing the stability of the power system.

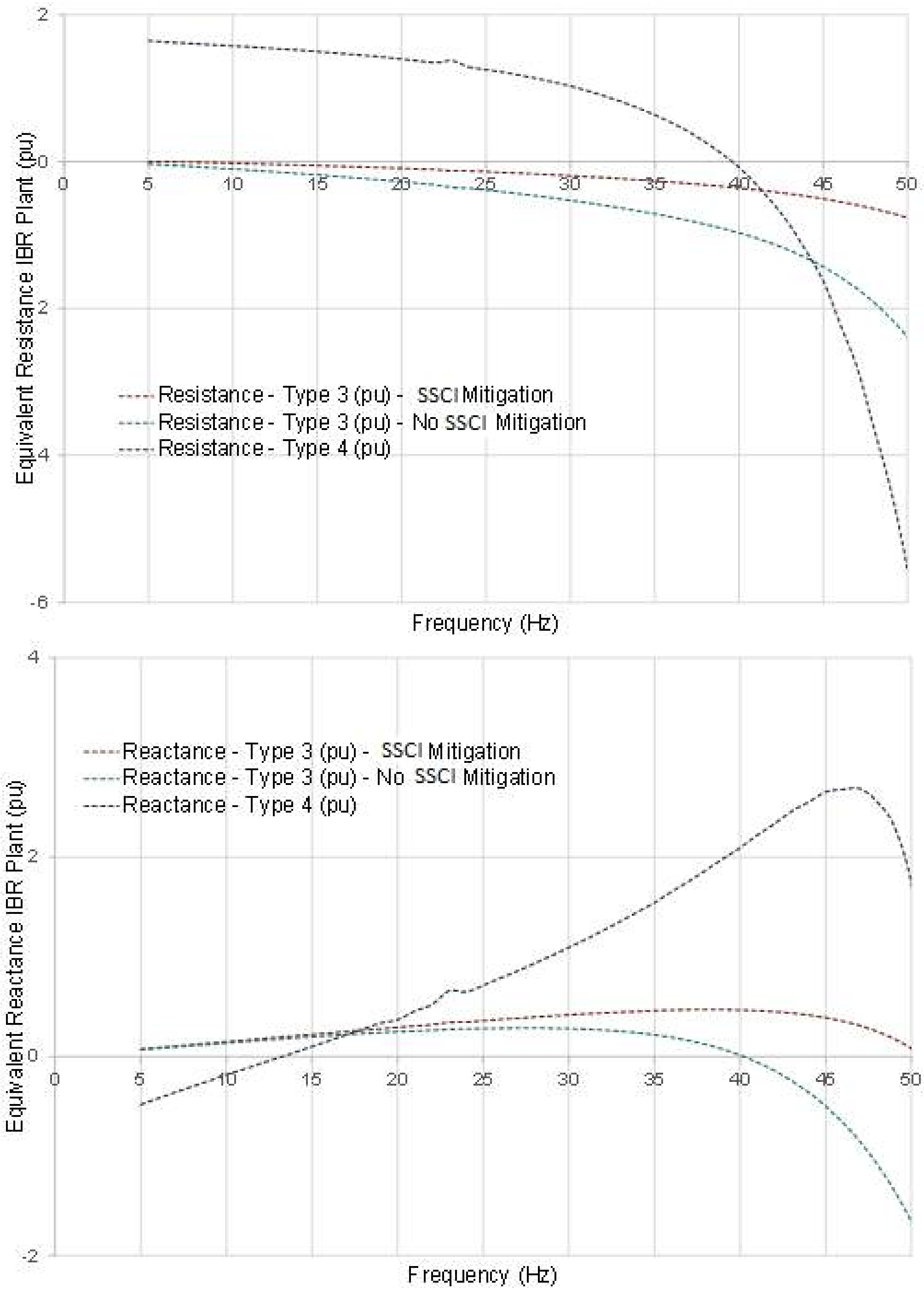


Figure 6.9: Impedance Scan Comparison

The SSCI issue arises when the combined resistance of the grid and the WTG become negative at a certain frequency. This typically occurs when the series compensation capacitance neutralizes the inductance, leading to resonance. To mitigate this, reducing the gain of the rotor current controller can decrease the virtual negative resistance exhibited by the WTG. Additionally, it is crucial to synchronize the adjustments by also reducing the bandwidth of the power controller following any reduction in the current controller's bandwidth. This step is essential to maintain stable operation of the WTG.

The stability analysis of the system can be done by using the impedance-based stability criterion, where the small signal model of the system is divided into a WTG and a grid subsystem as shown in **Figure 6.10**. Accordingly, the current IWTG flowing from the WTG to the grid is as follows:

$$I_{WTG}(s) = \frac{V_{WTG}(s) - V_g(s)}{Z_{WTG}(s) + Z_g(s)}$$

Therefore, the system will be stable if ZWTG/Zg fulfills the Nyquist criterion (i.e., the ZWTG/Zg trace does not encircle the point -1 in the complex plane) and if the following assumption are also valid:

- The equivalent voltage source VWTG(s)-Vg(s) has no unstable poles
- The grid impedance Zg has no right-half plane zeros

It is worth noting that the below representation is only valid for small-signal analysis; large-scale stability must be ensured with dynamic analyses. Therefore, it is not in the scope of this guideline.

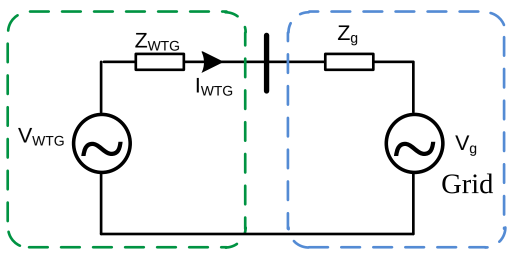


Figure 6.10: Small-Signal Model of a WTG Connected to the Grid

Subsynchronous Ferroresonance[31]

Ferroresonance is a nonlinear resonance that occurs when a circuit contains saturable nonlinear inductance and capacitance with minimal resistance. This effect is particularly common in configurations like a transformer-terminated double circuit line, in which power transformers, as key sources of nonlinear inductance, are linked to extensive transmission lines running parallel to another line. This setup facilitates ferroresonance through capacitive interaction between the lines, and increasing voltage levels may induce transformer saturation, heightening the risk of ferroresonance. Such dynamics can lead to significantly elevated currents and frequency distortions. Moreover, the oscillatory behaviors induced by ferroresonance can merge with torsional oscillations associated with SSR, thereby increasing the complexity of the system's operational dynamics. It is essential to accurately model these nonlinearities, including the saturation of power transformers, when assessing the grid-interconnection impacts of IBRs connected to series-compensated lines. Proper modeling can be achieved by using EMT time domain simulation tools, which allow for the correct representation of power transformer saturation in their simulations.

Considering the hypothetical equivalent circuit illustrated in **Figure 6.11**, an IBR plant is connected to the network via a parallel transmission line arrangement. In this scenario, one of the lines includes a series compensation. Should a

[31] R. Rogersten, R. Eriksson, "A ferroresonance case study involving a series-compensated line in Sweden," IPST, 2019

fault occur on Line B and the protection mechanism at Breaker 1 (Brk1) activate, thus isolating the line, the IBR plant will still maintain a radial connection through the line with series compensation. This configuration underscores the importance of considering the dynamics and potential operational scenarios of the network, especially in terms of fault response and system stability.

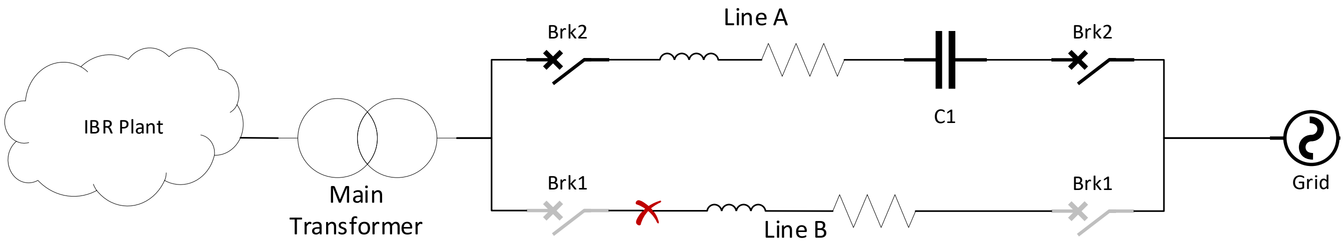
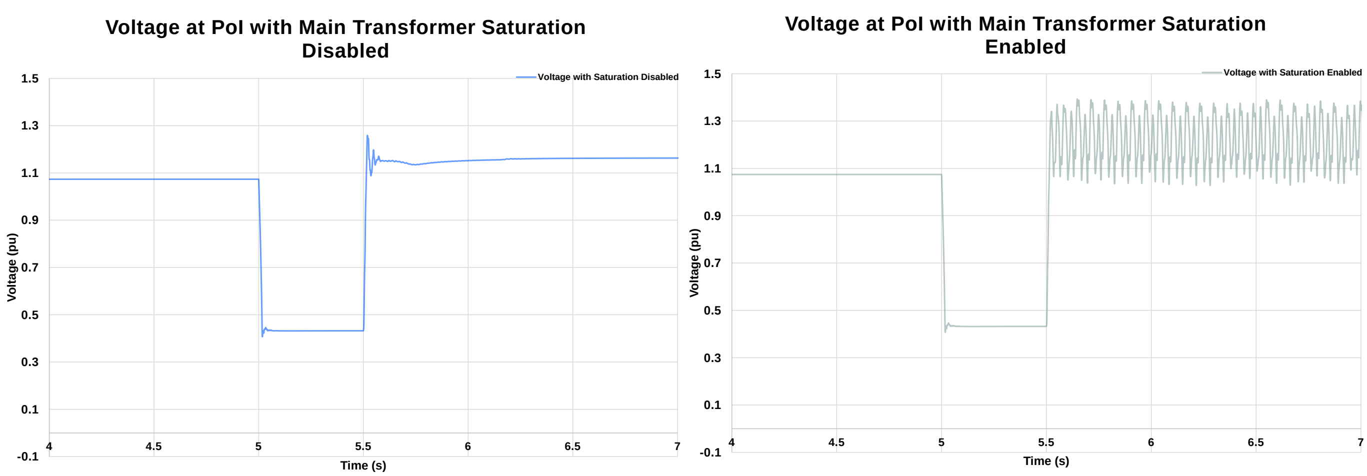


Figure 6.11: Single-Line Diagram of a Series-Compensated Plant

In the simulations of the scenario depicted in **Figure 6.11**, significant discrepancies are observed in the results depending on the modeling approach of the transformer. When the main substation transformer is modeled both with and without considering core saturation, the outcomes are markedly different (shown in **Figure 6.12**). Without including core saturation in the main transformer model, the plant successfully rides through a fault on Line B and its subsequent clearance, maintaining a radial connection through Line A. However, when core saturation is included in the main transformer model, the plant exhibits instability, characterized by sustained oscillations around 20 Hz. This contrast underscores the critical impact of accurate transformer modeling on the stability and operational reliability of the plant, particularly during fault conditions and subsequent network configurations.



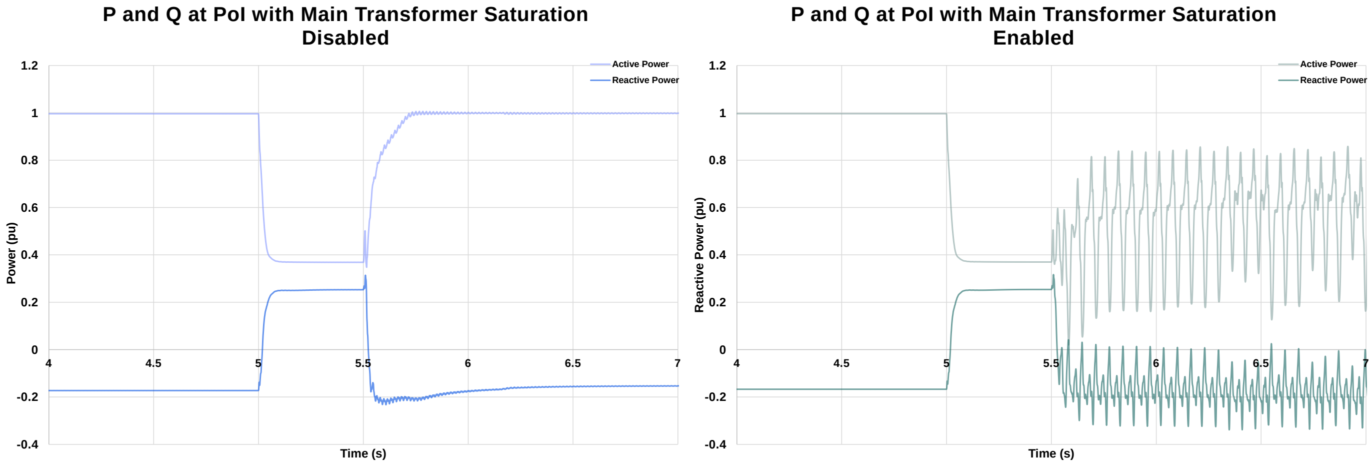


Figure 6.12: Comparison of Simulation Results of IBR in a Series-Compensated Line with and without Transformer Saturation

SSCI/SSR Screening Studies

As explained in **Chapter 5**, the critical study scenarios to be studied in time domain EMT simulations can be narrowed down by screening for credible conditions that are conducive to SSCI and SSR phenomena. SSCI/SSR screening studies[32] involve two main steps – passive frequency scanning and active (dynamic) frequency scanning. The passive frequency scanning identifies electrical resonances in the power system in the range of 2 Hz to 55 Hz using phasor domain calculations. Both PSPD and EMT tools can be used to produce impedance versus frequency plots as seen from the POI of IBRs. Active frequency scanning approximates an "effective impedance" of each converter which, combined with passive frequency scanning results, can estimate the net damping for electrical resonances in the system. The scenarios resulting in net negative damping are selected for further analysis in time domain EMT simulation studies.

Real-World SSO Event Study Framework[33,34]

Ideally, SSO events should be minimized by strengthening the power grid and developing suitable mitigation actions in the system planning and operation stages. EMT studies to assess and mitigate potential SSO issues are well documented. Nonetheless, it is still difficult to completely prevent oscillation events due to the complicated SSO mechanisms. Thus, post-SSO-event studies are sometimes needed to identify root causes and mitigate potential SSO issues. Therefore, this guideline instead focuses on post-event, root-cause analysis for SSO.

The National Renewable Energy Laboratory (NREL) developed a real-world SSO event analysis framework with six steps as displayed in **Figure 6.13** below. In this framework, both measurement- and model-based analysis are leveraged to identify the SSO sources, understand the SSO event root cause, and recommend effective mitigation methods.

[32] "Guidelines for Subsynchronous Oscillation Studies in Power Electronics Dominated Power Systems ", CIGRE TB 909, 2023, https://www.e-cigre.org/publications/detail/909-guidelines-for-subsynchronous-oscillation-studies-in-power-electronics-dominated-power-systems.html
[33] S. Dong, B. Wang, J. Tan, C. J. Kruse, B. W. Rockwell, K. Horowitz, and A. Hoke, "Analysis of November 21, 2021, Kauai Island Power System 18-20 Hz Oscillations". arXiv preprint arXiv:2301.05781. 2023 Jan. 13.
[34] J. Tan, S. Dong, and A. Hoke. "Island Power Systems with High Levels of Inverter-Based Resources: Stability and Reliability Challenges." United States. https://www.osti.gov/servlets/purl/1996391

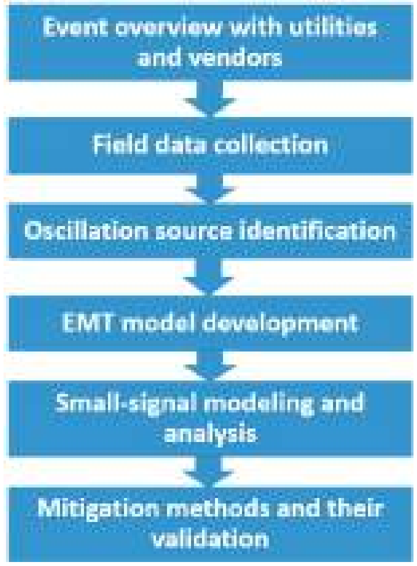


Figure 6.13: Real-World SSO Event Analysis Framework Proposed by NREL

- **Step 1:** Review the event with utilities, IBR vendors, and/or OEMs.
- **Step 2:** Collect the field data of the SSO event (e.g., low-/high-speed DFR data, Universal Grid Analyzer (UGA) data, and SCADA data.
- **Step 3:** Identify the oscillation source based on measurement-based methods like the dissipative energy flow (DEF)[35,36] and sub/super-synchronous power flow method.[37]
- **Step 4:** Develop EMT model to replay the SSO event. In this step, parallel simulation can be leveraged to accelerate the simulation speed.
- **Step 5:** Develop small-signal model and apply the small-signal analysis to understand the root cause of the SSO oscillations. Frequency scanning studies can be performed while analyzing the event.
- **Step 6:** Propose mitigation methods and validate them in the EMT simulation, power hardware-in-the-loop (PHIL) experiment, or field test.

Case Study of Kaua`i Island Power System 18–20 Hz Oscillations

The analysis performed following the Kaua`i Island 18-20 Hz SSO event provides an example that demonstrates the effectiveness of the SSO event analysis framework. Kaua`i Island is Hawaii's fourth-largest island and has a meshed and isolated power system that is operated by Kaua`i Island Utility Cooperative (KIUC). The Kaua`i power system features high penetration of IBRs during its operation. For example, according to KIUC's 2021 annual report, 44.8% of Kaua`i Island's annual generation comes from IBRs.[38]

[35] L. Chen, Y. Min, and W. Hu, "An energy-based method for location of power system oscillation source," IEEE Trans. Power Syst., vol. 28, no. 2, pp. 828–836, 2013.
[36] S. Maslennikov and E. Litvinov, "ISO New England Experience in Locating the Source of Oscillations Online," in IEEE Trans. Power Syst., vol. 36, no. 1, pp. 495-503, Jan. 2021.
[37] X. Xie, Y. Zhan, J. Shair, Z. Ka, and X. Chang, "Identifying the source of subsynchronous control interaction via wide-area monitoring of sub/super-synchronous power flows," IEEE Trans. Power Del., vol. 35, no. 5, pp. 2177–2185, 2020.
[38] Kaua'i Island Utility Cooperative, "Hitting the target – KIUC 2021 annual report," Lihue, HI, Dec. 2021.

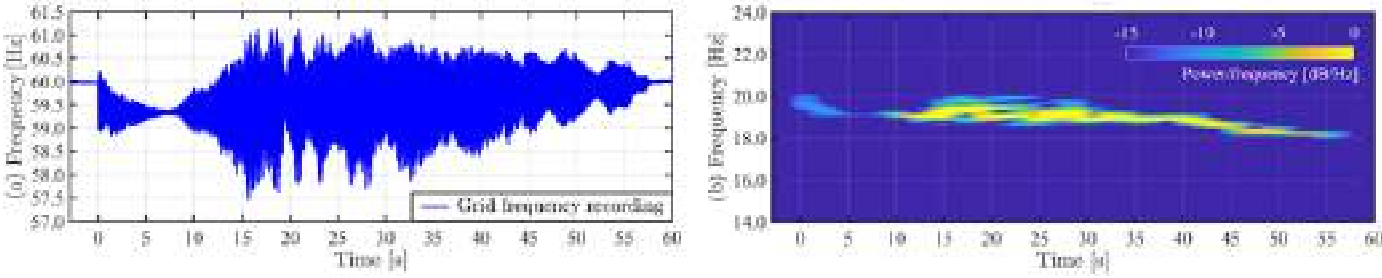


Figure 6.14: Kaua`i Island Frequency Recording with 18–20 Hz Oscillations

A 18–20 Hz oscillation event occurred on Kaua`i Island at 5:30 a.m. Hawaii-Aleutian Standard Time on November 21, 2021 (see **Figure 6.14**) following the tripping of a synchronous generator that was supplying 60% of the total load. This generator trip represented the most severe N-1 contingency in the Kaua`i power system. These 18–20 Hz oscillations triggered by the generator trip posed serious challenge to the stability of the Kaua`i power system. To prevent similar events in the future, the root cause of this event should be fully understood, and effective mitigation methods should be explored. Thus, as detailed below, this SSO event was studied with the analysis framework shown in **Figure 6.13**: Real-World SSO Event Analysis Framework Proposed by NREL.

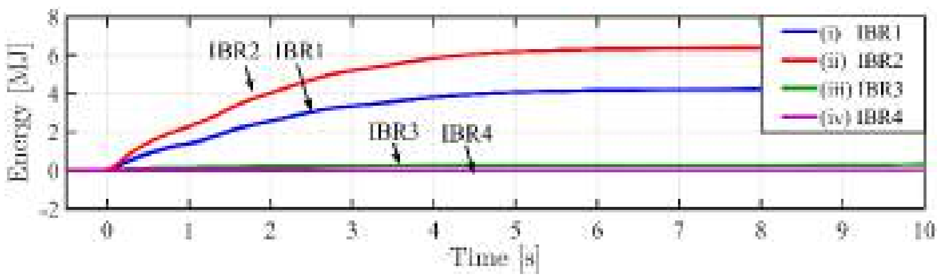


Figure 6.15: Identification of Oscillation Sources with the DEF Method

- **Steps 1–3**: After reviewing the event (Step 1), KIUC's field data was collected for the event (Step 2), which was recorded by DFR. Step 3 was then completed, and the oscillation source(s) were identified with two measurement-based algorithms—DEF and sub/super-synchronous power flow method. The DEF method only requires low-speed phasor data, and, as shown in **Figure 6.15**, two IBRs with grid-following (GFL) controllers (i.e., IBR1 and IBR2) were injecting dissipating energy into the power systems while the oscillation event occurred. Thus, the DEF method infers that IBR1 and IBR2 were the oscillation sources in this event. To crosscheck the DEF analysis results, the high-speed point-on-wave DFR data was leveraged to compute the sub/super-synchronous power flow corresponding to the 18–20 Hz oscillation frequency. The sub/super-synchronous power flow also suggests that IBR1 and IBR2 were the sources of oscillations. Hence, it was concluded that the 18–20 Hz oscillation event was caused by two IBRs with GFL controllers.
- **Step 4**: In this step, EMT studies were performed to recreate the oscillation event. EMT simulation studies were performed instead of phasor-domain simulation since phasor-domain simulation cannot replay these 18–20 Hz oscillations. One key step in EMT studies is re-creating the oscillation event in the simulation. To achieve this goal, the detailed EMT model for the Kaua`i island power system was built by converting the KIUC PSS/E model and integrating available vendor-provided IBR models. There was no challenge in defining the modeling boundary since the Kaua`i power system is a small and isolated island power system. It should also be highlighted that the vendor model should be validated against the field data and tuned based on the inputs from the utility because some IBR parameters like P/f droop constant can be revised remotely by system operators after being commissioned and these parameters can play an important role in the event. Another challenge is that some IBRs did not have available vendor-provided models, instead using generic models with their parameters tuned based

on the field data. After these modeling efforts, the 18–20 Hz oscillations were successfully recreated in EMT simulation as shown by the red trace in Figure 6.16. Simulated and recorded grid frequencies have similar time-domain responses and FFT spectra, which can be used to validate the EMT model accuracy.

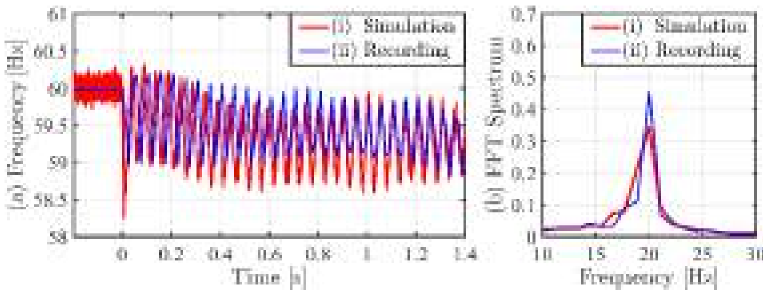


Figure 6.16: (left) Simulated and Recorded Grid Frequency Waveforms. (right) FFT Analysis Results.

- **Step 5**: After recreating the event with EMT simulation in Step 4, parameter sensitivity analysis, small-signal stability analysis, or frequency-scanning studies (Step 5) should be performed. Taking the parameter sensitivity analysis as an example, about 40 controller parameters were identified and perturbed to check for the impact on the simulated oscillation frequency and magnitude. Based on the parameter sensitivity analysis, the P/f droop constant and PLL gain in IBR1 and IBR2 made the most significant impact on the simulated oscillations. In addition, IBR1 and IBR2 were connected to medium weak grid, following the N-1 contingency. Increasing the grid strength can eliminate oscillations. Thus, this event was caused by a combination of different non-optimal settings and system conditions. These findings were further confirmed by detailed small-signal analysis.

- **Step 6**: Based on the findings in Step 5, three mitigation methods could be proposed: adopting less aggressive IBR1 and IBR2 P/f droop constant; reducing PLL gain in IBR1 and IBR2; and converting GFL controllers to grid-forming ones. Finally, the effectiveness of these mitigation methods was validated using EMT simulations. Taking mitigation method 1 as an example, as shown by the **blue** trace in Figure 6.17, the simulated frequency no longer has obvious 18–20 Hz components after adopting method 1, demonstrating the effectiveness of the proposed method.

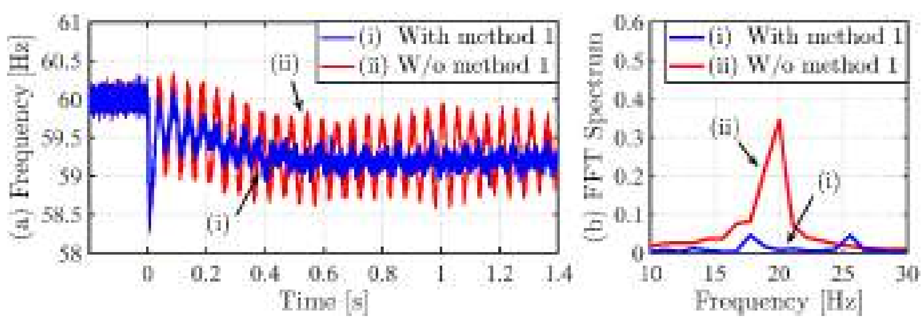


Figure 6.17: (left) Simulated Grid Frequencies Measured at IBR1 with and without Method 1. (right) FFT Analysis Results of Simulated Grid Frequencies.

Transmission System Protection Validation Studies

As the number of IBRs connecting to the North American BPS continues to rise, transmission system protection engineers are becoming increasingly concerned about the potential impacts on existing industry protocols. Traditional protection methods were established over a century ago when IBR presence was minimal—if not nonexistent—and fault currents were predominantly influenced by the behavior of rotating machinery, particularly synchronous generators. In fact, traditional protection schemes were optimized based on the behavior of synchronous generation to abnormal system conditions and faults. The response of a synchronous generator during a fault event, dictated by the laws of physics, is well understood by protection engineers, who utilize linear circuit analysis techniques incorporating relevant machine impedances and time constants which determine the fault current behavior.

Subtransient and transient impedances from synchronous generation are not directly applicable to IBRs since their impedance profile is mostly determined by the inverter control system. The fault response of an IBR depends on how its control system is programmed to react rapidly to abnormal terminal conditions. This rapid response from IBRs remains less understood by protection engineers. Furthermore, there is inconsistency in response between IBRs from different manufacturers.[39]

The existing protection practices are not designed for systems with high penetration of IBRs. Currently, industry practices rely on synchronous generation to provide the operating quantities for relaying. This may prove insufficient as more synchronous generations are retired and IBR penetration grows. This highlights the need for reassessment and potential adjustments in transmission system protection strategies.

Objective

The main objective of the protection system validation study is to verify the validity of existing transmission protection schemes and their settings for systems with high levels of IBR penetration and make necessary adjustments to settings or algorithms to ensure reliable operation with high levels of IBRs. Objectives also include the following:

- Identification of scenarios where transmission system reliability could potentially be compromised by insufficient fault current and/or poorly characterized responses to system faults. These threats to reliability could be in the form of degraded dependability or security of protective relaying schemes.
- Guidance could be provided to practicing transmission system protection engineers on criteria to evaluate whether further analysis of fault responses is needed in the interconnection study process.

Methodology

Similar to the Dynamic System Impact Assessment Study in **Chapter 6**, disturbances will be applied throughout the system. The list of disturbances (as discussed in **Chapter 5**) to be applied will be decided based on the protection relays under study. A general approach is to select contingencies that could result in less contribution from synchronous generators for operating quantities applicable to the relays under study. The relays that are typically affected due to high penetration of IBRs are impedance-based relays (e.g., distance protection, out-of-step protection, negative sequence directional elements).[40]

Ideally, the real code EMT models of transmission system protective devices are also to be included in the EMT model so that a direct indication of the relay operation can be observed (i.e., expected, mal/mis operation). Typically, however, the real code EMT models of transmission system protective devices are not available (at least to the extent that can be used in a study). In case of unavailability of real code EMT models of protective devices, approximate or generic protection models are not suitable for the protection system studies. This is because the relay outputs are highly dependent on the OEM algorithms, filtering, sampling, phasor calculation techniques, and internal settings/thresholds used in the relay. Therefore, voltage and current waveforms will be recorded in certain file formats (typically COMTRADE) and will be played back at the actual relay using real-time simulations via hardware-in-the-loop (HIL) tests.

[39] https://www.osti.gov/biblio/1595917

[40] https://www.researchgate.net/publication/379952862_Protection_of_100_Inverter-dominated_Power_Systems_with_Grid-Forming_Inverters_and_Protection_Relays_-_Gap_Analysis_and_Expert_Interviews

Model
The same system model used for the Dynamic System Impact Assessment Study can be used for the protection systems validation studies as well. In most cases, the aggregated representation of each IBR plant will be sufficient since this study is mainly focused on the protection of the transmission system.

The accurate representation of saturation in instrument transformers (current transformers (CTs) and voltage transformers (VTs)) is important, especially for scenarios in which CTs are prone to saturate during and after disturbances that result in high voltage conditions and sub- and super-synchronous harmonics.

Simulation Quantities to Monitor
Simulation quantities that are typically monitored to assess the reliability and security of protection systems include the following:

- Operating quantity of the relay (e.g., calculated impedance for a distance relay, output of a directional element)
- Settings of the relay (i.e., the characteristic that the operating quantity is compared against); (e.g., blinder and mho circle settings for a distance relay)
- Filtered sequence components of voltage and currents
- Instantaneous voltages and currents
- Active power, reactive power, and frequency.
- Trip signals, pickup signals, timer outputs of the relay

Note: It is important to use the outputs from the relays as much as possible (i.e., if the measured impedance is available as an output from the relay, it should be used in the analysis instead of deriving the impedance externally using generic calculations).

Processing Results
There may be several hundred pages of simulation results to analyze. The results may be screened by using an automated post-processing method that sets quantitative thresholds that are set conservatively such that only the very well-performing results pass. For example, if an expected result is no-trip, neither Pick Up signal nor Trip signal should be observed. This helps the study engineer focus on poor performance, although all result traces should still be reviewed with good engineering judgment.

Mitigation
In case of relay misoperation or maloperation, it is important to utilize mitigation techniques to resolve the observed issues. Commonly seen mitigation options include the following:

- Apply modifications of relay settings
- Make changes to relay protection algorithm
- Introduce/modify RAS schemes to avoid conditions where relay maloperations are observed
- Complete change of the protection relay or scheme (e.g., replacing a distance relay with a current differential relay)

Once the mitigation option is selected, it is recommended to re-study the affected scenarios to make sure that there are no additional concerns due to changes made.

Examples

Documented cases of relay misoperations attributed to lack of, or incorrect, fault current injection from IBRs, are discussed below:

- For a relay misoperation case documented by BC Hydro, a 230 kV ground fault occurred on a transmission line feeding a large wind plant consisting of Type 3 (DFIG) WTGs. Ground fault protection at each line terminal consisted of negative-sequence voltage-polarized ground overcurrent elements in multi-function microprocessor-based relays. The terminal near the wind plant failed to trip due to the negative-sequence forward directional element failing to assert, caused by an unforeseen angular difference between the negative-sequence voltage and current phasors (demonstration of degraded dependability).[41]
- In another relay misoperation case by BC Hydro, a 138 kV ground fault occurred on a low, short-circuit strength portion of the BC Hydro system. The fault location was near a pair of static synchronous compensators (STATCOMs) with a combined ±24 MVAr rating. A Zone 1 ground distance relay at the substation hosting the STATCOMs tripped for an out-of-zone fault, a demonstration of degraded security attributed to insufficient negative sequence current injection from the STATCOMs to reliably polarize the ground distance relay and prevent false tripping.

Summary

In scenarios with high IBR penetration, unforeseen fault responses may lead to the loss of security in transmission line protective relays. This can occur due to inaccurate impedance or reactance calculations if relay settings are based on the fault responses of synchronous generators and traditional practices. Both the reliability and security of protective relays may suffer as a result. Consequently, modifications to existing protection systems require additional investigations that include inverter manufacturers and system operators to come up with actionable industry guidance that is based on a common understanding of how inverters should respond during grid disturbances. Grid code requirements help OEMs to standardized inverter responses but will be difficult to achieve a level of consistency as in synchronous machines. Validation studies of transmission protection systems pinpoint these issues and assist utilities and OEMs in enhancing their protection settings and schemes to prevent potential relay malfunctions.

[41] Nagpal, M., Henville, C. (2018). Impact of Power-Electronic Sources on Transmission Line Ground Fault Protection. IEEE Transactions on Power Delivery, 33(1), 62-70.

Chapter 7: Additional Guidance on Modeling of IBR Plants

This chapter provides additional guidance on the modeling of both legacy and new IBR plants, HIL validation of IBR unit models, model fidelity for different study use cases, modeling and testing of protection system elements of an IBR plant and guidelines on OEM IBR model integration.

Modeling of Legacy IBR Without Equipment-Specific EMT Model

Many IBRs were constructed before detailed positive-sequence or EMT models were required by TPs and PCs. In addition, the requirements from TPs and PCs for detailed modeling have been evolving, meaning some may have not even existed just a few years ago. Finally, some inverter manufacturer companies are no longer in business, making it extremely challenging for GOs to obtain detailed models for their inverters. The term “legacy” has been used to name such resources. Expanding on the previous guideline on EMT modeling, this section provides additional guidance on the modeling of legacy IBR plants.

The requirements to provide detailed EMT models for such legacy plants are usually defined by ISOs, but in the absence of equipment-specific models in general, generic model components built into simulation software may be used to represent such plants. These generic models, however, have limitations and only provide an unrefined approximation of the actual plant’s behavior, meaning that the generic model response should be validated against field measurement. In addition, generic models being used should comply with applicable technical specification requirements from TPs and PCs.

As they ensure the accuracy and reliability of the models used to represent older IBRs, field data verification and model quality tests are critical in the modeling of legacy plants. Validation tests help in identifying and rectifying discrepancies between the model’s predictions and the actual behavior of the plant. This is particularly important for legacy plants, as their original design data might be outdated or unavailable. Field data verification, on the other hand, involves collecting real-time operational data from the plant and using it to validate and fine-tune the model. This step is crucial for understanding how these older plants interact with the modern grid and for making informed decisions about upgrades, maintenance, and integration with newer technologies. Ensuring model accuracy through these tests and verifications is essential for grid stability and efficient operation.

Including a comprehensive set of tests like flat start, POI voltage step changes, HVRT and LVRT for both leading and lagging scenarios, and frequency step changes in both directions is crucial in model quality testing. Additionally, considering both scenarios with and without headroom for frequency stepdown tests adds depth to the evaluation. Tests like short-circuit ratio and phase angle jump test are also essential. These tests collectively ensure a thorough assessment of the model’s ability to accurately simulate the plant’s response to a wide range of grid conditions and disturbances, highlighting its reliability and robustness in real-world scenarios.

“Generic” EMT models have also been developed over the years to produce standardized IBR plant models. In the United States and Europe, these efforts have been led by the Western Electricity Coordinating Council (WECC) and the IEC, respectively.[42] The focus has been put on developing WTG models that can conduct typical TS studies, including specific controllers like those in IBRs to test the expected performance of WTGs as an individual WTG or as an aggregate representation of a wind power plant. Models have been developed for WTG Types 1, 2, and 3, including mass turbine and generator inertia, for use in both positive-sequence and EMT simulation tools.

In short, a detailed model is equipped with the following control systems:

- Plant-level outer control loops for voltage and reactive power

[42] https://www.esig.energy/wiki-main-page/generic-models-individual-turbines/

- Unit-level voltage and current inner control loops. This would include the PLL dynamics for electronic equipment and ride-through models
- Outer control loop for dispatching active power
- Outer control loop for frequency response

For legacy plants, the idea of using generic models is valid if the model represents the above control system features and is validated against field measurement. Among the above control system features, the PLL configuration might be the most difficult to mimic in a generic model.

Many of the control features and behavior of legacy plants can be verified by using staged tests at the inverter and plant levels. Small-signal disturbances, such as voltage and frequency steps, can be implemented at the plant level. The obtained test results can be utilized to examine the validity of developed generic models. Furthermore, the generic EMT model can be benchmarked against positive-sequence models.

Ultimately, the usability of a generic EMT model for a legacy plant depends on factors like plant location, system strength, plant size, and the types of study for which the TP needs this generic model. For example, in large-area grid studies and in the case of a legacy plant with Type 1 wind turbines, only the electrical characteristics of the machine are important, and detailed control features of the machine do not need to be modeled in EMT software. Therefore, generic models are acceptable if the model can provide good electrical approximation of the machines.

GOs might be able to obtain a vendor-specific detailed model for similar inverters from the same OEM.

Appendix A provides examples of legacy IBR plant modeling.

Validation of Legacy IBR Models with Field Measurements

There are limitations with generic EMT IBR models to represent all the nuanced behaviors of controls and protection elements. While OEM's might not be involved in the design of the balance of plant facilities, GOs and their model developers should coordinate to accurately develop models that capture plant behavior accurately along with OEM inputs. Whenever available, vendor-specific OEM models are best suited to closely model real-world plant behaviors. However, if vendor-specific OEM models do not exist, an existing legacy IBR plant could be represented with a generic model that has been parameterized to reflect the plant based on available documentation and field measurements. Models of similar plants with similar ratings and control functions could also possibly be adapted to represent such legacy plants as a close alternative. If disturbance events are recorded in the field, this data can be used to validate the model response under the same conditions. For example, when the actual controller of the wind turbine is equipped with an auxiliary input, test signals can be injected to test a variety of wind conditions.[43] This way, a large amount of field results can be acquired to compare with the model response in the same test scenarios. Another published example of HIL validation includes a study where a generic wind turbine model is tuned and validated against the field tests of a real wind turbine through a short-circuit container[44], which allows for applying different faults with different voltage dips at the turbine terminals.[45,46]

[43] Clark, Kara, Nicholas W. Miller, and Juan J. Sanchez-Gasca. "Modeling of GE wind turbine-generators for grid studies." GE energy 4 (2010): 0885-8950.

[44] A short-circuit container is a test setup with variable reactances and appropriate switchgear to apply different types and depths of faults.

[45] A. S. Trevisan, A. A. El-Deib, R. Gagnon, J. Mahseredjian and M. Fecteau, "Field Validated Generic EMT-Type Model of a Full Converter Wind Turbine Based on a Gearless Externally Excited Synchronous Generator," in IEEE Transactions on Power Delivery, vol. 33, no. 5, pp. 2284-2293, Oct. 2018, doi: 10.1109/TPWRD.2018.2850848.

[46] Langlois, Charles-Eric, Mohamed Asmine, Markus Fischer, and Stephan Adloff. "On-site under voltage ride through performance tests—Assessment of ENERCON wind energy converters based on Hydro-Québec transénergie requirements." In 2012 IEEE Power and Energy Society General Meeting, pp. 1-8. IEEE, 2012.

If no detailed description of the legacy plant is available, parameter estimation of a generic controller model is a potential approach to obtain the approximate parameters. The damped least square method can be used to identify the control parameters for the outer power control loop and the inner current control loop through step changes in the power setpoints.[47] Similarly, wide-area monitoring data can be leveraged to identify the dominant control parameters to represent a DFIG wind farm with improved genetic algorithms.[48] In general, it would be very important to identify the fundamental frequency equivalent series impedance of the network that would be essential to calculate and take into account before any parameter estimation algorithm is applied. Furthermore, such an approach might work only for small-signal disturbances or may require a thorough test plan to make the parameter estimation of each control and protection function match different disturbances, such as load dips/rejection and step responses.

The objectives of the validation of IBR models with field data are comprehensive:

- **Data Collection and Filtering**: This involves gathering and refining data related to IBR protection, grid, and control parameters as well as PPC parameters. This step is crucial for ensuring that the data used in the model is representative of the actual operating conditions of the IBRs.
- **EMT Dynamic Model Verification**: This aims to validate the EMT dynamic models. This includes checking the accuracy of protection systems and renewable generation models to ensure that they align with the actual, as-found equipment parameters.
- **Compliance with Standards**: This seeks to ensure that the models meet the requirements set out in the TP/PC Model Verification guidelines. This compliance is essential for the models to be accepted and used in operational planning and grid-stability assessments.

Overall, the goals of the model validation are geared toward ensuring that the IBR models are reasonably accurate (given the lack of equipment-specific models), reliable, and compliant with industry standards, thereby enhancing grid stability and operational efficiency.

HIL Validation of New IBR Models

One of the main requirements from TPs and PCs from the perspective of model validation should be the benchmarking of an EMT model against actual field equipment. Validation tests can be achieved with HIL tests or with Factory Acceptance Testing (FAT) results (e.g. functional and performance tests) when field tests are not available[49]. To validate the plant controller model, the remaining components of the IBR plant can be simulated in an EMT model and executed on a real-time simulator as in a typical controller-hardware-in-the-loop (CHIL) setup as shown in **Figure 7.1**. A hardware control unit would be connected to the simulator as if it was connected to the actual plant. Measurement signals (e.g., active, reactive power, RMS voltages, binary signals like breaker status) would be accounted for in the model and transferred to the controller through wired connections or communication protocols. Secondary instantaneous voltages and currents can also be interfaced if necessary. In the other direction, power setpoints and control commands can be sent back to the simulated model and the changes would be applied to the simulated plant in real time. Different contingencies could be performed in the model to record the controller response. These recordings can then be the references to compare with the plant controller model. Through such tests, the impact of the delay introduced by communication or signal filtering can be assessed and then considered in the equivalent model.

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[47] NREC, Reliability Guideline Model Verification of Aggregate DER Models used in Planning Studies, March 2021

[48] M. Kong, D. Sun, J. He and H. Nian, "Control Parameter Identification in Grid-side Converter of Directly Driven Wind Turbine Systems," 2020 12th IEEE PES Asia-Pacific Power and Energy Engineering Conference (APPEEC), Nanjing, China, 2020, pp. 1–5, doi: 10.1109/APPEEC48164.2020.9220436.

[49] IEEE Standards Association (IEEE SA), "P2004 – Recommended Practice on Hardware-in-the-Loop (HIL) Simulation Based Testing of Electric Power Apparatus and Controls," URL: https://standards.ieee.org/ieee/2004/11300/

The PPC for a BESS plant was validated against a commercially available PPC running on a General Electric (GE) PLC through HIL tests.[50] Different real power and reactive power control loops as well as capacitor bank control were validated.

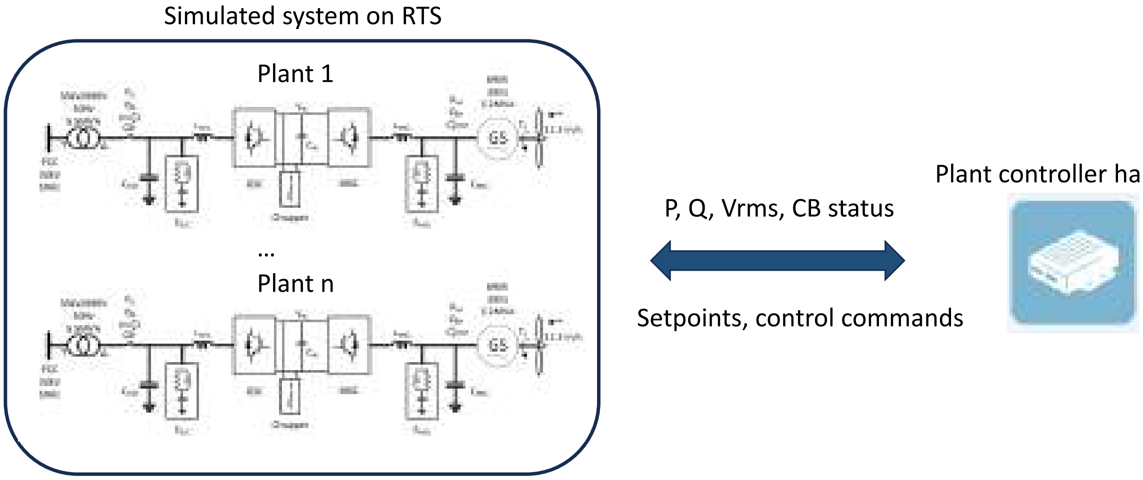

Figure 7.1: CHIL Setup for Power Plant Controller Validation

To go one step further, power-hardware-in-the-loop (PHIL) tests would allow the utilization of actual electrical hardware components in the validation setup, which would potentially eliminate the uncertainties from the simulation of specific hardware components. The key difference between PHIL and CHIL is that PHIL would create a virtual power interface between the simulated system and the hardware devices. Therefore, the device under test can be electric components, such as power converters, batteries with a management system, electric machines, and drives as shown in **Figure 7.2**. For example, when considering a small-scale PV system inverter and its controller being part of the hardware setup, the dynamics of their equivalents in the EMT model can be compared and validated through different disturbances. One caveat, however, is that at this point, PHIL amplifiers that exist on the market are only available in a limited range of powers and voltages. Furthermore, PHIL is still a more expensive solution than CHIL. However, continuous research and development is ongoing to build power amplifiers suitable for higher power ranges. The PHIL Simulator project at the Hydro Québec Research Institute[51] aims to design a 7.5 MW power amplifier to connect a real 25 kV distribution network to a transmission system simulated on a real-time simulator as shown in **Figure 7.2**. Similarly, some research labs in the United States also have medium-voltage, controlled grid interfaces to support high-powered PHIL experiments for HIL validation studies. The proliferation of such setups would allow for easier PHIL integration to study and integrate distributed energy resources, smart grids, and microgrids.

[50] V. Lakshminarayanan, C. Patabandi, O. Nayak and B. Lopez, "HIL Validation of Power Plant Controller Model," 2022 North American Power Symposium (NAPS), Salt Lake City, UT, USA, 2022, pp. 1-6, doi: 10.1109/NAPS56150.2022.10012177.

[51] K. SLIMANI, R. GAGNON, D. RIMOROV, O. T REMBLAY, B. LAPOINTE, "IREQ PHIL Simulator Project Update: Power Amplifier Design," 6th International Workshop on Grid Simulator Testing of Wind Turbine Power Trains and Other Renewable Technologies, Nov. 2022.

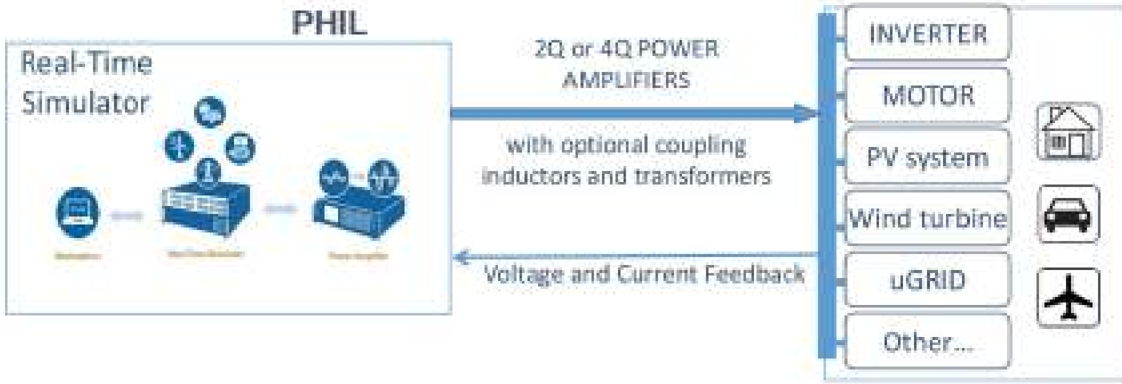

Figure 7.2: PHIL Setup to Interface Electric Components

Another example is an EMT model of a GE DFIG wind turbine unit being validated against the actual hardware test data in the lab using the test facilities as shown in **Figure 7.3**.[52] A 20 MVA cascaded H-bridge converter-based programmable voltage source was used to simulate the grid. The full-scale electrical hardware, including the transformer, the turbine, and the converter control, was configured in the lab. Voltage ride-through tests and phase jump tests at different short-circuit ratios were performed to consider the variation in system strength. Subsynchronous impedance characteristics were also analyzed with a frequency scan to validate the fidelity of the model under small-signal disturbances.

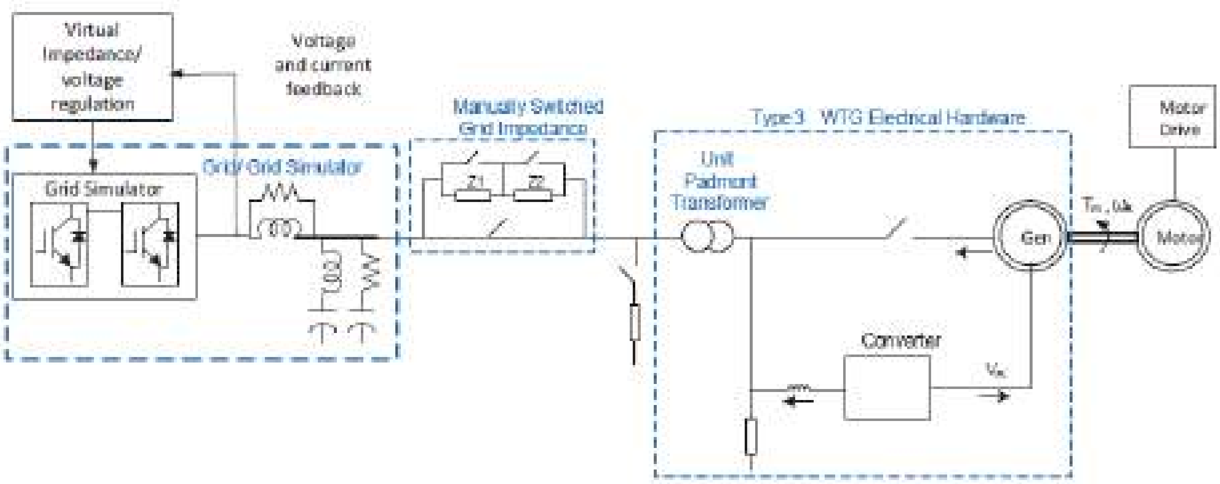

Figure 7.3: Schematic Diagram of the GE Lab Test Facilities

[52] A. Kazemi, J. Kaur, F. Ramirez, D. Gautam, M. Lwin and A. Ridenour, "EMT Model Validation of DFIG Wind Turbine Using Full-Scale Electrical System Lab Tests and Lessons Learned," 2023 IEEE Power & Energy Society General Meeting (PESGM), Orlando, FL, USA, 2023, pp. 1–5, doi: 10.1109/PESGM52003.2023.10253152

A Spectrum of Model Fidelity for Different Study Use Cases

Depending on the study use cases, EMT models of varying fidelity may be best suited to balance between accuracy and efficiency. This section provides an overview of such a spectrum of model fidelity as applied to inverter electrical model, inverter controls and protection models, PPC models, and the overall plant models.

Inverter Control Models

Depending on the desired level of detail for different areas in the study case, the following types of EMT models for inverter controls can offer a balance between accuracy and efficiency. TPs and PCs may consider requiring one or more, in addition to real code models as the minimum requirement.

- **Real Code Model** (most precise model)
  - Exact replica with all protections included (including all IBGT blocking protections)
  - May be validated with all validations proposed for EMT models in IEEE2800
  - Intended to be used as a reference or inside the study area, close to perturbation
  - Usually has timestep constraints and may be a large computation burden
- **Simplified Model**
  - Model with simplifications allowing to simulate with larger timesteps, up to 100/200us. May be derived from a phasor-domain model
  - Validated for small voltage or frequency perturbations and for step-changes (for the same validations a phasor-domain model goes through)
  - May be modeled, for example, using a controlled current source
  - Such a model may be used to represent IBRs located far away from perturbation
  - Warning mechanisms may be implemented when the model is being simulated outside of its range of validation
- **Relaxed Real Code Model**
  - May use the same code as the true replica with some functions disabled, such as protections based on instantaneous quantities and control loops with dynamics faster than 250 Hz
  - This model may be used for some studies when the true replica model suffers from tripping or malfunction due to its collector aggregation
  - Warning mechanisms may be implemented when the model is being simulated outside of its range of validation
  - May be simulated with a timestep slightly larger than the true replica

A similar modeling philosophy can be applied to power plant controllers.

Inverter Electrical Models

Inverter electrical models are discussed in the previous EMT guideline on switching model vs. average converter model.[53]

Overall Plant Models

There are generally three approaches to modeling an IBR plant. This section further details these modeling approaches and their recommended uses.

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

- **Non-Aggregated Models (Inverter-Level Models or Detailed Plant Models)**:[54] These models represent the entirety of the plant in full detail down to the individual inverter level, capturing each device's characteristics and their interconnections. These models are particularly important for ride-through studies in wind power plants where there is a significant voltage difference among turbines dispersed throughout the plant. However, a primary drawback of these models is their increasing computational burden as the number of turbines rises. Detailed models are recommended to be used by GOs to ensure the plant is designed to meet performance and ride-through requirements and do not contribute to differential-mode circulating oscillations; TPs and PCs are recommended to use those detailed models to verify the plant ride-through behavior and required performance.
- **Semi-Aggregated Models**: In cases where the number of inverters becomes impractical for simulation[55] and when they are geographically close (e.g., in solar or BESS plants), semi-aggregated collector-level models can be employed. When semi-aggregated models are used, the study engineer should ensure that at least two inverters are present in the model to reveal oscillations between parallel IBRs (i.e., circulating oscillations or differential mode oscillation). Another application for semi-aggregated models is to represent a single site including multiple different OEM facilities and/or hybrids of wind or solar and BESS.
- **Aggregated Models (Plant-Level Models)**: In these models, the entirety of the plant is consolidated as a single-machine single-collector equivalent model, offering a more efficient way to simulate a large number of IBRs. These models are typically used today for conducting system impact studies for stability and ride-through assessment.

More details on these modeling approaches and recommended uses are presented in **Appendix B**.

Modeling and Testing of Protection System Elements of an IBR Plant

Application of EMT modeling in power system protection has been increasing in recent years. EMT simulation results can give protection engineers better insight into dynamic behavior of loads or harmonics that can cause issues for protection systems for any applications. In addition, the traditional RMS power flow and short-circuit simulation tools assume that the system is balanced. There are various unbalanced conditions in power system studies. Furthermore, the EMT tools provide insights into frequencies other than fundamental. This information is valuable for studying the impact of harmonics on relay operation and inverter protection. As the protective relays and inverter protection must operate in transient conditions, EMT tools can provide more insights over conventional short-circuit simulation software.

Protection elements within IBRs are subject to various NERC Reliability Standards, such as PRC-019, PRC-024-3[56], PRC-025-2 and PRC-027-1. Inverter controls and protection should be coordinated with other forms of protection elements within the IBR plant. The IBRs have several protection elements, both at the inverter level and the plant level, including those listed below:

- Inverter Protection functions[57]
    - ac and dc overcurrent protection
    - dc undervoltage protection
    - Under/over frequency protection
    - Under/overvoltage protection

[54] These types of plant models were previously described as "detailed plant model" in the previous reliability guideline on EMT Model Requirements and Verification. Updated term is used here to align with IEEE 2800.2.
[55] See Chapter 9 for leveraging parallel computing to accelerate simulation of a detailed wind farm model.
[56] Updates to PRC-024 and a new PRC-029 for IBRs are forthcoming.
[57] Inverter protection functions refer to those embedded within the inverter control system. For more details, see Reliability Guideline: EMT Modeling for BPS-Connected IBRs – Recommended Model Requirements and Verification Practices, March 2023.

  - ac ground fault protection
  - Anti-islanding (phase jump) protection
- Inverter Transformer Protection (e.g., Volt/Hz, ANSI 24)
- Collector System Protection [58] (e.g., over current and over voltage protection)
- Main Power Transformer Protection
- Main Plant Interconnection Line (gen-tie) and Breaker Protection

The inverter protection functions for these resources can use instantaneous quantities (per phase point on wave measurements) instead of positive-sequence values. In this case, the positive-sequence dynamic simulation tools might not capture the behavior of inverters during the fault. In addition, the simulated fault clearing time may exceed the inverter ride-through capability in some cases. Therefore, EMT simulation tools might be needed to fully capture the dynamic behavior of the protection schemes relative to inverter capabilities.

GOs can utilize EMT tools to build the detailed non-aggregate model of an IBR plant, representing the full collector system and individual inverters. The inverter model and associated protection elements should come from the OEM. After the site-specific model is built in an EMT tool, various grid conditions can be simulated to determine the plant voltage and frequency ride-through performance compliance with the upcoming NERC PRC-029.

Another critical aspect is the consideration of model simplifications and assumptions made in EMT models. It is important to acknowledge that EMT models are not inherently accurate, as the accuracy of each model depends on the model development process, its fidelity to the actual product behavior, and the simplifications made during model development. Multiple protection systems are typically studied within the simulation domain, which can sometimes lead analysts to draw incorrect conclusions due to false positives in the simulation. A recent and common scenario involves the multiple fault ride-through (MFRT) requirements introduced in IEEE 2800-2022. The limitations of MFRT in IBRs primarily hinge on two factors: thermal and mechanical constraints. While mechanical constraints might be applicable to Type 3 WTG, thermal constraints are relevant to all IBRs. However, most OEMs do not represent detailed thermal characteristics of the power electronics in their EMT simulations. Therefore, any conclusions regarding multiple fault ride-through capabilities derived from an EMT model that lacks thermal modeling may be fundamentally flawed.

A similar situation occurs with RoCoF studies, also recently included in IEEE 2800. Most modern converters can handle much higher RoCoF levels than those specified in the standard. The converters monitor the frequency through the PLL code and trip only when the frequency or RoCoF exceeds the normal operating range. However, a critical vulnerability in relation to RoCoF for wind turbines lies with their auxiliary services. These components are often not adequately modeled or even included in EMT simulations. Consequently, just like with MFRT, RoCoF studies may lead to misleading conclusions and false positives.

In conclusion, the effectiveness of EMT models in simulating real-world phenomena like MFRT and RoCoF in wind turbines heavily relies on the accuracy and comprehensiveness of the models used. The omission of critical elements like thermal and auxiliary system behaviors can lead to significant discrepancies between simulated outcomes and actual field performance. Therefore, it is crucial for analysts and engineers to critically evaluate the assumptions and limitations inherent in their simulation models. This awareness is essential for making informed decisions and ensuring that conclusions drawn from EMT studies align closely with operational realities, ultimately leading to more reliable and robust wind turbine designs and grid integration strategies.

[58] *Odessa Disturbance, Texas Events: May 9, 2021, and June 26, 2021, Joint NERC and Texas RE Staff Report*, September 2021.

Validation of Equipment-Specific IBR Unit Models Provided by OEMs

Typically, IBR unit models that are provided by OEMs are black-boxed due to intellectual property concerns. Such black-boxed models abstract the exact mechanics of the underlying control schemes and protection mechanisms while ensuring some level of compliance with expected performance requirements. While some are black-boxed models that are developed and compiled in specific simulation tools, others encapsulate actual code that is used in actual controllers that are deployed on OEM hardware. Despite their limited transparency, one of the major advantages of using OEM-specific, verified accurate models is the accurate representation of the actual device. When it comes to validating the EMT model quality of equipment-specific IBR unit models, the following considerations are essential.

First, TPs and PCs should require GOs (in turn, OEMs) to provide detailed validation reports of the IBR unit performance with SMIB tests under a range of different SCR ratios and operating conditions, preferably with comparisons to field tests or HIL testing. Benchmarking with an equivalent RMS model should also be required. Second, GOs (and in turn OEMs) should be required to provide test results for a wide range of test case scenarios that include a flat-run scenario, scenarios with voltage and frequency disturbances, scenarios with various types of balanced and unbalanced faults, voltage ride-through tests, system strength tests and phase jump tests. Additional test case scenarios considering operating conditions at reduced energy inputs and at minimum system short-circuit ratios should also be required.

While a validated OEM-provided, site-specific, and black-boxed model provides the closest match with real-world behavior, an associated drawback is that they often come with practical challenges in terms of integration with EMT simulation tools. Some of these issues, such as inconsistent modeling practices and compiler dependencies, hinder the ability of TPs and PCs to utilize them across a broad range of EMT-based integration and planning studies. To this end, appropriate guidelines need to be established and communicated to GOs (and in turn, OEMs) by the TPs and PCs while requesting models. The following section provides guidelines to standardize OEM-specific black-box IBR model integration.

Guidelines on Equipment-Specific IBR Model Integration for GOs

Consistency oof Black-Boxing Control and Electrical Components

There is currently no consistent practice among OEMs in terms of which functional blocks associated with an IBR plant model are encapsulated inside their black-boxed models. For example, in some OEM models, only the controllers are pre-compiled and associated electrical components of the IBR plant are modeled using the native library components from the EMT simulation software used to provide the model. In other cases, the converters and other electrical components are included in the black boxes along with the controls. From a user perspective, if TPs and PCs utilize an EMT simulation tool different from the one GO and OEMs have provided the model for, such inconsistencies complicate integration and limit model portability across tools. Furthermore, this variance in black-boxing components contributes to potential issues when the software versions of the EMT tool are updated as well.

Equipment-specific models should follow standardized and existing guidelines, such as CIGRE WG B4.82, when preparing these black-box models to facilitate their interoperability across different simulation platforms. Furthermore, OEM-provided black-box models should not require specific versions of compilers and operating systems that introduce additional complexity when moving across versions of the same EMT tool or across different tools. To minimize such issues, EMT modeling requirements should encourage model interoperability across different platforms.

Support for a Range of Timesteps

Equipment-specific models from some OEMs currently require a specific timesteps, which may be different, in some cases, from the simulation timestep chosen by study engineers for dynamic system studies. Furthermore, some of the equipment-specific models perform well only at specified timesteps and suffer from accuracy or numerical stability issues at other timesteps. EMT modeling requirements should ensure that the models not only operate at specified timesteps but also support a broader range of values commonly supported by EMT simulation tools considering both small-scale, plant-oriented studies and large-scale system level stability analysis.

Optimizing Computational Performance

In specific cases, the computational performance of the equipment-specific models is a key factor in determining the overall simulation speed. If simulation speed is a bottleneck to adopt large-scale EMT simulation, modeling techniques, such as switching function models[59] or average voltage source model should be considered in favor of detailed switching-level inverter models to find a suitable compromise between simulation accuracy and speed according to the scale of the system model being studied using EMT simulations.

Typically, simulation performance is not optimized when the controller code is generated for pre-compiled equipment-specific black-box models. Computational speed or performance of black-box controller code might not be a concern when the code is deployed on an industrial controller because of the associated sampling rate of the signals. However, in an EMT simulation that is executing at timesteps in the order of 10–50 microseconds, having a non-optimized set of controller codes can introduce a huge computational bottleneck as they are often the limiting factor. This could be mitigated by ensuring that developers of OEM-provided black-box code work closely with EMT simulation tools.

Initialization of OEM Provided Black-Box Controllers

The initialization of black-box controllers is another area that needs attention and improvement. Typically, the electrical components in an EMT model can be initialized by applying initial voltages and currents from the load flow results. However, the initial states inside the black-box controllers are not easily accessible by users. IBR black-box controllers are initialized at the start of every simulation run with a slow ramp-up with a voltage source in parallel and then switching over after the initialization matches the voltage source used. If assuming an average simulation time of 30 seconds, this current practice would require stopping and restarting the simulation with reinitialization from zero for every scenario when running a large set of scenarios. However, it would be very beneficial to be able to initialize OEM black-box controllers, thereby allowing the acceleration of multi-scenario tests efficiently by reinitializing the simulation to a steady-state power flow condition every time. TPs and PCs should work together with OEM, GOs, developers and industry working groups/task forces, such as CIGRE WG B4.82 to standardize initialization to reduce total simulation time across scenarios.

Documentation Guidelines

TPs and PCs should require GOs (in turn, OEMs) to deliver models with detailed documentation as much as possible. In the pre-compiled, black-box code, comprehensive error messages should be configured to provide information to the users whenever any exceptions are encountered. In addition to the models being managed appropriately with version tracking and continuous integration over time as updates happen, it is essential that the associated model documentation and test reports also get updated by leveraging automated scripting across a set of standard test scenarios.

Importance of Measurement Models

Both inverter-level controls and plant-level controls utilize electrical measurements, such as instantaneous voltage and current, RMS voltage and current, active and reactive power, and frequency. Care should be taken when a model is expecting a measurement input, and a corresponding meter model has not been supplied by an OEM. The response of a control system depends on the quality of the input signal. Using measurements from standard library meter models may introduce inaccuracies. Special consideration should be given to frequency measurement as internal algorithms of some standard library meter models could be susceptible to phase angle shifts which can cause artificial

[59] S. Fazeli, et al, “Switching Functions Models of a Three-phase Voltage Source Converter (VSC)”, Journal of Power Electronics, Vol. 17, No. 2, pp. 422-431, March 2017

spikes as shown in **Figure 7.4**. Similar attention should be paid to RMS quantities and parameters that could affect them, such as filter time constant or calculation methods. TPs and PCs reviewing the EMT models should look out for the use of such standard library components and question their accuracy.

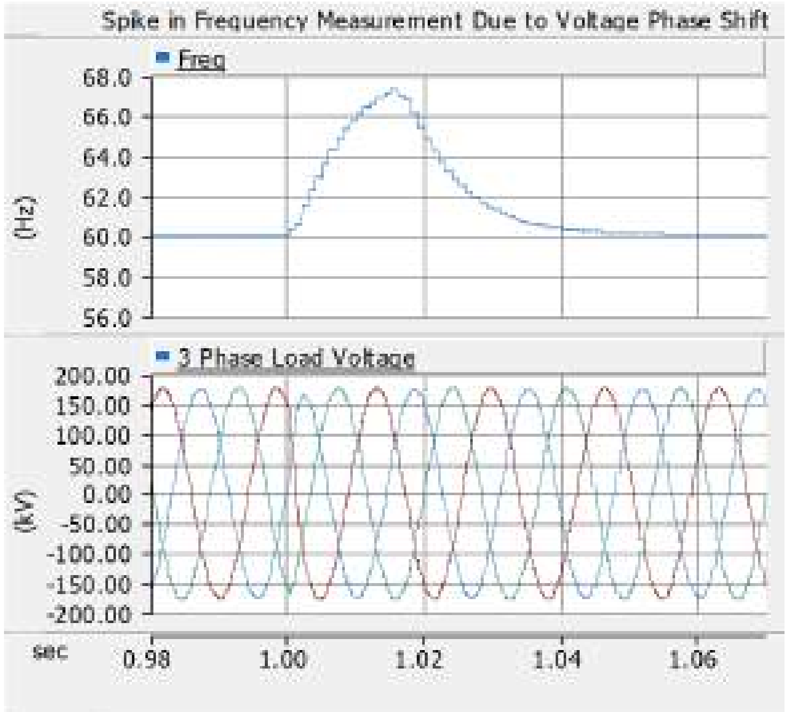

Figure 7.4: Spike in Standard Library Frequency Measurement Due to Voltage Phase Shift

Chapter 8: Accelerating EMT Simulations

EMT simulation studies were originally used to study fast transients with high-frequency content, encompassing switching transients, lightning surges, protection, harmonics, transient overvoltages, and transformer energization. The shared characteristic among EMT simulations lies in their historically localized nature, necessitating the simulation of a specific reduced network section with equivalents for surrounding networks. The applications of EMT have expanded to include the analysis of the transient behavior of conventional HVdc, VSC-HVdc, and various power electronics-based systems, such as FACTS and IBRs. It has become necessary to simulate large to very large power grids in EMT mode. Such cases include the studies of control interactions and SSO. TS assessments (TSA) require the simulation of very large-scale grids due to the globality of involved transients.

Historically, large-scale power system simulations and studies were conducted using positive-sequence RMS tools, also known as phasor-domain tools. However, with high levels of IBR integration, the phasor-domain tools struggle to provide accurate transient simulations. These shortcomings are primarily caused by the model simplifications and/or omissions of certain components, such as manufacturer-specific PLL logics, especially under weak system conditions. Therefore, the simulation of large-scale power systems in an EMT environment becomes necessary for systems with significant numbers of inverter-based devices, including wind farms, solar PV plants, batteries, HVdc, and FACTS. Contrary to common belief, the simulation of very large-scale power systems in EMT mode no longer constitutes a prohibitively slow process, although relatively slower compared to PSPD simulations.

EMT platforms may require more details to reach higher accuracy levels, especially for IBR models. The full power system dynamics require the usage of small numerical integration timesteps, ranging from 1 to 500 µs. The timestep selection is constrained by the highest frequency of interest. For TS analysis of large power grids, the timestep shall be selected to capture control and protection system reactions affecting overall system stability. In several cases, simplified or average-value inverter models can be used to accelerate simulations without compromising accuracy for evaluating system stability.

The simulation timestep is a very important factor that impacts the simulation execution time, but it is not the only one. The size of the system, reflected in the number of nodes (also control diagram blocks), can also slow down simulations. Most EMT tools rely on the companion circuit model theory with nodal (or based on nodal) analysis for building the grid's system of equations. Some tools are based on state-space representation for formulating grid equations. The high number of nodes makes the system matrix dimension large and its solution more challenging. It constitutes a linear algebra problem in which unknowns are found through lower-upper (LU) decomposition followed by the forward-backward substitution process. Sparse matrix techniques must be used to significantly accelerate this process. The LU decomposition can be time-invariant and henceforth performed only once. However, this is not the case when the grid contains device models with time dependency, such as switches, faults, or other components. The grid model may also contain nonlinear models, such as magnetization branches, arresters, detailed diode and Insulated-gate bipolar transistor (IGBT) models. Such devices modify the coefficient matrix and require repetitive recalculations of LU decomposition for several solution timepoints and even several times per timepoint when an iterative solver is used to guarantee precision and numerical stability.[60]

Due to the challenges mentioned above for the simulation of a large system with power electronic-based devices, there is an urgent need to accelerate the EMT simulation without compromising its accuracy. Traditionally, the EMT simulations used to run on a single central processing unit (CPU) core, and the processes were performed sequentially. Since the advent of parallel EMT simulations, commercial EMT platforms have evolved and allow running EMT simulations in parallel using multiple CPU cores simultaneously (i.e., multi-thread parallel computing). This feature can significantly reduce the processing time of a simulation, especially for a large-scale network

[60] A. Abusalah, O. Saad, J. Mahseredjian, U. Karaagac and I. Kocar, "Accelerated Sparse Matrix-Based Computation of Electromagnetic Transients," in IEEE Open Access Journal of Power and Energy, vol. 7, pp. 13-21, 2020, doi: 10.1109/oajpe.2019.2952776.

simulation and/or networks with multiple power electronics devices modelled in full detail (e.g., a detailed wind farm model). The extent of achievable performance improvement hinges on the sophistication of the parallel processing technology employed. This entails a proficient exchange of data among processor cores, aiming to reduce communication delays and, thus, secure overall efficiency and scalability.

Parallel computing in power systems simulation involves splitting a large network into smaller subnetworks so that they can be solved separately and simultaneously. The most common method for connecting the subnetworks is through the application of natural delay-based transmission line (TLM) or cable models. The propagation delay of such distributed-parameters models allows networks to decouple without any loss of accuracy. This method, named hereinafter as the TLM-based method, can be fully automated through grid topology analysis. When TLM delays are not available, or when the transmission lines are too short, it is possible to apply the compensation method[61], which is able to cut through arbitrary wires. The combination of nodal and state-space equations is another solution for splitting networks at arbitrary locations. Parallel computing methods are advantageously used today to accelerate simulation time. Furthermore, these performances can be achieved through automatic initialization from load-flow solutions and the utilization of fully iterative solvers to ensure the highest levels of accuracy in time-domain results.

Mapping individual component models with detailed controls onto individual CPU cores is another key aspect of improving the performance of EMT simulations, especially in the context of detailed IBR plant models, where each plant model includes multiple logical blocks and control loops to be solved. In this context, detailed EMT IBR plant models usually have stringent timestep requirements that are sometimes less than 50 µs (typically around 4–20 µs); therefore, decoupling the system model without introducing modeling approximations also becomes a challenging task. In certain cases, there is very little visibility into how some of the detailed plant models are implemented and coded as most of them are packaged as independent black boxes with their own timestep and solvers. The exact implementation mechanism also plays a major role in these cases, and, oftentimes, those end up being the primary bottlenecks in the overall performance of large-scale and complex EMT simulations with hundreds of IBR plant models. While plant models have efficient implementations using languages in some cases, such as C or FORTRAN, implemented plant models are not computationally efficient most of the time. As more and more TPs and PCs adopt and perform large-scale EMT studies, more work is needed to have OEM black-box models optimized for performance on top of them meeting the required accuracy needs.

Some recent efforts have sought to investigate the use of graphics processing units (GPU) as a potential alternative/complement to leveraging CPUs to accelerate simulations. However, the use of GPUs in this regard is still in its infancy and has not been tested and validated in practical power systems.

Techniques Used for Accelerating EMT Simulations

There are other methods to accelerate the overall simulation performance, but these methods, in contrast to parallel computing, may impact the overall accuracy of the simulation. Therefore, their results should be validated for the required studies. Some of these techniques are described below.

Optimizing the Study Model

The study model should first be optimized to reduce computing requirements. For example, having special metering components such as RMS or DFT calculations can add computing burdens and therefore, unnecessary meters should be removed. Level of IBR model details such as using detailed IGBTs or average value models should also be considered to reduce computation burden while maintaining required accuracy for the types of studies being performed.

[61] B. Bruned, J. Mahseredjian, S. Dennetière, J. Michel, M. Schudel and N. Bracikowski, "Compensation Method for Parallel and Iterative Real-Time Simulation of Electromagnetic Transients," in IEEE Transactions on Power Delivery, vol. 38, no. 4, pp. 2302-2310, Aug. 2023, doi: 10.1109/TPWRD.2023.3238422.

Multi-Sampling Rate or Multi-Timestep Simulation

In this method, the power system is divided into subsections that are simulated at different time steps. The detailed subsection can be simulated with a small timestep, and the rest of the system can use a larger timestep (faster simulation time). This method also allows multiple OEM models requiring different timesteps to be simulated in the same system.

The timestep of each portion may be as large as possible but small enough to simulate the range of frequencies with non-negligeable magnitudes that may appear inside its boundaries. The further away from the origin of the perturbation, the larger the timestep may be. Care must be taken in the selection of timesteps such that the ratio of large timestep/small timestep is minimized to reduce the errors due to interpolation techniques.

EMT-Phasor Hybrid Simulation

This method is similar to the multi-sampling rate, but instead of using different timesteps within the same EMT platform, the EMT platform is interfaced with a positive-sequence RMS platform. The network is divided into two parts with a detailed part that is modeled in the EMT mode and the rest of the network modeled using the positive-sequence RMS platform. This method is discussed in detail in **Chapter 3**.

Aggregation and Equivalency

The complexity of simulating over 100 power electronic devices can be reduced if the devices can be aggregated into a single device or smaller number of devices. The equivalent system should provide a close match with the actual system for the required studies.

Using Relaxed Models for Phasor Portion

Using high-fidelity IBR models everywhere in the EMT study area can be a bottleneck to achieving reasonable simulation speed performance. Similar to using phasor-domain modeling for hybrid simulations to simulate model regions far enough from or outside the study region, where the perturbation frequencies and magnitudes are limited, EMT network representations using relaxed models that allow simulations with large timesteps and are less computationally intensive can help significantly accelerate EMT simulations. For example, IBRs may be modeled as controlled current sources without the inclusion of the inner control loop model or other fast dynamic controls. Such relaxed models may be easily obtained from the phasor-domain database and be simulated with a timestep up to 150 µs.

Synchronous generators may also be simulated in the EMT domain with a very large timestep, up to 150 µs or 1,000 µs, if the machine equations are solved with network equations.

Additional Considerations on Solution Timestep and Its Impact on Accuracy

Using a larger timestep when the EMT model includes non-linearities can introduce errors that may accumulate over time. Solution techniques that help address this issue (e.g., iterative solution, interpolation techniques, dynamic phasors) are available. See the following figure of a transformer inrush current with and without iteration at 100 µs.

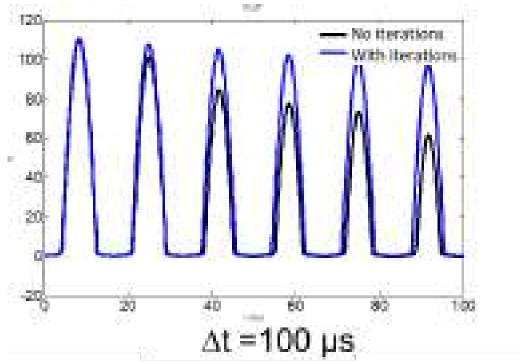

Figure 8.1: Inrush Current with and without Iteration

Caution: Attention must be paid to the accuracy of the solution technique used (e.g., convergence tolerance and whether the solution is converged or not if iterative solution is used; errors due to timestep ratio if interpolation or dynamic phasor techniques are used.)

If artificial timestep delays are introduced when aggregating multiple electrical resources or allocating certain electrical components on different physical computing resources for the purpose of parallel processing (e.g., power or current scaling or stub lines), the timestep may remain below 20 µs. The figure below demonstrates the error introduced by a current scaling device with a 50 µs timestep delay in the active power (left) and reactive power (right). The error manifested in the wrong phase angle between voltage and current, resulting in incorrect reactive power. Current scaling devices are used for generation aggregation. A current scaling device model injects current on one side, which is a multiplication of the current entering on the other side. Stub lines are typically used to split network equations for parallel processing at a location where there are no transmission lines available to apply the TLM-based method. This approach introduces an artificial delay to allow decoupling equations.

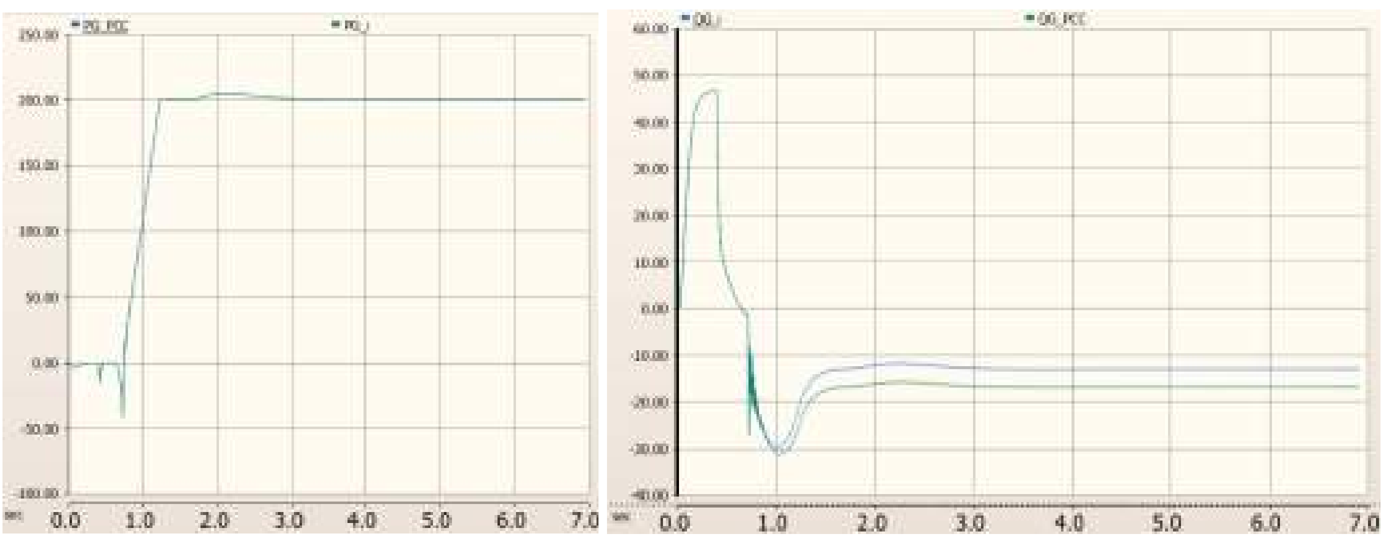

Figure 8.2: Error Introduced by a Current Scaling Device

Best Practices for Developing Large EMT Models

The integration of more and more IBRs into the power grid across the United States renders the need to extensively study grid behaviors during a range of operating conditions and fault scenarios more compelling. Under these conditions, large-scale EMT studies might need to be performed repeatedly as a routine part of planning and operational studies. Current practices involve performing EMT studies on targeted regional system models with the wide-area system being equivalenced appropriately to limit scale. Furthermore, the starting point in many cases involves porting phasor-domain models of the transmission network and the synchronous generators. To develop high-fidelity and large-scale validated EMT models, there are certain best practices that could be followed by TPs and PCs.

It is essential to ensure that model porting/conversion steps from existing phasor-domain tools are automated to minimize errors in populating parameters. While most of the standard network elements would be converted appropriately, special attention needs to be paid when converting or porting user-coded models as a comparable equivalent might not be readily available. The model import process should be approached as a multistep process with appropriate validations at each level. The first step would involve the validation of the network in terms of the transmission lines and the topology, which could be validated through a comparison of power flows. Following this step, generation and load sources could then be integrated before being validated with steady-state comparisons followed by specific types of step changes and fault scenarios.

Also deserving of close attention would be the initialization of generation sources, including IBR plant models. Some of the detailed IBR models are black-box models and might not support initialization to a steady state. In such cases, the model needs to have corresponding logical elements to slowly bring them to an appropriate state. A non-trivial aspect that affects EMT simulation performance is the inclusion of elements for measuring electrical quantities in the model. They should be optimized so that only those that are necessary for the use case being studied are recorded.

As mentioned previously, it is essential to identify long transmission lines modeled as distributed parameter lines to enable the decoupling of large EMT models to parallelize them and accelerate simulations. Furthermore, as necessary, areas of the system that might not be relevant need to be reduced with an appropriate network equivalent. In situations in which specific areas in the system might not have very long lines for effective decoupling, lines could be combined to artificially form a line that is long enough to decouple. Additionally, if those are insufficient in some cases, stub lines could be considered with borrowed inductance and capacitance from nearby transformers or lines to minimize loss of fidelity. Inverter models utilizing detailed switching models should be sidestepped because they prolong simulation times without contributing further understanding to the stability assessment of extensive grid systems. For most practical applications, it is advisable to use average or switching function models, which are integrated with detailed PLL and quick-response protection system models, to expedite the simulation process.

Looking Forward–Challenges with Speed and Scalability of EMT Simulations

The scale of the bulk power system studies that have been referenced in the above chapters is in the order of hundreds to thousands of buses, which is sufficient for most systems that are or will be studied in the near future. As the penetration of power electronics increases in the grid, the size of the power system that needs to be studied is expected to grow in EMT simulations. For example, with simplified aggregated IBR models in today's BPS models, the power grid in United States has in the range of 100,000 buses. If more detailed, non-aggregated IBR models are needed, the number of buses can easily reach the millions. In such cases, it may not be simple to split the model only based on transmission lines to introduce parallelism and speed-up. Hence, research is being conducted into numerical methods to enable utilization of the properties and features of the grid dynamics to enable faster simulations.[62,63,64]

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[62] J. Choi and S. Debnath, "Electromagnetic Transient (EMT) Simulation Algorithm for Evaluation of Photovoltaic (PV) Generation Systems," 2021 IEEE Kansas Power and Energy Conference (KPEC), Manhattan, KS, USA, 2021, pp. 1–6.

[63] S. Debnath and M. Chinthavali, "Numerical-Stiffness-Based Simulation of Mixed Transmission Systems," in IEEE Transactions on Industrial Electronics, vol. 65, no. 12, pp. 9215–9224, Dec. 2018

[64] B. Bruned, J. Mahseredjian, S. Dennetière and N. Bracikowski, ""Optimized Reduced Jacobian Formulation for Simultaneous Solution of Control Systems in Electromagnetic Transient Simulations,"" in IEEE Transactions on Power Delivery, vol. 38, no. 5, pp. 3366-3374, Oct. 2023, doi: 10.1109/TPWRD.2023.3275221.

Additionally, research is exploring parallelism in solvers within multi-core CPUs for further speed-up in simulations.[65,66,67,68]

Hardware: In addition to multi-core CPUs, recent research trends have focused on using GPUs for scalable simulations in an attempt to assist with the speed-up of certain types of power grids and/or IBRs.[69,70] This is not guaranteed for all types of systems.

Automation: Research into automatic parallelization of models and solvers is ongoing to assist with scalability in the future, but there is limited published work available at this time.

[65] M. Ouafi, J. Mahseredjian, J. Peralta, H. Gras, S. Dennetière, B. Bruned, "Parallelization of EMT simulations for integration of inverter-based resources,", Electric Power Systems Research, Vol. 223, Oct. 2023, 8 pages, DOI: 10.1016/j.epsr.2023.109641.

[66] T. Cheng, T. Duan and V. Dinavahi, "Parallel-in-Time Object-Oriented Electromagnetic Transient Simulation of Power Systems," in IEEE Open Access Journal of Power and Energy, vol. 7, pp. 296–306, 2020.

[67] S. Debnath, "Parallel-in-Time Simulation Algorithm for Power Electronics: MMC-HVdc System," in IEEE Journal of Emerging and Selected Topics in Power Electronics, vol. 8, no. 4, pp. 4100–4108, Dec. 2020.

[68] J. Choi, P. Marthi, S. Debnath, Md Arifujjaman, N. Rexwinkel, F. Khalilpour; A. Arana; H. Karimjee, "Hardware-based Advanced Electromagnetic Transient Simulation for A Large-Scale PV Plant in Real Time Digital Simulator," 2023 IEEE Energy Conversion Congress and Exposition (ECCE), Nashville, TN, USA, 2023, pp. 965–971.

[69] S. Yan, Z. Zhou and V. Dinavahi, "Large-Scale Nonlinear Device-Level Power Electronic Circuit Simulation on Massively Parallel Graphics Processing Architectures," in IEEE Transactions on Power Electronics, vol. 33, no. 6, pp. 4660–4678, June 2018.

[70] J. Sun, S. Debnath, M. Saeedifard and P. R. V. Marthi, "Real-Time Electromagnetic Transient Simulation of Multi-Terminal HVDC–AC Grids Based on GPU," in IEEE Transactions on Industrial Electronics, vol. 68, no. 8, pp. 7002–7011, Aug. 2021.

Appendix A: Additional Materials on Legacy Plant Modeling

Development of a Generic EMT Model from Existing Positive-Sequence Model

The manufacturer of the Type 1 wind turbine generator is no longer in business and only a positive-sequence model, in WECC second generation format, was available to the GO. Therefore, a generic EMT model was developed using both standard library components and custom control models and benchmarked against the available positive-sequence model. The resulting EMT models may not necessarily bring any more accuracy than the bandwidth of the original positive-sequence model.

The induction generator WT1G1 is represented by the induction machine model from the standard library of a given EMT software. The other models are user-defined models developed based on the block diagrams and descriptions found in the user manual of the positive-sequence tool. The two-mass turbine model (WT12T1) and the pseudo-governor model (WT12A1) are represented together in one user-defined model. The under/overvoltage generator trip relay (VTGTPAT) and under/over frequency generator trip relay (FRQTPAT) each have their corresponding user-defined model in the EMT software.

The following figure shows the model developed in the EMT tool:

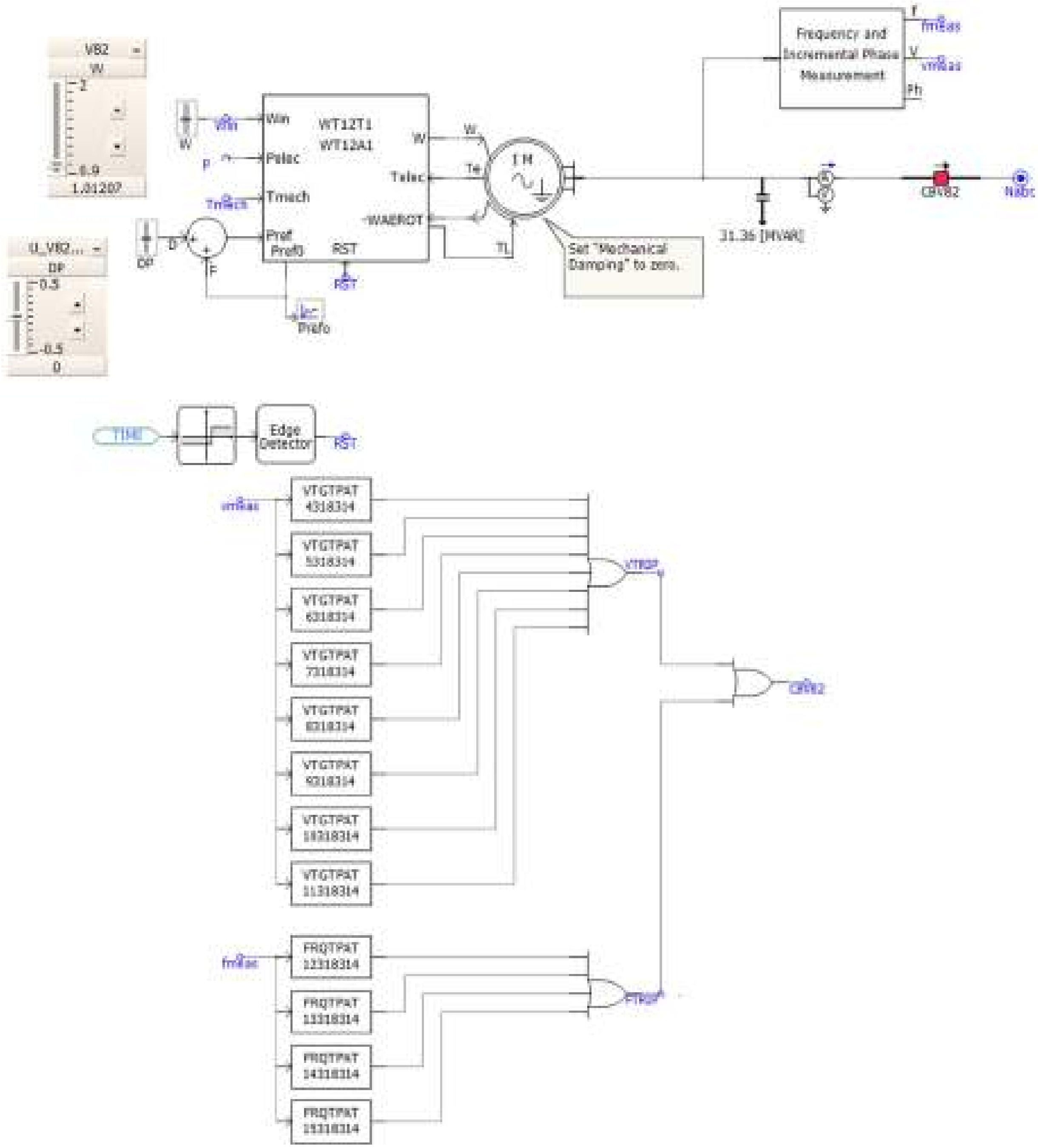

Figure A.1: Details of the EMT Model

Model Initialization

Initialization of an EMT simulation differs from software to software. The steps described here are for a single piece of the EMT software and may not be applicable in other software.

After building the model, its initialization is presented to match a solved power flow. The induction generator in the power flow program is treated the same as a synchronous generator. The active and reactive powers from the machine are calculated based on the specified values and the capability given by Qmax and Qmin. In the dynamic simulation, the positive-sequence tool then adds a shunt reactance at the terminals of the machine to account for the difference between the reactive power absorbed by the induction machine (determined by the applied voltage and the slip) and the reactive power calculated when the power flow was solved. The value of this added reactance is given in VAR(L) of the WT1G1 model and should be added in the EMT model to maintain consistency. To obtain the value of VAR(L), a no-disturbance positive-sequence dynamic simulation is required in addition to solving the power flow.

Next, the initial speed of the machine must be specified in the EMT model. This value is also obtained from a no-disturbance positive-sequence simulation and is equal to (1 + SPEED) of the induction generator. When an EMT simulation is started, the speed of the machine is kept constant at this given value before the machine is released at a user-specified time instant. **Figure A.2** shows the locations in the model where the user needs to enter the data for initialization.

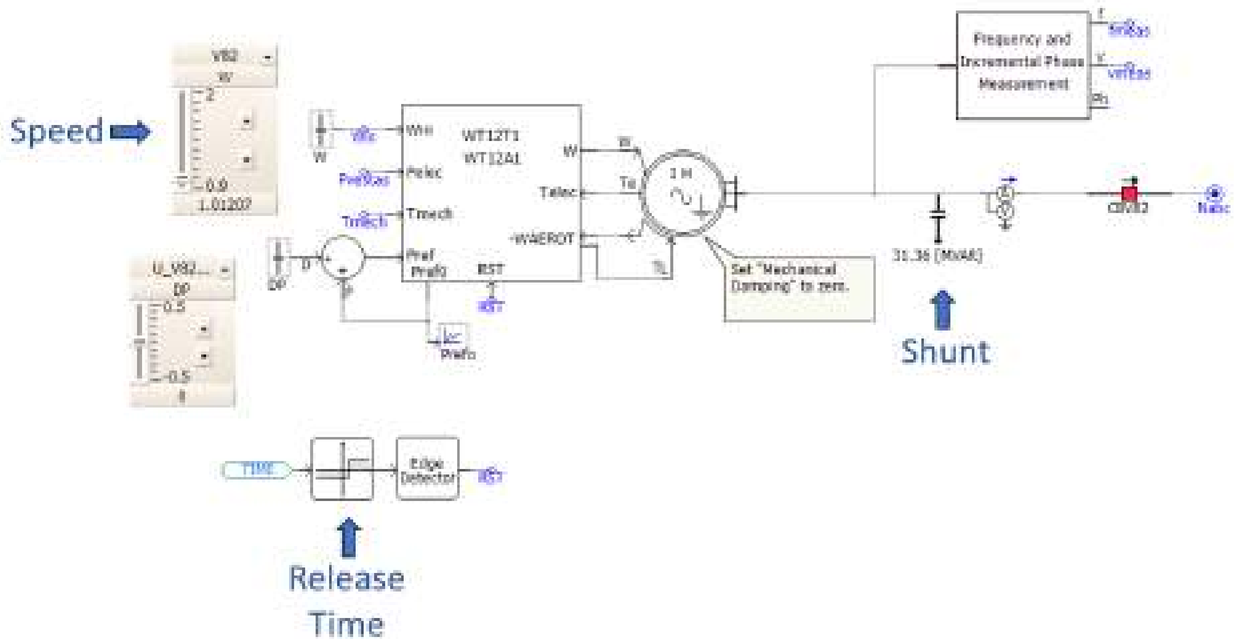

Figure A.2: Initialization of the EMT Model

Benchmarking the EMT Model against the Positive-Sequence Model

Once the model was initialized to the same power flow as that in positive-sequence dynamic simulation, the developed EMT model modules for WT12T1 and WT12A1 were individually tested by playing back positive-sequence dynamic simulation waveforms to their inputs and comparing their outputs to the corresponding curves from the same positive-sequence dynamic simulation. A voltage step test was also used to compare the behavior of the overall EMT model against the positive-sequence model. Results show the comparison of the two simulations where the EMT model behaves similarly to the positive-sequence model.

The following figures show the benchmarking results using a playback test.

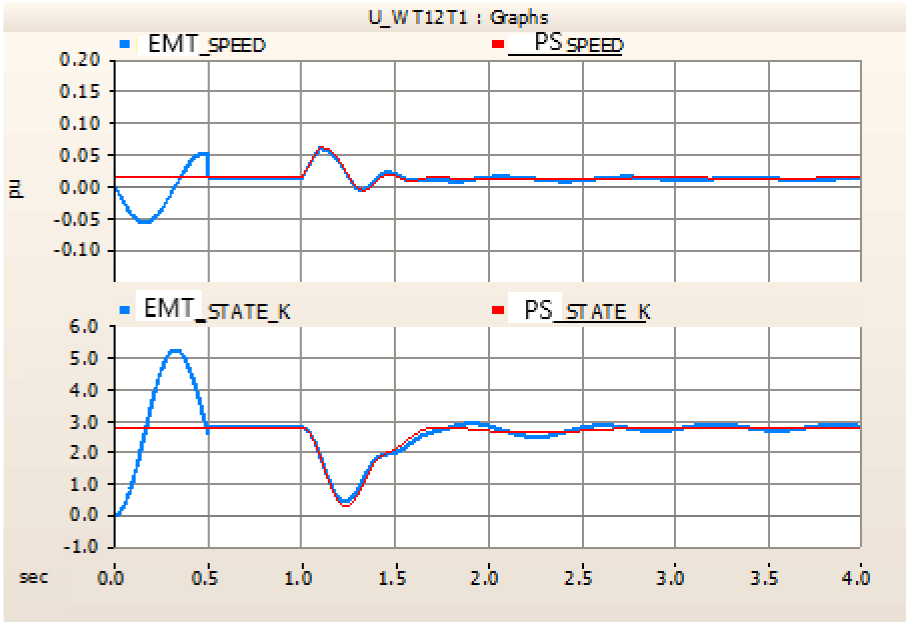

Figure A.3: Comparison of WT12T1 Responses Between EMT and Positive-Sequence Simulation

Figure A.4: Comparison of WT12A1 Responses Between EMT and Positive-Sequence Simulation

Figure A.5, Figure A.6, and Figure A.7 show the benchmarking results using a voltage step test in which a voltage disturbance was introduced at the POI by dropping the voltage down to 0.05 pu for 0.1 seconds and brought back to 1 pu.

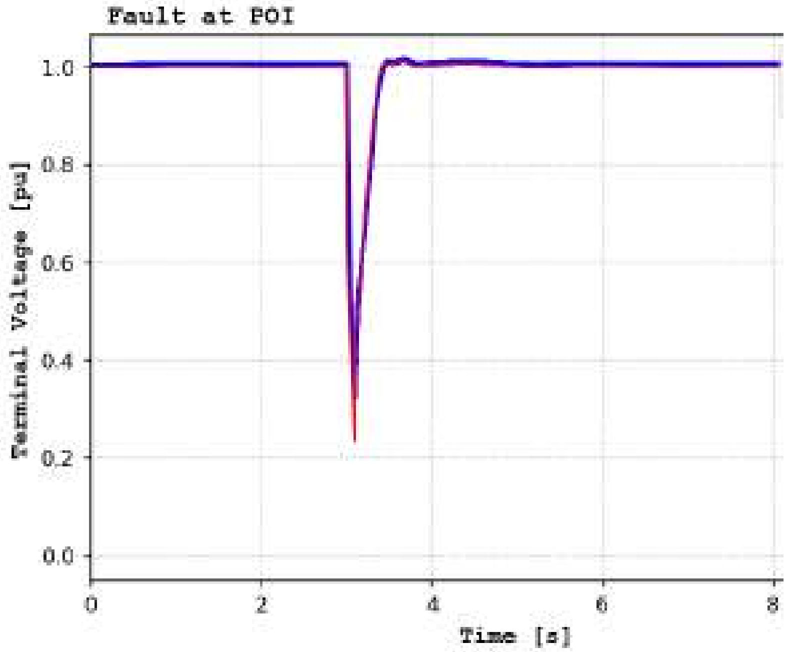

Figure A.5: Comparison of Terminal Voltages Between EMT (Blue) and Positive-Sequence (Red) Models

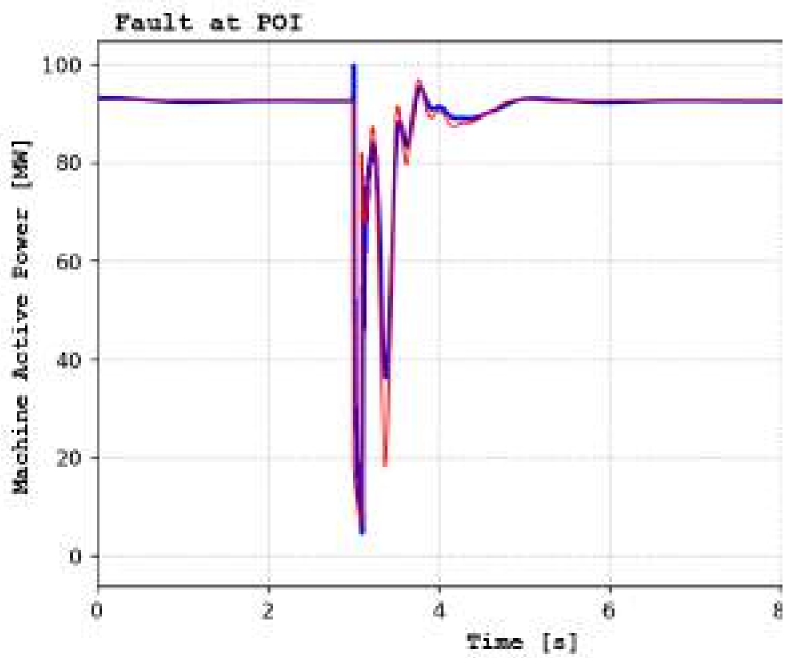

Figure A.6: Comparison of Active Powers Between EMT (Blue) and Positive-Sequence (Red) Models

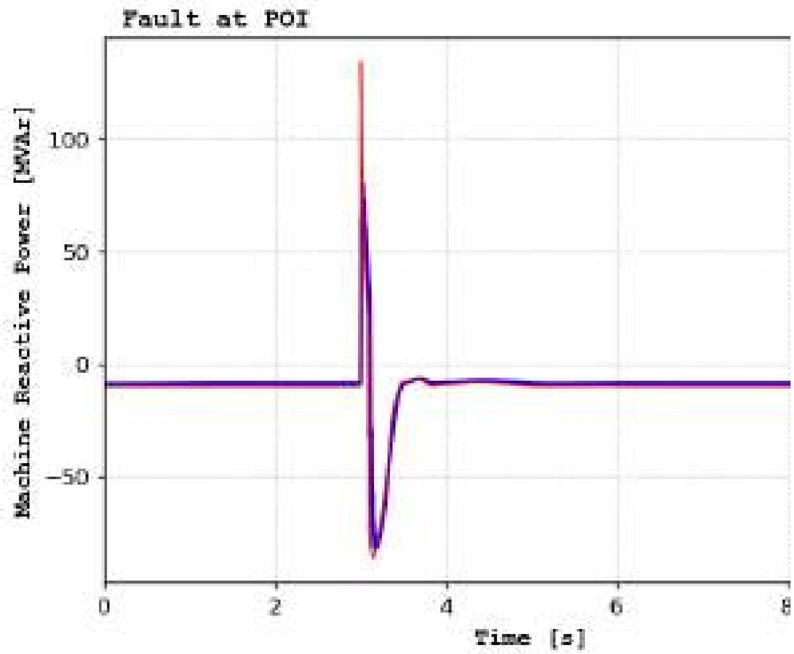

Figure A.7: Comparison of Reactive Powers Between EMT (Blue) and Positive-Sequence (Red) Models

In summary, legacy plants can be modeled in EMT using generic models if no other option is available and it is acceptable by TOs and ISOs. Although these generic models will lack the detailed control system features of legacy units, they still provide a good representation of plants' behaviors within the validity and accuracy range of the original positive-sequence model.

Tuning and Validating Generic EMT Models Using Field Disturbance Data

There exist generic EMT models with enough flexibility to be tuned to represent a given equipment with some degree of accuracy. It has been shown that they can be tuned and validated to represent legacy IBR plant. For example, a generic EMT-type model for a type-IV WTG considering a gearless externally excited synchronous generator and a three-stage full converter was benchmarked against the measurements from a wind turbine.[71] This model implemented protection and follow-ride-through control to be consistent with grid codes in North America and Europe and included a mixture of average values modeling and equivalent circuits for the power electronic switching stages that allowed the use of longer calculation intervals (i.e., around 50 µs for specific cases to speed up the simulation time to the point that it could eventually make it suitable for real-time simulations). The proposed model developed for individual representations could also handle aggregate WTG groupings to simulate the entire generation plant operating at maximum power. The generic model was able to mimic the fault-ride-through calculations from a WTG field test involving a 365 MW wind power plant in Québec. The results are shown in **Figure A.8** and **A.8**. A good correlation between calculations and measurements is observed. The deviations that occurred at fault clearing were partially attributed to the approximations in the representation of the distribution grid, particularly of the collector system due to the absence of real data and to the use of generic WTG parameters and controllers instead of OEM-specific data. The results could improve if OEM-specific data were available.

[71] Trevisan, A.S., El-Deib, A.A., Gagnon, R., Mahseredjian, J., Fecteau, M., Field Validated Generic EMT-Type Model of a Full Converter Wind Turbine Based on a Gearless Externally Excited Synchronous Generator, IEEE Trans. on Power Delivery, Vol 33, No. 5, October 2018.

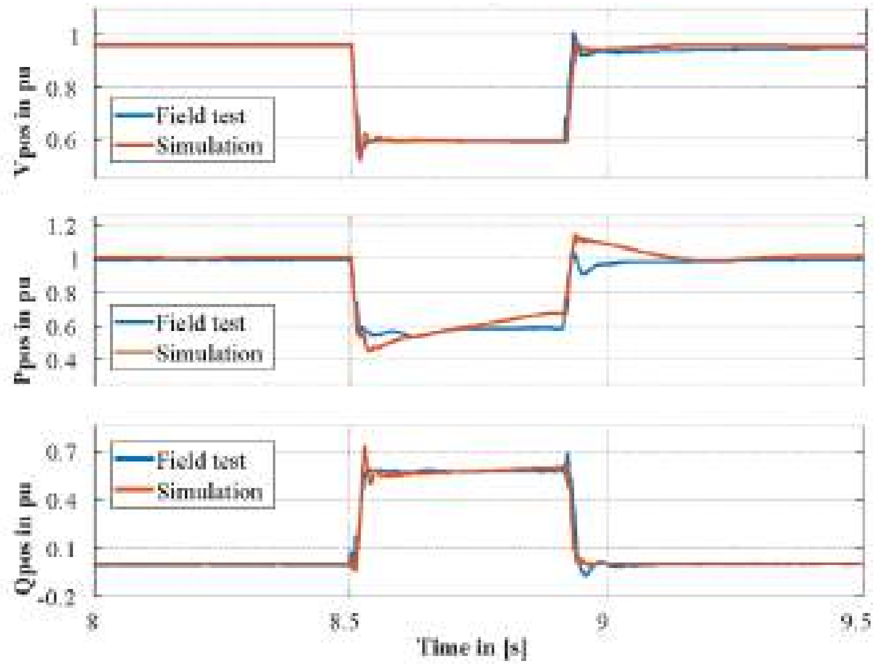

Figure A.8: Simulations and Field Test Validation for an Unsymmetrical Fault

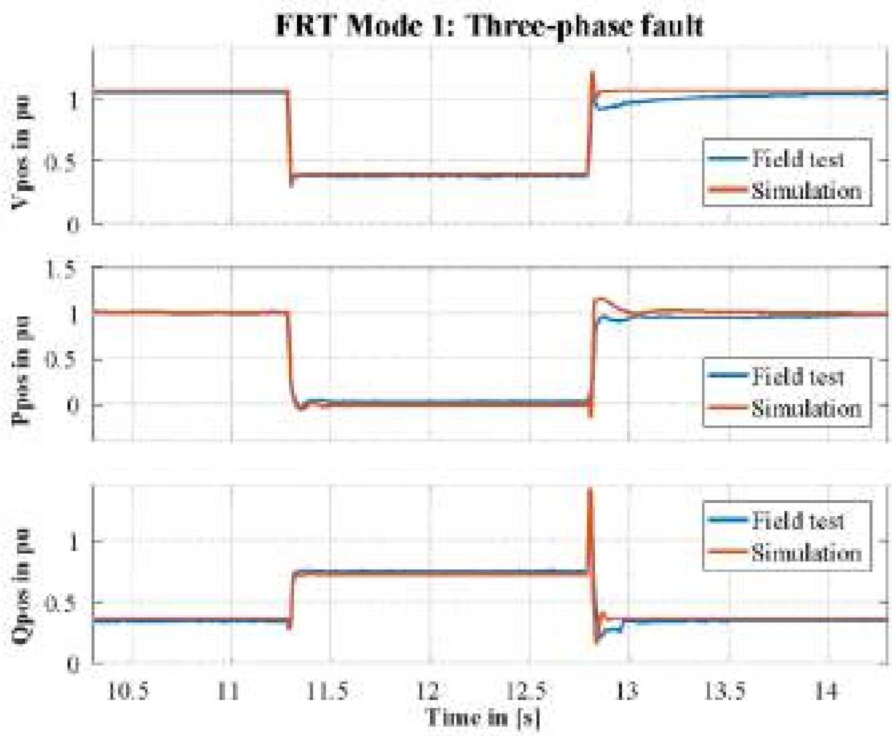

Figure A.9: Simulations and Field Test Validation for a Symmetrical Fault

Similarly, there exist generic EMT models to represent PV plants. One specific example features the required flexibility to be tuned to suit the design of specific PV inverters and PV plants.[72] The example implements the control architecture developed by WECC. The model features both a detailed (switching model) representation of a PV inverter as a current source inverter (CSI) and the average model in which the controlled IGBT switching was replaced

[72] https://www.esig.energy/wiki-main-page/user-guide-for-pv-dynamic-model-simulation-written-on-pscad-platform/

by an infinite switching frequency leading to a pure sinusoidal output from the CSI, which also allowed the use of a large solution timestep, resulting in much shorter simulation times. With careful tuning, the model was able to replicate the field measured response, showcasing a good application of generic models to represent legacy plants without equipment-specific models. The current waveforms from the detailed model were very similar to the current waveforms from the average model with only higher order harmonics showing up on the detailed model but with the fundamental components matching very closely.

The use of field data captured during system disturbances looks promising as an effective resource to tune and validate generic EMT models to represent legacy plants for which there are no equipment-specific models.

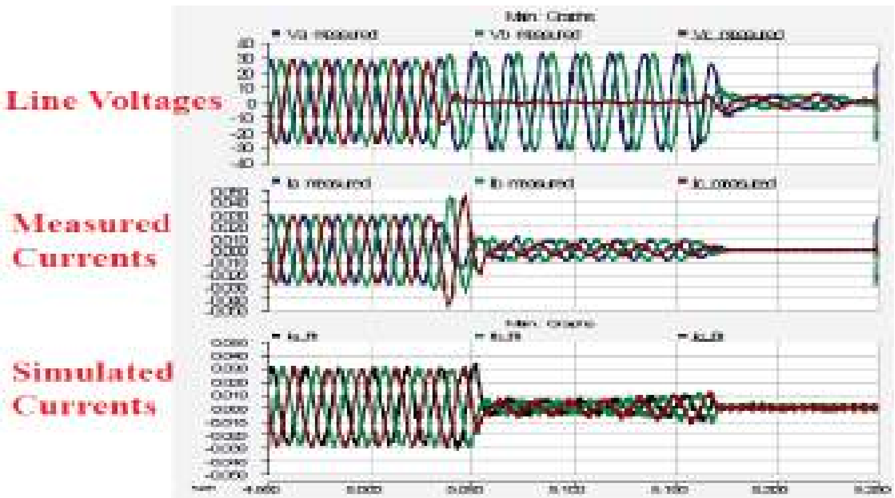

Figure A.10: Comparisons Between Calculated and Measured Parameters Using a Detailed Switching Model [3]

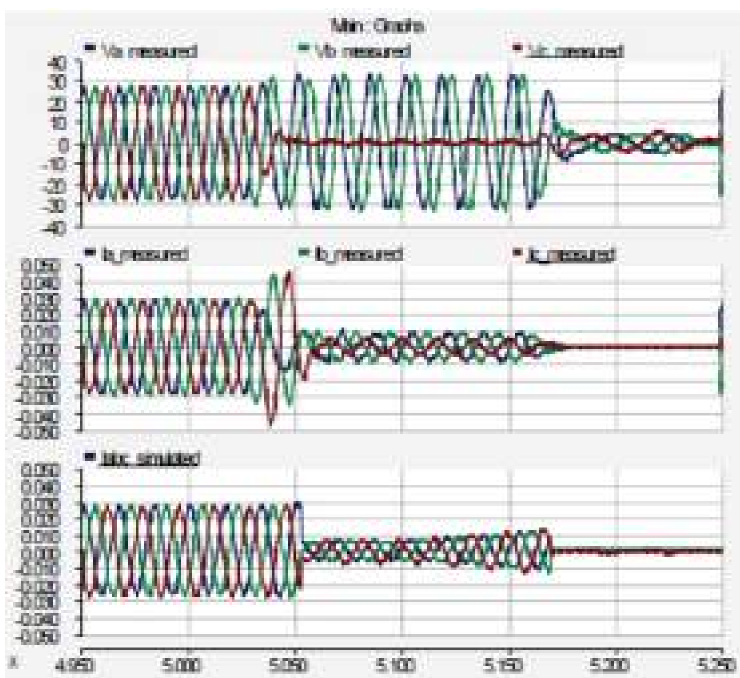

Figure A.11: Comparisons Between Calculated and Measured Parameters Using an Average Converter Model

In summary, based on the referred work, the use of field data captured during system disturbances looks promising as an effective resource to tune and validate generic EMT models for type-IV WTGs and Average PV dynamic simulation models to represent legacy plants for which there are no equipment-specific models.

Appendix B: Limitations of Aggregated Representation of IBR

It is important to note that, while compliance with ride-through capability is mandated at the plant level, it must also be validated at the individual device level. Consequently, the aggregated model can be employed to evaluate the plant's adherence to power-frequency standards but not to verify if the power plant satisfies the voltage ride-through criteria.

In the context of modeling large-scale IBR plants (wind, solar, BESS) in a wide-area system study, there are different levels of fidelities (detailed inverter-level models, semi-aggregated plant models, aggregated plant models) when it comes to the representation of the entire plant itself. A typical plant consists of several hundred individual units, such as several wind turbines in the case of a wind plant with its own inverter, filters, and transformers interconnected through collector systems to the point of interconnection. Similarly, in the context of a solar plant, there are individual PV modules with their own dc-dc converters and inverters along with their filters and transformers and the collector systems to interconnect them. As detailed representations of the entire IBR plant model with their constituent components require significant computational resources for performing detailed EMT studies, they are typically aggregated to have an equivalent behavior at the plant-level for several use cases.[73,74,75,76]

In some cases, instead of aggregating the entire plant into a single equivalent inverter, multiple units are utilized to aggregate the plant. This is typically the case when the IBR plant has inverters from different OEMs or has inverters with different operating characteristics or controllers or when an existing plant has been upgraded to increase capacity. Under these cases, the method used to obtain the multi-inverter equivalent of the IBR plant is extremely important. This typically includes the following steps: clustering of related units or identifying groups within the plant, aggregation of units within an identified cluster, equivalencing the collector network, and validating the multi-unit aggregated plant model.[77] There exist a variety of clustering algorithms including k-means, fuzzy-based, dynamic time-warping distance, etc. The selection of appropriate indices to cluster could also be based on several categories, such as unit features, operating conditions, controller parameters, and dynamic responses. Obtaining the equivalent parameters for the aggregated inverter includes the application of one of the following: weighting methods based on capacities, central parameter substitution method, or optimization methods. Similarly, for the equivalent collector network model, there are four main approaches, namely the voltage deviation, current injection, power loss, and circuit transformation methods. The most critical part of the equivalencing process as indicated above is the model validation step with field test data or at least with a detailed plant model for a selected set of use case scenarios and comparing dynamic responses to assess the overall performance match. In the context of wind plants, an approach to obtain a semi-aggregated, multi-machine model for a large wind power plant with an equivalent representation of the collector system obtained based on the power loss method was developed several years ago.[78] Similar to the criteria described above for PV plants, several methods for grouping wind turbines exist, namely based on the diversity of the wind speeds, turbine types, impedances, control algorithms, transformer sizes, and short-circuit capacity.

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[73] WECC REMTF Generic solar photovoltaic system dynamic simulation model specification, September 2012.

[74] IEC, 2012. Grid integration of large-capacity renewable energy sources and use of large capacity electrical energy storage, International Electrotechnical Commission (IEC) White Paper, Geneva.

[75] Ackermann, T., Ellis, A., Fortmann, J., Matevosyan, J., et al., 2013. Code shift: grid specifications and dynamic wind turbine models. IEEE Power Energ. Mag. 11 (6),
72–82.

[76] WECC, 2015. WECC central station photovoltaic power plant model validation guideline, WECC Renewable Energy Modeling Task Force. [Online]. Available here: https://www.wecc.biz/Administrative/150616.

[77] Pupu Chao, Weixing Li, Xiaodong Liang, Yong Shuai, Feng Sun, Yangyang Ge, "A comprehensive review on dynamic equivalent modeling of large photovoltaic power plants," Solar Energy, Volume 210, 2020, Pages 87-100, ISSN 0038-092X, https://doi.org/10.1016/j.solener.2020.06.051.

[78] E. Muljadi, S. Pasupulati, A. Ellis and D. Kosterov, "Method of equivalencing for a large wind power plant with multiple turbine representation," 2008 IEEE Power and Energy Society General Meeting - Conversion and Delivery of Electrical Energy in the 21st Century, Pittsburgh, PA, USA, 2008, pp. 1-9, doi: 10.1109/PES.2008.4596055.

Overall, any type of aggregated IBR plant model needs to be appropriately validated for the use cases for which it is used as there are some specific use cases, such as protection and fault ride-through studies, in which they do not produce similar behavior as a fully detailed plant-level EMT model due to factors, such as inverter configuration variations, geographical variations in irradiances or wind speeds within the plant, and variation of collector cable impedances. These factors could result in variation of power produced by the various units and cause differences in transient voltages at different locations within the plant, causing individual inverters to behave slightly differently and potentially trip on various conditions like overvoltages or imbalances.[79,80]

One of the use cases for the use of detailed models of all IBRs in a region is to understand the impact of unbalanced faults in the grid and the responses observed in each IBR present in the region. This assumes significance upon observing the impact of transient events recorded in NERC reports from 2016 onward that have shown that an unbalanced fault has affected several IBRs in a region and many IBRs have shown partial reduction in power generation. An example large PV plant is shown in **Figure B.1**. The large PV plant is composed of 50–100 seconds of PV systems (PV inverters connected to one distribution transformer) in the medium-voltage (34.5 kV) distribution system, which is connected to the high-voltage (230 kV) transmission system. The PV system consists of PV arrays, PV inverter modules (dc-dc converters and dc-ac inverters), and inverter firmware. There is a PPC present in the PV plant.

[79] WECC, 2014. WECC solar plant dynamic modeling guidelines, WECC Renewable Energy Modeling Task Force. [Online].

[80] Han, P., Lin, Z., Wang, L., Fan, G., et al., 2018. A survey on equivalence modeling for large-scale photovoltaic power plants". Energies. 11, 1–14.

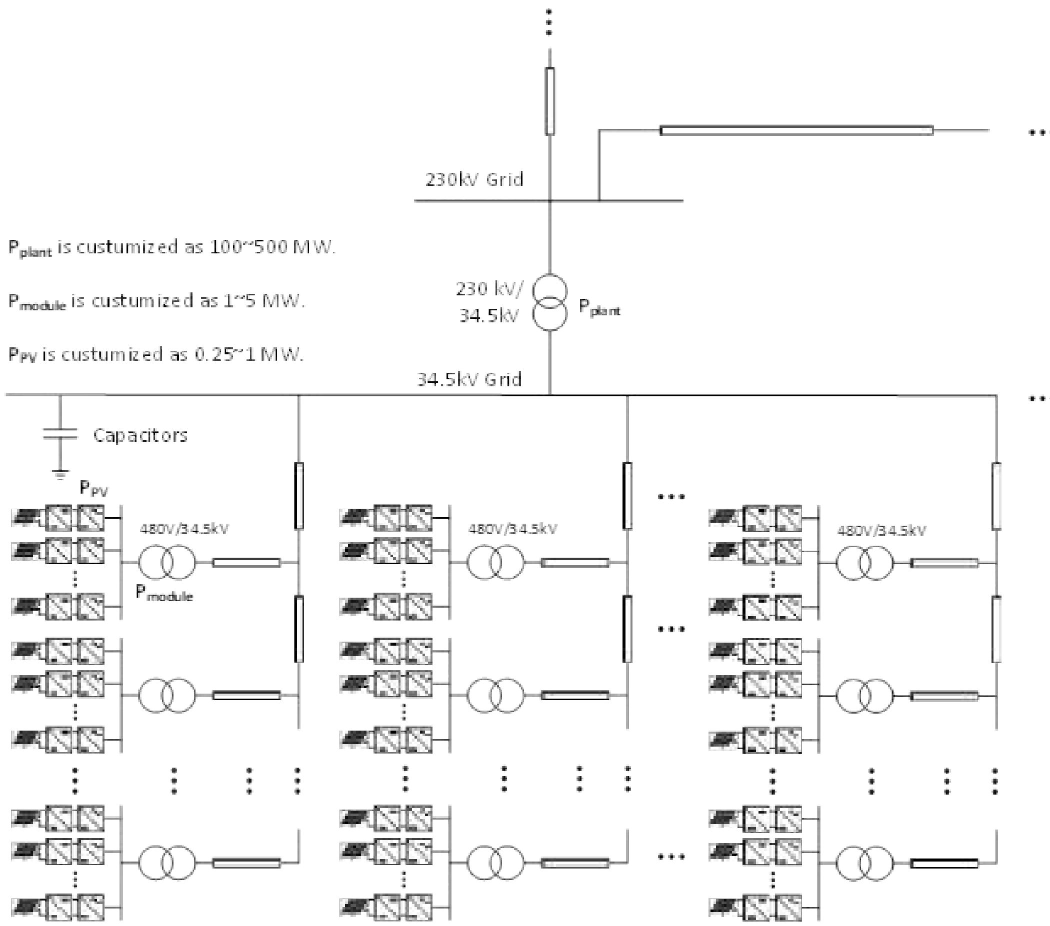

Figure B.1: Configuration of a Large PV Plant in Medium-Voltage (e.g., 34.5 kV) Distribution System Connected to High-Voltage (e.g., 230 kV) Transmission System

PV Inverter Module Model

The high-fidelity model of a PV inverter module consists of a PV array, a dc-dc boost converter, an ac-dc three-phase voltage source inverter, and an LCL filter. The PV inverter module is illustrated in **Figure B.2**. Different types of inverters have been considered in the models to be representative of inverters from different vendors and/or from different generations of inverters from the same vendor. The controller used in dc-dc converter and dc-ac inverters is implemented in a multi-rate implementation, similar to the field implementation in which the controller is implemented in 50–100 μs.

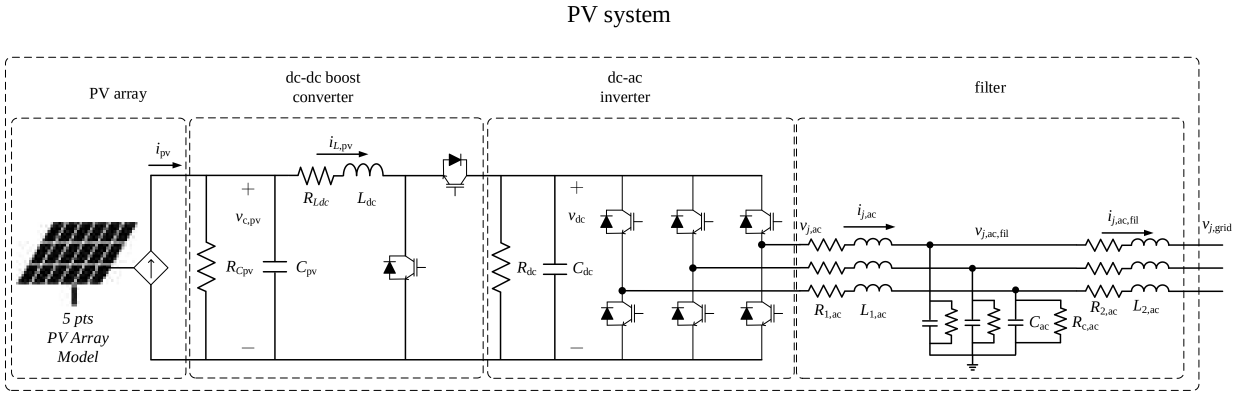

Figure B.2: Configuration of PV Inverter Module

PV System Model

A number of PV inverter modules are connected to a distribution transformer in a PV system. In the high-fidelity model, up to five inverter modules may be connected. The PV system is shown in **Figure B.3**.

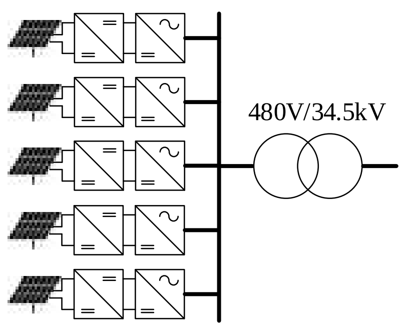

Figure B.3: Configuration of Multiple PV Inverter Modules Through a Distribution Transformer (PV System)

Collector System Model

The collector system[81] within the PV plant is modeled considering the lines, cables, shunts, and transformers that may be present. The lines and cables are modeled using the pi-section model, and the transformers are modeled using the T-type model. A detailed model of the PV plant models includes the collector system with all the PV systems present.[82]

To replicate the Angeles Forest 2018 event, the region of the power grid from the fault to the location of the one affected PV plant is modeled in the EMT domain as a simple test case to showcase the utility of EMT simulations and the use of detailed (or high-fidelity) models. This analysis should be extended to the area affected by the fault and to all the affected PV plants.

Event Replication

The integrated EMT model of the power grid with the detailed model of one of the affected PV plants is evaluated for a line-to-line fault incident that replicates the Angles Forest disturbance scenario. The line-to-line fault is incepted at t = 1.99 s. The simulation results of the voltages and currents at the local and remote ends of the faulted line in the integrated model are shown in **Figure B.4**. These results are very similar to those observed in the NERC report on

[81] Sometimes referred to as *plant distribution grid*.

[82] S. Debnath and J. Choi. 2022. "Electromagnetic Transient (EMT) Simulation Algorithms for Evaluation of Large-Scale Extreme Fast Charging Systems (T & D Models)." In *IEEE Transactions on Power Systems*, doi: 10.1109/TPWRS.2022.3212639.

the event. Subplot (a) and (b) show voltages and currents, respectively, at the near end of the faulted line; subplot (c) and (d) show voltages and currents, respectively, at the remote end of the faulted line.

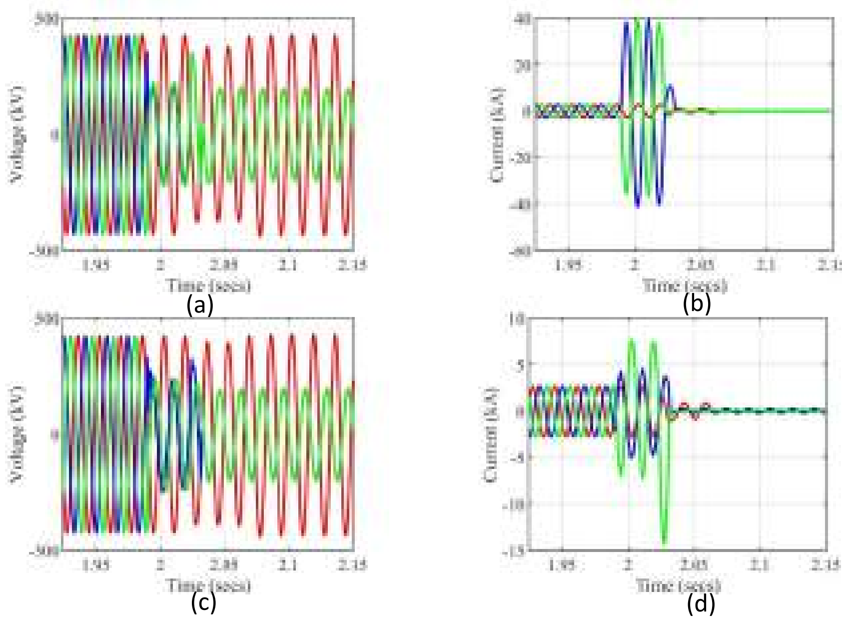

Figure B.4: Simulation Results from the Integrated EMT High-Fidelity Model (Grid-Plant) During Line-to-Line Fault

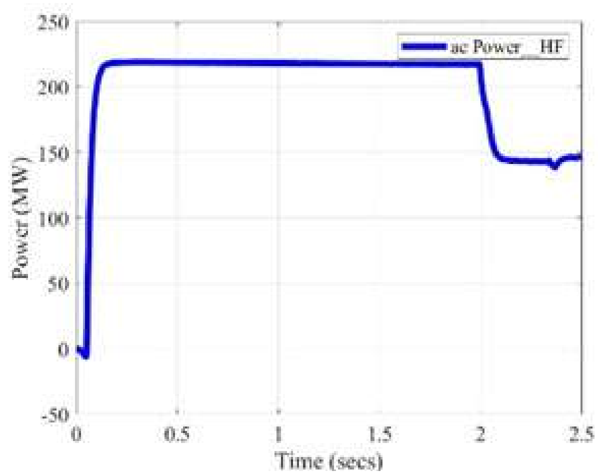

Figure B.5: Active Power (in Megawatts) from Simulation of a High-Fidelity Switched Model of a PV Plant with All the Inverters Represented in Electromagnetic Transient Simulations

The simulation result of active power from the plant is shown in Figure B.5. From the figure, it is observed that the active power from the plant reduces in response to the line-to-line fault incepted. The observed reduction in the power is due to a transient condition observed at only some of the inverters within the plant, thereby reducing their corresponding power generations to zero. The rest of the inverters within the PV plant continue to operate. This is a first-of-its-kind replication using EMT simulations to replicate a field event with trips in IBRs recurrently being observed in the field.[83] Different average-valued aggregated single inverter models of the PV plant do not replicate the behavior observed in the field.

This type of analysis needs to be expanded to the region typically affected by the unbalanced faults and to incorporate the detailed (high-fidelity) models of all the affected PV plants to accurately reflect the partial reduction in power generation at each affected PV plant during these events. Changes are needed to the contingency analysis performed in planning to accommodate this new behavior observed in planning that may assist with minimizing such behavior being observed in operations moving forward.

[83] Suman Debnath, et. al., "Library of Advanced Models of large-scale PV (LAMP) (Final Technical Report)", ORNL Technical Report, 2023. [Online] Available: https://www.osti.gov/biblio/2345308.

Appendix C: Real-World Case Studies for Leveraging Parallel Computing to Accelerate EMT Simulations

The following sections present several practical case studies of how parallel computing has been leveraged to accelerate EMT simulations for large or complex power systems.

Example 1: Modeling a Full Wind Farm: An Example with Large Number of IBRs

The detailed EMT model of a full wind farm consists of multiple wind turbines, a switching model of each wind turbine converter, a detailed MV collector grid model with cables, MV/HV transformer(s), and detailed HV cable/line models for collecting to grid side. As discussed earlier, the bottleneck of the simulation time and the main sources of the computational burden are the nonlinear switching of power electronic devices. The length of any detailed line/cable model is also very important to enable parallel computations if any such line propagation delay is larger than the timestep of the simulation. Therefore, the full wind farm simulations can be divided into multiple sections based on the number of available CPU cores in the machine. To optimize the speed of simulation, all available CPU cores should be equally loaded with the simulation of switching power electronics, detailed electrical circuits, and the decoupling enabled by short lines/cables. The system can be decoupled with the TLM-based approach when the shortest line propagation delay is greater (typically 10 times) than the simulation timestep.

Parallel computing is very efficient with the use of the high-performance computer (HPC), which consists of dozens of CPU cores. The HPC can efficiently simulate detailed wind farms and large-scale grids. As an example, the Iberdrola Innovation Middle East (IBME) lab is equipped with three HPCs and storage that has the capability to solve high computational and time-consuming simulations. The specs and the setup of the HPCs are shown in **Table C.1** and **Figure C.1**, respectively. **Figure C.2** shows a comparison between the simulation time of a full wind farm of more than 100 wind turbines using different numbers of CPU cores. The HPC is able to reduce the computing time by a factor of 15 when compared to a single-core simulation.

Table C.1: Hardware Specs for HPC and Storage Units [Source: IBME]

Specs	HPC unit	Storage unit
CPU	128 cores (2x64 AMD 7763, 2.45GHz)	2 Intel Xeon CPUs 24 cores, 2.2 GHz
RAM	1024 GB (RDIMM)	192 GB (RDIMM)
Storage	19.2 TB (SSD vSAS)	38.4 TB (SSD vSAS)
GPU	4x NVIDIA HGX A100	-

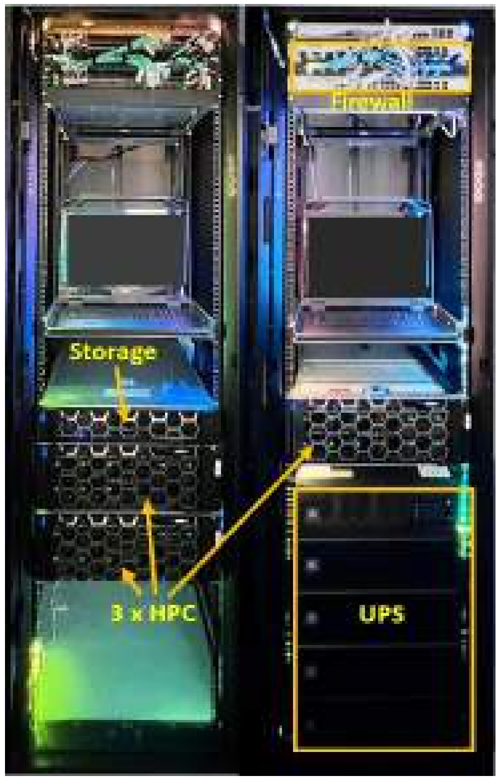

Figure C.1: HPC Setup in IBME Lab [Source: IBME]

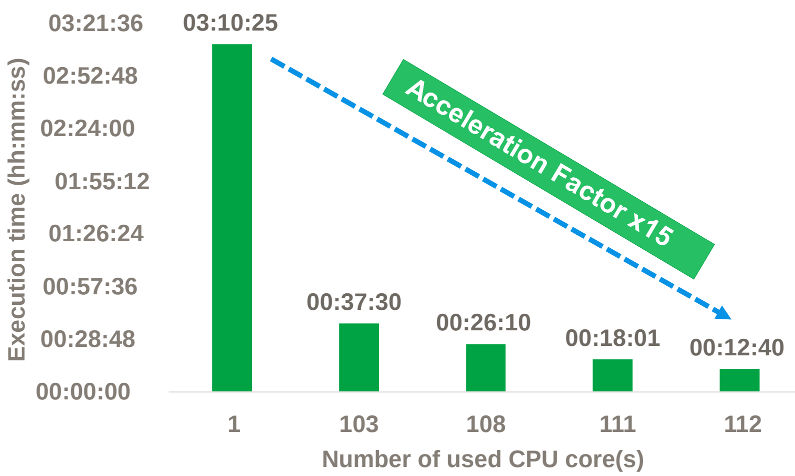

Figure C.2: Simulation Time Using Different Numbers of Cores [Source: IBME]

Another Wind Farm Example

This test case illustrates the simulation of a detailed wind park using the compensation method for parallel computations. In this case, due to the short cables in the collector grid of the wind park, it is not possible to use TLM-based decoupling. The cables are modeled as PI-sections (without propagation delay). There is a total of 45 full converter wind turbines of 1.5 MW each represented by average-value models. They are distributed on three feeders. The nonlinear magnetization branches of individual transformers are included and require iterations. Each wind turbine generic model contains 1,500 components. The computing time with a timestep of 50µs for 1 seconds of simulation on a single core is 275 s. It reduces to 55 seconds with 9 cores. Although the implementation of the iterative compensation method is more complex, it allows parallelization in the absence of transmission line delays.

Example 2: Modeling Hydro-Québec High-Voltage Transmission Network

Method 1: Accelerating EMT Simulation Using Offline EMT Tool

The following example presents the simulation of the very large Hydro-Québec grid. A top-level view is presented below.

Figure C.3: Hydro-Québec Power System Example in EMT (Off-Line)

The EMT model includes all voltage levels from 735 kV down to 25 kV loads in some places. The main case data is as follows:

- 2,098 transformers, 23,181 RLC branches
- 860 PI-line models, 398 CP-line models
- 3,675 ideal switches (e.g. circuit breakers)
- 174 arresters, 99 nonlinear inductances
- 349 synchronous machines with magnetization, exciter, and governor controls
- 2,701 PQ loads
- 10 static var compensators
- 56,202 control diagram blocks (e.g., each gain is considered as a block)
- Total number of electric nodes: 29,803

The computing time for 1 seconds with a timestep of 50 µs on a single core is only 3 minutes, including load-flow solution and automatic initialization. This remarkable performance is due to the usage of sparse matrices with fast convergence using Newton’s method. With 8 cores, the computing time reduces to 75 s. TLM-based decoupling is used to achieve these results on a basic laptop, i7-12800H, 2.4 GHz. No artificial lines are added in the grid for creating more decoupling since that requires user intervention and impacts accuracy. Discontinuity treatment is enabled for switching devices.

It should be noted that this simulation does not require any user intervention. What is drawn in the schematic diagram is what is simulated, starting with an integrated load-flow solution that initializes immediately the time-domain computations. Flat frequency trace is achieved, and a fully iterative solver is used for nonlinear models. The control block diagrams are solved directly with an algebraic loop solver, and no user intervention is required.

Method 2: Reaching Real-Time Speed with 56 Processors with 6 12-Pulse HVdc Converters and 10 Static Var Compensators

Table C.1 delineates the components of a modified Hydro-Québec power system model that was introduced earlier. This categorization includes both the type and quantity of components, providing a thorough insight into the system's architecture. Table C.2 highlights the variation in simulation speed as a function of the number of processors deployed. The data unequivocally demonstrates that substantial gains in performance efficiency are achievable through the incremental addition of CPU cores. This enhancement extends from offline simulations to real-time simulations executed at 40 µs, utilizing 56 CPU cores for an extensive system that encompasses roughly 1,666 three-phase buses. The possibility of utilizing additional processors indicates the potential for achieving speeds that exceed real time. This capability is exceptionally beneficial for the swift analysis of various contingencies within a constrained timeframe, offering a significant improvement in the system's analytical efficiency and operational reliability.

Table C.2: Real-Time Simulation of Hydro-Québec Grid on 56 CPU Cores at 40 µs

Components	Quantity
Three-phase buses	1,666
Electrical Machines	111
Lines and Cables	432
Three-phase Transformers	338
Governors, Exciters, and Stabilizers	221
Static Compensators	10
Wind Power Plants	10
HVDC Converters	6
Dynamic Loads	165

Table C.3: Simulation Time for a 15-Second Event

CPU Type	# of CPUs	Measured Simulation Time (s)	Theoretical Simulation Time with 100% Efficiency (s)	Actual Efficiency (%)
i9-10900X	1	2565	NA	NA
i9-10900X	4	786	641	82%
Xeon Gold 6144	56	15	46	305%

The previous examples for the Hydro-Québec grid model clearly demonstrate the scalability of parallel EMT simulations. The prospect of conducting several parallel simulations on vast cloud computing platforms further amplifies this potential, underscoring the scalable nature of the system's simulation capacity.

Example 3: Modeling the Chilean Grid

In the second case, parallel computations are achieved for the Chilean grid for studying the integration of renewable energies. The increasing penetration of variable renewable energy (VRE) generation along with the decommissioning of conventional power plants in Chile has raised several operational challenges in the Chilean National Power Grid (NPG), including transmission congestion and VRE curtailment. To mitigate these limitations, an innovative virtual transmission solution based on BESS, known as Grid Booster (GB), has been proposed to increase the capacity of the main 500 kV corridor of the NPG. A top-level view of the NPG characterized by five voltage control areas (VCA), corresponding to distinct geographical regions (Big North, Small North, Center, and Center South), is shown in Figure C.4. This system has been studied with a wide-area EMT model.

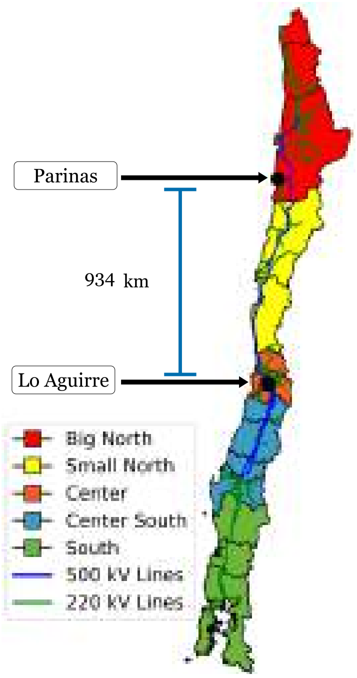

Figure C.4: Chilean Power System Example in EMT

The large numbers of IBRs made it necessary to simulate this grid in parallel using a co-simulation technique where several instances of EMT solvers are used to run on separate cores and in parallel[84]. This TLM-based approach allowed a performance of 13 seconds for 1 seconds of simulation with a timestep of 50 µs. A total of 60 CPUs were used on a basic desktop computer (AMD Ryzen Threadripper PRO 5995WX, 2.7 GHz). Scalability can be observed in Figure C.5.

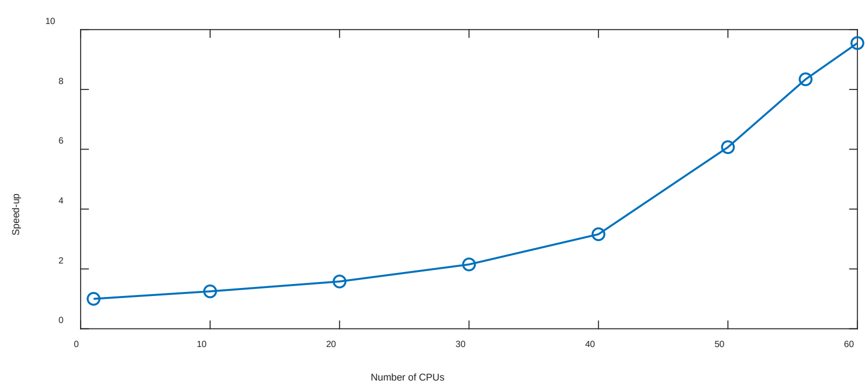

Figure C.5: 1.15 Scalability with Increasing # of CPUs

[84] M. Ouafi, J. Mahseredjian, J. Peralta, H. Gras, S. Dennetière, B. Bruned, "Parallelization of EMT simulations for integration of inverter-based resources," Electric Power Systems Research, Vol. 223, Oct. 2023, 8 pages, DOI: 10.1016/j.epsr.2023.109641.

The complete network includes the following:

- 27 wind parks and 32 photovoltaic parks, generic models
- 307 PI-line models, 297 CP-line models
- 57 synchronous generators with magnetization data when available with governor and exciter controls
- 48 transformers with nonlinear magnetization branches
- 57,708 control diagram blocks
- 6,785 total electric nodes

Example 4: Modeling Very Large 4,000-Bus Australian System

A recent case study considered a 4,000-bus EMT benchmark that was developed based on a synthetic model of the Australian electricity network[85]. In this case study, the setup (as shown in Figure 4) interconnected multiple multi-core CPU real-time simulators together with a fast communication link over optical fiber. In this architecture, the entire EMT simulation of the network and its associated elements (including main grid models, controls, protection, measurement, black-box control, and plant model) were distributed between various multi-core CPUs (in particular, a high-performance 128-core Windows computer interconnected to 22 high-performance 18-core computers) to accelerate the overall performance of the EMT simulation. Overall, 100 cores were used for the computation of the network solution while about 300 cores were used for detailed simulations of OEM controller codes for various IBR plants. The details about the components of the model are shown in **Table C.2**.

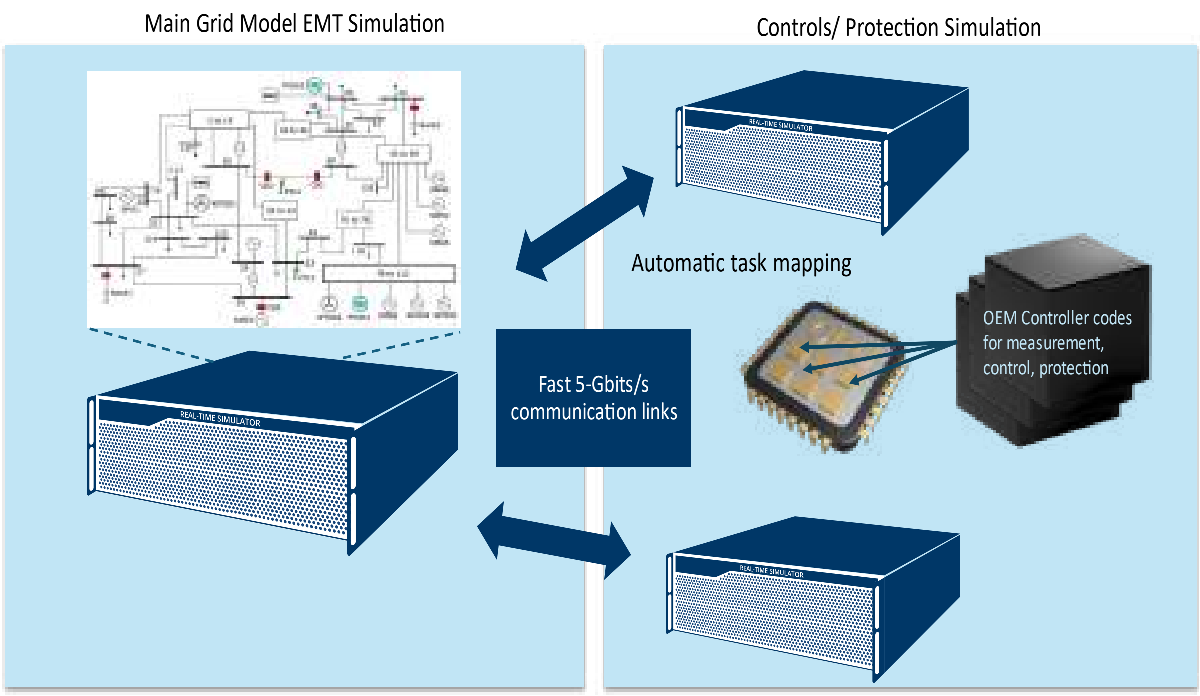

Figure C.6: Multiple Simulator, Multi-Core CPU Real-Time Simulation Architecture for Accelerating EMT Simulation

[85] S. Li et al., "Fast and real-time EMT simulations for Hardware-in-the-Loop controller performance testing and for on-line transient stability analysis of large-scale low-inertia power systems." Paper CIGRE-689, CIGRE Canada, Vancouver, BC, Sept. 25 – 28 2023. [Online] Available: https://cigreconference.ca/papers/2023/paper_689.pdf

The goal of this case study was to achieve real-time simulation speeds for a large-scale system. However, the actual speed of simulation was limited by several OEM black-box controller codes that were not implemented efficiently, negatively affecting the potential for reaching real-time performance. Regardless, this setup showed a significant performance improvement (30 seconds of simulation in 90 seconds of wall-clock time) to reduce the time taken to perform EMT studies while including detailed OEM black-box models. Overall, in the interest of accelerating EMT simulations with detailed site-specific models, it is crucial for the industry to not only establish standards for model interoperability, such as the Functional Mock-Up Interface (FMU) or the guidelines provided by CIGRE, but also to mandate that the implementations of OEM controller codes can achieve, or exceed, real-time speeds. Adopting this comprehensive approach is imperative for accelerating EMT simulation performance at scale to support the need for detailed system studies.

Table C.4: 4,000-Bus Synthetic EMT Benchmark Components List

Component	Approximate # of components
Buses (3-phase)	4,000
Lines, loads, switched shunt reactors	6,700
Transformers and synchronous machines	2,000
Protection relay models	100
IBR plants (Solar, Wind)	150
OEM Controllers (precompiled DLLs)	300
FACTS and HVDC converters	70

Summary

The examples presented in the case studies underscore the efficacy of parallel computation in facilitating rapid EMT simulation of extensive power grids with minimal user intervention.

It is acknowledged that, particularly for large power systems, a hybrid EMT-Phasor simulation might be applicable. Nonetheless, the selection of appropriate EMT and phasor-domain zones to accurately assess transient stability remains a formidable challenge and an area of active research. Best accuracy is achieved with EMT-only simulation mode.

EMT Analysis in Operations

The rapid growth of IBRs and DER challenge existing power system reliability assessment processes. These resources and their software-defined behaviors expose the limitations of conventional phasor-domain simulation techniques across all aspects of power system engineering, including system operations. There are unique challenges presented by EMT analysis and the associated engineering processes when carried out within the operations planning time horizon. This section briefly explores challenges and solutions for study methodologies and model management processes for successful EMT analysis in operations space.

- Why is EMT analysis needed in the operations space?
  - EMT analysis in interconnection studies may typically cover a limited set of potential topology conditions and generation patterns since they necessarily make assumptions about a future system state. The operations planning time horizon is typically much nearer to the real-time system topology and operating conditions than planning studies, so there is less uncertainty when assessing for example a planned maintenance outage condition, unique expected generation pattern, or other system conditions. This may allow for a deeper analysis of a specific topology condition than could otherwise be justified in an interconnection study.

    - Operations engineering analysis typically revolves around the need for testing the boundary conditions and testing hypothetical and real-time scenarios with a wide variety of operating conditions involving topology and generation patterns. The goal is to provide operating guidance for the system operators, identifying the most limiting factors and describing the mechanisms to prevent adverse outcomes following a criteria contingency. Due to the complexity of IBR behaviors and the EMT models representing these resources, these operating studies can be atypical compared to conventional resources.

- What are the necessary processes that need to be in place for successful EMT analysis pipeline in operations?
    - (What are the attributes of) A complete IBR model life cycle management process that produces a repository of accurate, ready-to-use EMT models:
        - As-studied model evolution into an as-built model, changes tracked and validated.
        - Repository contains EMT models that passed model accuracy and usability acceptance tests and whose performance benchmarks well against real system events.
        - Model documentation that covers relevant simulation prerequisites and particulars
    - (What are the attributes of) A mature study and simulation pipeline for EMT analysis:
        - Process for conveying initial steady-state conditions and disturbance characteristics into test case
        - Process for executing simulations in a performant manner (enhance ability for study engineer to iterate)
        - Process for extracting meaningful results from the simulation output (plotting)
- Why are these processes so important to EMT analysis in operations?
    - Timelines: An operations engineer may need to return an answer to a reliability question in a matter of weeks, days, or even hours, which does *not* allow time for:
        - Chasing down model quality or usability issues
        - Collecting EMT models from potentially disparate sources or extracting them from prior studies.
        - Verifying that the models to be used represent the most up-to-date configuration of the projects that fall within the scope of the study area.
        - Chasing down model documentation
        - Undertaking manual intervention to achieve an EMT simulation initial condition that matches a known steady-state starting point
- What are the challenges of performing EMT analysis in operations time horizon?
    - Impact of contingencies on neighboring areas due to Interconnection reliability operating limit (IROL) impact, which may expand the study area model, making it challenging for EMT tools

Establishing mature processes to support EMT analysis in the operations space has knock-on benefits that extend to any point in the lifecycle of an IBR that requires EMT analysis. For example, an actively managed EMT model repository can benefit the generation interconnection process by reducing the time and effort required to collect, process, and validate EMT models of resources near a future project under study.

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

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Guideline Information and Revision History

Guideline Information	
Category/Topic: EMTTF	**Reliability Guideline/Security Guideline/Hybrid:** Reliability Guideline: Recommended Practices for Performing EMT System Studies for Inverter-Based Resources
Identification Number: [NERC use only]	**Subgroup:** EMTTF

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

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:

- Number of TPs and PCs that have implemented screening methods and criteria for EMT modeling
- Number of TPs and PCs performing select EMT studies recommended herein

Effectiveness Survey

On January 19, 2021, the Federal Energy Regulatory Commission (FERC) accepted the NERC proposed approach for evaluating reliability guidelines. This evaluation process takes place under the leadership of the RSTC and includes the following:

- 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 that use reliability and security guidelines to respond to the short survey provided in the link below.

Guideline Effectiveness Survey [insert hyperlink to survey]

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Reliability Guideline

Recommended Practices for Performing EMT System Studies for Inverter-Based Resources

~~May~~December 2024

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Table of Contents

Preface

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

Reliability | Resilience | Security

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

The North American BPS is made up of six Regional 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~~made with consideration of system design, configuration, and business practices.

Executive Summary

Accelerating changes in the ~~bulk power system's (BPS)~~BPS' resource mix, increasing penetrations of inverter-based resources (IBR) and their documented reliability challenges, and the added complexity of IBR controls and IBR plant configurations necessitate leveraging advanced electromagnetic transient (EMT) modeling and simulation tools to adequately assess reliability risks. These EMT models and simulations ~~are essential as they often~~should utilize manufacturer-specific control logic and code in the form of equipment-specific models (ESM), allow for the modeling of communication delays and protocols, and ~~can~~have the ability to capture high~~-~~-resolution ~~and accurate~~ study results not possible in other simulation domains.

The Inverter-Based Resource Performance Subcommittee (IRPS) ~~has~~ previously published *Reliability Guideline: Electromagnetic Transient Modeling for BPS~~-~~-Connected IBRs—~~-~~Recommended Model Requirements and Verification Practices*, which provides foundational knowledge to ~~help enable~~facilitate effective system impact assessments of IBRs using highly accurate EMT models. This ~~Reliability Guideline~~reliability guideline expands on the previous document and ~~will provide~~provides recommended EMT modeling practices for establishing screening criteria to determine if an EMT study is needed, study area selection, appropriate modeling of the study area and the surrounding network to balance ~~between~~the overall accuracy of the study result and the computational and human resource burden, and general best practices for ~~a~~ selection of EMT studies.

The focus of this ~~Reliability Guideline~~reliability guideline is within the generator interconnection studies process, primarily system impact studies, and not conventional EMT studies, such as insulation coordination~~, etc~~. The goal is to equip transmission planning engineers and other industry engineers with the necessary knowledge to begin screening for and studying the impact of IBRs on the BPS with detailed equipment~~-~~-specific EMT models within the EMT simulation domain.

Recommendations

This ~~Reliability Guideline~~reliability guideline provides recommendations for Transmission Planners (TP), Planning Coordinators (PC), Generator Owners (GO), equipment manufacturers, and consultants for conducting EMT modeling and studies for interconnection of ~~inverter-based resources~~IBRs; NERC strongly encourages these entities to adopt all of the recommendations ~~contained~~ throughout this guideline and are summarized in **Table ES.1**.

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Table ES.1: Recommendations and Applicability	
Recommendations	**Applicability**
Reiterating the Need for Resourcing: TPs and PCs should prepare for the growing need for EMT modeling and studies related to the reliable interconnection of ~~inverter-based resources~~IBRs in the near future. As the penetration of ~~inverter-based resources~~IBRs grows, the need for ~~conducting~~ EMT studies to adequately ensure reliable operation of the BPS ~~increases~~becomes more ~~rapidly~~pressing. This may require upskilling existing staff as well as acquiring new talent and resources in this area. A robust understanding of the EMT simulation environment, IBR controls and behavior, and general power system analysis fundamentals ~~are~~is an important ~~pre-requisites to~~basis for conducting EMT analysis.	TPs and PCs
Modeling Data Quality and Consistency: TPs and PCs should enhance their modeling data management processes for improved quality and consistency between different modeling platforms, which helps streamline the development of corresponding EMT network models from the existing modeling data sources.	TPs and PCs
Screening for the Need for EMT Studies: TPs and PCs should develop, document, and maintain clear methods and criteria to determine when EMT studies are necessary in the interconnection study process. No single metric should rule *out* the EMT study need. While certain metrics have been known to be inadequate in predicting control instability and therefore determining the need for EMT studies, they can still be useful to "rule in" the need for EMT studies. For example, while high short-circuit current level alone should not rule out ~~the~~ EMT study need, low short-circuit current level ~~should~~may be a trigger for conducting an EMT study. See **Chapter 1**.	TPs and PCs
EMT Study Area Selection: TPs and PCs should leverage the recommendations herein to develop, document, and maintain clear methods and criteria to ensure that the EMT study area is adequately "sized" such that correct system behavior and potential interactions between various dynamic devices can be captured. See **Chapter 2**.	TPs and PCs
Modeling of EMT Study Area and Rest of System: TPs and PCs should consider the recommended modeling methods herein for representing the study area and the rest of the system in EMT. See **Chapter 3**.	TPs and PCs
Consideration for Study Scenarios: TPs and PCs should consider the most critical contingencies and ~~the~~ worst-case credible operating conditions ~~in which less~~where fewer grid~~-~~-stabilizing characteristics ~~are available~~, such as system strength, inertia, and damping~~.~~, are available. See **Chapter 5**.	TPs and PCs
Cross-Platform System Model Benchmarking: TPs and PCs should establish modeling practices to ensure that EMT and positive~~-~~-sequence system models are benchmarked against each other such that responses are consistent, ~~given~~considering modeling and simulation platform limitations. As the consistency of system models are dependent on the consistency of IBRs models, TPs and PCs should require GOs to provide properly benchmarked models as recommended in the Reliability Guideline: EMT Modeling for BPS-Connected IBRs – Recommended Model Requirements and Verification Practices and NERC Dynamic Modeling Recommendations. See **Chapter 4**.	TPs and PCs
Performing EMT Analysis: TPs and PCs should consider the analysis methods recommended herein when assessing dynamic system impact, resonances, and transmission system protection. TPs and PCs should also ~~develop~~consider the quantitative post-processing methods recommended herein to narrow down the results to identify issues quickly. See **Chapter 6**.	TPs and PCs
Addressing the EMT Analysis Results: When addressing criteria violations~~ / ~~/performance concerns (such as instability and ride-through issues) observed during the EMT analysis, any control tuning as part of mitigation should be performed by the original equipment manufacturer (OEM) or with direct permission~~ / ~~/instruction from the OEM as other parties do not know the full implications of	TPs, PCs, and GOs

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Table ES.1: Recommendations and Applicability	
Recommendations	**Applicability**
individual parameter changes and should not take responsibility for these changes. Control tuning done outside of the purview of the OEM should be considered investigative only. See **Chapter 6**.	

Introduction

~~The purpose of this~~This guideline ~~is to provide~~provides guidance on when and how to conduct select EMT studies, including how to scope and model the study area, the system external to the study area, and legacy IBR plants.

Although EMT modeling allows for highly accurate and detailed models, ~~it does~~ not ~~mean~~ all EMT models are inherently accurate. The accuracy and fidelity of a given EMT model depends on the model development process, the modeling requirements ~~they were~~for which it was developed ~~for~~, and assumptions. All models, both EMT and positive sequence~~, inherently~~ phasor-domain (PSPD), have inherent limitations that should be understood by engineers carrying out modeling studies. Having thoroughly vetted models is a prerequisite to an accurate modeling study. Comprehensive model requirements and model quality verification practices recommended in the previous guideline[1] should be followed.

The following is a summary of this guideline's chapters:

- **Chapter 1** provides recommended considerations for when EMT studies should be conducted.
- **Chapter 2** covers how to scope an EMT study by selecting an appropriate study area to be modeled in detail.
- **Chapter 3** covers how to model the selected study area and the rest of the BPS external to the study area.
- **Chapter 4** touches on the importance of system model validation and recommendations to ensure a certain level of confidence in the base-case model before proceeding with dynamic studies.
- **Chapter 5** provides guidance on preparing study cases and consideration for contingencies to be studied.
- **Chapter 6** provides methodologies for three select types of EMT studies ~~—~~—dynamic system impact assessment ~~study~~, subsynchronous oscillation ~~study~~, and transmission system protection validation ~~study. **Chapter 7** contains additional guidance on modeling legacy IBR plants, expanding on the previous guideline. **Chapter 8** includes ways to accelerate EMT simulations. Additional materials on legacy plant modeling is covered in **Appendix A**. Additional examples and exploratory discussion on EMT analysis in Operations are provided in **Appendix B and C**.~~.
- **Chapter 7** expands on the previous guideline[1] with additional guidance on modeling legacy IBR plants.
- **Chapter 8** discusses how to accelerate EMT simulations.
- Additional materials on legacy plant modeling are covered in **Appendix A**.
- Additional examples and exploratory discussion on EMT analysis in operations are provided in **Appendix B** and **Appendix C**.

The flow chart below illustrates how contents in different chapters tie together in an EMT study process.

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[1] Reliability Guideline: Electromagnetic Transient Modeling for BPS-Connected Inverter-Based Resources—Recommended Model Requirements and Verification Practices, March 2023

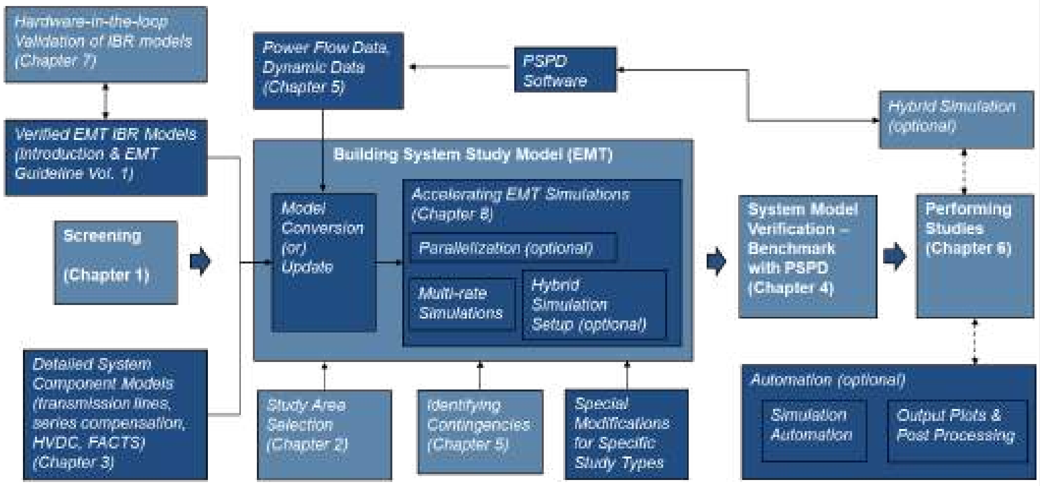

Figure I.1: Overview of an EMT Study Process

Chapter 1: When to Perform EMT Studies

This guideline provides recommended study practices for the following ~~three~~ types of EMT studies:

- Dynamic system impact assessment~~,~~ related to interconnection of IBRs
- Subsynchronous oscillation
- Transmission protection system validation

~~What is of~~Of interest to be evaluated in ~~those~~these studies are aspects related to ~~controller~~control stability~~,~~; interactions between IBRs and other dynamic devices such as FACTS, HVDC and synchronous condensers; and transmission protection system settings and schemes, such as remedial action schemes~~.~~ (RAS). While a detailed EMT study can provide valuable insight into these phenomena, the computational and human resource burden associated with carrying out such a study necessitates careful screening to identify the need for one. This chapter provides recommended considerations for deciding when to perform those EMT studies.

If any one of the situations detailed below applies, EMT studies should be considered.

Low System Strength

With the increasing penetration of IBRs and retirement of synchronous generators, specific areas of the BPS may experience reduced system strength ~~or~~(also known as voltage stiffness~~. To~~). Various steady-state system-strength metrics can approximate the strength of an area, ~~there are various steady state system strength metrics available. Most are~~mostly documented in the ~~Technical Brochure of~~ International Council on Large Electric Systems (CIGRE) WG B4.62 *Connection of* ~~wind farms~~*Wind Farms* *to* ~~weak~~*Weak* *AC* ~~networks[2].~~*Networks* technical brochure.[3] These metrics are, however, based on the steady~~-~~-state network topology and power flow across the network~~. They~~ and do not consider the impact of the control system design and its parameterization. Nevertheless, a combination of these metrics can be used to broadly determine whether an area of interest is "weak~~".~~." There are also tools available ~~which~~that use those metrics to screen for weak areas.[4]~~.~~

~~Transmission Providers (TPs)~~TP and ~~Planning Coordinators (~~PCs~~)~~ are encouraged to ~~get an understanding of~~understand the strength of their footprint and adopt or develop system strength metrics and criteria to determine weak areas for which EMT studies may be required. ~~Important to note here is that~~Importantly, having a high level of system strength alone should not rule out the need for EMT studies without evaluating for the rest of the recommended considerations presented in this chapter. ~~Further, it~~It is further important to note that applicability of these system strength metrics ~~should not be applied without appropriate justification for the~~may vary with specific ~~footprint~~footprints under consideration. Generalizing justifications across footprints is not recommended.

Stability Criteria

If transient stability studies performed in positive~~-~~-sequence, phasor~~-~~-domain root mean square (RMS) tools ~~indicates~~indicate any ~~violation or close~~poor performance with respect to ~~violation of~~the stability criteria set forth by TPs and PCs, EMT studies can be considered to double-check those results[5]. If numerical instability is suspected in positive~~-~~-sequence, phasor~~-~~-domain RMS simulations, it is recommended that TPs and PCs first verify if the positive~~-~~-sequence, phasor~~-~~-domain RMS models have been constructed in a robust manner. The presence of numerical instability by itself is not necessarily indicative of the need for an EMT study. If ~~the~~ numerical instability persists after

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~~[2] https://www.e-cigre.org/publications/detail/671-connection-of-wind-farms-to-weak-ac-networks.html~~

[3] https://www.e-cigre.org/publications/detail/671-connection-of-wind-farms-to-weak-ac-networks.html

[4] Example: EPRI's system strength assessment tool - https://www.epri.com/research/products/000000003002027116

[5] "Power System Dynamic Modelling and Analysis in Evolving Networks (CIGRE Green Book)", Editors: Babak Badrzadeh, Zia Emin, Springer, 2024

~~verifying~~ the robustness and quality of the model are verified, it is recommended that the scenarios ~~should~~ be further studied in EMT tools. It is important to ensure that all credible scenarios and contingencies ~~were~~are considered in positive~~-~~-sequence, ~~phase~~ phasor-domain studies (e.g~~.~~., minimum synchronous generation dispatch).

Small~~-~~-signal stability can be assessed ~~using~~with analytical methods, such as either impedance scanning methods or Eigen value analysis and can provide ~~an~~ insight ~~with respect to~~into the possibility of control interactions, resonance, and/or instability in the small~~-~~-signal realm. ~~The use of these~~These analytical methods can help further refine the necessity for an EMT study. Analytical methods can also be used to evaluate the fault ride~~-~~-through ability of IBRs based on known limits and gain insight into the maximum duration of fault that the IBR can withstand, which can also be compared with the operation time of protection within the ~~region [ref]~~area[6].

~~Keep in mind~~As positive~~-~~-sequence models are an approximation and may not have sufficient details to represent all relevant dynamics of actual equipment~~. Therefore, in some cases, it is likely to see~~, false ~~negative~~stable results in positive~~-~~-sequence stability studies~~.~~ are likely to be seen in some cases. For example, a Hawaiian island system performed stably in positive~~-~~-sequence transient stability studies but showed instability in small-signal stability ~~study~~[7] and EMT ~~study~~studies. Therefore, TPs and PCs should consider adding some buffer in their positive~~-~~-sequence transient stability criteria to account for the lack of details in positive~~-~~-sequence models. For example, if an area has 3% damping criteria based on positive~~-~~-sequence simulations, then with decreasing system strength, increasing the threshold (screening criteria) to 5% based on positive~~-~~-sequence simulations could indicate the need for an EMT simulation. This should not, however ~~not~~, imply that the mere presence of an EMT study automatically implies accuracy. If appropriate EMT models and simulation techniques are not used, EMT studies can show false ~~negative~~ results ~~which~~that can consume significant ~~amount~~amounts of engineer time.

System Topology or Conditions ~~Conducive to Instability~~with Stability Risks

TPs ~~or~~and PCs should ~~be aware~~ consider the need for EMT studies in areas with any of the following characteristics ~~of an area of interest in which EMT studies are being contemplated. If any one of those applies, EMT studies should be considered.~~:

- Pre-existing oscillation or oscillatory modes
- Presence of the following devices nearby:[8]~~:~~
  - Series-compensated lines
  - Flexible ac transmission system (FACTS) devices
  - ~~HVDC~~HVdc lines
  - Other IBRs
- High IBR penetration level
- Presence of any specialized protection schemes, such as ~~Remedial Action Schemes~~RASs
- Presence of transmission lines protected by distance relays and declining fault current levels
- Areas ~~where there is~~seeing a trend of decreasing system strength
  - TPs and PCs should monitor the system strength trend as it indirectly impacts the small-~~signal~~ and large -signal stability of the system.

[6] Vishal Verma 8/6/2024 10:07 AM • S. Thakar, S. Konstantinopoulos, V. Verma, D. Ramasubramanian, M. Bello, J. Xu, W. Zhou, J. Mesbah, W. Zhou, and B. Bahrani (2024) Topic 2 – Analytical methods for determination of stable operation of IBRs in a future power system. CSIRO, Australia.

[7] Small~~-~~-signal stability study was based on more detailed EMT models.

[8] See Chapter 3: Study Area

- Areas where there is a trend of increasing rate of change of frequency (RoCoF) or decreasing inertia
  - Increase in RoCoF due to decreasing system inertia could lead to delayed or non-operation of protective relays and ~~could~~ jeopardize system integrity.

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EMT Studies Following System Events

In addition to the system planning horizon, conducting an EMT study is also ~~deemed~~ necessary during the ~~operational timeframe~~operation time horizon, particularly following ~~the identification of~~ a ~~qualified~~ system event. When ~~such~~ an event occurs and the observed phenomena cannot be accurately replicated through simulation using a positive~~-~~-sequence model~~,~~ (or if it significantly deviates from the behavior and performance ~~resulted~~results from the past EMT simulations~~, it necessitates~~), a new EMT study~~.~~

is needed. This ~~study is essential for correcting~~is required to correct any potential errors in existing EMT models and ~~verifying~~verify the quality of the simulation base case~~. This~~ and is an important feedback loop introduced between the reality and simulation study. By replicating the results of the event, the study ensures the accuracy of the simulation and lays the groundwork for validating proposed mitigations. This step is crucial to ~~prevent~~preventing the introduction of unintentional or unacceptable reliability risks to the ~~Bulk Electric System (BES).~~

BPS and requires coordination and cooperation among GOs, TOPs, RCs, PCs, TPs and other relevant stakeholders. It is important to acknowledge that replication of system events in simulation requires verified and validated models of all dynamic elements in the power system.

Chapter 2: How to Select Study Area to Be Modeled

It is not always practical or necessary to directly represent an entire interconnected power system (e.g., ~~eastern interconnection~~Eastern Interconnection wide database) in EMT tools. ~~Typically, in~~In EMT studies, ~~the model directly includes the equipment within~~ a study area ~~that~~ is ~~only~~ a portion of the larger interconnected power system ~~with~~and the steady-state and/or dynamic contributions of the ~~external~~rest of the power system (external system) are represented as an equivalent (discussed in **Chapter 3**). Typically, only the equipment within the study area are represented explicitly. Some techniques, such as the use of hybrid ~~simulations~~simulation tools, allow the co-simulation of EMT tools and phasor-domain simulation tools simultaneously. However, even for these simulations, ~~it is necessary for~~ the study engineer needs to determine how much of the system needs to be modeled in the EMT domain. For studies ~~which are~~ intended to ~~quantify~~analyze the behavior, impact, or potential interaction between various IBRs, synchronous machines, and power electronic devices, it is important to ensure that the study area is adequately "sized" such that ~~correct~~necessary system ~~behavior~~characteristics and potential interactions between various dynamic devices can be captured. This ~~Chapter~~chapter will discuss the impacts of the ~~time scale~~timescale of power system dynamic phenomena on study area selection as well as methods for determining which dynamic devices should be included within ~~the~~a study area.

Study Area Selection

~~For~~The goal of system modeling~~, the goal~~ is to represent the associated equipment accurately for the phenomena of interest. As such, the system modeling techniques and simulation ~~time-step~~timestep should be selected according to the phenomena under evaluation, as illustrated in **Figure 2.1**.

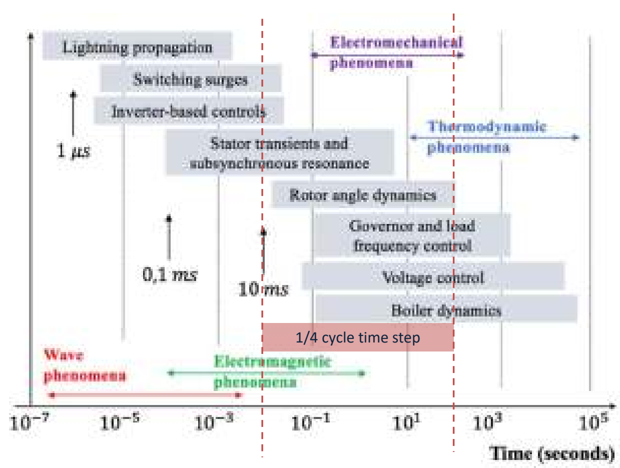

Figure 2.1: Timescales of Power System Phenomena ["Definition and Classification of Power System Stability~~—~~–Revisited & Extended"; IEEE Transactions on Power Systems, July 2021]

The power system phenomena of primary interest for typical EMT simulations are as follows [Institute of Electrical and Electronics Engineers (IEEE) Std. C62.82.2-2022 and International Electrotechnical Commission (IEC) 60071-2 ED5]:

- **EMT System Impact Assessment Studies:** A Few ~~Hzs –~~Hz–2 kHz~~.~~

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- This is the primary focus of this guideline. Phenomena of ~~interests~~interest include evaluation of controls interactions, fault ride-~~-~~through performance issues, and weak grid stability issues.
- Typically, the study area will be selected to provide adequate electromagnetic and electromechanical performance.

- **Temporary Overvoltage (TOV) Studies**: Up to 1 kHz
  - TOVs can be caused by fault initiation and clearing, grounding effectiveness, load rejection, resonance conditions, or system non-linearities.
  - The study area will be selected to provide adequate electromagnetic performance and, if necessary, electromechanical performance.
  - The modeling and analysis techniques discussed ~~within~~in this document are applicable to modeling for TOV studies.
- **Slow-~~-~~Front Transients**: Up to 20 kHz
  - Slow-~~Front-~~front transients are primarily caused by switching events, such as capacitor bank switching, transmission line switching, transformer switching, and fault initiation and clearing.
  - The study area will be selected to provide adequate electromagnetic performance and traveling wave behavior.
  - This is provided for information only. Study area selection for this phenomenon is outside the scope of this document.
- **Fast-~~-~~Front Transients:** 10 kHz~~—~~–1 MHz
  - Fast-~~Front-~~front transients are primarily caused by high-~~-~~frequency phenomena, such as lightning strokes.
  - The study area will be selected to provide adequate electromagnetic performance and traveling wave behavior.
  - This is provided for information only. Study area selection for this phenomenon is outside the scope of this document.

As the frequency of the phenomena under study increases, the size of the study area (e.g., electrical distance from the bus of interest) decreases and the level of modeling detail for equipment will increase. For example, when performing ~~a~~an EMT system impact assessment~~ study~~, it is acceptable to neglect the impedance of bus-work within a substation. However, for a ~~Fast Front Transients~~fast-front transients study, the individual sections of bus-work down to the exact meter of bus-work length ~~becomes~~become important. **Figure 2.2** ~~provides an illustration of~~illustrates study area size for different types of EMT studies. In this context, study area size represents the electrical impedance between the study bus and the boundary equivalents representing the system beyond the study area.

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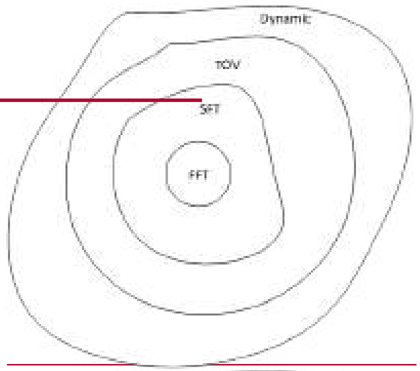

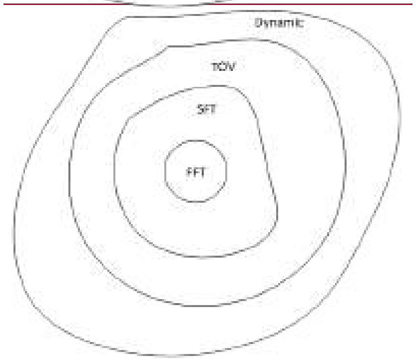

Figure 2.2: Study Area Size for Different Types of EMT Studies~~.~~

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For electromagnetic phenomena, because of the relatively high frequencies under study, the frequency~~-~~-dependent nature of inductance ($X_L = 2\pi fL$) and capacitances ($X_C = 1/2\pi fC$) will dominate the relative impedance between nodes within a system. At higher frequencies (>10 kHz~~)~~), the series inductance of the electrical system as well as frequency -dependent resistance from conductors due to skin effect will dominate and result in such transients ~~to become~~becoming a more local phenomenon. When performing EMT studies for ~~IBR's~~IBRs, it is necessary to ensure adequate ~~Electromagnetic~~ system representation for the phenomena of interest at a given bus or between buses. ~~There are~~The different methods to accomplish this ~~which~~ will be discussed ~~within~~in this ~~Chapter~~chapter. However, conceptually, the process of ~~Electromagnetic sizing~~scoping the appropriate system area for EMT studies would involve quantifying the frequency~~-~~-dependent impedance at a given bus within the power system considering progressively larger ~~EMT~~portion of the system~~ models~~. For example, calculate the harmonic impedance at a given bus for a system including the study bus and all buses within a given N number of buses from the study bus then iteratively ~~increasing~~increase the study area until further increases in the size of the modeled system ~~have negligible~~negligibly impact~~ on~~ the system frequency response.

Figure 2.3 provides an illustration of ~~electromagnetic sizing for~~the determination of the size of the EMT ~~system models.~~study area. In **Figure 2.3**, the frequency~~-~~-dependent impedance (Z) of three different system models is provided~~,~~ with the study area increasing in size by including all equipment within 6, 9, and 10 ~~busses~~buses out from the study bus. There is a significant difference between the 6-bus out and 9-bus out models, especially around 800~~-1100~~–1,100 Hz. However, the additional impact of going from a 9-bus out to a 10-bus out model is much smaller~~,~~ and perhaps negligible compared to the increased model size and solution time required for the wider model.

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In performing this process, the study engineer must ~~take into account~~consider the following critical items:

- Throughout this discussion, the word “~~busses~~buses” has been used as a proxy to represent “electrical impedance~~”.~~.” Practically, when performing study area selection, the goal is to ensure that sufficient electrical impedance exists between the study bus or ~~busses~~buses and the boundary equivalents representing the system outside of the study area. Improper study area selection can result in incorrect study ~~results~~conclusions, such as indication of false system resonance points or failure to identify system operating conditions of concern.

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- **Figure 2.3** provides a very simplified study area selection process. In practice, the study engineer should be performing verification work to confirm that the boundary does not ~~induce false behaviors~~introduce inaccuracies within the frequency range of interest. The process could be iterative in nature.

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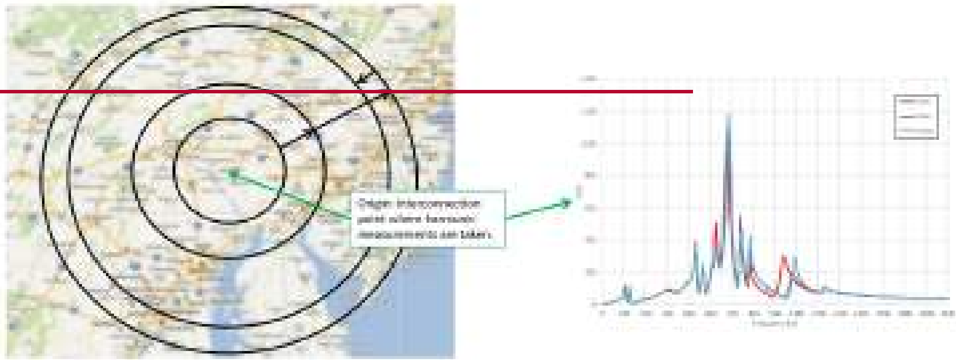

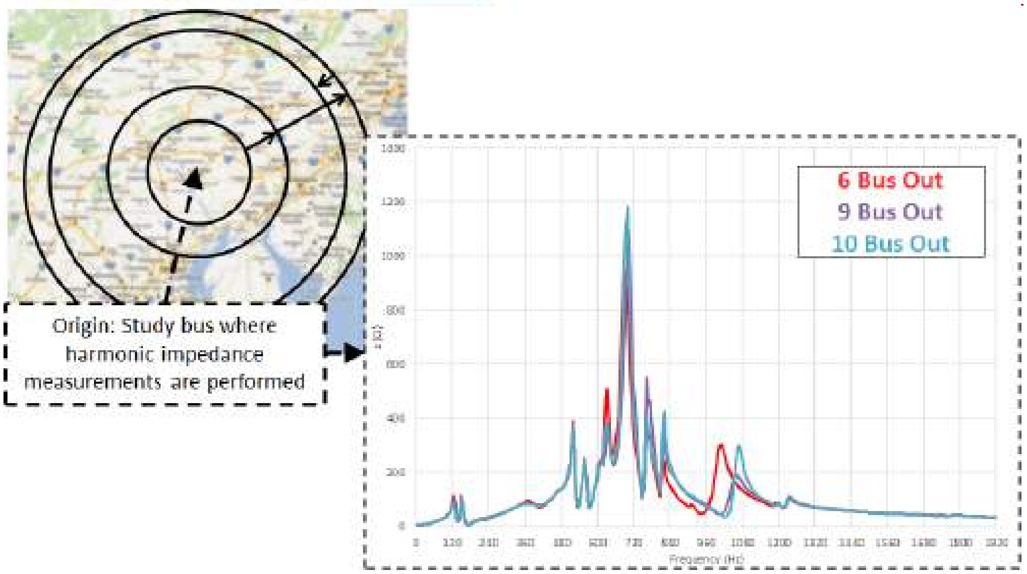

Figure 2.3: Concept of Iterative Approach to ~~Electromagnetic Model~~ Sizing an EMT Study Area

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For studies analyzing IBRs, the impacts on ~~Electromechanical~~electromechanical phenomena ~~typically need to be considered. For example,~~, such as interactions with existing turbine~~-~~ generators and their excitation or governor control systems~~.~~, typically need to be considered. It is also important to ensure that the developed EMT model is adequate to represent key electromechanical modes of oscillation. This can be accomplished through including dynamic representations of power electronic devices, IBRs, turbine~~-~~ generators, and loads within the developed EMT model or through more advanced techniques, such as ~~co-~~hybrid simulation or electromechanical ~~or~~ dynamic network equivalents, which will be discussed in **Chapter 3** of this guide. ~~For an illustration of~~**Figure 2.4** illustrates benchmarking for a developed EMT model ~~please refer to **Figure 2.4**.~~. This example shows the RMS voltage response for both an EMT (~~Black~~**black**) and phasor~~-~~-domain (~~Red~~**red**) simulation tool at a given bus for a three-phase grounded fault.

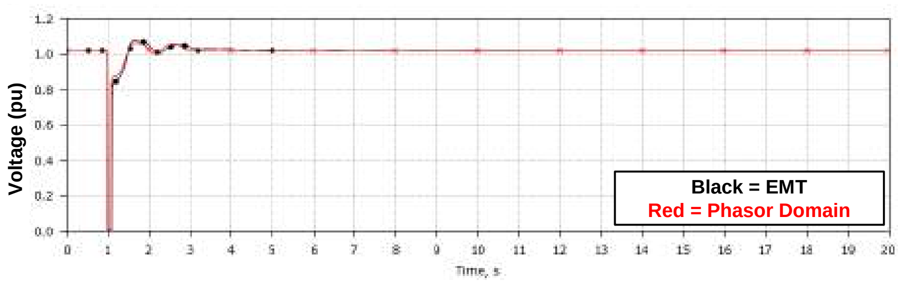

Figure 2.4: Comparison of RMS Voltage Response for a Given Fault Event Between ~~Electromagnetic~~EMT and Phasor~~-~~-Domain Simulation Tools~~.~~

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Determining Which Dynamic Devices to Include in the Study Area

Beyond the ~~electromagnetic and electromechanical sizing~~ techniques for determining the extent of the EMT domain study area previously outlined, there are techniques that can be used by study engineers to assist in determining which dynamic devices need to be explicitly modeled within the EMT study area. ~~-~~If a dynamic device, such as an IBR plant or ~~Flexible AC Transmission System (~~FACTS~~)~~ device, is omitted from the study area, then its dynamic behavior will be omitted from the study and could ~~result in errors~~introduce inaccuracies in the overall dynamic response of the system ~~or prevents capturing~~, thus preventing the observation of potential interactions that may actually occur between dynamic devices or other adverse reliability impacts. The following are examples of methods for determining which equipment should be included in the study area when performing EMT studies for IBRs:

- ~~Engineers~~**Engineer**, Experience

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  - For study engineers performing EMT studies in a system ~~where~~in which they have already performed EMT studies or ~~performed~~ detailed screening assessments, ~~it is possible~~their experience with the system can be used to determine which dynamic devices need to be included within the study area ~~primarily using their experience with the system~~.
  - ~~This~~For additional confidence, this experience can also be coupled with system measurements and event analysis ~~to build confidence. For example,~~—such as gaining an understanding about the phenomenon or a type of system event being studied~~,~~; observing voltage and frequency magnitude before, during, and after the event if the phase measurement unit (PMU), digital fault recorder (DFR), or supervisory control and data acquisition (SCADA) data is available~~,~~; or noting how fast or slow~~,~~ and how deep the oscillations penetrate into the system. ~~If this information is not available other approaches and techniques could be used to determine the boundary of the system. Sometimes a combination of different analysis and tools is needed to determine the boundary of the system.~~

- **Voltage Interaction Assessment**
  - One potential method to assist in choosing which dynamic devices need to be included within the study area is to use indices that offer insight into the electrical proximity between two buses within the system. Multi-infeed interaction factor (MIIF~~)~~),[9]~~,~~ improved/weighted MIIF~~[10], Multi-Infeed Voltage Interaction Factor,~~[11] multi-infeed voltage interaction factor (MVIF~~)~~),[12] ~~and~~ other indices as introduced in CIGRE, IEEE, and other publications~~,~~ aid engineers in studying and assessing potential interaction levels between two devices connected to the system at specific buses. These indices can be calculated using dynamic simulation tools and essentially serve as indicators of the ~~AC~~ac voltage variation at one bus in response to a minor ~~AC~~ac voltage change at another bus. They offer valuable insights into the extent of potential interactions between dynamic devices.
  - The voltage interaction method provides a high-level assessment of potential interactions between devices at two points in a system.
- **Short~~-~~-Circuit~~-~~-Based Assessment**
  - Short~~-~~-circuit~~-~~-based assessments are typically used to indicate if a single facility or cluster of facilities ~~require~~requires further, more detailed~~,~~ analysis. ~~Some examples of short-~~Short-circuit current~~-~~-based methods include~~, Available~~ available fault level, ~~Weighted Short Circuit Ratio (WSCR), or Composite Short Circuit Ratio (CSCR)[13].~~weighted short-circuit ratio, and composite short-circuit ratio.[14]
  - If a short~~-~~-circuit~~-~~-based assessment was used to determine if a single facility or cluster of facilities ~~require~~requires detailed EMT studies, then the facilities considered~~ facilities~~ should be included within the study area. Additionally, the system operating conditions (e.g., generation dispatch and system outage conditions) that led to the need for a detailed EMT study should be ~~taken into account~~considered when creating the study area. For example, if a certain line or generation outage leads to a system condition necessitating detailed study, then the study area should allow such an event to be simulated dynamically by including this equipment.

Typically, study area selection and dynamic device inclusion for EMT studies is an iterative approach. For example, the study engineer may notice that the dynamic response of their developed EMT model is not a good match when compared to the reference phasor~~-~~-domain database. This type of mismatch may be caused by the omission of the dynamic behavior of a key generator, IBR facility, or power electronic device close to the study area. Additionally, it may be necessary to use some combination techniques when determining the EMT study area. Ultimately, the choice of the EMT study area should consider specific system characteristics, the phenomenon under study, findings from past studies, and engineering judgment.

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[9] CIGRE Technical Brochure 364: *Systems with Multiple DC Infeed*

~~[10] CIGRE Technical Brochure 881: Electromagnetic transient simulation models for large-scale system impact studies in power systems having a high penetration of inverter-connected generation~~

[11] CIGRE Technical Brochure 881: *Electromagnetic transient simulation models for large-scale system impact studies in power systems having a high penetration of inverter-connected generation*

[12] Hao Xiao; Yinhong Li, "Multi-Infeed Voltage Interaction Factor: A Unified Measure of Inter-Inverter Interactions in Hybrid Multi-Infeed HVDC Systems~~"~~,," IEEE Transactions on Power Delivery, Vol. 35, Issue 4 August 2020)

~~[13]https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Item_4a._Integrating%20_Inverter-Based_Resources_into_Low_Short_Circuit_Strength_Systems_-_2017-11-08-FINAL.pdf~~

[14]https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Item_4a._Integrating%20_Inverter-Based_Resources_into_Low_Short_Circuit_Strength_Systems_-_2017-11-08-FINAL.pdf

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Chapter 3: How to Model Systems

EMT simulations are computationally intensive, making it challenging to simulate an entire large-scale electrical system in an EMT environment. Additionally, the influence of electrically distant areas becomes less pronounced on disturbances within the study area due to high electrical impedance. Because of these factors, ~~it is a common practice for~~ study engineers ~~to~~commonly model the study area in full detail in an EMT environment~~,~~ while employing an equivalent representation for the rest of the system, which has less impact on the study outcomes.

However, two important questions arise:

- How to define ~~'electrically distant'~~"electrically distant" areas? Or, in other words, where to stop the detailed model and start employing an electrical equivalent for the rest of the system?
- How to represent the rest of the system external to the study area using an electrical equivalent?

~~In~~These questions will be discussed in the following sections~~, we will be discussing these questions~~.

Modeling of Study Area

The power system equipment within the study area should be modeled to the level of detail necessary for the power system dynamic phenomena under evaluation. With EMT studies, there is not always a one-size-~~fit~~fits-all representation for modeling power system equipment. Many of the commercially available tools~~ which are~~ used for automated creation of EMT models have a default method of modeling equipment and will generate a usable model. For example, these tools will typically import steady-state and dynamics data from a phasor-~~-~~domain tool and will generate an EMT model that can run time domain simulations at a given simulation ~~time-step~~timestep. However, because of limitations ~~of~~in data available in the source databases, such models will not include many system modeling details that are typically important for EMT level simulation, such as the following:

- Correct zero sequence impedance of transmission lines or cables
- Frequency-dependent impedance of transmission lines or cables
- Mutual coupling between transmission lines
- Transformer winding configuration and grounding information
- Transformer saturation characteristics
- Custom or user-defined representation for load or generation
- Lack of representation of some system elements, such as surge arresters and grounding transformers, in the phasor-domain tools~~.~~
- Inability to import all dynamic models from the phasor-domain tools; for example, newly added standard library models in phasor-domain programs may not be immediately available or some models, such as ~~HVDC~~HVdc and FACTS, may not be properly exported~~.~~

It is necessary for the study engineer to ensure that power system equipment is modeled appropriately for the phenomena of interest under evaluation. Providing a complete and detailed discussion on power system modeling for EMT is outside the scope of this document.

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~~For the~~ It is recommended that dynamic devices within the study area, especially power electronic devices and IBR plants, ~~it is recommended that they are~~be represented by using EMT models, provided by a manufacturer, of the device/plant for the phenomena under study. A recreation of a WECC ~~Generic Renewable models~~generic renewable model in an EMT tool can provide correct dynamic response for events ~~which~~that are within the models' bandwidth.

However, such a model will not provide additional information beyond that captured in a phasor~~-~~-domain tool. Ideally, within the study area, the power electronic devices and IBR plants under study should be represented with validated ~~real-code model provided by a manufacturer.~~equipment specific models. However, it is not always possible to ~~get~~obtain these models for existing plants. It may be necessary to use simplified models for legacy plants. **Chapter 7** provides further guidance on how to model legacy plants. **Chapter 8** provides guidance on modeling plants with detailed plant~~-~~-specific models.

In practice, the effort used to develop a model for a given "study area" can be used in future studies that are similar in scope and type. The process is slightly different depending on the specific EMT tool. However, these detailed models for dynamic devices and power system equipment should be maintained for future use. It is recommended that entities performing these studies begin to curate and maintain validated equipment model libraries.

Modeling of External System

Static ~~voltage source~~Voltage Source

In this approach, the external system is represented as a fixed voltage source behind an equivalent impedance~~. The equivalent impedance~~, which is obtained through the application of admittance matrix reduction techniques. This is the simplest technique for representing boundaries and is the approach employed by most software packages. However, it has the disadvantage that using a ~~'fixed'~~"fixed" voltage source can generate fictitious active/reactive powers during power imbalance conditions, potentially leading to inaccurate results as it masks the contributions provided by local generation within the study area. For the above reasons, it is recommended to use static voltage representation only when the boundary buses are located far from the study area.

A generator-trip study conducted in the Australian ~~NEM~~National Electricity Market (NEM) network (CIGRE TB 881 Section 4.1.7) demonstrated the drawbacks of employing a static voltage source equivalent to represent the boundary network. When the equivalent sources are positioned extremely close to the study area, the constant voltage source equivalent supplied a substantial amount of MW in response to the initial frequency dip following the loss~~-~~-of~~-~~-generation event. This action not only immediately restored the network frequency but also prevented real generator governors from increasing their power output to compensate for the generation loss in the area.

Dynamic ~~voltage source~~Voltage Source

To overcome the drawbacks of the previous representation, a controlled voltage source is sometimes used instead of a fixed voltage source. The internal voltage magnitude and phase angle of the equivalent voltage source are controlled to sustain the pre-disturbance active and reactive power injections from the ~~boundary~~external system. ~~However, the disadvantage of~~Not only may this approach ~~is that it entirely cancels out~~fail to fully capture the ~~contribution provided by~~dynamic interactions between the ~~boundary~~study system ~~during~~and the external system, but it may also introduce false dynamics due to the equivalent sources attempting to maintain pre-disturbance~~, which is not the case if the boundary buses were not placed too far away from the study area.~~ power flow conditions.

To avoid this drawback, some ~~ISOs~~independent system operators (ISO) (like Ontario's IESO) have chosen to represent the external system using equivalent synchronous machines with simplistic exciter and governor models. The parameters of these dynamic models are optimized to ensure that they maintain the response of the original external system. Additionally, constraints can be added to the optimization problem to preserve parameters, such as equivalent system inertia and short~~-~~-circuit level at the boundary buses~~, etc~~. Then, the developed, reduced model can be exported into an EMT program. This approach is labor intensive~~; however, it~~ but can provide more accurate results as depicted below.

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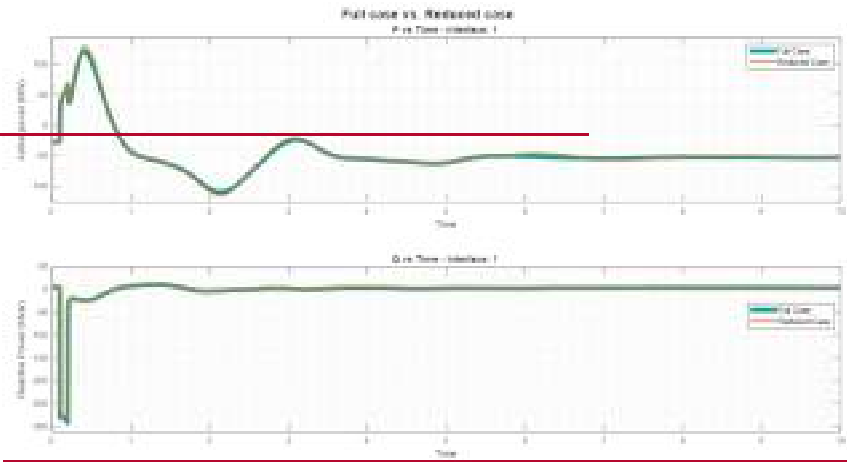

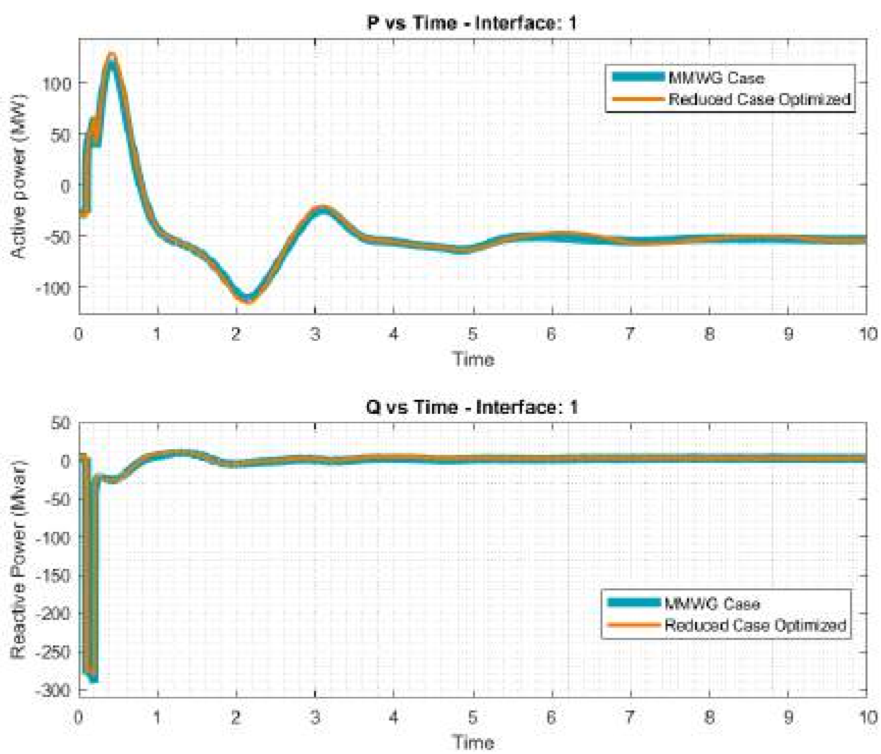

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Figure 3.1: Full ~~system~~System vs. ~~reduced system response~~Reduced System Response with ~~equivalent machines~~Equivalent Machines

Another approach to ~~develop~~developing a reduced dynamic model that can capture a particular dynamic behavior at low frequencies is to utilize the available network reduction techniques in transient stability domain.[15][16][17][18] For example, coherency-based methods can be employed to identify a group of generators that oscillate together and replace them with an aggregated unit that can mimic the same behavior. Then, the reduced model can be imported into an EMT program~~,~~ while preserving the same low~~-~~-frequency dynamic behaviors that will occur due to the interactions between the units in the study area and the external system. The network reduction in positive~~-~~-sequence phasor~~-~~-domain tool can result in artifacts, such as negative resistance produced from the network reduction~~,~~ in an equivalent branch connecting two buses of different voltage levels through a line instead of transformer.

Hybrid Simulation (~~positive sequence phasor domain~~Positive-Sequence Phasor Domain + EMT)

The requirements for dynamic analysis in power systems are ~~undergoing significant changes~~significantly changing due to shifts in generation and load characteristics. A considerable portion of newly interconnected generation resources, along with various loads, now connect to the grid through power electronic (PE) converters. Transient stability (TS) simulation tools ~~have inherent limitations~~are inherently limited in adequately representing PE devices, especially during fault periods. These modeling deficiencies may lead to either an overestimation or underestimation of the ~~system's~~system's reliable operation boundary and stability limits. Consequently, this can result in systems operating under heightened risk or less efficient conditions.

Conversely, EMT simulation tools can provide detailed ~~representation~~representations of PE and single-phase devices. However, the portion of the system required to ~~model~~be modeled in ~~detailed~~detail in an EMT tool ("study area") has ~~incresed siginificantly~~increased significantly due to high penetration of IBRs. ~~This has rasied a concern~~Such EMT simulations with larger study area may result in ~~terms of~~requiring higher computational ~~burden of EMT simulations~~resources. To address these challenges, various simulation methods have been proposed, including parallel processing by breaking up a large network into smaller, decoupled networks~~,~~; EMT-TS hybrid/co-~~simualtion,~~simulation; frequency-dependent network equivalents~~,~~; and dynamic phasor-based approaches. Among ~~them,~~these, the hybrid simulation approach has garnered ~~a~~ significant attention from both industry and academia due to multiple use cases. Some of the major use cases are detailed below:

- **High path flows through EMT study area**: When there is a high-power flow path through the selected study area ~~–~~ (i.e~~.~~., study area is in the middle of a transmission corridor~~,~~), the post-contingency power flow solution (mainly voltage magnitudes and angles) will be less accurate at the boundaries with fixed-source equivalents.
- **Inter-area machine dynamics**: If there is a known inter-area oscillation ~~–~~ (i.e~~.~~., areas swinging against each other~~,~~), it will not be visible with fixed-source boundary equivalents.
- **Interaction of power electronics components with system frequency**: In the case of interaction of PE components with system frequency, it will be important to model a wider power grid. In such cases, EMT ~~model~~models of PE components and the local regions are developed with the wider power grid being

[15] J. P. Yang, G. H. Cheng and Z. Xu, "Dynamic reduction of large power system in PSS/E," 2005 IEEE/PES Transmission & Distribution Conference & Exposition: Asia and Pacific, Dalian, China, 2005, pp. 1-4, doi: 10.1109/TDC.2005.1546815~~.~~

[16] F. Ma, X. Luo and V. Vittal, "Application of dynamic equivalencing in large-scale power systems," 2011 IEEE Power and Energy Society General Meeting, Detroit, MI, USA, 2011, pp. 1-10, doi: 10.1109/PES.2011.6039372

[17] Kai, S., Che, Y., Zhang, F., Wu, G., Zhou, Z., Huang, P.: "A review of power system dynamic equivalents for transient stability studies." J. Eng. 2022, 761–772 (2022). https://doi.org/10.1049/tje2.12157

[18] M. Matar, N. Fernandopulle, and A. Maria, "Dynamic model reduction of large power systems based on coherency aggregation techniques and black-box optimization" International Conference on Power Systems Transients (IPST2013) in Vancouver, Canada July 18–20, 2013

represented in the TS model (phasor-domain~~)~~).[19]~~.~~ Example use cases are grid fault response from PV plants and the corresponding impact on the power grid as well as ~~HVDC~~HVdc system fast control in low ~~SCR~~system strength regions to provide reliability to the power grid.

Note: There are no standard techniques that determine the size of the "study area" in EMT in hybrid EMT-TS simulations. One of the techniques used in literature ~~include use of~~employs a reactive power injection to understand the area in which voltage ~~gets~~is affected.[20]~~.~~ Another technique used in literature is based on the sensitivity of the size of the "study area" in EMT such that the smallest~~-~~-sized study area~~, which matches~~ matching the results from the larger~~-~~-sized study area~~,~~ is used in EMT simulations.

Caution~~:~~

- Care must be taken to place boundaries at locations where voltages and currents do not have dynamic content with a period lower than ~~5~~five cycles ~~—~~(i.e~~.~~., high~~-~~-frequency oscillations/dynamics should not be visible at the boundary bus~~.~~).
- Care must be taken to place boundaries at locations where voltages and currents do not have significant unbalance since the TS simulation is mainly positive sequence.

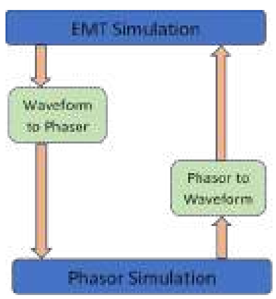

Figure 3.2: Communication ~~between~~Between EMT and ~~phasor simulations.~~Phasor Simulations

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[19] ORNL, SCE, FPL/NextEra, Pennsylvania State University, CAISO, "Library of Advanced Models of large-scale PV (LAMP)" project.

[20] Y. Liu et al., ~~"~~"Hybrid EMT-TS Simulation Strategies to Study High Bandwidth MMC-Based HVdc Systems~~,"~~," 2020 IEEE Power & Energy Society General Meeting (PESGM), Montreal, QC, Canada, 2020, pp. 1~~-~~–5.

Chapter 4: System Base~~-~~-Case Model ~~Validation~~Benchmarking

Before starting EMT studies, it is important to verify that the system model is a reasonably accurate representation of the actual system. Past and current industry practice on large-scale system~~-~~-level studies have traditionally been centered around using a validated phasor~~-~~-domain system model. Consequently, validated phasor~~-~~-domain system models serve as the starting point for building an EMT model for TPs and PCs. While the process of ~~validating~~benchmarking EMT models ~~ensure~~ensures consistency with the phasor~~-~~-domain models across power flow, dynamic studies, and short circuit studies, care needs to be taken when extending such an approach, especially when there is ~~a lot of~~significant planned IBR integration into the system and even more so when dealing with weak system conditions. Such scenarios could present cases ~~where~~in which the results of phasor~~-~~-domain models deviate from actual system behaviors, and it could be misleading to try and ~~validate~~benchmark EMT models against phasor models. The following sections ~~provide an explanation of~~explain the ~~validation~~benchmarking process and the possible reasons for any discrepancies that may arise.

System Model ~~Validation~~Benchmarking

The primary means of ~~validation~~benchmarking is to verify that the EMT model can simulate the dynamic response of the power system with reasonable accuracy when compared to the validated positive-sequence dynamic model and/or an actual system dynamic event. The comparison also identifies errors and parameters that cause mismatches. These errors and parameters can then be corrected or adjusted so that the EMT model emulates the actual conditions.

The system model can be developed by utilizing conversion or import tools to convert the validated positive-sequence dynamic model into the EMT model. The development and ~~validation~~benchmarking of the EMT system model should consider both positive-sequence dynamic modeling data, short-circuit modeling data, and/or field measurement data. ~~The process in~~ **Figure 4.1** shows an example of the system model ~~validation.~~ benchmarking process. Engineering judgement is needed to determine the acceptable accuracy.

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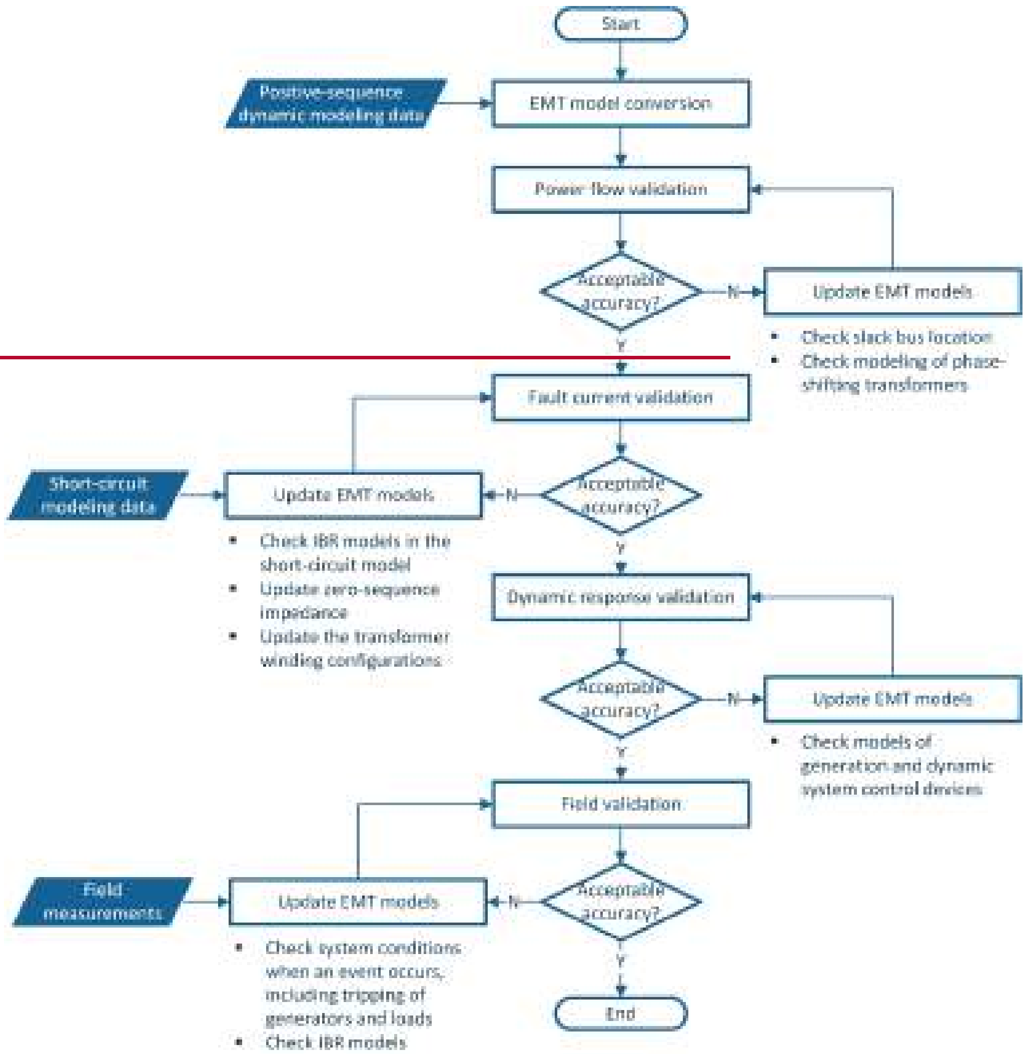

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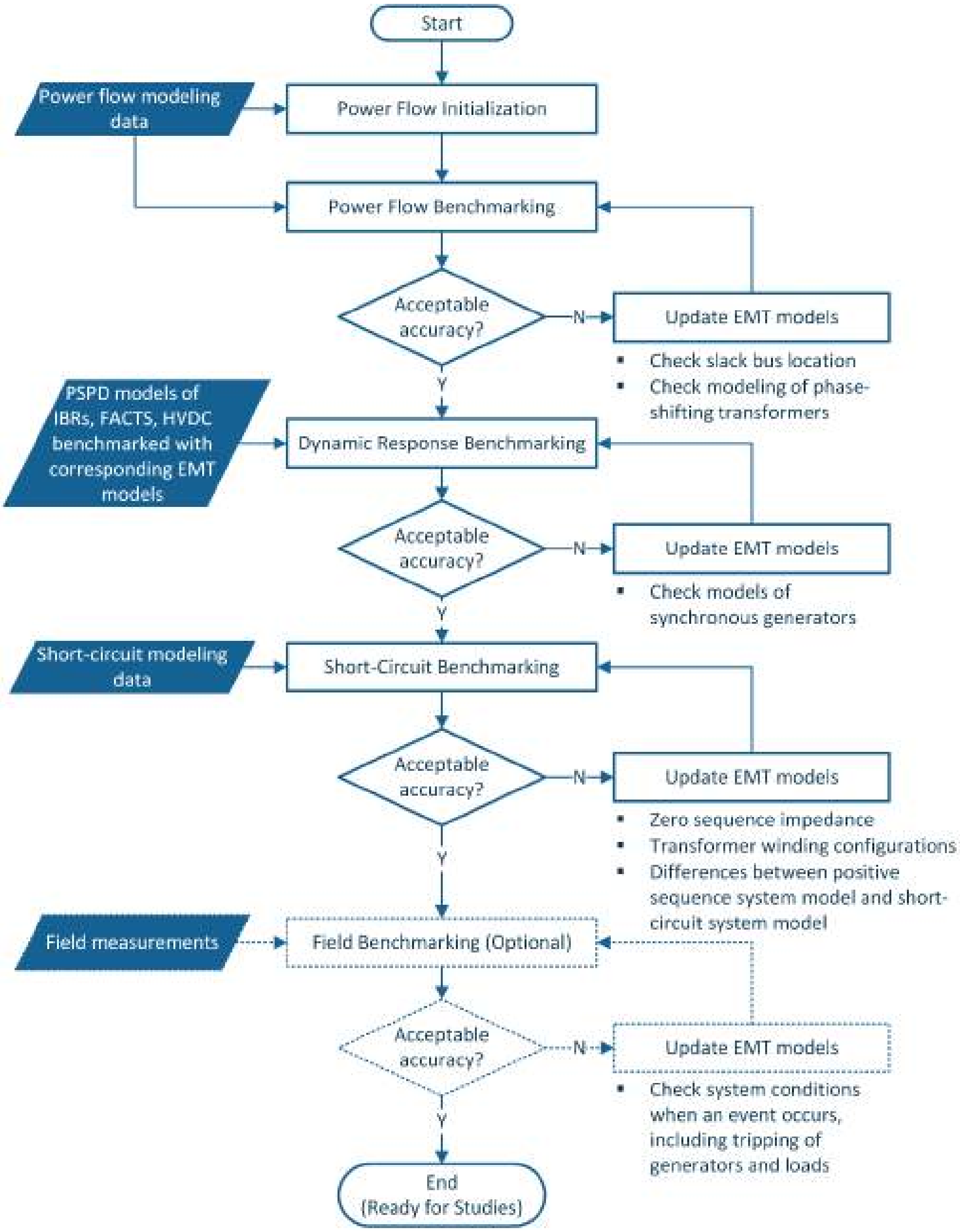

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Figure 4.1: Example of System Model ~~Validation~~Benchmarking Process

The following ~~validations~~benchmarking should be considered:

- ~~1.~~ Power flow ~~validation by~~ benchmarking by comparing the EMT model against the positive-sequence dynamic model~~.~~
- ~~2.~~ Fault current ~~validation~~benchmarking by ~~benchmarking~~comparing the EMT model against the short-circuit model for balanced and unbalanced faults~~.~~
- ~~3.~~ Dynamic response ~~validation~~benchmarking by ~~benchmarking~~comparing the EMT models against the positive-sequence dynamic model~~.~~
- ~~4.~~ Field ~~validation~~benchmarking by ~~benchmarking~~comparing the EMT models against recorded data from actual system events~~.~~

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Power ~~flow validation~~Flow Validation

The EMT model should be ~~validated~~benchmarked against the positive-sequence dynamic model for power flow results by comparing each ~~branch's~~branch’s real and reactive power flow.

Typically, ~~the~~an EMT model is a reduced network model derived from the positive-sequence dynamic model of the entire power system. There is a possibility that the swing buses in the EMT model and the positive-sequence dynamic model ~~are~~do not ~~the same~~match, leading to the discrepancy in the power flow. The phase-shifting transformers can have significant impact on the power flow distribution. However, the EMT conversion tools may use regular transformers to model the phase-shifting transformers, resulting in a discrepancy in power flow comparison. The modeling of phase-shifting transformers in the EMT ~~model also impacts the discrepancy in power flow~~system model should be verified.

Fault ~~current validation~~Current Validation

The EMT model should be ~~validated~~benchmarked against the short-circuit model for balanced and unbalanced faults by comparing the bus fault currents. Since short-circuit tools give steady-state fault currents in a numerical format, the RMS value of steady-state currents in the EMT simulation should be recorded for ~~comparisons~~comparison. The fault duration in an EMT simulation should be set to a long enough period to ~~get~~obtain a steady~~-~~-state fault current, and the last 10~~ to ~~–20 cycles of the fault current can be used for calculating the RMS value. The generators should ~~be~~ run at a fixed rotor speed ~~(they are "~~(“locked”) to ~~get~~obtain steady-state fault currents. **Figure 4.2** shows an example of recorded fault current in the EMT simulation and the data for RMS value.

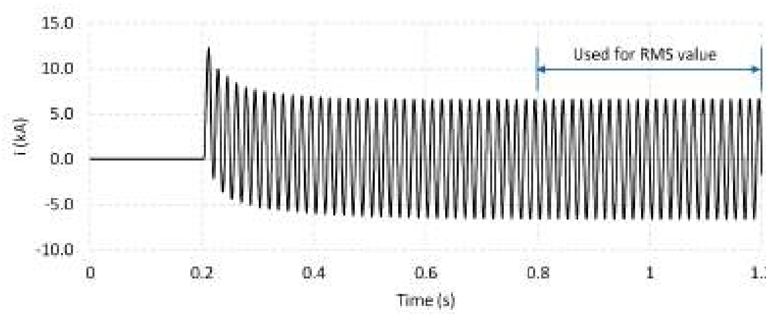

Figure 4.2: Example of Steady-State Fault Current

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The discrepancy in fault current comparison can be caused by several factors, such as the following:

- ~~1.~~ The IBR models in the EMT model and the short-circuit model are different ~~if the~~ . The collected IBR models ~~were collected before requiring EMT model requirements. There is a possibility that the collected IBR models were~~may not have been accurately ~~modelled~~modeled in the short-circuit model.
- ~~2.~~ The zero-sequence impedances in the EMT model and short-circuit model are different. The conversion or import tools typically use the positive-sequence dynamic model. If the zero-sequence data is unavailable, these tools will estimate the zero-sequence impedance based on positive-sequence impedance. This estimation causes the difference in unbalanced fault current between these models. The zero-sequence impedance from the short-circuit modeling data should be used in this step to update the EMT model.
- ~~3.~~ The transformer winding configurations in the EMT model and the short-circuit model are different, leading to the discrepancy in unbalanced fault currents between these models. The transformer winding configurations from the short-circuit modeling data should be used to update the EMT model.

Updating the EMT model with the short-circuit modeling data will improve the accuracy of the EMT model. Since the EMT model is developed based on the positive-sequence dynamic model, this task can be challenging if the naming convention in positive-sequence dynamic model and short-circuit model is different or there are differences between the two models.

Dynamic ~~response validation~~Response Benchmarking

The EMT model should be ~~validated~~benchmarked against the positive-sequence dynamic model for dynamic response under disturbances. The discrepancy in dynamic response between the EMT model and the positive-sequence dynamic model can be caused by differences in the modeling of generation, including exciters and governors, and dynamic devices. The response of the generators can be used for comparison. The typical quantities used to check for comparison include the output real and reactive power, generator speed, terminal voltage, and output current.

Figure 4.3 shows an example of dynamic response ~~validation~~benchmarking for a 350-bus power system by comparing the real and reactive power output, the generator speed, and the terminal voltage in the EMT model and the positive-sequence dynamic model. ~~The discrepancy in~~ Engineering judgement is needed to determine the acceptable accuracy of dynamic response ~~between the EMT model and the positive-sequence dynamic model can be caused by the difference in the modeling of generation, including exciters and governors, and dynamic system control devices.~~ benchmarking results.

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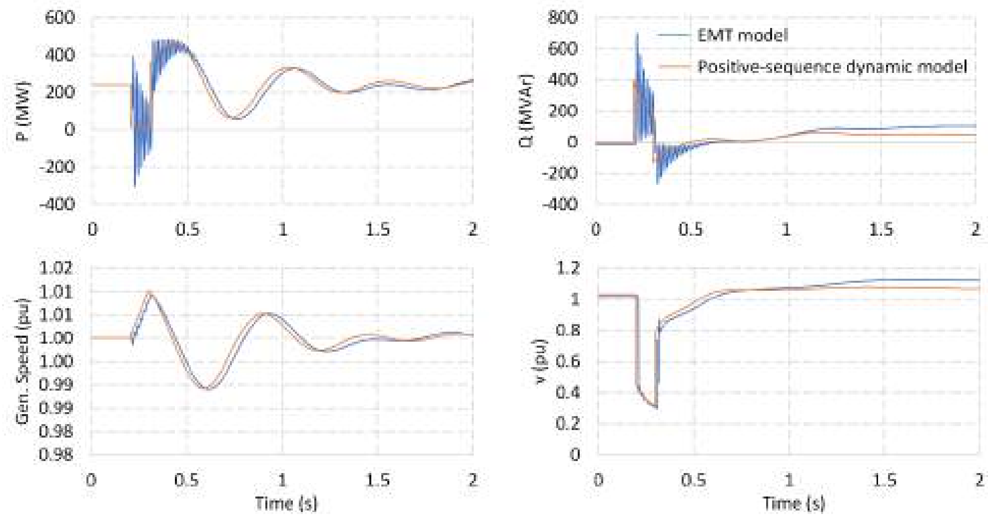

Figure 4.3: Example of Dynamic Response Validation for a 350-~~bus~~Bus System Model

Field ~~Validation~~Benchmarking

~~The developed EMT model can be further fine-tuned by validating against the field measurement data. Previous~~From the perspective of model fidelity, a carefully built and validated EMT model of the system is expected to reflect real-world system behavior across a range of broad use cases if it sufficiently captures the behavior of controls and protection elements. While previous processes of ~~validating~~benchmarking EMT models ensure consistency with ~~the validated~~ positive-sequence dynamic models and short-circuit model, care needs to be taken when extending such an approach, especially when ~~there is a lot of~~the system is slated for significant planned IBR integration ~~into the system~~ and even more so when dealing with weak system conditions. Such scenarios could present cases ~~where~~in which the results of phasor-~~-~~domain models deviate from actual system behaviors, and it could be misleading to try and validate system-level EMT models only against previously validated phasor models~~. This is because IBR plants have dynamic and transient responses which are intimately related to the vendor and site-specific control and protection algorithms and parameters. While generic IBR plant models might not suffice, even vendor-specific models that are not validated properly might not produce results like real-world behavior due to code issues, parameter discrepancies, and other modeling errors. Several recent disturbance reports from NERC have shown that even validated system level phasor models have failed to replicate real-world system behavior especially those pertaining to IBR plant tripping, partial power reduction, etc., highlighting potential gaps in system level~~ without performing adequate validation and ~~motivating the need for a systematic and recurring model validation both at plant levels and system level in order to maintain their similarity in predicting real-world behavior for future occurrences. [to add references and possible figures]~~model fine-tuning based on field measurements.

~~From the perspective of model fidelity, a carefully built and validated EMT model of the system is expected to be closest to real-world system behavior across a range of broad use cases as it sufficiently captures the behavior of controls and protection elements appropriately. While it is impractical to build and validate large-scale EMT models with real-world field test data due to several constraints including the lack of system-wide, high-resolution data that might be needed, the importance of validating EMT models periodically against real-world ground truth is critical, nevertheless. The current recommended practice in this regard is to ensure that vendor and plant~~ The current

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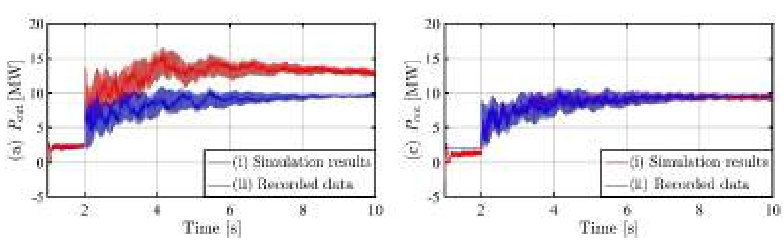
recommended practice is to ensure that vendor- and plant-specific IBR plant models are thoroughly validated with various types of test case scenarios before commissioning ~~as a part of integration studies.~~using lab tests or during commissioning with appropriate tests. These validated, vendor- and plant-specific IBR plant models are then integrated into existing system-level EMT models~~, which~~ that are then ~~validated~~benchmarked against phasor-~~-~~domain models.

While this assumption of composing the system-level EMT models from a set of validated plant-level EMT models ~~is reasonable given practical constraints, it might not be adequate to compare only against phasor models in the near future with the tremendous amount of IBRs that are getting integrated across the entire bulk power system. This is due to the reason that phasor models might not capture certain dynamic interactions between new IBR plants and existing synchronous and non-synchronous resources, thereby leading to lack of awareness against potentially new failure modes that could lead to unanticipated system impacts.~~and previously validated phasor models is reasonable given practical constraints, lack of field measurement data to perform the necessary model validation in the EMT domain could result in inaccurate predictions about system behavior during disturbances. Several recent disturbance reports from NERC have shown that even validated system-level phasor models have failed to replicate real-world system behavior, especially pertaining to issues like IBR plant tripping and partial power reduction, highlighting potential gaps in system-level validation and underlining the need for a systematic and recurring model validation in the EMT domain with high-resolution field measurement data in order to maintain their usefulness in predicting real-world behavior for possible future disturbances. Therefore, it is essential to include efforts that collect field test data periodically from available system resources to continuously validate system-~~-~~level EMT models against real-world behaviors.

Figure 4.4 shows a case study from Hawaii ~~comparing~~that compares the results from a system-~~-~~level EMT model with a vendor-provided IBR model against recorded~~,~~ field data.[21] ~~. Initially, there~~ Differences were visible initially. In order to resolve the differences~~.~~, a single-inverter infinite bus system with recorded three-phase voltage waveforms was used to observe the simulated and recorded real and reactive power outputs while control parameters were tuned. The tuning of parameters was done with appropriate vendor/OEM guidance to understand which parameters can be tuned and which ones should not be modified. In order to fix the mismatches in steady-state active power the real-power/frequency droop constant(s) were tuned. Even with this, there were some mismatches during the transients, which were resolved by tuning the current loop parameters. After the model was ~~tuned~~ carefully tuned, the system -level EMT model was able to match the recorded field test data, uncovering potential issues with settings and parameters in the model~~,~~ and thereby exemplifying the importance of IBR model true-up during commissioning and periodically validating system-~~-~~level EMT models with either hardware-~~-~~in-~~-~~the-~~-~~loop or field test data ~~periodically~~. This also highlights the importance of model true-up during commissioning.



[21] Tan, Jin, Dong, Shuan, and Hoke, Andy. Island Power Systems ~~With~~with High Levels of Inverter-Based Resources: Stability and Reliability Challenges. United States: N. p., 2023. Web.

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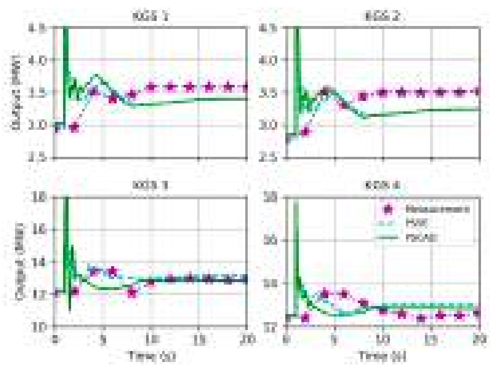
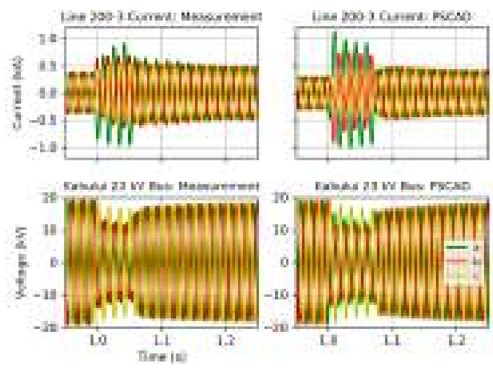
(a) before model tuning~~—~~ **(b) after model tuning**

Figure 4.4: EMT-~~domain simulation (red line~~Domain Simulation (Red Line) and ~~field-testing data (blue line~~Field-Testing Data (Blue Line) of ~~vendor-provided~~Vendor-Provided IBR EMT ~~model~~Model

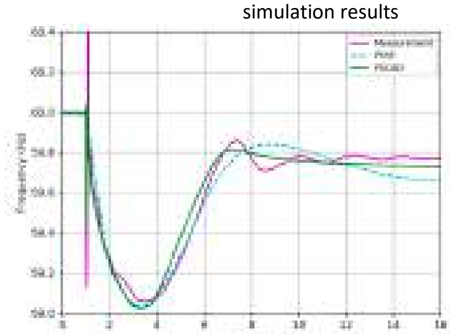
Figure 4.5 shows the validation of the Maui EMT model against the ~~utility PSSE~~utility's PSPD model and field data for an event that consisted of a single-phase fault followed by a generation trip.[22]~~.~~ The available monitoring data included SCADA data with a two-second sampling rate for the utility-generating units and three-phase current and voltage measurements for the unit that experienced the disturbance. Additionally, high-resolution frequency data was also obtained from the Kahului generating station. ~~The EMT model was fine-tuned to match the recorded data of generator outputs, fault currents, and system frequency.~~



(a) Kahului generation station unit outputs from measurement data and simulated responses



(b) Kahului generation station main bus three-phase voltages and tie line currents; measured and EMT simulation results



(c) Kahului generating station frequency following the fault and generation trip

Figure 4.5: Field Validation of the EMT Models~~ in [ref. 4.2]~~

[22] R. W. Kenyon, B. Wang, A. Hoke, J. Tan, C. Antonio and B. -M. Hodge, "Validation of Maui PSCAD Model: Motivation, Methodology, and Lessons Learned," 2020 52nd North American Power Symposium (NAPS), Tempe, AZ, USA, 2021, pp. 1~~-~~–6, doi: 10.1109/NAPS50074.2021.9449773.

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~~Recommendations~~

- TPs and PCs should ensure the consistency of the naming convention in positive-sequence dynamic models and short-circuit models. For example, the bus names and bus numbers in the positive-sequence dynamic model and the short-circuit model should ~~be the same~~match. By maintaining this consistency, the short-circuit modeling data can be easily utilized ~~in~~when updating the EMT model.

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- TPs and PCs should ensure that vendor- and plant-~~-~~specific IBR plant models are thoroughly validated with various ~~types of~~ test-~~-~~case scenarios before commissioning ~~as a part of integration studies~~using lab tests or during commissioning with appropriate tests.

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Chapter 5: Study Scenarios

This chapter provides an overview of how the study scenarios should be selected and prepared. The first step in developing a base case is to select an appropriate study area~~. The~~, the size of ~~the study area~~which depends on the type of study performed. For example, the study area for a subsynchronous oscillation (SSO) or dynamic system impact assessment study differs from that of an insulation coordination ~~studies. However~~study. For dynamic system impact assessment study, the study area is generally selected to include the major transmission corridor, major loads, and nearby generation (synchronous machine or other IBRs). ~~More details on the~~ Study area selection ~~of the study area can be found~~is further detailed in **Chapter 3**.

~~Once~~As described in **Chapter 4**, once the study area ~~was~~is selected ~~in RMS domain, it can~~ and EMT model has been built, the EMT model must first be ~~converted~~initialized to ~~EMT domain and validated as described in **Chapter 4**~~. ~~Base~~given operating conditions considering base cases ~~representing different~~ for network power flow conditions~~,~~ (including generation mix) and prior outages~~, etc. can be created in the RMS domain first and then converted into EMT domain.~~. This step ~~makes sure~~ensures that the ~~converted~~ EMT study case has correct initial conditions. In addition, to capture the worst-case scenarios, the ~~IBR~~ dispatch levels for an interconnecting IBR can be selected to include operation under Pmax/Qmin, Pmax/Qmax, Pmin/Qmin, and Pmin/Qmax conditions. ~~Furthermore, the~~The initial active power condition can be considered for ~~Battery Energy Storage Systems.~~battery energy storage systems (BESS).

Contingencies to be Considered

The most critical contingencies ~~must be considered to capture the worst stress on the IBRs performance. This can be~~, including tripping ~~any~~a transmission corridor, large load, or a generation plant as well as different fault scenarios~~. The information~~, must be considered to capture the worst stress on IBR performance. Information from system operators ~~is useful in the process (e.g.,~~, such as on a known oscillation in a specific network topology~~).~~, and PSPD transient stability study results are useful in the process.

~~The following list provides an example of different~~When simulating contingencies ~~that can~~, the following aspects should be considered:

- ~~Large signal disturbances:~~ Fault at ~~POC~~POI (bolted) and X-buses away from POC (different retained/residual voltage seen at ~~POC~~POI)
- Different types of faults: ~~LLLG, LG, LL, LLG~~L-L-L-G, L-G, L-L, L-L-G
- Fault on the line side of the breaker so that it clears~~.~~
- Breaker arrangement from utility, also considering ~~Remedial Action Scheme (~~RAS~~)~~
- ~~Clearing~~Transmission protection clearing times ~~from ISOs~~ (local and remote clearing times)
- Normally ~~Cleared, Breaker Failure~~cleared, breaker failure (backup protection), ~~Auto-Reclose~~auto-reclose (successful and unsuccessful)
- Protection ~~Relay~~relay logic is not modeled. Only operating times are used (underlying assumption protection will operate as designed).
- ~~Small signal disturbances:~~
- Switching with no faults: transmission lines, transformers, large loads, large generators, etc.

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~~Note that~~ Unsymmetrical faults are the most common faults ~~that~~to occur in transmission power systems ~~are unsymmetrical faults. A line~~. Line-to-ground ~~fault~~faults (L-G) ~~is~~are the most common ~~and the least severe~~ compared to other ~~types of~~ faults and represent 65~~-~~–80 ~~percent~~% of all faults in transmission lines ~~are of this type. Lightning~~. Issues like lightning and vegetation ~~under the line among others,~~ can cause these types of faults~~. They cause~~, when the conductor ~~to contact~~contacts the ~~earth or~~ ground.

~~Double line-to-ground~~L-L-G faults ~~in transmission lines~~, which cause two conductors to contact the ~~earth or~~ ground~~. They constitute 15 to 20 percent of all~~, and L-L faults~~. Heavy~~ in transmission lines are largely caused by heavy winds ~~are the major cause of these faults. They cause two conductors to contact one another and the ground, for instance, due to strong winds.~~.

Three-phase or symmetrical faults, which give rise to balanced currents displaced 120 degrees to each other, are the least common of all faults and ~~they~~ may provide the highest available fault current.

~~In all~~All fault cases~~,~~ cause voltage and current to deviate from their nominal values. ~~Storms resulting in collapsing of~~These faults are primarily caused by storms that collapse transmission towers or human ~~errors are the major cause of these faults~~error.

Selecting Study Scenarios

Performing studies for all possible options can result in an exhaustive list of scenarios and ~~requires a lot of~~require significant engineering hours to perform the simulation~~,~~ and collect and analyze the results. Therefore, due diligence must be taken when selecting the scenarios to capture the worst-case conditions. **Table 5.1** provides an example of the total number of simulation scenarios that can be considered for all possible options. **Table 5.2** ~~shows~~provides an example of the total number of simulation scenarios that can be considered to capture the worst-case conditions. Information from system operators, such as a known oscillation in a specific network topology, and PSPD transient stability study results are useful in narrowing down the study scenarios.

Table 5.1: An ~~example~~Example of ~~exhaustive list~~Exhaustive List of ~~study scenarios~~Study Scenarios for ~~all possible options~~All Possible Options	
Number of network power flow ~~scenarios~~cases	6
Number of IBRs dispatch	8
Number of contingencies	50
Total number of scenarios	6x8x50 = 2400
Average number of hours to simulate each scenario	45 min[23]
Total number of hours to simulate (assuming 4 cases at once)	45 x (2400/4) = 27,000 min = 450 hrs

Table 5.2: An ~~example~~Example of ~~reduced list~~Reduced List of ~~study scenarios based~~Study Scenarios Based on ~~capturing worst-case conditions.~~Capturing Worst-Case Conditions

[23] The time depends on the size of the network, number of PE devices (detailed or average model), simulation timestep, simulation time, and the performance of the PC used for the study.

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Base Case	Contingency														
A	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**
B	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x
C	x														
D			x		x		x					x			
E	x							x		x				x	x
F	x		x			x				x		x		x	
G			x			x			x						
H	x														

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Table 5.3 provides an example estimate of less computing time necessary to simulate only the worst-case conditions.

Table 5.3: Computing Time Estimate	
Total number of scenarios	40
Average number of hours to simulate each scenario	45 min
Total number of hours to simulate (assuming 4 cases at once)	45 x (40/4~~)=~~) = 450 min = 7.5 hrs

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When selecting contingencies to be studied in the EMT domain, the screening and ranking can be carried out using analytical methods and RMS domain runs. Common mode outages should be considered. ~~As IBR penetration increases, the size of a single generation loss event may reduce due to smaller sizes of IBR plants when compared to synchronous machine plants. However, due to the chance of many IBRs tripping on network events, the geographical spread of the event may widen. This must be considered when determining the contingencies to study.~~

Notes on Initialization

EMT simulations should first be initialized to achieve desired power flow scenarios. Depending on the EMT software being used~~,~~ and the capabilities of the models within the software, ~~initialization~~ a flat start may not be possible~~.~~ at the first run. As a result, if the EMT simulation is to start from a point away from the steady~~-~~-state pre-disturbance operating point, care must be taken to ensure an appropriate ramp to steady state. Here, the presence of deadbands in control loops can be impactful. Since the EMT simulation can have a transient state before it achieves pre-disturbance steady state, the deadband may result in a pre-disturbance steady~~-~~-state value that can be different from the power flow solution. As a result, a comparison between a study done in RMS simulation ~~vs a study done~~versus one in EMT simulation could result in mismatches.

~~Another aspect to bear in the mind is the~~The behavior of loads should also be considered. If motor load models are used in a study, then the reactive power consumed by the motor loads can be different in the EMT domain when compared to the power flow solution in the RMS domain~~. This is~~ because of the nuances associated with the method of initialization of motor loads in the RMS domain ~~has nuances associated with it~~.

Chapter 6: ~~Three Types of~~Performing EMT Studies

The study ~~methodology~~methodologies for the following ~~three~~ common types of EMT studies ~~is presented below~~are discussed in this chapter:

- Dynamic system impact assessment ~~study,~~studies
- ~~Subsynchronous oscillation (SSO) study, and~~
- SSO studies
- Transmission protection system validation ~~study.~~ studies

The first two are commonly conducted during the generator interconnection process as part of system impact studies. ~~Traditional~~Not included in the scope of this guideline are traditional EMT studies, such as those for substation/line design (~~TrOV, Surge~~transient overvoltage, surge arrester and Basic Insulation Level (BIL) rating (insulation coordination), current limiting reactor (CLR) rating, Transient Recovery Voltage (TRV) (breaker rating), induced ~~OV~~overvoltage due to mutual coupling from improper transposed or un-transposed lines, and secondary arc current (double-circuit line - induced current in opened line~~) are not in the scope of this guideline.~~).

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Dynamic System Impact Assessment ~~Study~~Studies

EMT dynamic performance studies are system-level studies (~~not~~ beyond Single Machine Infinite Bus (SMIB) tests) ~~which~~that seek to evaluate the performance of an IBR plant or group of IBR plants against applicable performance criteria ~~using~~with aggregate[24] or partially aggregate plant models. The performance of the system ~~which is~~ included in the EMT model can also be evaluated against applicable criteria~~,~~ to the ~~extent~~greatest possible extent. Steady-state and phasor-domain transient stability (PDTS) analysis should be performed before the EMT analysis if possible, and the system model used in the EMT analysis should include all upgrades ~~/~~ /mitigations ~~which were~~ deemed necessary in those studies. However, EMT dynamic performance studies typically ~~have~~take much longer ~~study schedules~~ than steady-state and PDTS~~, and due to overall schedule constraints,~~ analysis, potentially making it ~~may be~~ necessary to perform preliminary ~~modelling~~modeling and analysis in parallel with steady~~-~~-state and ~~transient stability~~TS analysis.

EMT Analysis

~~Analysis of EMT study results~~ It is typically more challenging to analyze EMT study results than ~~analysis of~~ phasor-domain study results due to the increased complexity of the device models (real code, black boxed) ~~as well as~~and the inherent simulation differences (e.g., phase quantities vs. RMS, zero and negative sequence, small timestep~~, etc.)~~). A robust understanding of the EMT simulation environment, IBR controls and behavior, and general power system analysis fundamentals should be considered ~~pre-requisites~~prerequisites to performing EMT dynamic performance studies. Many aspects of EMT dynamic performance analysis ~~should also be checked in PDTS analysis~~, such as IBR balanced fault-ride-through performance ~~/~~ /recovery and oscillation damping~~,~~ and voltage recovery, ~~etc.~~ should also be checked in PDTS analysis.

The following sections highlight additional performance aspects ~~which~~that should be considered in EMT dynamic performance studies. ~~Note that criteria~~Criteria violations ~~/~~ /performance concerns (such as instability and ride-through issues) observed during the analysis are typically addressed by the plant developers ~~/~~ /owners. Some issues may be mitigated by control tuning of participating devices. Any control tuning should be performed by the OEM or

[24] ~~Disaggregated~~ A disaggregated plant model may produce a different result than an aggregate plant model for some events, such as differences in how fast transients propagate throughout a long collector system. However, the current practice is to model plants as plant models are typically a single aggregate generator or a few partially aggregate generator models for dynamic system impact studies as the computational and engineering resource requirements associated with developing and simulating one or multiple fully disaggregated plant model are prohibitive within the schedule constraints of most interconnection studies.

with direct permission ~~/~~ /instruction from the OEM as other parties ~~do~~are not ~~know~~aware of the full implications of individual parameter changes and should not take responsibility for these changes. Control tuning done outside of the purview of the OEM should be considered investigative only.[25]

Stability

Assessing the stability of IBRs is typically a primary objective of EMT dynamic performance studies. Annex C of IEEE 2800-2022 ~~"~~*Inverter stability and system strength*~~" includes a thorough description of~~ thoroughly describes IBR stability concerns, including screening methods, examples, and mitigation. Stability in EMT dynamic performance typically concerns the following:

- **Oscillations:** Oscillations can occur over a wide frequency range in an EMT dynamic performance study due to the wide frequency range over which the model is valid (a few Hz to several kHz). Oscillations may occur at integer harmonics, ~~sub-synchronous~~subsynchronous, or super-synchronous frequencies~~,~~ and have many possible root causes ~~which~~that may involve natural system resonance and control-driven device characteristics ~~[~~. The ESIG "Diagnosis and Mitigation of Observed Oscillations in IBR-Dominant Power Systems"[26] guide and the CIGRE "Guidelines for Subsynchronous Oscillation Studies in Power Electronics Dominated Power Systems"[27] brochure ~~reference or ESIG oscillations guide].~~are good resources on this topic.

- **Control Mode Cycling ~~/~~ /Chattering:** EMT analysis of IBRs may result in interactions among IBRs or between IBRs and the system ~~which~~that are cyclic but not sinusoidal in nature. These kinds of interactions are often referred to as "control mode cycling" or "chattering~~",~~," as they involve controllers repeatedly toggling between control modes. While mode cycling is possible in phasor-domain simulation, it is more commonly observed in EMT simulation due to the detailed ~~modelling~~modeling of plant- and inverter-~~-~~level control loops ~~/~~ /thresholds and the possibility of poor transitions between these controllers. One example of mode cycling is when an IBR with a slow reactive power controller attempts to ramp up active power after a fault into a weak system. As the active power ramps up, system voltage drops~~,~~ and the reactive power from the IBR is too slow to avoid the voltage dropping to a low-voltage-ride-through (LVRT) threshold. Once the threshold is hit, the LVRT controls cause the active power to drop quickly and then begin ramping again, repeating the process. Another example is an IBR with a terminal voltage that is at the edge of an LVRT threshold after fault recovery. If the plant controller is slow to change the reactive power command and was perhaps requesting the inverters to absorb reactive power before the fault, the inverter controls may repeatedly toggle between the ~~PPC~~power plant controller (PPC) commands and the inverter-level LVRT commands (which would be requiring the inverter to inject reactive power). **Figure 6.1** shows an example of a plant ~~which~~that enters this type of mode cycling for several seconds following a three-phase fault and loss of line. The plant controller eventually increases the reactive power reference to allow the plant to recover. This behavior may repeat for much longer depending on the speed of the plant controller and the magnitude of the post-fault undervoltage. This type of response is typically not accepted as a stable response, however the severity and duration of oscillation, as well as the potential system impact, should be taken into consideration when making such assessments.

The possibility of any of the above cyclical ~~/~~ /periodic, sinusoidal, or non-sinusoidal ~~/~~ /non-linear behavior~~,~~ (or a combination thereof) can result in a somewhat arbitrary response shape ~~which~~that may not lend itself to be

[25] There are some exceptions to this, such as when the model for a legacy plant ~~which~~that no longer has OEM support is tuned to match behavior observed in operation.

[26] ESIG Stability Task Force "Diagnosis and Mitigation of Observed Oscillations in IBR-Dominant Power Systems", https://www.esig.energy/wp-content/uploads/2024/08/ESIG-Oscillations-Guide-2024.pdf, August 2024

[27] JWG C4/B4.52 "Guidelines for Subsynchronous Oscillation Studies in Power Electronics Dominated Power Systems", TB 909, 2023 , https://www.e-cigre.org/publications/detail/909-guidelines-for-subsynchronous-oscillation-studies-in-power-electronics-dominated-power-systems.html

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quantified with traditional criteria, such as damping ratio. Alternative quantitative metrics, such as minimum recovery time, settling time, and settling bands, may be more appropriate ~~[NER S5.2.5.5, 5.2.5.13, ATC criteria], however~~[28], but these should be applied in conjunction with engineering ~~judgement which~~judgment that considers the equipment and wider-grid implications of the response.

[28] For example, see IEEE 2800-2022.

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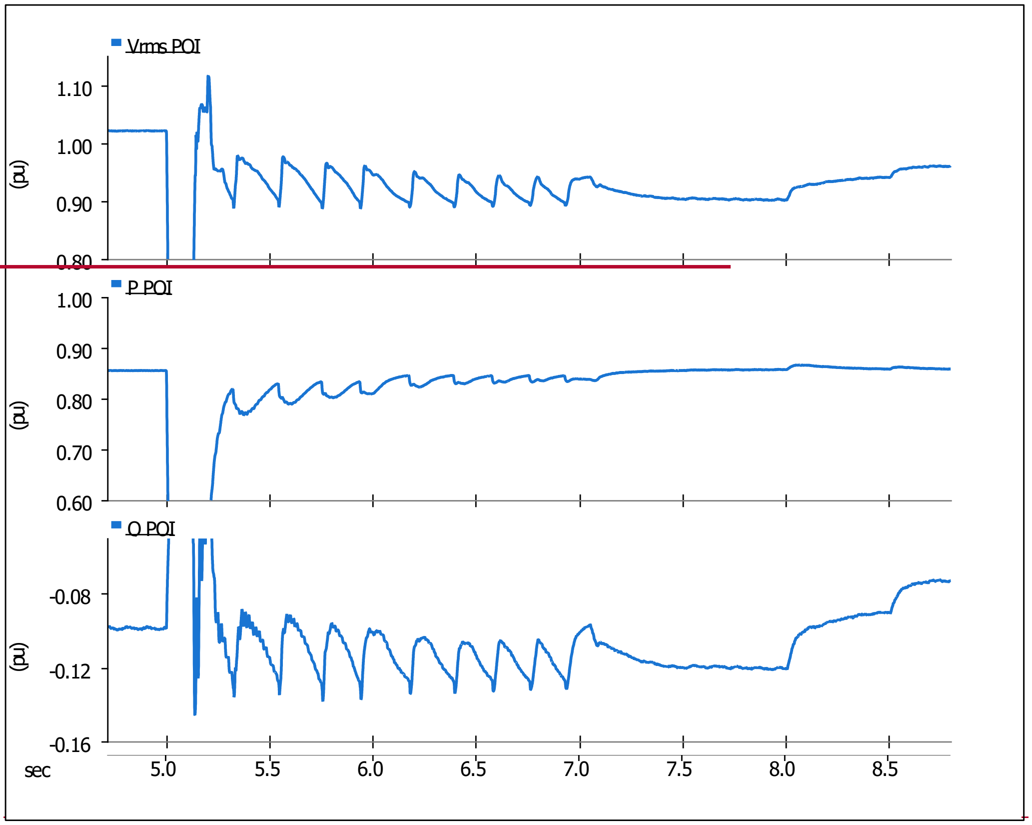

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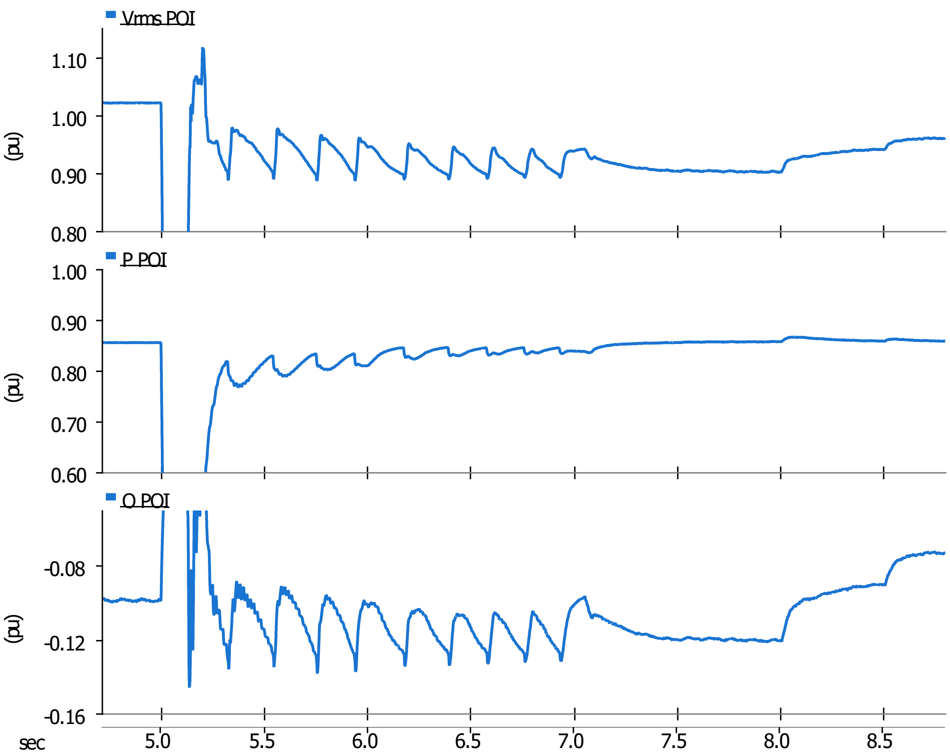

Figure 6.1: Reactive ~~power mode cycling example (courtesy~~Power Mode Cycling Example (Courtesy of American Transmission Company)

Ride-Through and Post-Disturbance Performance

Another primary objective of EMT dynamic performance studies ~~typically~~is to assess fault ride-through performance of a device or group of devices. IEEE 2800-2022 includes minimum capability requirements for IBR plants in response to abnormal events occurring on the transmission system and is a good reference for analyzing performance in EMT dynamic performance studies. The ride-through performance is typically assessed in the following terms~~,~~ and in the following order (IEEE 2800-2022 Chapter 4.7):

1. **Self-~~protection~~Protection:**[29]~~:~~ Do the devices remain connected throughout the disturbance or does a breaker or control signal cause devices to trip or self-protect for disturbances in which the system voltage and frequency ~~remains~~remain within the applicable ride-through ~~envelops~~envelopes? (PRC-024-02, IEEE 2800-2022 Chapter 7.2.2.1, IEEE 2800-2022 Chapter 7.3.2.1~~)?~~)

[29] Aggregate models cannot represent partial tripping where a portion of the inverters in the IBR tripped in response to contingencies., however, they are considered useful for gaining understanding of overall plant ride-through performance, where the majority of inverters could be subject to tripping.

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2. **Return to ~~service~~Service**: For energy resources, does the active power settle to an expected level (i.e~~.~~., close to pre-fault conditions) after the disturbance? (IEEE 2800-2022 Chapter 7.2.2.2~~)?~~)

3. **Current ~~injection~~Injection:** Do the devices provide adequate levels of positive-sequence real and reactive current injection (typically reactive current is priority, but not always) and negative-sequence current during the fault (IEEE 2800-2022 Chapter 7.2.2.3.4), and is the current injected in a fast and stable manner? (IEEE 2800-2022 Chapter 7.2.2.3.5~~)?~~)

4. **Post-~~event grid support: Does~~Event Grid Support:** Do the ~~device~~devices control system voltage (IEEE 2800-2022 Chapter 5) and frequency (IEEE 2800-2022 Chapter 6) with reasonable responsiveness and stability?

Figure 6.2 ~~below~~ shows an example of a plant responding to an event ~~which~~that reduced the point of interconnection (POI) voltage from 1.01 to 0.95 pu at ~~5s~~5 s. The plant does not begin responding to the undervoltage until 700 ~~mS~~ms post-fault, which is slower than the 200 mS reaction time required in Table 5 of IEEE 2800-2022. The plant has a response time of around ~~15s~~15 seconds for this event, which is within the typical range of 1~~-~~–30 seconds indicated in Table 5 of IEEE 2800-2022. The damping ratio requirement of 0.3 or higher is also met by this response.

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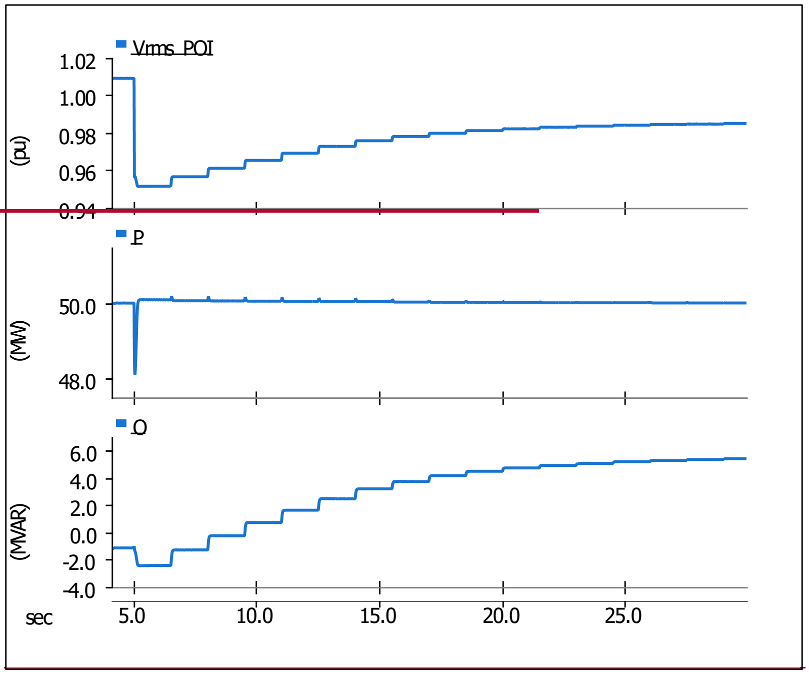
1074 

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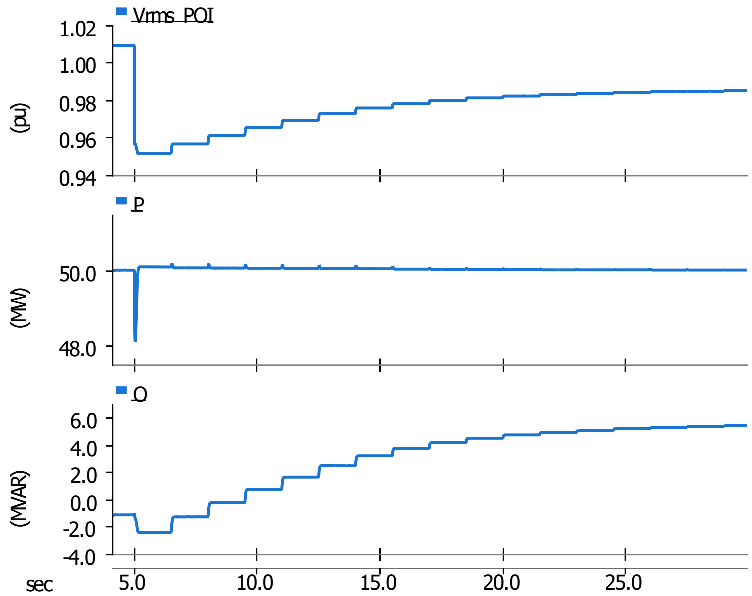

Figure 6.2: Plant Post-Event Voltage Support Example (~~courtesy~~Courtesy of American Transmission Company)

Harmonic Distortion ~~/~~ /Flicker

Harmonic distortion and flicker can be observed in EMT studies as many detailed load and generation models are sources and/or sinks of harmonic content. The distortion levels can be quantified from the instantaneous voltage and current waveforms (measured at relevant locations) and compared against applicable criteria, such as those listed in IEEE 519 and IEEE 2800-2022 in **Chapter 8**. Additionally, large voltage distortions at ~~IBR~~inverter terminals may lead to instantaneous or RMS overvoltage tripping as these are superimposed on the fundamental frequency voltage. If such a result is observed, the study engineer should ~~ensure that~~investigate whether the simulation model has sufficient ~~detail~~details to be reasonably accurate at the distortion frequencies before taking further action. This could be investigated through discussion with GOs (and in turn, device OEMs) and by verifying that the system model is appropriate (as outlined in **Chapter 2** and **Chapter 3**).

Transient ~~overvoltage~~Overvoltage and ~~overcurrent~~Overcurrent

Transient ~~over voltages~~overvoltages may occur in EMT simulation due to switching events and are often observed at fault clearing. These overvoltages may originate at the system level and propagate to ~~the IBR~~inverter terminals or may originate at ~~the~~inverter terminals and propagate into the system. These over voltages may be observed at terminals of all or some inverters. Investigating ~~IBR~~inverter tripping due to a transient overvoltage requires observation of the instantaneous inverter terminal voltages as the overvoltage is often too brief ~~in duration~~ to be fully visible in RMS measurements. Observation of overvoltage at levels at which surge arrestors begin conducting (e.g.~~.~~, around 1.7 pu) is an indicator that including surge arrestors in the simulation model may impact results. Observation of high and long overvoltage (e.g. >1.4 pu for longer than ½ cycle) at ~~an IBR terminal which~~ inverter terminals that does not cause the ~~IBR~~inverters to trip may require confirming that the EMT model has correctly ~~modelled~~modeled the overvoltage protection of the actual equipment. Likewise, observing a large instantaneous current at inverter terminals that appears to go well beyond (e.g. >1.5 pu) the ~~inverters~~inverter's rated continuous current limit for more than a few cycles~~,~~ but does not result in a trip~~, is an indicator~~ indicates that the model current limits and/or overcurrent protection should be verified against equipment capability. **Figure 6.3** shows an example of an inverter responding to an unbalanced fault, during which the inverter produces overcurrent of nearly 3 per~~-~~unit on a single phase for a number of cycles. This level of overcurrent ~~is~~maybe unrealistic due to the thermal constraints of switching devices in modern inverter equipment~~,~~ and therefore requires further investigation ~~into~~of the model quality.

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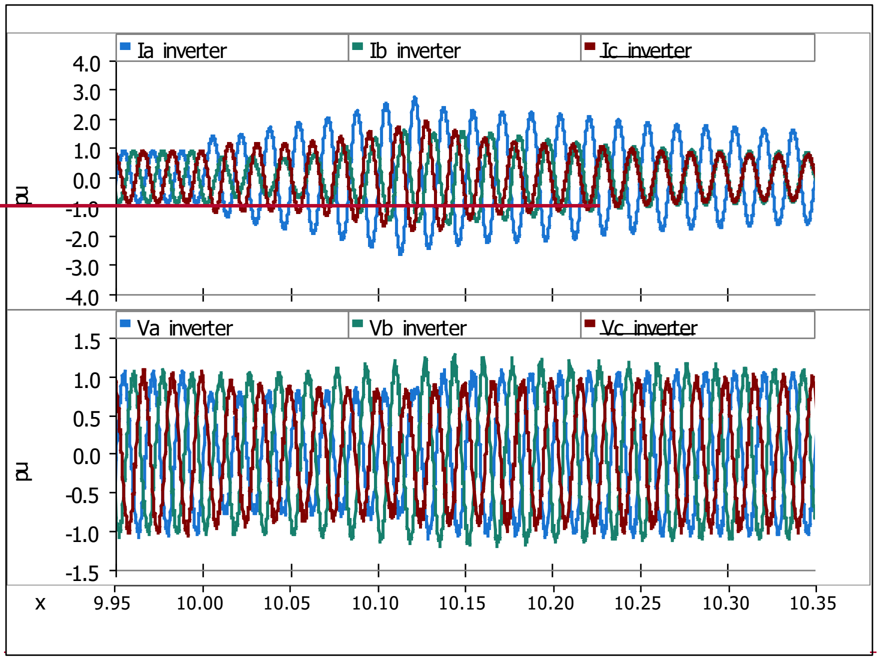

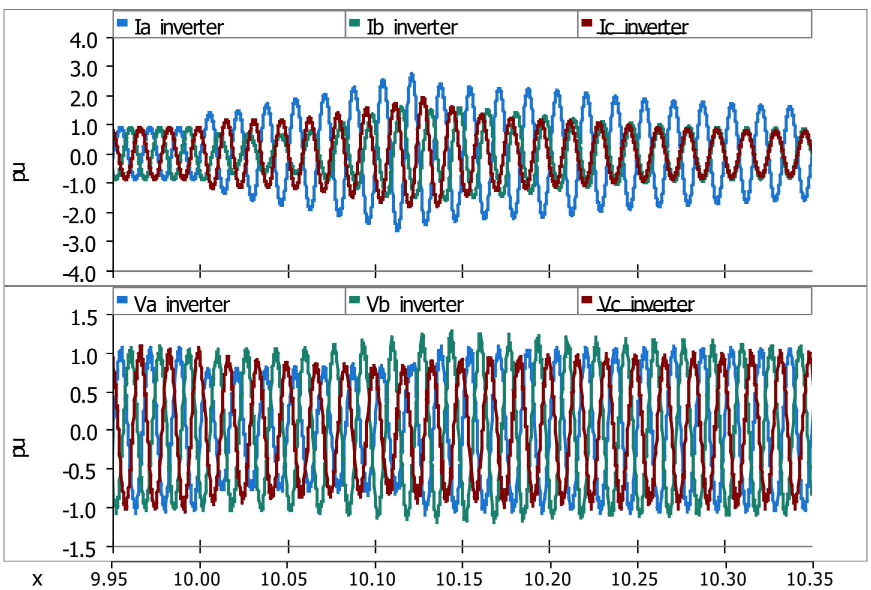

Figure 6.3: Example of ~~unrealistic overcurrent output~~Unrealistic Overcurrent Output at ~~inverter terminals~~Inverter Terminals

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Simulation ~~quantities~~Quantities to ~~monitor~~Monitor

Simulation quantities ~~which~~that are typically monitored to assess the dynamic performance of specific devices and the system include the following:

- **At the device terminals as well as at the reference point of applicability (**~~RPA) (e.g. point of interconnection): terminal~~**e.g., POI):** Terminal instantaneous voltage and current, RMS voltage and P/Q output~~.~~ should be monitored. System frequency[30] at the ~~RPA~~reference point of applicability may also be of ~~interested~~interest. Additional quantities ~~such as~~(e.g., real and reactive components of current, sequence components of voltage and current) may also be of interest and can be derived from the instantaneous phase voltages and currents. Analysis of these quantities can be used to verify the ride-through and post-disturbance performance requirements applicable to the plant(s) under study. The study engineer may need to look at the results with a narrow time-axis aperture (e.g~~.~~., less than 1~~-~~–2 seconds) to perform a thorough analysis, specifically for transients occurring at fault initiation and fault clearing.

- **Control signals exchanged between plant and inverter-level controllers**~~.~~**:** The commands sent from the plant controller to the inverters (typically P and Q commands) can be very informative in explaining plant behavior, particularly ~~in~~for diagnosing which controller is involved in unexpected behavior (i.e~~.~~., when the plant trips or fails to meet plant-level voltage/frequency control objectives). For example, if the active power unexpectedly reduces after the event, the study engineer can quickly determine if the reduction is caused by the plant controller or by an inverter-level control by observing the active power command sent from the plant controller. Note that the plant controllers and inverter controllers may exchange many more control signals, such as power availability and information about terminal conditions sent from inverter to the plant controller, or voltage/frequency setpoints rather than P/Q setpoint from the plant controller to the inverter controller.

- **Device trip**~~ / ~~**/ride-through mode flags**~~.~~**:** These are outputs of internal quantities produced by the device model~~,~~ and are useful ~~in~~for diagnosing reasons for tripping and explaining device behavior (as the user cannot have full access to internal variables of the black-boxed EMT model). In the example plots shown in ~~**Figure 6.4** below~~**Figure 6.5** , the LVRT and high-voltage-ride-through (HVRT) mode flags indicate that the inverters have stopped responding to the plant controller commands~~,~~ and are instead responding according to the LVRT and HVRT control algorithms implemented at the inverter level.

- **Internal control signal outputs**~~.~~**:** Internal control signals, such as measured phase-locked loop (PLL) frequency ~~/ ~~/tracking error, measured RMS voltage, and measured real and reactive current, can be useful in assessing device performance during and after faults, although in many models these control signals are not externalized or very selectively externalized~~,~~ and typically do not have in-depth explanations provided due to OEM ~~IP~~intellectual property concerns.

- **System instantaneous voltage, RMS voltage, and P/Q flows**: These should be monitored for buses and branches of interest, as needed to assess applicable system performance criteria.

Figure 6.4 and **Figure 6.5** ~~below~~ show example plots of typical POI and inverter-level simulation quantities. The inverter-level plot is zoomed~~-~~ in to show the behavior of the IBR during and after the fault. The inverter-level plot includes the inverter HVRT and LVRT mode flags~~,~~ as well as several flags indicating the activation of self-protection mechanisms.

[30] Some frequency measurement methods (possibly even those ~~which~~that are embedded in EMT simulation tools) are prone to producing erroneous frequency measurements, such as spikes during transients or errors in steady~~-~~-state measurement.

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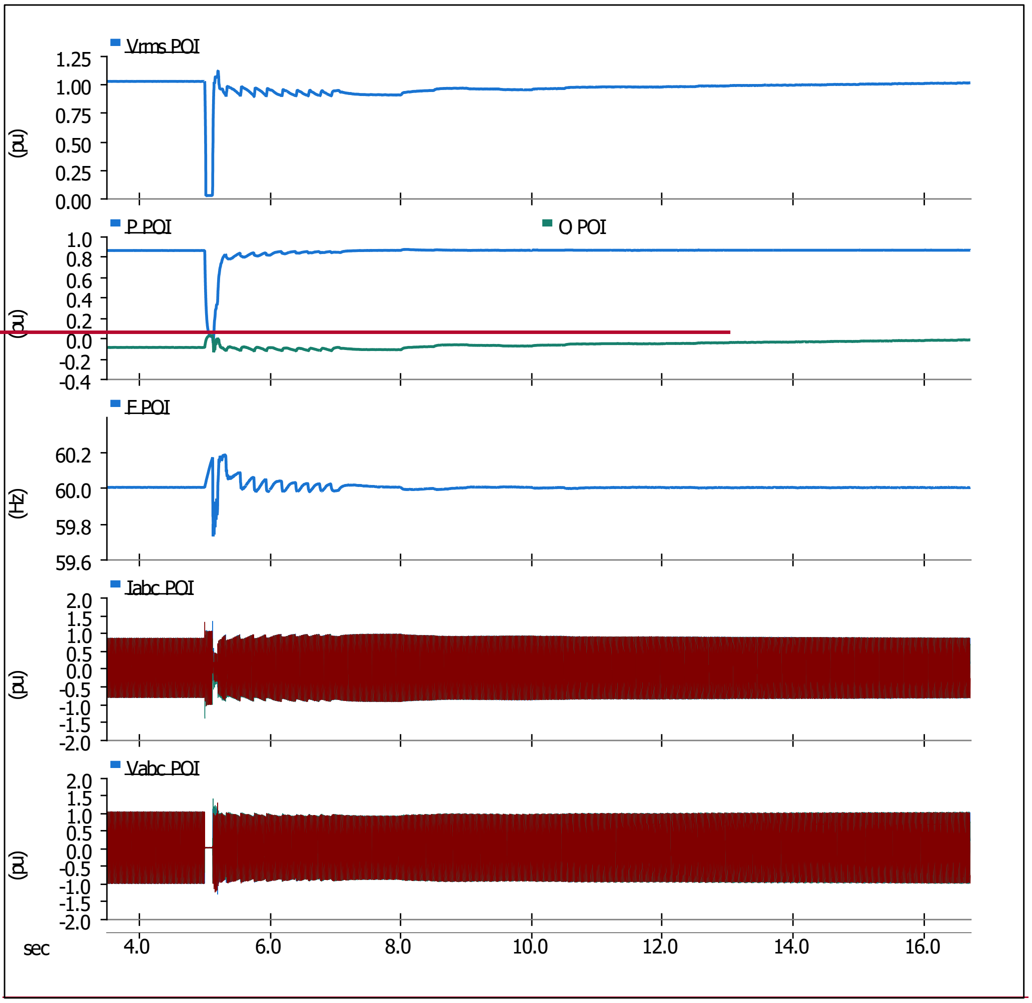

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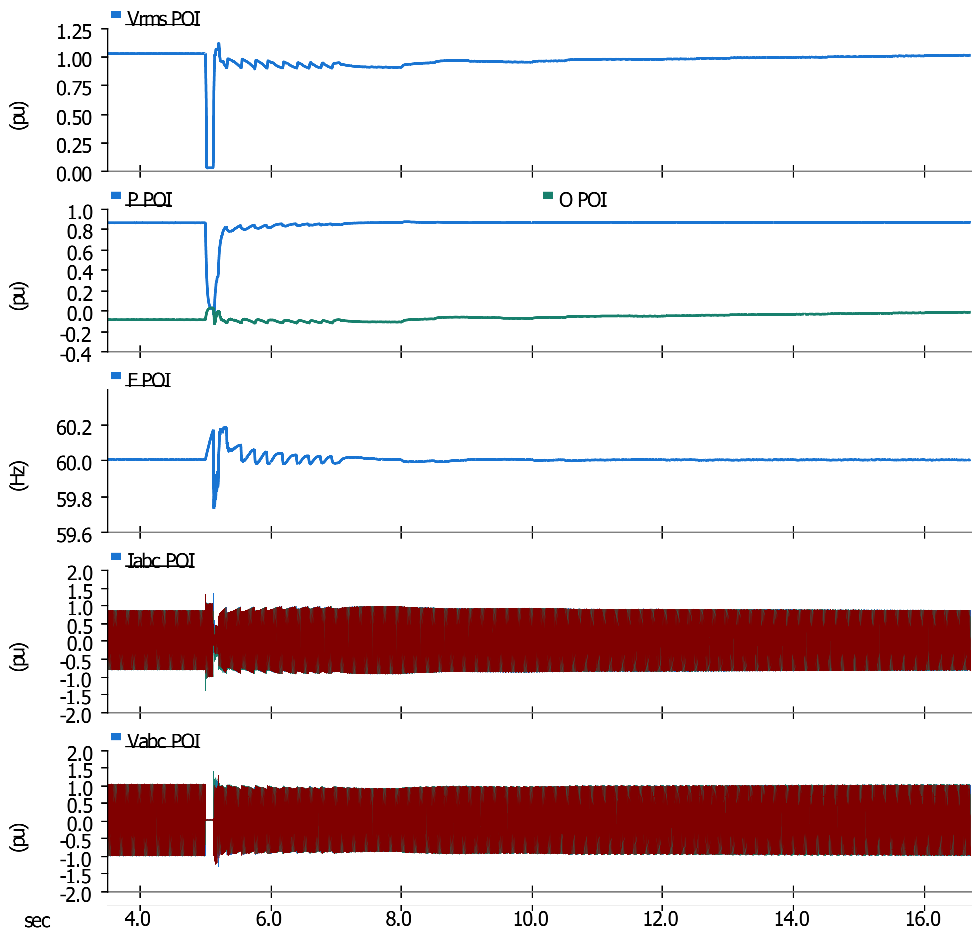

Figure 6.4: Example ~~plot~~Plot of ~~typical~~Typical IBR ~~plant~~Plant POI ~~quantities~~ ~~(courtesy~~Quantities (Courtesy of American Transmission Company)

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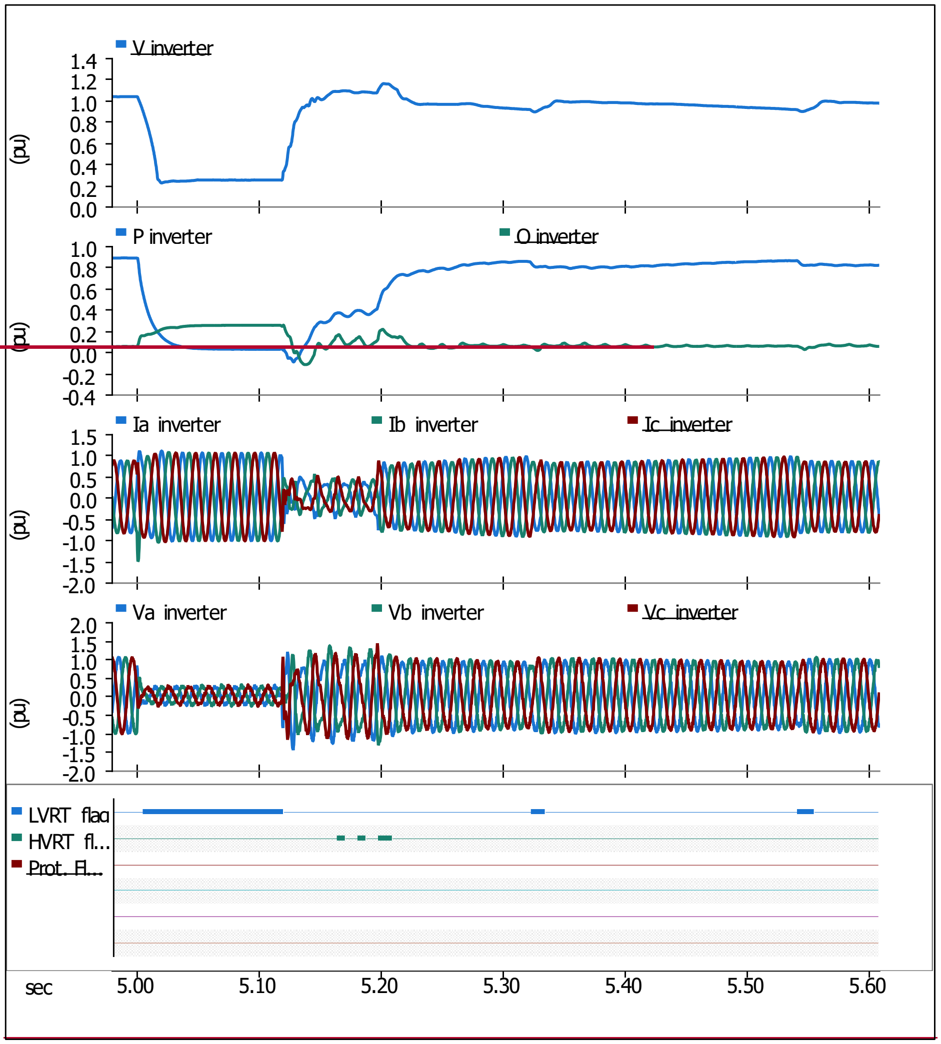

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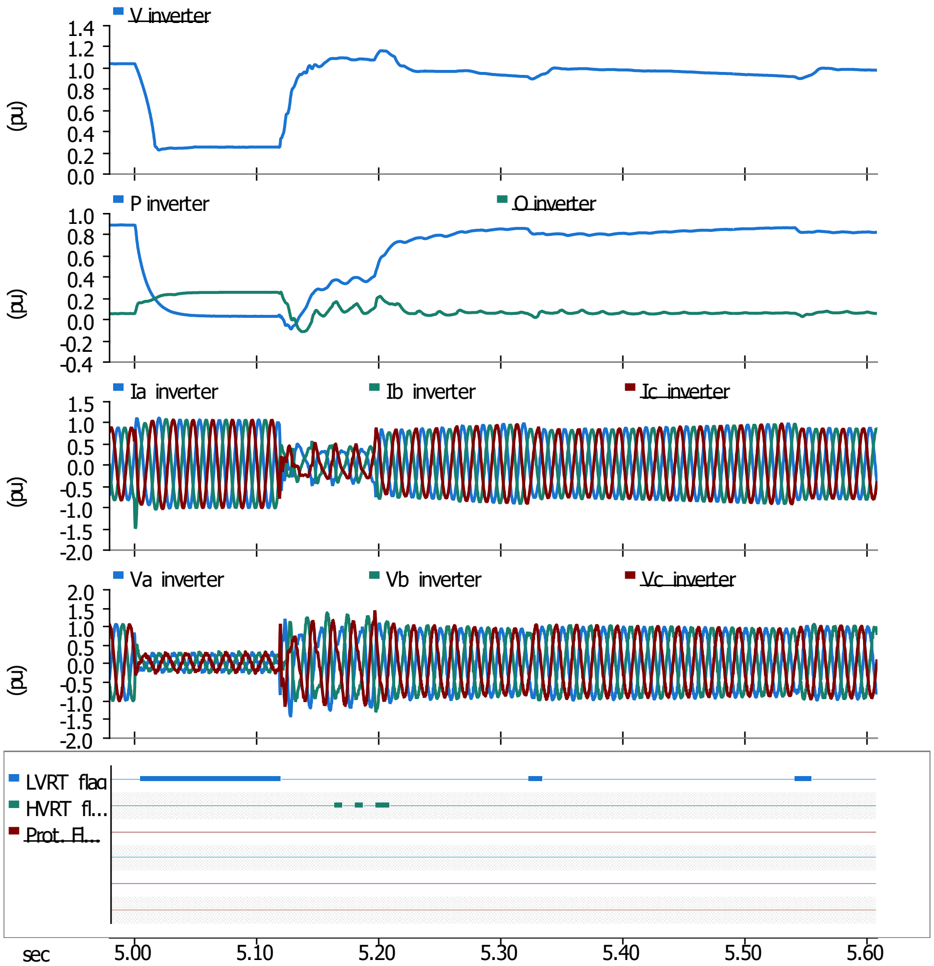

Figure 6.5: Example ~~plot~~Plot of ~~typical~~Typical IBR ~~inverter quantities (courtesy~~Inverter Quantities (Courtesy of American Transmission Company)

Processing Results

Depending on the size of the study, there may be several hundred pages of simulation results to analyze. The results may be screened by using a post-processing method ~~which~~that sets quantitative thresholds that are set conservatively such that only the very-_well performing results pass. This helps the study engineer focus on poor performance, although all ~~results~~result traces should still be reviewed with good engineering ~~judgement~~judgment.

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Comparison to Phasor-Domain Transient Stability (PDTS) Study Results

RMS results from the EMT dynamic study may be compared to PDTS results~~,~~ with the objective of either benchmarking the phasor-domain model against the EMT model (i.e~~.~~., substantial differences may be a result of ~~modelling~~modeling mistakes or inadequate ~~kept system~~study area selection) or ~~to identify~~identifying deficiencies in PDTS models (i.e~~.~~., how much is missed in PDTS studies). This should be done with the understanding that there will be differences between results because there are inherent differences between the tools, because many PDTS models may not have ~~not~~ been benchmarked thoroughly against corresponding EMT models~~,~~ and because the EMT system model is typically a subset of the PDTS system model and because load model dynamics is usually static in system wide EMT studies.

Subsynchronous Oscillation Studies

~~Subsynchronous oscillation (~~SSO~~)~~ is an electric power system condition ~~where~~in which the electric network exchanges significant energy with the generator at frequencies below the rated system frequency following a disturbance from the equilibrium.[31]~~.~~ Depending on the involved power system components, SSO is further classified into ~~sub-synchronous~~subsynchronous resonance (SSR), ~~sub-synchronous~~subsynchronous torsional interaction (SSTI), ~~and sub-synchronous~~subsynchronous control interaction (SSCI~~). Among them,~~) and subsynchronous ferroresonance (SSFR)[32].

SSR includes three phenomena – torsional interaction, induction generator effect and transient torque. SSCI is caused by the interaction between power electronics of IBRs and series-compensated lines or weak grid conditions. Thus, with the increasing penetration of IBRs on the BPS, there is an increased likelihood of encountering ~~Sub-Synchronous Oscillations (~~SSOs~~). These SSOs~~, which are detrimental for power systems~~,~~ since they may ~~exacerbate the power quality,~~ cause power ~~outage,~~quality issues or ~~destroy~~power outages, or damage power system components.

~~Another phenomena that might be encountered and categorized under the Subsynchronous oscillations are the subsynchrnous ferroresonances (SSFR).~~ The ferroresonance phenomenon ~~of ferro resonance~~ largely arises from the interaction between a capacitance (e.g., series-capacitor compensated lines) and a non-linear inductance~~,~~ (e.g., non-linear saturation of transformers), accompanied by minimal resistance. When the capacitance moves through a non-linear inductance region, ferroresonance is typically observed.

~~In a high-level comparison between Full Scale Converter Systems, known as Type 4 machines (FSCS) and Doubly-Fed Induction Generator (DFIG) wind turbines, known as Type 3 machines regarding their management and susceptibility to Subsynchronous Resonance (SSR), key differences emerge as follows:~~

~~Full Power Converter Systems (FSCS) Turbines~~

~~Electrical Isolation: Type 4 wind turbines manage all power conversion, changing all generated power to DC and then back to AC, which might completely isolates the turbine's mechanics from the grid's electrical disturbances depending on the control strategy utilized. This isolation shields Type 4 wind turbines from grid-related electrical resonances, such as SSR.~~

~~The comprehensive electrical isolation inherent in Type 4 turbines means they are inherently immune to SSR. This simplifies their operation as they do not require specific strategies for SSR mitigation related to electrical interactions. These turbines can operate optimally across various wind conditions because their operational speed is not influenced by grid frequency, promoting efficiency and reducing mechanical stress.~~

[31] I. S. R. W. Group et al., "Terms, definitions and symbols for subsynchronous oscillations," IEEE Transactions on Power Apparatus and Systems, vol. 104, no. 6, pp. 1326–1334, 1985.

[32] K. Gauthier, M. Alawie, "A special case of Ferroresonance involving a series compensated line," (2017)

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~~Doubly-Fed Induction Generator (DFIG) Turbines~~

~~Direct Grid Connection: DFIGs have a direct connection to the grid via the stator, with the rotor connected through converters that handle a portion of the power. This setup partially exposes DFIGs to grid disturbances, including SSR. The partial grid connection of DFIGs exposes them to SSR risks, particularly to phenomena like Induction Generator Effect and Torsional Interaction. This necessitates the implementation of specific control measures and possibly additional hardware to manage SSR effectively. DFIGs are economically favorable for variable speed operations due to the smaller size of the converters required compared to FPCs. However, this cost benefit comes with the increased complexity of managing potential SSR issues.~~

~~Type 4 turbines offer a straightforward and robust approach against SSR, ideal for settings with complex grid interactions due to their complete decoupling from the grid's electrical properties. In contrast, DFIG turbines, while cost-effective for achieving variable speeds, entail a greater complexity in design and operational strategies to adequately address their intrinsic susceptibility to SSR. This highlights a fundamental trade-off between operational flexibility and the complexity of system management and maintenance.~~

~~Nevertheless, regardless of the converter topology, both technologies might be susceptible to SSFR.~~ Ferroresonance primarily happens due to the presence of components with non-linear properties, such as capacitance and inductance, within the network. This interaction typically leads to a non-linear relationship between voltage and current levels and distorts waveforms, ~~deviating~~causing them to deviate from their usual sinusoidal shape. Consequently, ~~it's~~it is crucial to analyze this phenomenon in the time domain by accurately modeling the non-linear impedances in the system using EMT simulations, including the detailed saturation characteristics of power transformers.

~~Sub-Synchronous~~**Figure 6.6** summarizes the various types of subsychronous oscillations. For example, SSR is prevalent between series compensation and mechanical components of Type 3 WTGs.

	IBR Components		
	Mechanical Components	Converter Control / Power Electronics	Power Transformer
Series Capacitor (Susceptibility)	SSR (Type I, II, III WTGs)	SSCI (All IBRs)	SSFR (All IBRs)
Gas Turbines (Susceptibility)	-	SSTI (All IBRs)	-
Converter Control / Power Electronics (Susceptibility)	-	Control Interaction (All IBRs)	-

Figure 6.6: Various Types of SSO and Control Interaction involving IBRs

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~~Sub-synchronous~~

The following sections describe the key differences between full converter systems, such as PV, BESS and Type 4 wind turbines, and doubly-fed induction generator (DFIG) wind turbines, also known as Type 3 machines, regarding their susceptibility to subsynchronous phenomena.

Full Converter Systems (PV, BESS, Type 4 WTG)

PV and BESS resources employ inverters which are also known as full converter systems. These power electronic converters can interact with network resonances causing SSCI-related issues.

Similarly, Type 4 wind turbines employ full converter systems which might completely isolate the turbine's mechanical parts from the grid's electrical resonances, depending on the control strategy utilized, therefore, making

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them inherently immune to SSR. These turbines can operate optimally across various wind conditions because their operational speed is not influenced by grid frequency, promoting efficiency and reducing mechanical stress. However, Type 4 WTGs are still susceptible to SSCI and SSFR due to interaction between the converter control and network resonances.

Doubly-Fed Induction Generator (DFIG) Turbines

DFIGs have a direct connection to the grid via the stator with the rotor connected through converters that handle a portion of the power. This setup partially exposes DFIGs mechanical system to grid conditions and disturbances. DFIGs' partial grid connection exposes them to SSR risks like induction generator effect and torsional interaction in particular, necessitating the implementation of specific control measures and possibly additional hardware to manage SSR effectively. DFIGs are economically favorable for variable speed operations due to the smaller size of the converters required compared to Type 4 WTG. However, this cost benefit comes with the increased complexity of managing potential SSR issues. Regardless of the converter topology, both technologies can be susceptible to SSFR and SSCI.

Subsynchronous Control Interaction

SSCI are frequently observed between Type 3 ~~Wind Turbine Generators~~wind turbine generators (WTG) and weak, series-compensated grid lines. **Figure 6.~~6~~7** (top) and (bottom) ~~illustrate~~illustrates a typical setup of a wind farm connected to a series-compensated line and the configuration of a Type 3 wind turbine~~, respectively.~~. The control scheme of a ~~Doubly Fed Induction Generator (~~DFIG~~) -~~-based wind turbine can result in a negative equivalent resistance at ~~SSR~~SSCI frequencies, potentially leading to grid instability~~,~~ and introducing the risk of ~~a~~the SSCI phenomenon~~ called SSCI~~.

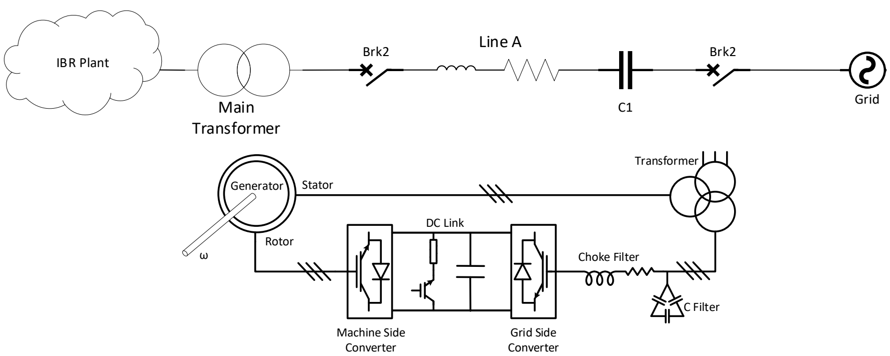

Figure 6.7: General ~~diagram~~Diagram of a ~~wind farm-connected series compensated network~~Wind Farm-Connected Series Compensated Network (Top), a DFIG-~~based~~Based WTG ~~configuration~~Configuration (Bottom)

The interaction between the grid impedance and the WTG impedance may ~~give rise to~~cause an unstable operation condition and may also influence the control performance of the turbine. ~~-~~To determine the equivalent impedance of the IBR plant, adopt a simple and pragmatic analytical approach~~ is adopted~~. At the ~~Point of Interconnection (~~POI~~)~~ of a wind farm, small voltage harmonics are superimposed on the fundamental waveform across various ~~sub-synchronous~~subsynchronous frequencies as shown in **Figure 6.~~2~~8**. The currents at these frequencies entering the wind plant are monitored. ~~Using a Discrete Fourier Transform (DFT) algorithm,~~Extract the magnitudes and phases of all relevant ~~sub-synchronous~~subsynchronous voltages and currents ~~are extracted.~~with a discrete Fourier transform algorithm. From these measurements, ~~using the initial harmonic perturbations,~~compute the resistance and reactance

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at each ~~sub-synchronous~~subsynchronous frequency ~~are computed~~ at the wind plant's terminals~~. This~~ with the initial harmonic perturbations. Use this resistance ~~is then used~~ to estimate the damping effects attributable to the plant.

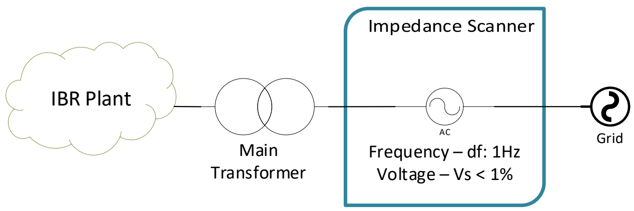

Figure 6.8: Single~~-~~-Line Diagram of Impedance Scanner

The process in **Figure 6.~~7~~8** should be simulated ~~using~~with time-domain simulation tools to accurately capture the currents and voltages over time. This detailed temporal data is crucial for further analysis, allowing for the conversion of these measurements into equivalent impedance values~~, which~~ that can be expressed in either polar or rectangular format. This method ensures a comprehensive understanding of the ~~system's~~system's dynamic responses and facilitates precise impedance characterization. Once the simulation data ~~its~~is obtained, a Fast Fourier Transform (FFT) analysis must be conducted to obtain the equivalent impedance.

As observed in **Figure 6.~~8~~9**, the real part of the impedance of various ~~Inverter-Based Resource (~~IBR~~)~~ plants is analyzed to evaluate their susceptibility to ~~Sub-Synchronous Resonance (SSR).~~SSCI. Type 3 wind turbines without ~~SSR~~SSCI mitigation display significant negative resistance, which can predispose them to stability issues. When the control systems of these Type 3 turbines are enhanced to include active frequency scanning and damping, their resistance becomes markedly less negative, improving their operational stability. In contrast, Type 4 turbines ~~inherently~~ exhibit ~~significantly~~ positive resistance, rendering them ~~inherently resistant~~less vulnerable to ~~Sub-Synchronous Control Interaction (~~SSCI~~)~~ compared to their Type 3 counterparts. Type 4 turbines and other full converter systems (PV and BESS) are still susceptible to SSCI if interconnected in areas with series compensation or weak grid conditions.

These insights are only obtainable through post-processing accurate ~~Electromagnetic Transient (~~EMT~~)~~ models, which are essential for analyzing the detailed control interactions of IBRs. This analysis highlights the critical role of advanced control mechanisms and high-fidelity modeling in mitigating ~~SSR~~SSCI risks and enhancing the stability of the power system.

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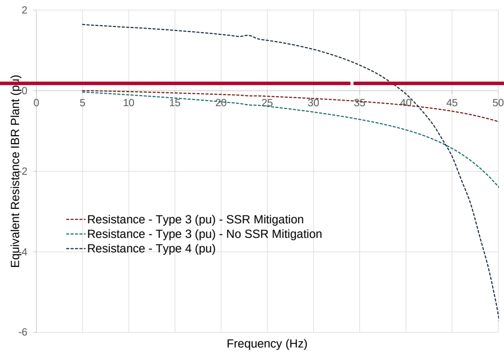

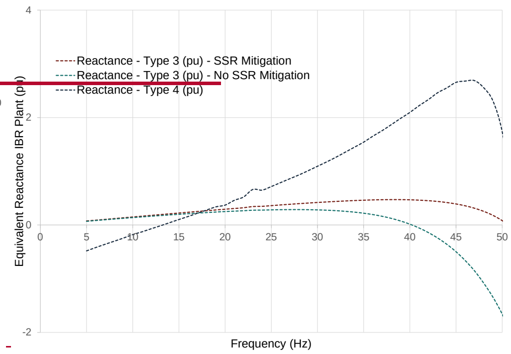

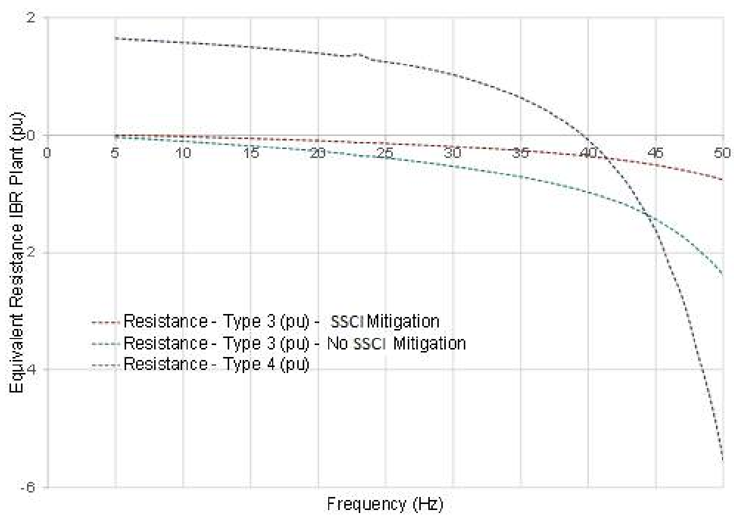

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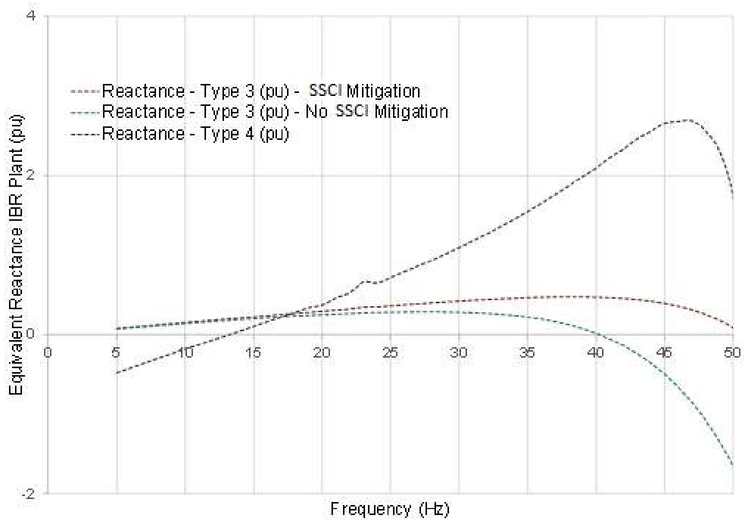

Figure 6.9: Impedance Scan Comparison

The SSCI issue ~~of Sub-Synchronous Resonance (SSR)~~ arises when the combined resistance of the grid and the ~~Wind Turbine Generator (~~WTG~~) becomes~~ become negative at a certain frequency. This typically occurs when the series compensation capacitance neutralizes the inductance, leading to resonance. To mitigate this, reducing the gain of the rotor current controller can decrease the virtual negative resistance exhibited by the WTG. Additionally, ~~it's~~it is crucial to synchronize the adjustments by also reducing the bandwidth of the power controller following any reduction in the current ~~controller's~~controller's bandwidth. This step is essential to maintain stable operation of the WTG.

The stability analysis of the system can be done by using the impedance-based stability criterion, where the small signal model of the system is divided into a WTG and a grid subsystem as ~~it is~~ shown in **Figure 6.~~4~~10**. Accordingly, the current IWTG flowing from the WTG to the grid is as follows:

$$I_{WTG}(s) = \frac{V_{WTG}(s) - V_g(s)}{Z_{WTG}(s) + Z_g(s)}$$

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Therefore, the system will be stable if ZWTG/Zg fulfills the Nyquist criterion (i.e., the ZWTG/Zg trace does not encircle the point -1 in the complex plane) and if the following assumption are also valid~~,~~:

- The ~~Equivalent~~equivalent voltage source VWTG(s)-Vg(s) has no unstable poles
- The grid impedance Zg has no right-half plane zeros

It is worth noting that the below representation is only valid for small-signal analysis~~, and the~~; large-scale stability must be ensured with dynamic analyses. Therefore, it is not in the scope of this guideline.

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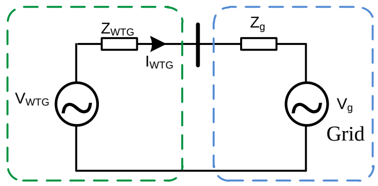

Figure 6.10: Small-~~signal model~~Signal Model of a WTG ~~connected~~Connected to the ~~grid.~~Grid

~~Sub-Synchronous~~Subsynchronous Ferroresonance[33]

Ferroresonance is a nonlinear resonance that occurs when a circuit contains saturable nonlinear inductance and capacitance with minimal resistance. This effect is particularly common in configurations ~~such as~~like a transformer-terminated double circuit line, ~~where~~in which power transformers, as key sources of nonlinear inductance, are linked to extensive transmission lines running parallel to another line. This setup facilitates ferroresonance through capacitive interaction between the lines, and increasing voltage levels may induce transformer saturation, heightening the risk of ferroresonance. Such dynamics can lead to significantly elevated currents and frequency distortions. Moreover, the oscillatory behaviors induced by ferroresonance can merge with torsional oscillations associated with ~~Sub-Synchronous Resonance (~~SSR~~)~~,, thereby increasing the complexity of the system's operational dynamics. It is essential to accurately model these nonlinearities, including the saturation of power transformers, when assessing the grid-~~-~~interconnection impacts of IBRs connected to series-~~-~~compensated lines. Proper modeling can be achieved by using EMT time domain simulation tools, which allow for the correct representation of power transformer saturation in their simulations.

Considering the hypothetical equivalent circuit illustrated in ~~Figure 6.10, an Inverter-Based Resource (IBR)~~**Figure 6.11**, an IBR plant is connected to the network via a parallel transmission line arrangement. In this scenario, one of the lines includes a series compensation. Should a fault occur on Line B and the protection mechanism at Breaker 1 (Brk1) activate, thus isolating the line, the IBR plant will still maintain a radial connection through the line with series compensation. This configuration underscores the importance of considering the dynamics and potential operational scenarios of the network, especially in terms of fault response and system stability.

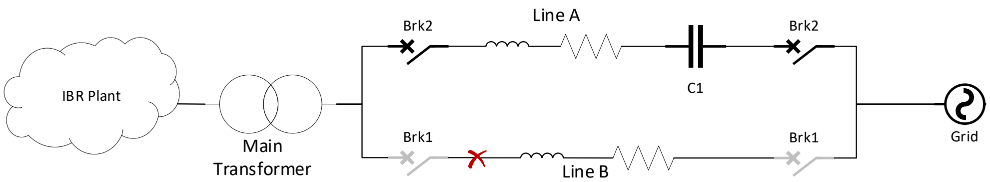

Figure 6.11: Single-~~-~~Line Diagram of a Series-~~-~~Compensated Plant

In the simulations of the scenario depicted in **Figure 6.~~10~~11**, significant discrepancies are observed in the results depending on the modeling approach of the transformer. When the main substation transformer is modeled both with and without considering core saturation, the outcomes are markedly different~~, as~~ (shown in **Figure 6.~~6~~12**~~.~~). Without including core saturation in the main transformer model, the plant successfully rides through a fault on Line B and its subsequent clearance, maintaining a radial connection through Line A. However, when core saturation is included in the main transformer model, the plant exhibits instability, characterized by sustained oscillations around

[33] R. Rogersten, R. Eriksson, "A ferroresonance case study involving a series-compensated line in Sweden," IPST, 2019

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20 Hz. This contrast underscores the critical impact of accurate transformer modeling on the stability and operational reliability of the plant, particularly during fault conditions and subsequent network configurations.

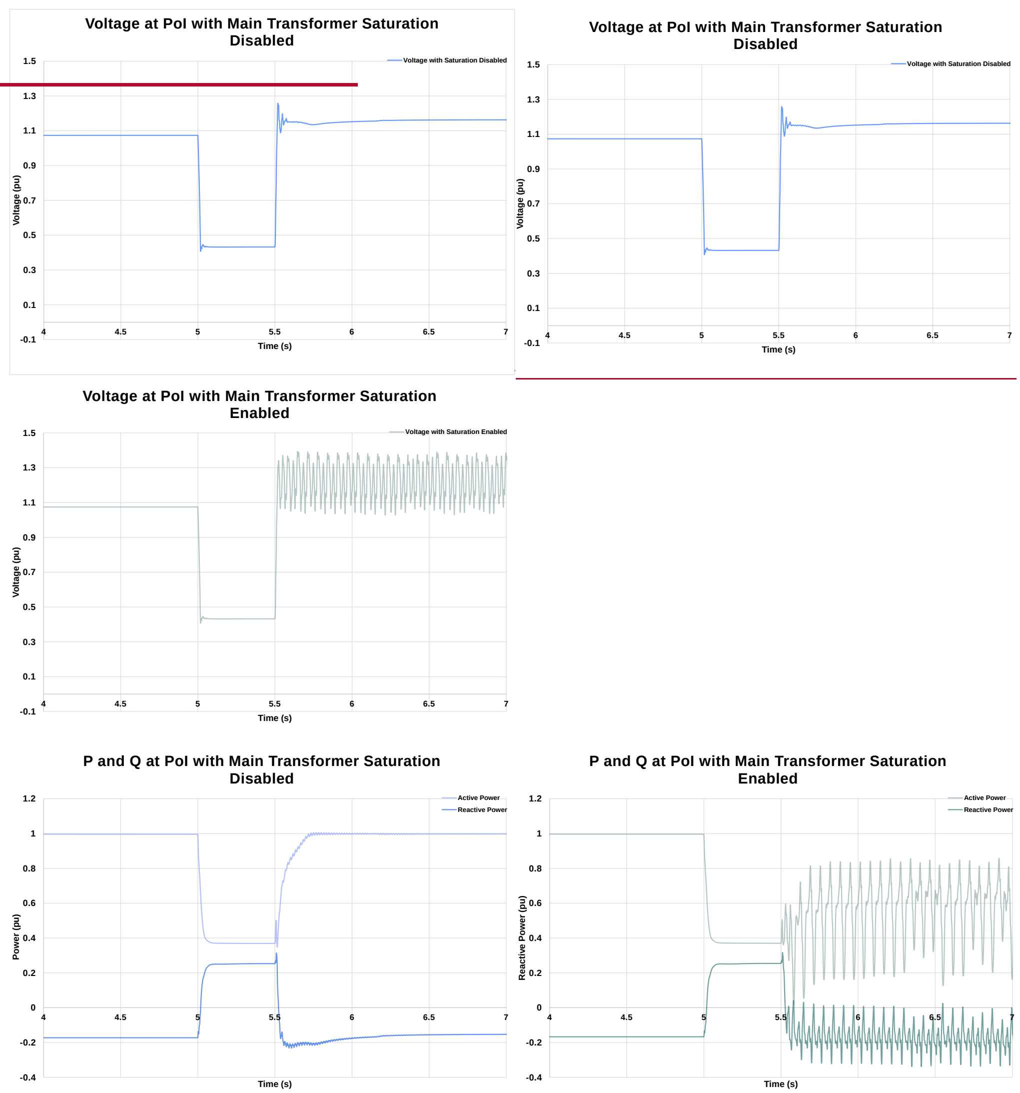

Figure 6.12: Comparison of Simulation Results of IBR in a Series~~-~~-Compensated ~~line~~Line with and without ~~transformer saturation~~Transformer Saturation

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SSCI/SSR Screening Studies

As explained in **Chapter 5**, the critical study scenarios to be studied in time domain EMT simulations can be narrowed down by screening for credible conditions that are conducive to SSCI and SSR phenomena. SSCI/SSR screening studies[34] involve two main steps – passive frequency scanning and active (dynamic) frequency scanning. The passive frequency scanning identifies electrical resonances in the power system in the range of 2 Hz to 55 Hz using phasor domain calculations. Both PSPD and EMT tools can be used to produce impedance versus frequency plots as seen from the POI of IBRs. Active frequency scanning approximates an “effective impedance” of each converter which, combined with passive frequency scanning results, can estimate the net damping for electrical resonances in the system. The scenarios resulting in net negative damping are selected for further analysis in time domain EMT simulation studies.

Real-World SSO Event Study Framework[35,36]

Ideally, SSO events should be minimized by strengthening the power grid and developing suitable mitigation actions in the system planning and operation stages. EMT ~~Studies~~studies to assess and mitigate potential SSO issues are well documented. ~~Yet~~Nonetheless, it is still difficult to completely prevent oscillation events due to the complicated SSO mechanisms. Thus, ~~sometimes,~~ post-SSO-event studies are sometimes needed to identify root ~~cause~~causes and mitigate potential SSO issues. Therefore, ~~in~~ this guideline~~, the focus is given~~ instead ~~to~~focuses on post-event, root-cause analysis for ~~root causing~~ SSO.

~~NREL~~The National Renewable Energy Laboratory (NREL) developed a real-world SSO event analysis framework with six steps as displayed in **Figure 6.~~12~~13** below. ~~This~~In this framework ~~features that~~, both measurement- and model-based analysis are leveraged to identify the SSO sources, understand the SSO event root cause, and recommend effective mitigation methods.

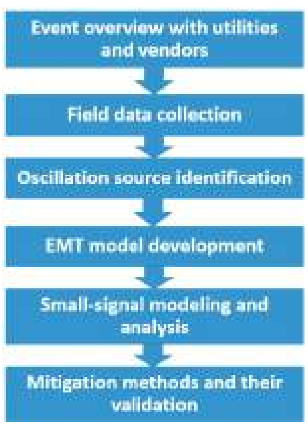

Figure 6.13: ~~A real-world~~Real-World SSO ~~event analysis framework proposed~~Event Analysis Framework Proposed by NREL

[34] https://www.electranix.com/wp-content/uploads/2019/05/Technical-Memo-SSCI-SSR-Screening-and-Modeling-requrements_Rev-0.pdf

[35] S. Dong, B. Wang, J. Tan, C. J. Kruse, B. W. Rockwell, K. Horowitz, and A. Hoke, “Analysis of November 21, 2021, Kauai Island Power System 18-20 Hz Oscillations”. arXiv preprint arXiv:2301.05781. 2023 Jan. 13.

[36] J. Tan, S. Dong, and A. Hoke. “Island Power Systems with High Levels of Inverter-Based Resources: Stability and Reliability Challenges.” United States. ~~https://www.osti.gov/servlets/purl/1996391~~https://www.osti.gov/servlets/purl/1996391

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- **Step 1:** ~~Overview~~Review the event with utilities, IBR vendors, and/or ~~original equipment manufacturers (~~OEMs~~)~~~~.~~.
- **Step 2:** Collect the field data of the SSO event~~,~~ (e.g., low-/high-speed ~~digital fault recorder (~~DFR~~)~~ data, Universal Grid Analyzer (UGA) data, and ~~Supervisory Control and Data Acquisition (~~SCADA~~)~~ data.
- **Step 3:** Identify the oscillation source based on measurement-based methods like the ~~Dissipative Energy Flow~~ dissipative energy flow (DEF)[37,38] and sub/super-synchronous power flow method.[39]~~.~~
- **Step 4:** Develop EMT model to replay the SSO event. In this step, ~~we can leverage~~ parallel simulation can be leveraged to accelerate the simulation speed.
- **Step 5:** Develop small-signal model and apply the small-signal analysis to understand the root cause of the SSO oscillations. ~~Also, we can perform frequency~~Frequency scanning studies can be performed while analyzing the event.
- **Step 6:** Propose mitigation methods and validate them in the EMT simulation, ~~Power Hardware~~power hardware-in-the-loop (PHIL) experiment, or field test.

Case Study of Kaua`i Island Power System 18~~-~~–20 Hz Oscillations

~~The~~The analysis performed following the Kaua`i Island 18-20 Hz SSO event provides an example that demonstrates the effectiveness of the SSO event analysis framework ~~was demonstrated by leveraging Kaua`i Island 18-20 Hz SSO event as an example.~~. Kaua`i Island is Hawaii's ~~4th~~ fourth-largest island and has a meshed and isolated power system that is operated by Kaua`i Island Utility Cooperative (KIUC). The Kaua`i power system features high~~-~~-penetration ~~renewables~~of IBRs during its operation. For example, ~~69.5~~according to KIUC's 2021 annual report, 44.8% of Kaua`i Island's annual generation comes from ~~renewables like solar, hydro, and biomass based on KIUC's 2021 annual report[40].~~IBRs.[41]

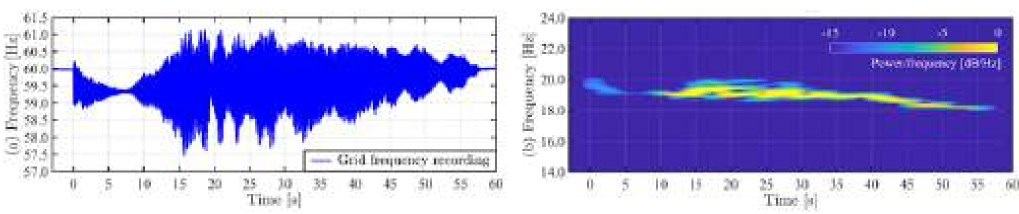


Figure 6.14: Kaua`i ~~island frequency recording~~Island Frequency Recording with 18~~-~~–20 Hz ~~oscillations~~Oscillations

~~Following the N-1 contingency, one~~A 18~~-~~–20 Hz oscillation event occurred ~~in~~on Kaua`i Island at 5:30 ~~am HST~~a.m. Hawaii-Aleutian Standard Time on November 21, 2021 (see **Figure 6.~~13~~14** ~~). Note that~~) following the ~~tripped~~tripping of a synchronous generator ~~supplied~~that was supplying 60% of the total load ~~before the event, and this~~. This generator trip ~~indeed~~ represented the most severe N-1 contingency in the Kaua`i power system. ~~Although the system was secured by four IBRs' fast frequency response, these~~These 18~~-~~–20 Hz oscillations ~~are systemwide and still~~

[37] L. Chen, Y. Min, and W. Hu, "An energy-based method for location of power system oscillation source," IEEE Trans. Power Syst., vol. 28, no. 2, pp. 828–836, 2013.

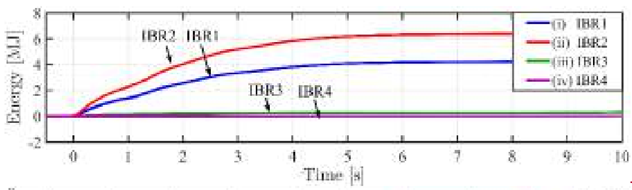
[38] S. Maslennikov and E. Litvinov, "ISO New England Experience in Locating the Source of Oscillations Online," in IEEE Trans. Power Syst., vol. 36, no. 1, pp. 495-503, Jan. 2021.

[39] X. Xie, Y. Zhan, J. Shair, Z. Ka, and X. Chang, "Identifying the source of subsynchronous control interaction via wide-area monitoring of sub/super-synchronous power flows," IEEE Trans. Power Del., vol. 35, no. 5, pp. 2177–2185, 2020.

~~[40] Kaua'i Island Utility Cooperative, "Hitting the target – KIUC 2021 annual report," Lihue, HI, Dec. 2021~~

[41] Kaua'i Island Utility Cooperative, "Hitting the target – KIUC 2021 annual report," Lihue, HI, Dec. 2021.

~~pose~~triggered by the generator trip posed serious challenge to the ~~stable operation~~stability of the Kaua`i power system. To prevent similar events in the future, the root cause of this event should be fully understood~~,~~ and effective mitigation methods should be explored. Thus, as detailed below, this SSO event was studied with the analysis framework shown in **Figure 6.~~12~~: ~~A real-world~~13**: Real-World SSO ~~event analysis framework proposed~~Event Analysis Framework Proposed by NREL~~, as detailed below.~~.



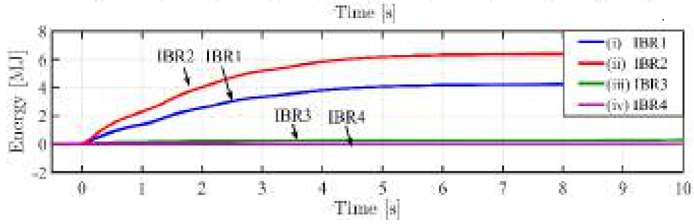


Figure 6.15: Identification of ~~oscillation sources~~Oscillation Sources with the DEF ~~method. This method shows that IBR1 and IBR2 are oscillation sources because they inject oscillation-frequency energy into the grid after t = 0 s~~Method

- **Steps 1~~-~~–3**: After ~~overviewing~~reviewing the event (~~step~~Step 1), KIUC's field data ~~were~~was collected for ~~this~~the event (~~step~~Step 2), which was recorded by ~~digital fault recorder (~~DFR~~). Then,~~. Step 3 was then completed, and the oscillation source(s) were identified with two measurement-based algorithms—DEF ~~[5]~~ and sub/super-synchronous power flow method. The DEF method only requires low-speed phasor data, and, as shown in **Figure 6.~~14~~15**, two IBRs with grid-following (GFL) ~~controller,~~ controllers (i.e., IBR1 and IBR2~~,~~) were injecting dissipating energy into the power systems while the oscillation event occurred. Thus, the DEF method infers that IBR1 and IBR2 ~~are~~were the oscillation sources in this event. To crosscheck the DEF analysis results, the high-speed point-on-wave DFR data ~~were~~was leveraged to compute the sub/super-synchronous power flow corresponding to the 18–20 Hz oscillation frequency ~~18-20 Hz~~. The sub/super-synchronous power flow also suggests that IBR1 and IBR2 ~~are~~were the ~~source~~sources of the oscillations. Hence, it was concluded that the 18~~-~~–20 Hz oscillation event was caused by two IBRs with GFL controllers.

- **Step 4**: In this step, EMT ~~model-based~~ studies were performed to ~~reveal~~recreate the ~~root cause of the~~oscillation event ~~and identify mitigation methods. Note that~~. EMT simulation studies were performed instead of phasor-domain simulation~~,~~ since phasor-domain simulation cannot replay these 18~~-~~–20 Hz oscillations. One key step in ~~model-based~~EMT studies is ~~to recreate~~re-creating the oscillation event in ~~our~~the simulation. To achieve this goal, the detailed EMT model for the Kaua`i island power system was built by converting the KIUC PSS/E model and integrating available vendor-provided IBR models. ~~Note that there~~There was no challenge ~~of~~in defining the modeling boundary~~,~~ since the Kaua`i power system is a small and isolated island power system. ~~Also, it~~It should also be highlighted that the vendor model should be validated against the field data and tuned based on the inputs from the utility~~. This is~~ because some IBR parameters like P/f droop constant can be revised remotely by system operators after being commissioned~~,~~ and these parameters can play an important role in the event. Another challenge is that some IBRs did not

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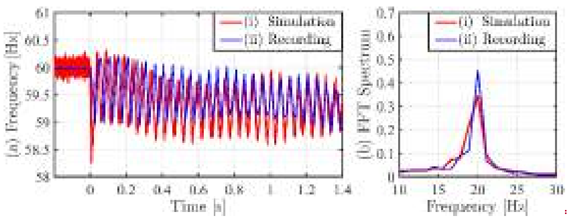
have available vendor-provided models~~; they were represented with~~, instead using generic models with their parameters tuned based on the field data. After these modeling efforts, the 18~~-~~–20 Hz oscillations were successfully recreated in EMT simulation as shown by the red trace in Figure 6.~~15~~16.



- ~~Figure 6.15:~~ Simulated and recorded grid frequencies have similar time-domain responses and FFT spectra, which can be used to validate the EMT model accuracy.~~ (a) Simulated and recorded grid frequency waveforms. (b) FFT analysis results~~

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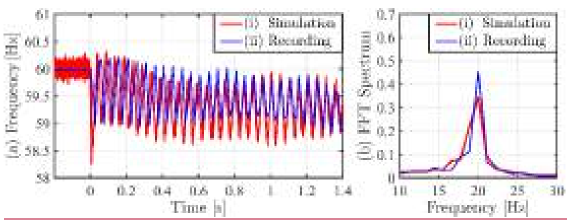

Figure 6.16: (left) Simulated and Recorded Grid Frequency Waveforms. (right) FFT Analysis Results.

- **Step 5**: After recreating the event with EMT simulation in ~~step~~Step 4,~~ model-based~~ parameter sensitivity analysis, small-signal stability analysis, or frequency-scanning studies (~~step~~Step 5) should be performed. Taking the parameter sensitivity analysis as an example, about 40 controller parameters were identified and perturbed to check for the impact on the simulated oscillation frequency and magnitude. ~~The~~ Based on the parameter sensitivity analysis, the P/f droop constant and ~~phase-locked loop (~~PLL~~)~~ gain in IBR1 and IBR2 ~~have larger~~made the most significant impact on the simulated oscillations. ~~Also~~In addition, IBR1 and IBR2 were connected to medium weak grid, following the N-1 contingency. Increasing the grid strength can eliminate the oscillations. Thus, this event ~~is~~was caused by a combination of different non-optimal settings~~.~~ and system conditions. These findings were further confirmed by detailed small-signal analysis.

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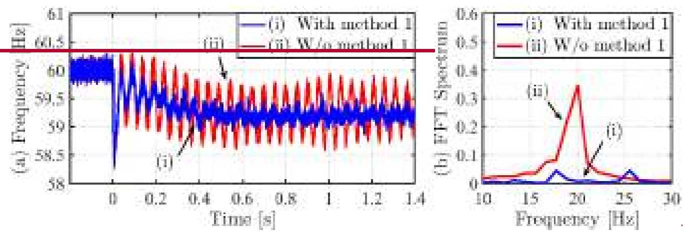

~~**Figure 6. 16: Validation of our Method 1, which aims to mitigate the 18–20 Hz oscillations. (a) Simulated grid frequencies measured at IBR1 with and without Method 1. (b) FFT analysis results of simulated grid frequencies.**~~

- **Step 6**: Based on ~~our~~the findings in ~~step~~Step 5, three mitigation methods could be proposed: ~~(i)~~ adopting less aggressive IBR1 and IBR2 P/f droop constant; ~~(ii)~~ reducing PLL gain in IBR1 and IBR2; and ~~(iii)~~ converting GFL controllers to grid-forming ones. Finally, the effectiveness of these mitigation methods was validated using EMT simulations. Taking ~~our~~ mitigation method 1 as an example, as shown by the **blue** trace in **Figure 6.~~16~~17**, the simulated frequency ~~does not have~~no longer has obvious 18–20 Hz components ~~any more~~ after adopting method 1, ~~proving~~demonstrating the effectiveness of ~~our~~the proposed method.

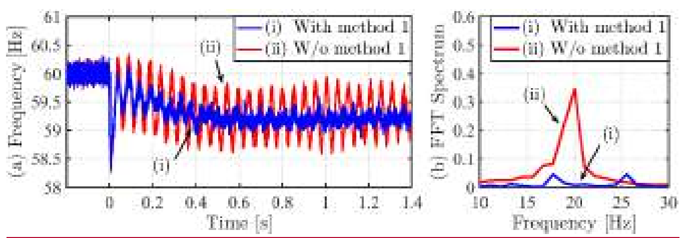

Figure 6.17: (left) Simulated Grid Frequencies Measured at IBR1 with and without Method 1. (right) FFT Analysis Results of Simulated Grid Frequencies.

Transmission System Protection Validation Studies

As the number of IBRs connecting to the North American ~~bulk power system~~BPS continues to rise, transmission system protection engineers are becoming increasingly concerned about the potential impacts on existing industry protocols. Traditional protection methods were established over a century ago when IBR presence was minimal—if not nonexistent—and fault currents were predominantly influenced by the behavior of rotating machinery, particularly synchronous generators. In fact, traditional protection schemes were optimized based on the behavior of synchronous generation to abnormal system conditions and faults. The response of a synchronous generator during a fault event, dictated by the laws of physics, is well understood by protection engineers, who utilize linear circuit analysis techniques incorporating relevant machine impedances and time constants ~~from that era~~which determines the fault current behavior.

~~In contrast, the~~Subtransient and transient impedances from synchronous generation are not directly applicable to IBRs since their impedance profile is mostly determined by the inverter control system. The fault response of an IBR depends on how its ~~inverter~~ control system is programmed to react rapidly to abnormal terminal conditions. ~~While the behavior of synchronous generators is predictable based on established physics, IBR responses vary based on the specific programming of their control systems.~~ This ~~aspect, particularly the~~ rapid ~~adjustments made by the inverter~~

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~~controls to changing terminal conditions,~~response from IBRs remains less understood by protection engineers. Furthermore, there is inconsistency in response between IBRs from different manufacturers.[42]

~~In essence, the current~~The existing protection practices~~,~~ are not designed for systems with ~~minimal IBR presence,~~high penetration of IBRs. Currently, industry practices rely on synchronous generation to provide the operating quantities for relaying. This may prove insufficient as more synchronous generation is retired and IBR penetration grows~~,~~ ~~highlighting~~. This highlights the need for reassessment and potential adjustments in transmission system protection strategies.

Objective

The main objective of the protection system validation study is to verify the validity of existing transmission protection schemes and their settings for systems with high ~~level~~levels of IBR penetration and ~~to~~ make necessary adjustments ~~for protection~~ to settings or ~~implement new schemes that works well~~algorithms to ensure reliable operation with high ~~level~~levels of IBRs. Objectives also include the following:

- Identification of ~~IBR-based power plant interconnection~~ scenarios where transmission system reliability could potentially be compromised by ~~a lack of~~insufficient fault current and/or poorly characterized ~~response~~responses to system faults. These threats to reliability could be in the form of degraded dependability or security of protective relaying schemes ~~or could manifest themselves as failure of the IBR to ride through grid voltage disturbances~~.
- Guidance could be provided to practicing transmission system protection engineers on criteria to evaluate whether further analysis of fault responses is needed in the interconnection study process.

Methodology

Similar to ~~"~~the Dynamic System Impact Assessment Study~~"~~ in ~~Chapter 6.1,~~**Chapter 6**, disturbances will be applied throughout the system. The list of disturbances (as discussed in ~~Chapter 5)~~**Chapter 5**) to be applied will be decided based on the protection relays under study. A general approach is to select contingencies that could result in less contribution from synchronous generators for operating quantities applicable to the relays under study. The relays ~~which~~that are typically affected due to high penetration of IBRs are impedance-based relays (~~i.~~e.g., distance protection, out-of-step protection, negative sequence directional elements~~, etc~~)).[43]~~.~~

~~Model~~

~~The same model which is used for the "Dynamic System Impact Assessment Study" can be used for Protection Systems Validation study as well. In most cases, the aggregated representation of each IBR plant will be sufficient since this study is mainly focused on the protection of the transmission system.~~

~~The accurate representation of instrument transformers (CTs and VTs) is important, especially for scenarios where CTs are prone to saturate during and after disturbances resulting in high voltage conditions.~~

~~**Note:**~~ Ideally, the real code EMT models of transmission system protective devices are also to be included in the EMT model~~. This way,~~ so that a direct indication of the relay operation can be observed (i.e~~.~~., expected, mal/mis operation). ~~But typically~~Typically, however, the real code EMT models of transmission system protective devices are not available (at least to the extent that can be used in a study). In case of unavailability of real code EMT models of

[42] ~~https://www.osti.gov/biblio/1595917~~ https://www.osti.gov/biblio/1595917

[43] ~~https://www.researchgate.net/publication/379952862_Protection_of_100_Inverter-dominated_Power_Systems_with_Grid-Forming_Inverters_and_Protection_Relays_-_Gap_Analysis_and_Expert_Interviews~~https://www.researchgate.net/publication/379952862_Protection_of_100_Inverter-dominated_Power_Systems_with_Grid-Forming_Inverters_and_Protection_Relays_-_Gap_Analysis_and_Expert_Interviews

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protective ~~device~~devices, approximate or generic protection models ~~may~~are not ~~be~~ suitable ~~to perform~~for the protection system studies. This is ~~due to the fact that~~because the relay outputs are highly dependent on the OEM ~~algorithm~~algorithms, filtering, sampling, phasor calculation techniques, and internal settings/thresholds used in the relay. Therefore, voltage and current waveforms will be recorded in certain file formats (typically COMTRADE) and will be played back at the actual relay using real~~-~~-time simulations via hardware~~-~~-in~~-~~-the~~-~~-loop (HIL) tests.

Model

The same system model used for the Dynamic System Impact Assessment Study can be used for the protection systems validation studies as well. In most cases, the aggregated representation of each IBR plant will be sufficient since this study is mainly focused on the protection of the transmission system.

The accurate representation of saturation in instrument transformers (current transformers (CTs) and voltage transformers (VTs)) is important, especially for scenarios in which CTs are prone to saturate during and after disturbances that result in high voltage conditions and sub- and super-synchronous harmonics.

Simulation Quantities to Monitor

Simulation quantities ~~to monitor~~that ~~Simulation quantities which~~ are typically monitored to assess the reliability and security of protection system include the following:

- Operating quantity of the relay (e.g~~.~~., calculated impedance for a distance relay, output of a ~~direction~~directional element)
- Settings of the relay (i.e~~.~~., the characteristic ~~where~~that the operating quantity is compared against~~). ~~); (e.g~~.~~., blinder and mho circle settings for a distance relay)
- Filtered sequence components of voltage and currents
- Instantaneous voltages and currents
- Active power, reactive power, and frequency.
- Trip signals, pickup~~/alarm~~ signals, timer outputs of the relay~~.~~

Note: It is important to use the outputs from the relays as much as possible~~.~~ (i.e~~.~~., if the measured impedance is available as an ~~internal~~ output from the relay, it should be used in the analysis instead of deriving the impedance externally using generic calculations~~.~~).

Processing Results

There may be several hundred pages of simulation results to analyze. The results may be screened by using ~~a~~an automated post-processing method ~~which~~that sets quantitative thresholds that are set conservatively such that only the very~~-~~ well~~-~~-performing results pass. For example, if an expected result is no-trip, neither Pick Up signal nor Trip signal should be observed. This helps the study engineer focus on poor performance, although all ~~results~~result traces should still be reviewed with good engineering ~~judgement~~judgment.

Mitigation

In case of relay ~~mal/mis operation occur~~misoperation or maloperation, it is important to utilize ~~mitigations~~mitigation techniques to resolve the ~~issues~~ observed~~. Some of the commonly~~ issues. Commonly seen mitigation options ~~are~~include the following:

- Apply modifications of relay settings

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- Make changes to relay protection algorithm
- Introduce/modify RAS schemes to avoid conditions where relay ~~mal-operations~~maloperations are observed
- Complete change of the protection relay or scheme (e.g~~.~~., replacing a distance relay with a current differential relay)

Once the mitigation option is selected, it is recommended to re-study the affected scenarios to make sure that there ~~is~~are no additional concerns due to changes made.

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Examples

~~There are documented~~Documented cases of relay ~~mis-operations that have been~~misoperations attributed to lack of, or incorrect, fault current injection from ~~IBR.~~IBRs, are discussed below:

- ~~A~~For a relay ~~mis-operation~~misoperation case documented by BC Hydro~~;~~, a 230 kV ground fault occurred on a transmission line feeding a large wind plant consisting of Type 3 (~~doubly-fed induction generator) wind turbine generators (WTGs).~~DFIG) WTGs. Ground fault protection at each line terminal consisted of negative-sequence voltage-polarized ground overcurrent elements in multi-function microprocessor-based relays. The terminal near the wind plant failed to trip due to the negative-sequence forward directional element failing to assert, caused by an unforeseen angular difference between the negative-sequence voltage and current phasors (demonstration of degraded dependability~~)~~).[44]~~.~~
- ~~Another~~In another relay ~~mis-operation~~misoperation case by BC Hydro, a 138 kV ground fault occurred on a low, short~~-~~-circuit strength portion of the BC Hydro system. The fault location was near a pair of static synchronous compensators (STATCOMs) with a combined ±24 MVAr rating. A Zone 1 ground distance relay at the substation hosting the STATCOMs tripped for an out-of-zone fault, a demonstration of degraded security ~~which was~~ attributed to insufficient negative sequence current injection from the STATCOMs to reliably polarize the ground distance ~~relay'~~relay and prevent false tripping.
- ~~Protection relay mis-operations during ERCOT Odessa Disturbance[45]~~

Summary

In scenarios with high IBR penetration~~ of IBRs~~, unforeseen fault responses may lead to the loss of security in transmission line protective relays. This can occur due to inaccurate impedance or reactance calculations if relay settings are based on the fault responses of synchronous generators and traditional practices. Both the reliability and security of protective relays may suffer as a result. ~~Currently, the industry lacks clear guidance on necessary~~Consequently, modifications to existing protection systems ~~without further investigation. Additionally,~~require additional investigations that include inverter manufacturers ~~are seeking direction on~~and system operators to come up with actionable industry guidance that is based on a common understanding of how ~~to appropriately~~inverters should respond ~~to~~during grid disturbances. Grid code requirements help OEMs to standardized inverter responses but will be difficult to ~~better support the power system during such events~~achieve a level of consistency as in synchronous machines. Validation studies of transmission protection systems pinpoint these issues and assist utilities and OEMs in enhancing their protection settings and schemes to prevent potential relay malfunctions.

~~Validation studies of protection systems pinpoint these issues and assist utilities and original equipment manufacturers (OEMs) in enhancing their protection settings and schemes to prevent potential relay malfunctions.~~

[44] Nagpal, M., Henville, C. (2018). Impact of Power-Electronic Sources on Transmission Line Ground Fault Protection. IEEE Transactions on Power Delivery, 33(1), 62-70.

~~[45] Odessa Disturbance, Texas Events: May 9, 2021 and June 26, 2021 Joint NERC and Texas RE Staff Report, September 2021.~~

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Chapter 7: Additional Guidance on Modeling of IBR Plants

This chapter provides additional guidance on the modeling of both legacy and new IBR plants, HIL validation of IBR unit models, model fidelity for different study use cases, modeling and testing of protection system elements of an IBR plant and guidelines on OEM IBR model integration.

Modeling of Legacy IBR Without Equipment-Specific EMT Model

Many ~~of Inverter Based Resources (~~IBRs~~)~~ were constructed before detailed positive~~-~~-sequence or EMT models were required by TPs and PCs. In addition, the requirements from TPs and PCs for detailed modeling have been evolving ~~and therefore~~, meaning some may have not even existed just a few years ago. ~~In addition~~Finally, some ~~of the~~ inverter manufacturer companies are no longer in business~~. This has posed great challenges~~, making it extremely challenging for ~~Generator Owners (~~GOs~~)~~ to obtain detailed models for ~~such~~their inverters. The term "legacy" has been used to name such resources. Expanding on the previous guideline on EMT modeling, this section provides additional guidance on the modeling of legacy IBR plants ~~are provided in this chapter~~.

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~~While the~~The requirements to provide detailed EMT models for such legacy plants are usually defined by ISOs, but in ~~general, in~~ the absence of equipment~~-~~-specific models in general, generic model components built into simulation software may be used to represent such plants. ~~It should be noted that these~~These generic models, however, have limitations and only provide an unrefined approximation of the actual plant's behavior~~. The~~, meaning that the generic model response should be validated against field measurement. ~~Also, if~~In addition, generic models ~~are~~ being used~~,~~ ~~they~~ should comply with applicable technical specification requirements ~~by~~from TPs and PCs.

~~Field~~As they ensure the accuracy and reliability of the models used to represent older IBRs, field data verification and model quality tests are critical in the modeling of legacy plants. ~~These processes ensure the accuracy and reliability of the models used to represent older IBRs.~~ Validation tests help in identifying and rectifying discrepancies between the ~~model's~~model's predictions and the actual behavior of the plant. This is particularly important for legacy plants, as their original design data might be outdated or unavailable. Field data verification, on the other hand, involves collecting real-time operational data from the plant and using it to validate and fine-tune the model. This step is crucial for understanding how these older plants interact with the modern grid and for making informed decisions about upgrades, maintenance, and integration with newer technologies. Ensuring model accuracy through these tests and verifications is essential for grid stability and efficient operation.

Including a comprehensive set of tests like flat start, POI voltage step changes, ~~High Voltage Ride Through (~~HVRT~~)~~ and ~~Low Voltage Ride Through (~~LVRT~~)~~ for both leading and lagging scenarios, and frequency step changes in both directions~~,~~ is crucial in model quality testing. Additionally, considering both scenarios with and without headroom for frequency ~~step down~~stepdown tests adds depth to the evaluation. Tests like ~~Short Circuit Ratio~~short-circuit ratio and phase angle jump test are also essential. These tests collectively ensure a thorough assessment of the ~~model's~~model's ability to accurately simulate the ~~plant's~~plant's response to a wide range of grid conditions and disturbances, highlighting its reliability and robustness in real-world scenarios.

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~~The objectives of the Field Data Verification Study for Inverter-Based Resource (IBR) models are comprehensive:~~

- ~~**Data Collection and Filtering:** This involves gathering and refining data related to IBR protection, grid, and control parameters, as well as Power Plant Controller (PPC) parameters. This step is crucial for ensuring that the data used in the model is representative of the actual operating conditions of the IBRs.~~
- ~~**EMT Dynamic Model Verification:** The study aims to validate the EMT dynamic models. This includes checking the accuracy of protection systems and renewable generation models to ensure they align with the actual, as-found equipment parameters.~~

- ~~**Compliance with Standards:** The study seeks to ensure that the models meet the requirements set out in the TP/PC Model Verification guidelines. This compliance is essential for the models to be accepted and used in operational planning and grid stability assessments.~~

~~Overall, the study's goals are geared toward ensuring that the IBR models are reasonably accurate, given the lack of equipment-specific models, reliable, and compliant with industry standards, thereby enhancing grid stability and operational efficiency.~~

~~Modeling of Legacy Wind Power Plant~~

"Generic" EMT models have also been developed over the years to produce standardized ~~Wind Turbine Generators~~WTGs and WTG plant models. In the ~~US~~United States and Europe, these efforts have been led by the Western Electricity Coordinating Council (WECC) and the IEC, respectively.[46]~~.~~ The focus has been put on developing WTG models that can conduct typical ~~transient stability~~TS studies, including specific controllers like those in IBRs to test the expected performance of WTGs as an individual WTG or as an aggregate representation of a ~~Wind Power Plant.~~ wind power plant. Models have been developed for WTG ~~types~~Types 1, 2, and 3, including mass turbine and generator inertia, for use in both positive~~-~~-sequence and EMT simulation tools.

In short, a detailed model is equipped with the following control systems:

~~1.~~• Plant-level outer control loops for voltage and reactive power~~.~~

~~2.~~• Unit~~-~~-level voltage and current inner control loops. This would include the PLL dynamics for electronic equipment and ride-through models~~.~~

~~3.~~• Outer control loop for dispatching active power~~.~~

~~4.~~• Outer control loop for frequency response~~.~~

For legacy plants, the idea of using generic models is valid if the model represents the above control system features and is validated against field measurement. Among the above control system features, the PLL configuration might be the most difficult ~~one~~ to mimic in a generic model.

~~In addition, many~~Many of the control features and behavior of legacy plants can be verified by using staged tests at the inverter and plant levels. Small~~-~~-signal disturbances, such as voltage and frequency steps, can be implemented at the plant level. The obtained test results can be utilized to examine the validity of developed generic models. Furthermore, the generic EMT model can be benchmarked against positive~~-~~-sequence models.

Ultimately, the usability of a generic EMT model for a legacy plant depends on ~~various~~ factors~~, such as~~ like plant location, system strength, ~~size of the~~ plant size, and the type of studies ~~that Transmission Planner~~for which the TP needs this generic model ~~for~~. For example, in large~~-~~-area grid studies and in the case of ~~having~~ a legacy plant with Type 1 wind turbines, only the electrical characteristics of the machine are important, and detailed control features of the machine do not need to be modeled in EMT software. Therefore, generic models are acceptable if the model can provide ~~a~~ good electrical approximation of the machines.

~~Additionally,~~ GOs might be able to obtain a ~~detailed model,~~ vendor-specific~~,~~ detailed model for similar inverters from the same OEM.

~~Some~~**Appendix A** provides examples of legacy IBR plant modeling ~~are provided in **Appendix A**.~~.

[46] ~~https://www.esig.energy/wiki-main-page/generic-models-individual-turbines/~~ https://www.esig.energy/wiki-main-page/generic-models-individual-turbines/

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~~Hardware in the Loop (HIL)~~ Validation of ~~Existing~~Legacy IBR ~~Plant~~ Models with Field Measurements

~~It is well-known that~~ There are limitations with generic EMT IBR models ~~are insufficient in being able~~ to represent all the nuanced behaviors of controls and protection elements. While OEM's might not be involved in the design of the balance of plant facilities, GOs and their model developers should coordinate to accurately develop models that capture plant behavior accurately along with OEM inputs. Whenever available, vendor-specific OEM models are best suited to closely model ~~the~~ real-world plant behaviors ~~and would be essential in performing accurate model validation.~~. However, ~~when we are looking at an existing, legacy IBR plant,~~ if vendor-specific OEM models do not exist, ~~then~~an existing legacy IBR plant could be represented with a generic models ~~could be used with these parameters to model~~that have been parameterized to reflect the plant based on available documentation~~. Also, models~~ and field measurements. Models of similar plants with similar ~~rating~~ratings and control functions could also possibly be adapted to represent such legacy plants as a close alternative. If disturbance events are recorded in the field, this data can be used to validate the model response under the same conditions. For example, when the actual controller of the wind turbine is equipped with an auxiliary input, test signals can be injected to test a variety of wind conditions.[47]~~.~~ This way, a large amount of field results can be acquired to compare with the model response in the same test scenarios. ~~A~~ Another published example of HIL validation includes a study where a generic ~~EMT-based~~ wind turbine model is tuned and validated against the field tests of a real wind turbine through a short-circuit container[48], which allows for applying different faults with different voltage dips at the turbine terminals[~~49~~][~~50~~]~~. At the system level, the metering at the utility-scaled DER, large load and station terminals have enough information to verify the complex models that represent aggregated DERs~~[~~51~~]~~. The uncertainty of the verification with disturbance recording lies in the fact that there are some unknown variables such as the network configuration, the operating conditions of other plants and nearby loads, as well as the equivalent system impedance. The comparison is also based on the assumption that the DER plant models are parameterized correctly to represent the actual plant's characteristics and ride-through settings. Therefore, engineering judgement is required to determine whether the model response is reasonably comparable.~~.[52,53]

If no detailed description of the legacy plant is available, parameter estimation of a generic controller model is a potential approach to obtain the approximate parameters. The damped least square method can be used to identify the control parameters for the outer power control loop and the inner current control loop through step changes in the power setpoints.[54]~~.~~ Similarly, wide-area monitoring data can be leveraged to identify the dominant control

[47] Clark, Kara, Nicholas W. Miller, and Juan J. Sanchez-Gasca. ~~"~~"Modeling of GE wind turbine-generators for grid studies~~."~~." GE energy 4 (2010): 0885-8950.

[48] A short-circuit container is a test setup with variable reactances and appropriate switchgear to apply different types and depths of faults.

~~[49] A. S. Trevisan, A. A. El-Deib, R. Gagnon, J. Mahseredjian and M. Fecteau, "Field Validated Generic EMT-Type Model of a Full Converter Wind Turbine Based on a Gearless Externally Excited Synchronous Generator," in IEEE Transactions on Power Delivery, vol. 33, no. 5, pp. 2284-2293, Oct. 2018, doi: 10.1109/TPWRD.2018.2850848.~~

~~[50] Langlois, Charles-Eric, Mohamed Asmine, Markus Fischer, and Stephan Adloff. "On-site under voltage ride through performance tests—Assessment of ENERCON wind energy converters based on Hydro-Québec transénergie requirements." In 2012 IEEE Power and Energy Society General Meeting, pp. 1-8. IEEE, 2012.~~

~~[51] Y. Wang, C. Lu, L. Zhu, G. Zhang, X. Li and Y. Chen, "Comprehensive modeling and parameter identification of wind farms based on wide-area measurement systems," in Journal of Modern Power Systems and Clean Energy, vol. 4, no. 3, pp. 383-393, July 2016, doi: 10.1007/s40565-016-0208-5.~~

[52] A. S. Trevisan, A. A. El-Deib, R. Gagnon, J. Mahseredjian and M. Fecteau, "Field Validated Generic EMT-Type Model of a Full Converter Wind Turbine Based on a Gearless Externally Excited Synchronous Generator," in IEEE Transactions on Power Delivery, vol. 33, no. 5, pp. 2284-2293, Oct. 2018, doi: 10.1109/TPWRD.2018.2850848.

[53] Langlois, Charles-Eric, Mohamed Asmine, Markus Fischer, and Stephan Adloff. "On-site under voltage ride through performance tests—Assessment of ENERCON wind energy converters based on Hydro-Québec transénergie requirements." In 2012 IEEE Power and Energy Society General Meeting, pp. 1-8. IEEE, 2012.

[54] NREC, Reliability Guideline Model Verification of Aggregate DER Models used in Planning Studies, March 2021

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parameters to represent a DFIG wind farm with improved genetic algorithms.[55]~~.~~ In general~~, it is to be noted that even with these kind of validation tests~~, it would be very important to identify the fundamental frequency equivalent series impedance of the network~~, which~~ that would be ~~very important~~essential to calculate and take into account before any parameter estimation algorithm is applied. Furthermore, such an approach might work only for small~~-~~-signal disturbances or may require a thorough test plan to make the parameter estimation of each control and protection function ~~to~~match different disturbances, such as load dips/rejection~~,~~ and step responses.

The objectives of the validation of IBR models with field data are comprehensive:

- **Data Collection and Filtering**: This involves gathering and refining data related to IBR protection, grid, and control parameters as well as PPC parameters. This step is crucial for ensuring that the data used in the model is representative of the actual operating conditions of the IBRs.
- **EMT Dynamic Model Verification**: This aims to validate the EMT dynamic models. This includes checking the accuracy of protection systems and renewable generation models to ensure that they align with the actual, as-found equipment parameters.
- **Compliance with Standards**: This seeks to ensure that the models meet the requirements set out in the TP/PC Model Verification guidelines. This compliance is essential for the models to be accepted and used in operational planning and grid-stability assessments.

Overall, the goals of the model validation are geared toward ensuring that the IBR models are reasonably accurate (given the lack of equipment-specific models), reliable, and compliant with industry standards, thereby enhancing grid stability and operational efficiency.

HIL Validation of New IBR Models

One of the main requirements from TPs and PCs from the perspective of model validation should be the benchmarking of an EMT model against actual field equipment. Validation tests can be achieved with ~~Hardware-In-the-Loop (~~HIL~~)~~ tests or with Factory Acceptance Testing (FAT~~-tests~~) results (e.g. functional and performance tests) when field tests are not available~~ [Cite IEEE P2004].~~[56]. To validate the plant controller model, the remaining components of the IBR plant can be simulated in an EMT model and executed on a real-time simulator as in a typical ~~Controller-Hardware~~controller-hardware-in-the-~~Loop~~loop (CHIL) setup as shown in ~~Figure 1.~~**Figure 7.1**. A hardware control unit would be connected to the simulator as if it was connected to the actual plant. Measurement signals ~~such as~~(e.g., active, reactive ~~powers and~~power, RMS voltages, ~~as well as~~ binary signals ~~such as~~like breaker status~~,~~) would be ~~measured~~accounted for in the model and transferred to the controller through wired connections or communication protocols. Secondary instantaneous voltages and currents can also be interfaced if necessary. In the other direction, power setpoints and control commands can be sent back to the simulated model and the changes would be applied to the simulated plant in real~~-~~ time. Different contingencies could be performed in the model to record the controller response. These recordings can then be the references to compare with the plant controller model. Through such tests, the impact of the delay introduced by communication or signal filtering can be assessed and then considered in the equivalent model.

[55] M. Kong, D. Sun, J. He and H. Nian, ~~"~~"Control Parameter Identification in Grid-side Converter of Directly Driven Wind Turbine Systems~~,"~~," 2020 12th IEEE PES Asia-Pacific Power and Energy Engineering Conference (APPEEC), Nanjing, China, 2020, pp. 1~~-~~–5, doi: 10.1109/APPEEC48164.2020.9220436.

[56] IEEE Standards Association (IEEE SA), "P2004 – Recommended Practice on Hardware-in-the-Loop (HIL) Simulation Based Testing of Electric Power Apparatus and Controls," URL: https://standards.ieee.org/ieee/2004/11300/

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The ~~power plant controller~~ PPC for a ~~Battery Energy Storage System (~~BESS~~)~~ plant was validated against a commercially available PPC running on a General Electric (GE) PLC through HIL tests.[57]~~.~~ Different real power and reactive power control loops as well as capacitor bank control were validated.

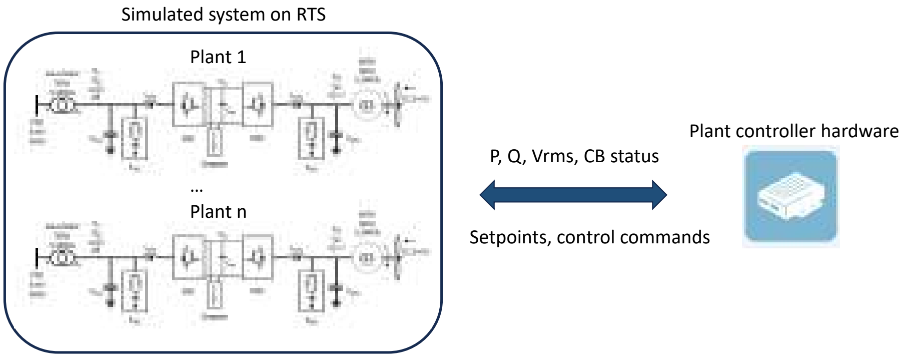

Figure 7.1: CHIL ~~set up~~Setup for ~~power plant controller validation~~Power Plant Controller Validation

To go one step further, ~~Power-Hardware-In~~power-hardware-in-the-~~Loop~~loop (PHIL) tests would allow ~~for utilizing~~the utilization of actual electrical hardware components in the validation setup, which would potentially eliminate the uncertainties from the simulation of specific hardware components. The key difference between PHIL and CHIL is that PHIL would create a virtual power interface between the simulated system and the hardware devices. Therefore, the device under test can be electric components, such as power converters, batteries with a management system, electric machines, and drives ~~and so on~~ as shown in ~~Figure 2.~~**Figure 7.2**. For example, ~~if we considered~~when considering a small-scale PV system inverter and its controller being part of the hardware setup, the dynamics of their equivalents in the EMT model can be compared and validated through different disturbances. One caveat ~~here though~~, however, is that at this point, PHIL amplifiers that exist on the market are only available in a limited range of powers and voltages. ~~Further~~Furthermore, PHIL is still a more expensive solution than CHIL. However, continuous research and development is ongoing to build power amplifiers suitable for higher power ranges. The PHIL Simulator ~~(SimP)~~ project at the Hydro ~~Quebec~~Québec Research Institute[58] aims to design a 7.~~5MW~~5 MW power amplifier to connect a real 25 kV distribution network to a transmission system simulated on a real-time simulator as shown in ~~Figure 2.~~**Figure 7.2**. Similarly, some research labs ~~within~~in the ~~US~~United States also have medium-voltage, controlled grid interfaces to support high-powered PHIL experiments for HIL validation studies. The proliferation of such setups would allow for easier PHIL integration to study and integrate distributed energy resources, smart grids, and microgrids.

[57] V. Lakshminarayanan, C. Patabandi, O. Nayak and B. Lopez, ~~"~~“HIL Validation of Power Plant Controller Model~~,"~~,” 2022 North American Power Symposium (NAPS), Salt Lake City, UT, USA, 2022, pp. 1-6, doi: 10.1109/NAPS56150.2022.10012177.

[58] K. SLIMANI, R. GAGNON, D. RIMOROV, O. T REMBLAY, B. LAPOINTE, “IREQ PHIL Simulator Project Update: Power Amplifier Design,” 6th International Workshop on Grid Simulator Testing Of Wind Turbine Power Trains And Other Renewable Technologies, Nov. 2022.

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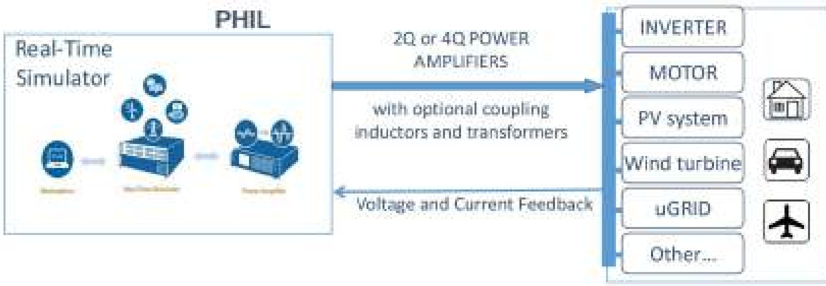

Figure 7.2: PHIL ~~setup~~Setup to ~~interface electric components~~Interface Electric Components

Another example is ~~where~~ an EMT model of a GE DFIG wind turbine unit ~~is~~being validated against the actual hardware test data in the lab[59]~~.~~ using the test facilities as shown in **Figure 7.3**.[60] A 20 MVA cascaded H-bridge converter-based programmable voltage source was used to simulate the grid. The full-scale electrical hardware, including the transformer, the turbine, and the converter control, was configured in the lab. Voltage ride-through tests and phase jump tests at different short~~-~~-circuit ratios were performed to consider the variation in system strength. ~~Sub-synchronous~~Subsynchronous impedance characteristics were also analyzed with a frequency scan to validate the fidelity of the model under small~~-~~-signal disturbances.

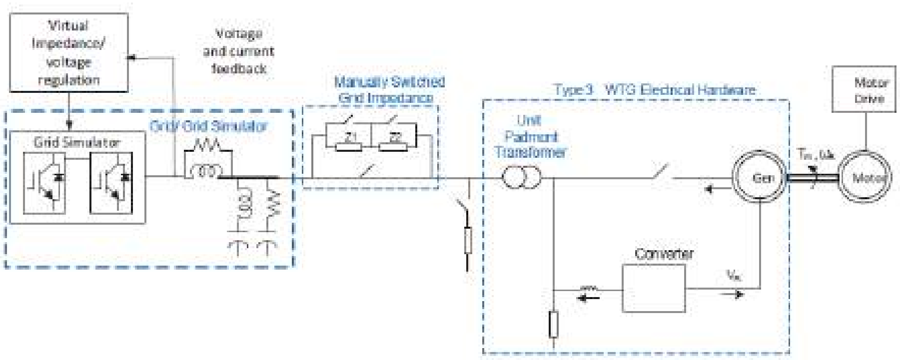

Figure 7.3: Schematic ~~diagram~~Diagram of the GE ~~lab test facilities~~Lab Test Facilities

~~[59] A. Kazemi, J. Kaur, F. Ramirez, D. Gautam, M. Lwin and A. Ridenour, "EMT Model Validation of DFIG Wind Turbine Using Full-Scale Electrical System Lab Tests and Lessons Learned," 2023 IEEE Power & Energy Society General Meeting (PESGM), Orlando, FL, USA, 2023, pp. 1-5, doi: 10.1109/PESGM52003.2023.10253152~~

[60] A. Kazemi, J. Kaur, F. Ramirez, D. Gautam, M. Lwin and A. Ridenour, "EMT Model Validation of DFIG Wind Turbine Using Full-Scale Electrical System Lab Tests and Lessons Learned," 2023 IEEE Power & Energy Society General Meeting (PESGM), Orlando, FL, USA, 2023, pp. 1–5, doi: 10.1109/PESGM52003.2023.10253152

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A Spectrum of Model Fidelity for Different Study Use Cases

Depending on the study use cases, EMT models of varying fidelity may be best suited to balance between accuracy and efficiency. This section provides an overview of such a spectrum of model fidelity as applied to inverter electrical model, inverter controls and protection models, ~~power plant controller~~PPC models, and the overall plant models.

Inverter Control Models

Depending on the desired level of ~~details at~~detail for different ~~regions~~areas in the study case, the following ~~different~~ types of EMT models for inverter controls can offer a balance between accuracy and efficiency. TPs and PCs may consider requiring one or more, in addition to real code models as the minimum requirement.

- **Real Code** ~~model (Most~~**Model** (most precise model~~)~~:)
  - Exact replica with all protections included (including all IBGT blocking protections)
  - ~~It may~~May be validated with all validations proposed for EMT models in IEEE2800~~.~~
  - ~~It is intended~~Intended to be used as a reference or inside the study area, close to perturbation~~.~~
  - ~~It usually~~Usually has ~~time-step~~timestep constraints and may be a large computation burden~~.~~

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- **Simplified** ~~model:~~ **Model**
  - Model with simplifications allowing to simulate with larger ~~time-steps~~timesteps, up to 100/200us. May be derived from a phasor-domain model~~.~~
  - Validated for small voltage or frequency perturbations and for step-changes (for the same validations a phasor-domain model goes through)
  - ~~For example, it may~~May be modeled~~,~~, for example, using a ~~WECC control scheme (~~controlled current source~~).~~
  - Such a model may be used to represent IBRs located far away from perturbation~~.~~
  - Warning mechanisms may be implemented when ~~it~~the model is being simulated outside of its range of validation~~.~~

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- **Relaxed Real Code** ~~model:~~**Model**
  - May use the same code as the true replica with some functions disabled, such as protections based on instantaneous quantities and control loops with dynamics faster than ~~250Hz.~~ 250 Hz
  - This model may be used for some studies when the ~~True~~true replica model suffers from tripping or malfunction due to its collector aggregation~~.~~
  - Warning mechanisms may be implemented when ~~it~~the model is being simulated outside of its range of validation~~.~~
  - ~~It may~~May be simulated with a ~~time-step~~timestep slightly larger than the ~~True Replica.~~true replica

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~~Similar~~A similar modeling philosophy can be applied to power ~~plant controllers~~PPCs.

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Inverter Electrical Models

~~Refer to~~Inverter electrical models are discussed in the previous EMT guideline on switching model vs. average converter model.[61]

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

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Overall Plant Models

There are generally three approaches to modeling an IBR plant. This section ~~presents more~~further details ~~on~~ these modeling approaches and their recommended uses.

- **Non-~~aggregated~~Aggregated Models (Inverter-Level Models or Detailed Plant Models):**[62]~~):~~ These models represent the entirety of the plant in full detail~~,~~ down to the individual inverter level, capturing each ~~device's~~device's characteristics and their interconnections. These models are particularly important for ride-through studies in wind power plants where there is a significant voltage difference among turbines dispersed throughout the plant. However, a primary drawback of these models is their increasing computational burden as the number of turbines rises. ~~As mentioned earlier, detailed~~Detailed models are recommended ~~for conducting~~ to be used by GOs to ensure the plant is designed to meet performance and ride-through ~~verifications~~requirements and ~~assessing~~do not contribute to differential-mode circulating oscillations~~.~~; TPs and PCs are recommended to use those detailed models to verify the plant ride-through behavior and required performance.

- **Semi-~~aggregated~~Aggregated Models**: In cases where the number of inverters becomes impractical for simulation[63]~~,~~ and when they are geographically close~~, such as~~ (e.g., in solar or ~~Battery Energy Storage Systems (~~BESS~~)~~ plants~~,~~), semi-aggregated collector-level models can be employed. When semi-aggregated models are used, the study engineer should ensure that at least two inverters are present in the model to reveal oscillations between parallel IBRs~~, ~~ (i.e., circulating oscillations or differential mode oscillation). Another application for semi-aggregated models is to represent a single site including multiple different OEM facilities and/or hybrids of wind or solar and BESS.

- **Aggregated Models (Plant-Level Models)**: In these models, the entirety of the plant is consolidated as a single-machine single-collector equivalent model, offering a more efficient way to simulate a large number of IBRs. These models are typically used today for conducting system impact studies for stability and ride-through assessment.

More details on these modeling approaches and recommended uses are presented in **Appendix B**.

Modeling and Testing of Protection System Elements of an IBR Plant

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Application of EMT modeling in ~~Power System Protection~~ power system protection has been ~~increased~~increasing in recent years. EMT simulation results can ~~assist~~give protection engineers ~~to have~~ better insight ~~regarding steady-state fundamental frequency~~into dynamic behavior of loads or harmonics ~~which~~that can cause issues for protection systems for any applications. In addition, the traditional RMS power flow and short-circuit simulation tools assume that the system is balanced. There are various unbalanced conditions in power system studies. Furthermore, the EMT tools provide insights ~~on~~into frequencies other than fundamental. This information is valuable for ~~harmonic rejections in~~ studying the impact of harmonics on the relay operation and inverter protection. As the protective relays~~.~~ and inverter protection must operate in transient conditions, EMT tools can provide more insights over conventional short-circuit simulation software.

~~Furthermore, EMT tools are very powerful for transient applications. The protective relays must operate in transient conditions and therefore EMT tools can be utilized over conventional short-circuit simulation software.~~

~~The~~ Protection elements within IBRs are subject to ~~the~~various NERC Reliability Standards, such as PRC-019, PRC-024-3[64], PRC-025-2~~,~~ and PRC-027-1. ~~In addition, the inverter~~ Inverter controls and protection ~~need to~~should be

[62] These types of plant models were previously described as "detailed plant model" in the previous ~~Reliability Guideline~~reliability guideline on EMT Model Requirements and Verification. Updated term is used here to align with IEEE 2800.2.

[63] See Chapter 9 for leveraging parallel computing to accelerate simulation of a detailed wind farm model.

[64] Updates to PRC-024 and a new PRC-029 for IBRs are forthcoming.

coordinated with other forms of protection elements within the ~~overall~~IBR plant. The IBRs have several protection elements~~ in their protection system. Few of these elements are~~, both at the inverter level and the plant level, including those listed below:

- Inverter ~~protection~~Protection functions~~:~~[65]
  - ac and dc overcurrent protection~~.~~
  - dc undervoltage protection~~.~~
  - Under/~~Over~~over frequency protection~~.~~
  - Under/~~Over voltage~~overvoltage protection~~.~~
  - ac ground fault protection~~.~~
  - ~~dc undervoltage~~Anti-islanding (phase jump) protection~~ for BESS~~
- Inverter ~~transformer~~Transformer Protection (e.g., differential protection~~.~~)
- Collector ~~system~~System Protection [66] (e.g., over current and over voltage protection~~.~~)
- Substation~~ and ~~/Main Power Transformer Protection~~.~~
- Main ~~line~~Plant Interconnection Line (gen-tie) and ~~breaker protection~~Breaker Protection

The inverter protection functions for these resources can ~~often ~~use ~~phase-based~~instantaneous quantities (per phase point on wave measurements) instead of positive~~-~~-sequence values. In this case, the positive~~-~~-sequence dynamic simulation tools might not capture the behavior of inverters during the fault. In addition, ~~in some cases ~~the simulated fault clearing time may be ~~passed~~exceed the inverter ride-through capability ~~of the inverters.~~in some cases. Therefore, EMT simulation tools might be needed to fully capture the dynamic behavior of the ~~inverters~~protection schemes relative to inverter capabilities.

GOs can utilize EMT tools ~~can be utilized in evaluation protection settings of IBRs. One of its applications is in NERC PRC-024-3 and examines over and under voltage settings of inverters. Attachment 2 of PRC-024-3 outlines how to evaluate protection settings. Basically, 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 100kV and a high side 100kV 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.~~

~~The EMT tool can be utilized ~~to build the detailed ~~power flow~~non-aggregate model of an IBR~~.~~ plant, representing the full collector system and individual inverters. The inverter model and associated protection elements should come from ~~Original Equipment Manufacturer (~~the OEM~~)~~.. After the site-specific model is built in an EMT tool,~~ then~~ various grid conditions can be simulated to determine ~~if ~~the plant voltage and frequency ride~~-~~-through performance compliance with the upcoming NERC PRC-~~024-3~~029.

Another critical aspect is the consideration of model simplifications and assumptions made in ~~Electromagnetic Transient (EMT)~~EMT models. It is important to acknowledge that EMT models are not inherently accurate~~. The~~, as the accuracy of each model depends on the model development process, its fidelity to the actual product behavior, and the simplifications made during model development. ~~There are multiple~~Multiple protection systems are typically

[65] Inverter protection functions refer to those embedded within the inverter control system. For more details, see Reliability Guideline: EMT Modeling for BPS-Connected IBRs – Recommended Model Requirements and Verification Practices, March 2023.
[66] *Odessa Disturbance, Texas Events: May 9, 2021, and June 26, 2021, Joint NERC and Texas RE Staff Report*, September 2021.

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studied within the simulation domain, which can sometimes lead analysts to draw incorrect conclusions due to false positives in the simulation. A recent and common scenario involves the multiple fault ride-through (MFRT) requirements introduced in IEEE 2800-2022. The limitations of MFRT in IBRs primarily hinge on two factors: thermal and mechanical constraints. While mechanical constraints might be applicable to Type 3 ~~Wind Turbine Generator (~~WTG~~) technologies and older~~, thermal constraints are relevant to all IBRs. However, most ~~Original Equipment Manufacturers (~~OEMs~~)~~ do not ~~include a~~represent detailed thermal ~~model~~characteristics of the power electronics in their EMT simulations. Therefore, any conclusions regarding multiple fault ride-through capabilities derived from an EMT model that lacks thermal modeling may be fundamentally flawed.

A similar situation occurs with ~~Rate of Change of Frequency (ROCOF)~~RoCoF studies, also recently included in IEEE 2800. Most modern converters can handle much higher ~~ROCOF~~RoCoF levels than those specified in the standard. ~~Especially in Type 4 machines, converters typically do not have ROCOF protection per se; rather, the~~The converters monitor the frequency through the ~~Phase-Locked Loop (~~PLL~~)~~ code and trip only when the frequency or RoCoF exceeds the normal operating range. However, a critical vulnerability in relation to ~~ROCOF~~RoCoF for wind turbines lies with their auxiliary services. These components are often not adequately modeled or even included in EMT simulations. Consequently, just like with MFRT, ~~ROCOF~~RoCoF studies may lead to misleading conclusions and false positives.

In conclusion, the effectiveness of EMT models in simulating real-world phenomena like MFRT and ~~ROCOF~~RoCoF in wind turbines heavily relies on the accuracy and comprehensiveness of the models used. The omission of critical elements like thermal and auxiliary system behaviors can lead to significant discrepancies between simulated outcomes and actual field performance. Therefore, it is crucial for analysts and engineers to critically evaluate the assumptions and limitations inherent in their simulation models. This awareness is essential for making informed decisions and ensuring that conclusions drawn from EMT studies align closely with operational realities, ultimately leading to more reliable and robust wind turbine designs and grid integration strategies.

Validation of Equipment~~-~~-Specific IBR Unit Models ~~from~~Provided by OEMs

Typically, IBR ~~plant~~unit models that are provided by OEMs are black-boxed due to intellectual property concerns. Such black-boxed models abstract the exact mechanics of the underlying control schemes and protection mechanisms while ensuring some level of compliance ~~to~~with expected performance requirements. While some ~~of these models~~ are black-boxed models that are developed and compiled in specific simulation tools,~~ some~~ others encapsulate actual code that is used in actual controllers that are deployed on OEM hardware. Despite ~~such black-boxed models offering~~their limited ~~insights into specific plant behaviors~~transparency, one of the major advantages ~~in having them~~ of using OEM-specific, verified accurate models is ~~to be able to replicate real-world behavior as closely as possible.~~the accurate representation of the actual device. When it comes to validating the EMT model quality of ~~OEM provided~~equipment-specific IBR ~~plant~~unit models, the following considerations are essential.

First, ~~OEMs~~TPs and PCs should ~~be required~~require GOs (in turn, OEMs) to provide detailed validation reports of the IBR ~~plant~~unit performance with SMIB tests under a range of different SCR ratios and operating conditions, preferably with comparisons to field tests or HIL testing. ~~Along with this, a comparison~~Benchmarking with an equivalent RMS model should also be required. Second, GOs (and in turn OEMs) should be required to provide test results for a wide range of test case scenarios that include a flat-run scenario, scenarios with voltage and frequency disturbances, scenarios with various types of balanced and unbalanced faults, voltage ride-through tests, system strength tests~~,~~ and phase jump tests~~, and sub-synchronous tests [9]~~. Additional test case scenarios considering operating conditions at reduced energy inputs and at minimum system ~~Short Circuit Ratios~~short-circuit ratios should also be required~~ [10].~~.

While a validated OEM~~-~~-provided, site-specific, and black-boxed model provides the closest match with real-world behavior, an associated drawback is that they often come with practical challenges in terms of integration with EMT simulation tools. Some of these issues, such as inconsistent modeling practices~~,~~ and compiler dependencies, ~~etc.,~~

hinder the ability ~~for~~of TPs and PCs to utilize them across a broad range of EMT-based integration and planning studies. To this end, appropriate guidelines need to be established and communicated to GOs (and in turn, OEMs) by the TPs and PCs while requesting models. The following section provides ~~some~~ guidelines to standardize OEM-specific black-box IBR model integration.

Guidelines on ~~OEM~~Equipment-Specific IBR ~~model integration~~Model Integration for GOs

Consistency ~~of black-boxing control~~oof Black-Boxing Control and ~~electrical components: Currently, there~~Electrical Components

There is currently no consistent practice among ~~various~~ OEMs in terms of which functional blocks associated with an IBR plant model are encapsulated inside their black-boxed models. For example, in some OEM models, only the controllers are pre-compiled and associated electrical components of the IBR plant are modeled using the native library components from the EMT simulation software used to provide the model. ~~Whereas, in~~In other cases, the converters and other electrical components are included in the black~~-~~ boxes along with the controls. From a user perspective, if TPs and PCs ~~plan to~~ utilize an EMT simulation tool ~~other than~~different from the one GO and OEMs have provided the model for, such inconsistencies complicate integration and limit model portability across tools. ~~Further~~Furthermore, this variance in black-boxing components contributes to potential issues when the software versions of the EMT tool are updated as well.

~~TPs and PCs~~Equipment-specific models should ~~recommend OEMs to~~ follow standardized~~,~~ and existing guidelines, such as ~~the guideline from~~ CIGRE WG B4.82, when preparing these black-box models to facilitate their interoperability across different simulation platforms. ~~Further~~Furthermore, OEM~~-~~-provided black-box models ~~often~~should not require specific versions of compilers and operating systems that ~~introduces~~introduce additional complexity when moving across versions of the same EMT tool or across different tools. To minimize such issues, ~~TPs and PCs should establish standardized, clear~~EMT modeling requirements ~~to ensure support~~should encourage model interoperability across ~~commonly used~~different platforms.

Support for a ~~range~~Range of ~~time-steps: Currently, OEMs define their own time-steps for their controller~~Timesteps

Equipment-specific models from some OEMs currently require a specific timesteps, which may be different, in some cases ~~are different,~~ from the ~~time-step of the system level EMT~~ simulation ~~model.~~timestep chosen by study engineers for dynamic system studies. Furthermore, some of the ~~OEM provided~~equipment specific models perform well only at specified ~~time-steps~~timesteps and ~~have~~suffer from accuracy or numerical stability issues at other ~~time-steps. TPs and PCs~~timesteps. EMT modeling requirements should ensure that ~~OEM provided~~the models not only operate at specified ~~time-steps,~~timesteps but also support a broader range of values commonly supported by EMT simulation tools considering both small-scale, plant-oriented studies and large-scale system level stability analysis.

Optimizing ~~computational performance: The~~ Computational Performance

In specific cases, the computational performance of the ~~OEM~~equipment-specific models is ~~another aspect to consider. On the electrical modeling side, whether detailed switching model or average voltage source model shall be used needs to be determined based on~~a key factor in determining the ~~intended use case for the IBR plant model.~~overall simulation speed. If simulation speed is a bottleneck to adopt large-scale EMT simulation, modeling techniques, such as switching function models~~-~~[67] or average voltage source model should be considered in favor of detailed switching~~-~~-level inverter models to find a suitable compromise between simulation accuracy and speed according to the scale of the system model being studied using EMT simulations.

[67] S. Fazeli, et al, "Switching Functions Models of a Three-phase Voltage Source Converter (VSC)", Journal of Power Electronics, Vol. 17, No. 2, pp. 422-431, March 2017

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Typically, simulation performance is not optimized when the controller code is generated for pre-compiled ~~OEM~~equipment-specific black-box models. Computational speed or performance of black-box controller code might not be a concern when the code is deployed on an industrial controller because of the associated sampling rate of the signals. However, in an EMT simulation that is executing at ~~time-steps~~timesteps in the order of 10~~ – ~~–50 microseconds, having a non-optimized set of controller codes can introduce a huge computational bottleneck as they are often the limiting factor. This could be mitigated by ensuring that developers of OEM~~-~~-provided black-box code work ~~together~~closely with EMT simulation tools~~ closely~~.

~~provided black-box controllers: Initialization~~Initialization of OEM Provided Black-Box Controllers

The initialization of black-box controllers is another area that needs attention and ~~could be improved~~improvement. Typically, the electrical components in an EMT model can be initialized by applying initial voltages and currents from the load flow results. However, the initial states inside the black-box controllers are not easily accessible by users. IBR black-box controllers are initialized at the start of every simulation run with a slow ramp-up with a voltage source in parallel and then switching over after the initialization matches the voltage source used. If ~~we were to assume~~assuming an average simulation time of ~~30s~~30 seconds, this current practice would require stopping and restarting the simulation with reinitialization from zero for every scenario when running a large set of scenarios. However, it would be very beneficial ~~if we are~~to be able to initialize OEM black-box controllers, ~~then we can accelerate~~thereby allowing the acceleration of multi-scenario tests efficiently by reinitializing the simulation to a steady-state snapshot every time. TPs and PCs should work together with OEM, GOs, developers and industry working groups/task forces, such as CIGRE WG B4.82 to standardize initialization to reduce total simulation time across scenarios.

Documentation ~~guidelines:~~ Guidelines

TPs and PCs should require GOs (in turn, OEMs) to deliver models with detailed documentation as much as possible. In the pre-compiled, black-box code, comprehensive error messages should be configured to provide information to the users whenever any exceptions are encountered. In addition to the models being managed appropriately with version tracking and continuous integration over time as updates happen, it is essential that the associated model documentation and test reports also get updated by leveraging automated scripting across a set of standard test scenarios.

Importance of Measurement Models

Both inverter~~-~~-level controls and plant~~-~~-level controls utilize electrical measurements, such as instantaneous voltage and current, RMS voltage and current, active and reactive power, and frequency. Care should be taken when a model is expecting a measurement input~~,~~ and a corresponding meter model ~~was~~has not been supplied by an OEM. The response of a control system depends on the quality of the input signal. Using measurements from standard library meter models ~~can~~may introduce inaccuracy. Special consideration should be given to frequency measurement as ~~those calculated by~~internal algorithms of some standard library meter models could be susceptible to phase angle shifts ~~producing~~which can cause artificial spikes ~~(see~~as shown in **Figure 7.4**~~ for example)~~. Similar attention should be paid to RMS quantities and parameters that could affect them, such as filter time constant or calculation methods. TPs and PCs reviewing the EMT models should look out for the use of such standard library components and question their accuracy.

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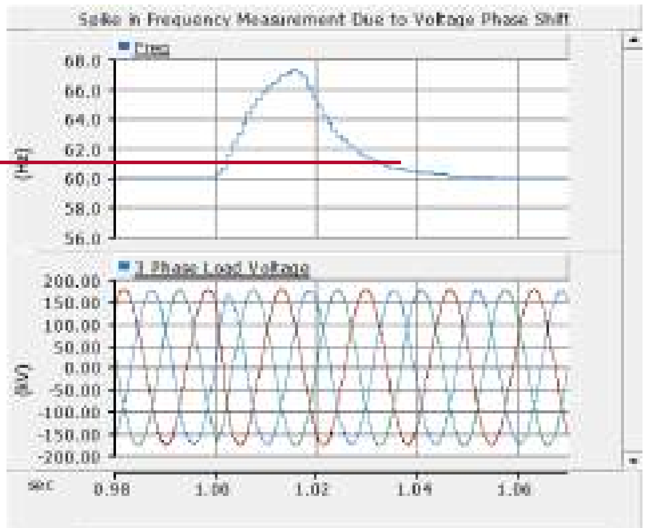

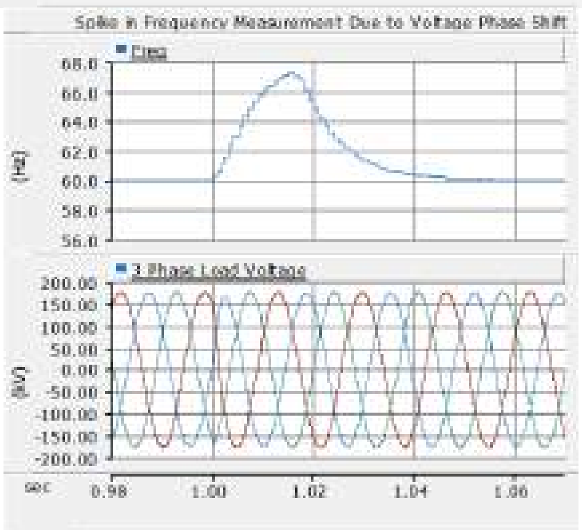

Figure 7.4: Spike in ~~standard library frequency measurement due~~Standard Library Frequency Measurement Due to ~~voltage phase shift~~Voltage Phase Shift

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Chapter 8: Accelerating EMT Simulations

~~Electromagnetic Transient (~~EMT~~)~~ simulation studies were originally ~~utilized for studying~~used to study fast transients with high~~-~~-frequency content, encompassing switching transients, lightning surges, protection, harmonics, transient ~~over-voltages~~overvoltages, and transformer energization. ~~The applications of EMT have expanded to include the analysis of the transient behaviour of conventional HVDC, VSC-HVDC and various power electronics-based systems, such as IBRs.~~ The shared characteristic among EMT simulations lies in their historically localized nature, necessitating the simulation of a specific reduced network section with equivalents for surrounding networks. ~~In some other cases, it is~~The applications of EMT have expanded to include the analysis of the transient behavior of conventional HVdc, VSC-HVdc, and various power electronics-based systems, such as FACTS and IBRs. It has become necessary to simulate large to very large power grids in EMT~~-~~ mode. Such cases include~~, for example,~~ the studies of ~~long-duration temporary harmonic over-voltages. Transient stability assessment~~control interactions and SSO. TS assessments (TSA) ~~requires~~require the simulation of very large-scale grids due to the globality of involved transients.

Historically, large-scale power system simulations and studies were conducted using positive-sequence ~~root-mean-square (~~RMS~~)~~ tools, also known as phasor-domain tools. However, with high levels of IBR integration, the phasor-domain tools ~~fail~~struggle to provide accurate transient simulations. ~~The main reasons for these~~These shortcomings are primarily caused by the model simplifications and/or omissions of certain components, such as ~~the phase-locked loop (~~manufacturer-specific PLL~~),~~ logics, especially under weak system conditions. Therefore, the simulation of large-scale power systems in an EMT environment ~~starts to become~~becomes necessary for systems with significant numbers of inverter-based devices, including wind farms, solar PV plants, batteries, ~~HVDC~~HVdc, and ~~FACTs~~FACTS. Contrary to common belief, the simulation of very large-scale power systems in EMT~~-~~ mode ~~does not constitute~~no longer constitutes a prohibitively slow process~~ anymore.~~, although relatively slower compared to PSPD simulations.

EMT platforms may require more details to reach higher accuracy levels, especially for IBR models. The full power system dynamics require the usage of small numerical integration ~~time-steps~~timesteps, ranging from 1 to ~~500µs~~500 µs. The ~~time-step~~timestep selection is constrained by the highest frequency of interest. For ~~transient stability~~TS analysis of large power grids, the ~~time-step~~timestep shall be selected to capture control and protection system reactions affecting overall system stability. In several cases, simplified or average-value inverter models can be used to accelerate simulations without compromising accuracy for evaluating system stability.

The simulation ~~time-step~~timestep is a very important factor that impacts the simulation execution time, but it is not the only one. The size of the system, reflected in the number of nodes (also control diagram blocks), can also slow down simulations. Most EMT tools rely on the companion circuit model theory with nodal (or based on nodal) analysis for building the grid's system of equations. Some tools are based on state-space representation for formulating grid equations. The high number of nodes makes the system matrix dimension large and its solution more challenging. It constitutes a linear algebra problem ~~where~~in which unknowns are found through lower-upper (LU) decomposition followed by the forward-backward substitution process. Sparse matrix techniques must be used to significantly accelerate this process. The LU decomposition can be time-invariant and henceforth performed only once. ~~-~~However, this is not the case when the grid contains device models with time~~-~~ dependency, such as switches, faults, or other components. The grid model may also contain nonlinear models, such as magnetization branches, arresters, detailed diode and ~~detailed~~ Insulated-gate bipolar transistor (IGBT) models. Such devices modify the coefficient matrix and require repetitive recalculations of LU decomposition for several solution ~~time-points~~timepoints and even several times per ~~time-point~~timepoint when an iterative solver is used to guarantee precision and numerical stability.

Due to the challenges mentioned above for the simulation of a large system with power electronic-based devices, there is an urgent need to accelerate the EMT simulation without compromising its accuracy. Traditionally, the EMT simulations used to run on a single ~~Central Processing Unit~~central processing unit (CPU) core, and the processes were performed sequentially. Since the advent of parallel EMT simulations, commercial EMT platforms have evolved and

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allow running EMT simulations in parallel using multiple CPU cores simultaneously~~, –~~ (i.e., multi-thread parallel computing~~.~~). This feature can significantly reduce the processing time of a simulation, especially for a large-scale network simulation and/or networks with multiple power electronics devices modelled in full detail~~,~~ (e.g., a detailed wind farm model~~.~~). The extent of achievable performance improvement~~ achievable~~ hinges on the sophistication of the parallel processing technology employed. This entails a proficient exchange of data among processor cores, aiming to reduce communication delays and, thus, secure overall efficiency and scalability.

Parallel computing in power systems ~~is related to~~simulation involves splitting a large network ~~tearing~~ into smaller subnetworks so that they can be solved separately and ~~in parallel.~~simultaneously. The most ~~popular and simple tearing~~common method for connecting the subnetworks is through the application of natural delay-based transmission line (TLM) or cable models. The propagation delay of such distributed-parameters models allows networks to decouple ~~networks~~ without any loss of accuracy. This method, named hereinafter as the TLM-based method, can be fully automated through grid topology analysis. When TLM delays are not available, or when the transmission lines are too short, it is possible to apply the compensation method, which is able to cut through arbitrary wires. The combination of nodal and state-space equations is another solution for splitting networks at arbitrary locations. Parallel computing methods are advantageously used today to accelerate ~~computations. Even on a single CPU, very high performances can be achieved.~~simulation time. Furthermore, these performances can be achieved through automatic initialization from load-flow solutions~~,~~ and the utilization of fully iterative solvers to ensure the highest levels of accuracy in time-domain results.

~~Furthermore, mapping~~

Mapping individual component models with detailed controls onto individual CPU cores is another key aspect of improving the performance of EMT simulations, especially in the context of detailed IBR plant models, where each plant model includes multiple logical blocks and control loops to be solved. In this context, detailed EMT IBR plant models usually have stringent ~~time-step~~timestep requirements that are sometimes ~~lesser~~less than 50 ~~us~~µs (typically around 4~~ – ~~–20 ~~us),~~µs); therefore, decoupling the system model without introducing ~~modelling~~modeling approximations also becomes a challenging task. In certain cases, there is very little visibility into how some of the detailed plant models are implemented and coded as most of them are packaged as independent black~~-~~ boxes with their own ~~time-step~~timestep and solvers. The exact implementation mechanism also plays a major role in these cases, and, oftentimes, those end up being the primary bottlenecks in the overall performance of large-scale and complex EMT simulations with hundreds of IBR plant models. While~~ in some cases~~ plant models have efficient implementations using languages in some cases, such as C or FORTRAN, ~~most of the time,~~ implemented plant models are not computationally efficient~~.~~ most of the time. As more and more ~~Transmission Planners~~TPs and ~~Planning Coordinators~~PCs adopt and perform large-scale EMT studies, more work is needed to have OEM black-box models optimized for performance on top of them meeting the required accuracy needs.

~~Recently, there have been some~~Some recent efforts have sought to investigate the use of ~~Graphics Processing Units (GPUs~~graphics processing units (GPU) as a potential alternative/complement to leveraging CPUs to accelerate simulations. However, ~~it is to be noted that~~ the use of GPUs in this regard is still ~~at~~in its infancy and has not been tested and validated in practical power systems.

Techniques Used for Accelerating EMT Simulations

There are other methods to accelerate the overall simulation performance, but these methods, in contrast to parallel computing, ~~these methods~~ may impact the overall accuracy of the simulation. Therefore, their results should be validated for the required studies. Some of these techniques are described below.

~~Multi-sampling rate or multi-time-step simulation~~

Optimizing the Study Model

The study model should first be optimized to reduce computing requirements. For example, having special metering components such as RMS or DFT calculations can add computing burdens and therefore, unnecessary meters should

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be removed. Level of IBR model details such as using detailed IGBTs or average value models should also be considered to reduce computation burden while maintaining required accuracy for the types of studies being performed.

Multi-Sampling Rate or Multi-Timestep Simulation

In this method, the power system is divided into subsections ~~which~~that are simulated at different time steps. The detailed subsection can be simulated with a small ~~time-step~~timestep, and the rest of the system can use a larger ~~time-step~~timestep (faster simulation time). ~~Also, this~~This method also allows multiple OEM models requiring different ~~time steps~~timesteps to be simulated in the same system.

The ~~time-step~~timestep of each portion may be as large as possible~~,~~ but small enough to simulate the range of frequencies with non-negligeable magnitudes ~~which~~that may appear inside its boundaries. The further away from the origin of the perturbation, the larger the ~~time-step may be.~~ timestep may be. Care must be taken in the selection of timesteps such that the ratio of large timestep/small timestep is minimized to reduce the errors due to interpolation techniques.

~~This approach has several advantages:~~

- ~~No such delays as the transformation instantaneous quantities to phasors required by the~~ EMT-Phasor ~~hybrid approach.~~
- ~~No restrictions on sequence~~
- ~~Nonlinearities (transformer saturation, MOV of series compensated lines) are included in the boundaries.~~
- ~~Within the same software environment~~

~~**Caution:**~~

- ~~Care must be taken in the selection of time steps such a way that the ratio of large time step/small time step minimize to reduce the errors due to interpolation techniques.~~

~~Co-simulation with hybrid simulation~~Hybrid Simulation

This method is similar to the multi-sampling rate, but instead of using different ~~time-steps~~timesteps within the same EMT platform, the EMT platform is interfaced with a positive-sequence RMS platform. The network is divided into two parts~~,~~ with a detailed part that is ~~modelled~~modeled in the EMT~~-~~ mode and the rest of the network ~~is modelled~~modeled using the positive-sequence RMS platform. This method is discussed in detail in ~~Chapter 3.~~**Chapter 3.**

Aggregation and ~~equivalency~~Equivalency

The complexity of simulating over ~~a hundred~~100 power electronic devices can be reduced if ~~they~~the devices can be aggregated into a single device or smaller number of devices. The equivalent system should provide a close ~~matching~~match with the actual system for the required studies.

Using ~~relaxed models~~Relaxed Models for ~~phasor portion~~Phasor Portion

Using high-fidelity IBR models everywhere in EMT area ~~model~~ can be a bottleneck to ~~achieve~~achieving reasonable simulation speed performance. ~~Similarly,~~Similar to using phasor-domain ~~modelling~~modeling for hybrid simulations to simulate model regions far enough from or outside the study region, where the perturbation frequencies and magnitudes are limited, EMT network representations using relaxed models ~~which~~that allow simulations with large ~~time-steps~~timesteps and are less computationally intensive can help significantly accelerate EMT simulations. For example, ~~inverter-based resources~~IBRs may be ~~modelled~~modeled as controlled current sources~~,~~ without the inclusion

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of the inner control loop model or other fast dynamic controls. Such relaxed models may be easily obtained from the phasor-domain database and be simulated with a ~~time-step~~timestep up to ~~150µs~~150 µs.

Synchronous generators may also be simulated in the EMT domain with a very large ~~time-step~~timestep, up to 150 µs or ~~1000~~1,000 µs, if the machine equations are solved with network equations.

Additional Considerations on Solution ~~Time Step~~Timestep and Its Impact on Accuracy

Using a larger ~~time step~~timestep when the EMT model includes non-linearities can introduce ~~error which~~errors that may accumulate over time. ~~There are solution~~Solution techniques ~~available~~ that help address this issue (e.g~~.~~., iterative solution, interpolation techniques, dynamic phasors~~, etc.~~) are available. See the following figure of a transformer inrush current with and without iteration at ~~100µs~~100 µs.

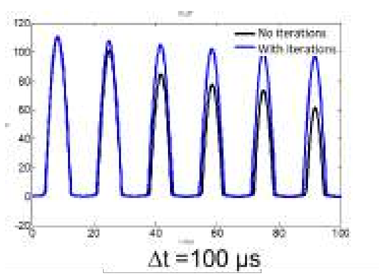

Figure 8.1: Inrush ~~current with~~Current With and ~~without iteration~~Without Iteration

Caution: Attention must be paid ~~for~~to the accuracy of the solution technique ~~use~~used (e.g., convergence tolerance and whether the solution is converged or not if iterative solution is used; errors due to ~~time step~~timestep ratio if interpolation or dynamic phasor techniques are used.)

If artificial ~~time-step~~timestep delays are introduced when aggregating multiple electrical resources or allocating certain electrical components on different physical computing resources for the purpose of parallel processing (e.g~~.~~., power or current scaling or stub lines), the ~~time-step~~timestep may remain below ~~20us~~20 µs. The figure below demonstrates the error introduced by a current scaling device with a ~~50us time-step~~50 µs timestep delay in the active power (left) and ~~the~~ reactive power (right). The error manifested in the wrong phase angle between voltage and current, resulting in incorrect reactive power. Current scaling devices are used for generation aggregation. ~~It~~A current scaling device model injects ~~a~~ current on one side, which is a multiplication of the current entering on the other side. Stub lines are typically used to split network equations for parallel processing at a location where there are no transmission lines available to apply the TLM-based method. ~~It~~This approach introduces an artificial delay to allow decoupling equations.

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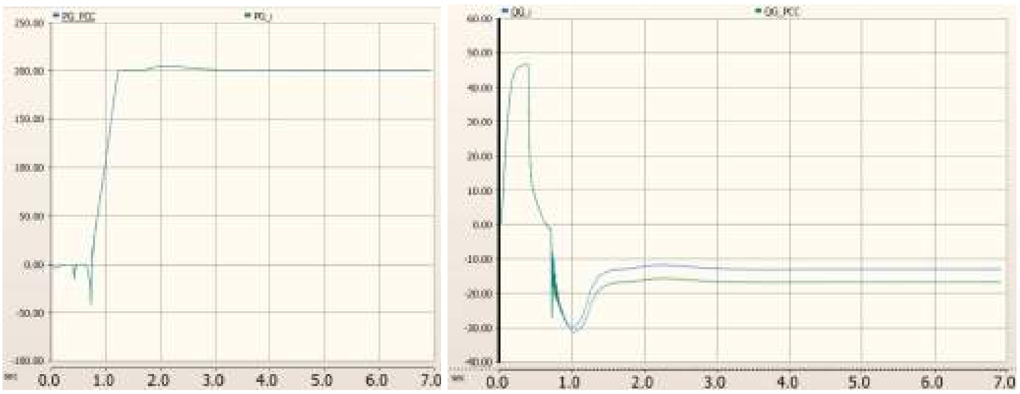

Figure 8.2: Error ~~introduced~~Introduced by a ~~current scaling device~~Current Scaling Device

Best Practices for Developing Large EMT Models

~~As~~ The integration of more and more IBRs ~~are integrated~~ into the power grid across the ~~US,~~United States renders the need ~~for~~to extensively ~~studying~~study grid behaviors during a range of operating conditions and fault scenarios ~~would be~~ more ~~than~~ compelling. ~~Large~~Under these conditions, large-scale EMT studies ~~would~~might need to be performed repeatedly as a routine part of planning and operational studies. Current ~~practice involves~~practices involve performing EMT studies on targeted~~,~~ regional system models with the wide-area system being equivalenced appropriately to limit scale. ~~Further~~Furthermore, the starting point in ~~a lot of~~many cases involves porting phasor-domain models of the transmission network and the synchronous generators. To develop high-fidelity and large-scale validated EMT models, there are certain best practices that could be followed by TPs and PCs.

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~~Ensuring~~It is essential to ensure that model porting/conversion steps from existing phasor-domain tools are automated to minimize errors in populating parameters ~~is very important.~~. While most of the standard network elements would be converted appropriately, special attention needs to be paid when converting or porting user-coded models as a comparable equivalent might not be readily available. The ~~process of~~ model import process should be approached as a ~~multi-step~~multistep process with appropriate validations at each level. The first step would involve the validation of the network in terms of the transmission lines and the topology, which could be validated through a comparison of power flows. Following this step, generation and load sources could then be integrated ~~and then could be~~before being validated with steady-state comparisons followed by specific types of step changes and fault scenarios.

~~Another aspect to pay~~ Also deserving of close attention ~~to~~ would be ~~in~~ the initialization of generation sources, including IBR plant models. Some of the detailed IBR models are black-box models and might not support initialization to a steady state. In such cases, the model needs to have corresponding logical elements to slowly bring them to an appropriate state. A non-trivial aspect that affects EMT simulation performance is the inclusion of elements for measuring electrical quantities in the model. They should be optimized so that only those that are necessary for the use case being studied are recorded.

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As mentioned previously, it is essential to identify long transmission lines modeled as distributed parameter lines to enable the decoupling of large EMT models to parallelize them and accelerate simulations. ~~Further~~Furthermore, as necessary, areas of the system that might not be relevant need to be reduced ~~or equivalenced~~ with an appropriate network equivalent. ~~There might be~~ In situations ~~where~~in which specific areas in the system might not have very long lines for effective decoupling~~. In such cases~~, lines could be combined to artificially form a line that is long enough to decouple. Additionally, ~~in some cases, ~~if those are insufficient in some cases, stub lines could be considered with borrowed inductance and capacitance from nearby transformers or lines to minimize loss of fidelity. Inverter models utilizing detailed switching models should be sidestepped because they prolong simulation times without contributing further understanding to the stability assessment of extensive grid systems. For most practical applications, it is advisable to use average or switching function models, which are integrated with detailed ~~Phase-Locked Loop (~~PLL~~)~~ and quick-response protection system models, to expedite the simulation process.

Looking Forward~~—~~–Challenges with Speed and Scalability of EMT Simulations

The scale of the bulk power system ~~studied~~studies that have been referenced in the above ~~sections~~chapters is in the order of ~~1000s~~hundreds to thousands of buses, which is sufficient for most systems that ~~is~~are or will be studied in the near future. As the penetration of power electronics increases in the ~~power~~ grid, the size of the power system that needs to be studied is expected to grow in EMT simulations. For example, with simplified ~~distribution grid~~aggregated IBR models in today's ~~phasor-domain transient stability (TS) simulators~~BPS models, the power grid in United States has in the range of 100,000 buses. If more detailed~~ distribution grid~~, non-aggregated IBR models ~~and/or IBRs~~ are ~~modelled in detail~~needed, the number of buses can easily reach the millions. In such cases, it may not be simple to ~~perform splitting of~~split the model only based on transmission lines to introduce parallelism and speed-up. Hence, research is being conducted into numerical methods ~~are being researched upon~~ to enable utilization of the properties and features of the dynamics of the ~~power~~ grid to enable faster simulations.[68,69,70] Additionally, research is exploring parallelism in solvers within multi-core CPUs ~~are being explored~~ for further speed-up in simulations.[71,72,73,74]

Hardware: In addition to multi-core CPUs, ~~there have been~~ recent research trends ~~in~~ have focused on using ~~graphics processing unit (GPU)~~GPUs for scalable simulations~~. It may~~ in an attempt to assist with the speed-up of certain types of power grids and/or IBRs.[75,76] This is not guaranteed for all types of systems.

Automation: ~~Automatic~~Research into automatic parallelization of models and solvers is ongoing ~~research and will~~to assist ~~in future~~ with scalability~~. There~~ in the future, but there is limited published work available at this time.

[68] S. Debnath and J. Choi, "Electromagnetic Transient (EMT) Simulation Algorithms for Evaluation of Large-Scale Extreme Fast Charging Systems (T& D Models)," in IEEE Transactions on Power Systems, vol. 38, no. 5, pp. 4069–4079, Sept. 2023.

[69] J. Choi and S. Debnath, "Electromagnetic Transient (EMT) Simulation Algorithm for Evaluation of Photovoltaic (PV) Generation Systems," 2021 IEEE Kansas Power and Energy Conference (KPEC), Manhattan, KS, USA, 2021, pp. 1–6.

[70] S. Debnath and M. Chinthavali, "Numerical-Stiffness-Based Simulation of Mixed Transmission Systems," in IEEE Transactions on Industrial Electronics, vol. 65, no. 12, pp. 9215–9224, Dec. 2018

[71] S. Debnath, "Real-Time Simulation of Modular Multilevel Converters," 2018 IEEE Energy Conversion Congress and Exposition (ECCE), Portland, OR, USA, 2018, pp. 5196–5203

[72] T. Cheng, T. Duan and V. Dinavahi, "Parallel-in-Time Object-Oriented Electromagnetic Transient Simulation of Power Systems," in IEEE Open Access Journal of Power and Energy, vol. 7, pp. 296–306, 2020.

[73] S. Debnath, "Parallel-in-Time Simulation Algorithm for Power Electronics: MMC-HVdc System," in IEEE Journal of Emerging and Selected Topics in Power Electronics, vol. 8, no. 4, pp. 4100–4108, Dec. 2020.

[74] J. Choi, P. Marthi, S. Debnath, Md Arifujjaman, N. Rexwinkel, F. Khalilpour; A. Arana; H. Karimjee, "Hardware-based Advanced Electromagnetic Transient Simulation for A Large-Scale PV Plant in Real Time Digital Simulator," 2023 IEEE Energy Conversion Congress and Exposition (ECCE), Nashville, TN, USA, 2023, pp. 965–971.

[75] S. Yan, Z. Zhou and V. Dinavahi, "Large-Scale Nonlinear Device-Level Power Electronic Circuit Simulation on Massively Parallel Graphics Processing Architectures," in IEEE Transactions on Power Electronics, vol. 33, no. 6, pp. 4660–4678, June 2018.

[76] J. Sun, S. Debnath, M. Saeedifard and P. R. V. Marthi, "Real-Time Electromagnetic Transient Simulation of Multi-Terminal HVDC–AC Grids Based on GPU," in IEEE Transactions on Industrial Electronics, vol. 68, no. 8, pp. 7002–7011, Aug. 2021.

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Appendix A: Additional Materials on Legacy Plant Modeling

Development of a Generic EMT Model from Existing Positive-~~-~~-Sequence Model

The manufacturer of the Type 1 wind turbine generator is no longer in business and only a positive~~-~~-sequence model, in WECC ~~2nd~~second generation format, was available to the GO. Therefore, a generic EMT model was developed using both standard library components and custom control models and benchmarked against the available positive~~-~~-sequence model. ~~It should be noted that the~~The resulting EMT models may not necessarily bring any more accuracy than the bandwidth of the original positive~~-~~-sequence model.

The following table shows the available positive~~-~~-sequence model and the generic EMT model~~.~~:

Table A.1: ~~Use this for Appendix Tables~~Available Generic Models in PSPD and EMT

Positive~~-~~-Sequence Model	Description	EMT Model components
WT1G1	Direct Connected (Type 1) Generator	Master Library Model Induction Machine
WT12T1	Two-Mass Turbine Model for Type 1 and Type 2 Wind Generators	bbx_U_V82_WECC_Controls
WT12A1	Pseudo-Governor Model for Type 1 and Type 2 Wind Generators	
VTGTPAT	Under/Over Voltage Generator Trip Relay	bbx_U_VTGTPAT
FRQTPAT	Under/Over Frequency Generator Trip Relay	bbx_U_FRQTPAT

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The induction generator WT1G1 is represented by the induction machine model from the standard library of a given EMT software. The other models are user-defined models developed based on the block diagrams and descriptions found in the user manual of the positive~~-~~-sequence tool. The two-mass turbine model (WT12T1) and the pseudo-governor model (WT12A1) are represented together in one user-defined model. The under/~~over voltage~~overvoltage generator trip relay (VTGTPAT) and under/over frequency generator trip relay (FRQTPAT) each have their corresponding user-defined model in the EMT software.

The following figure shows the model developed in the EMT tool:

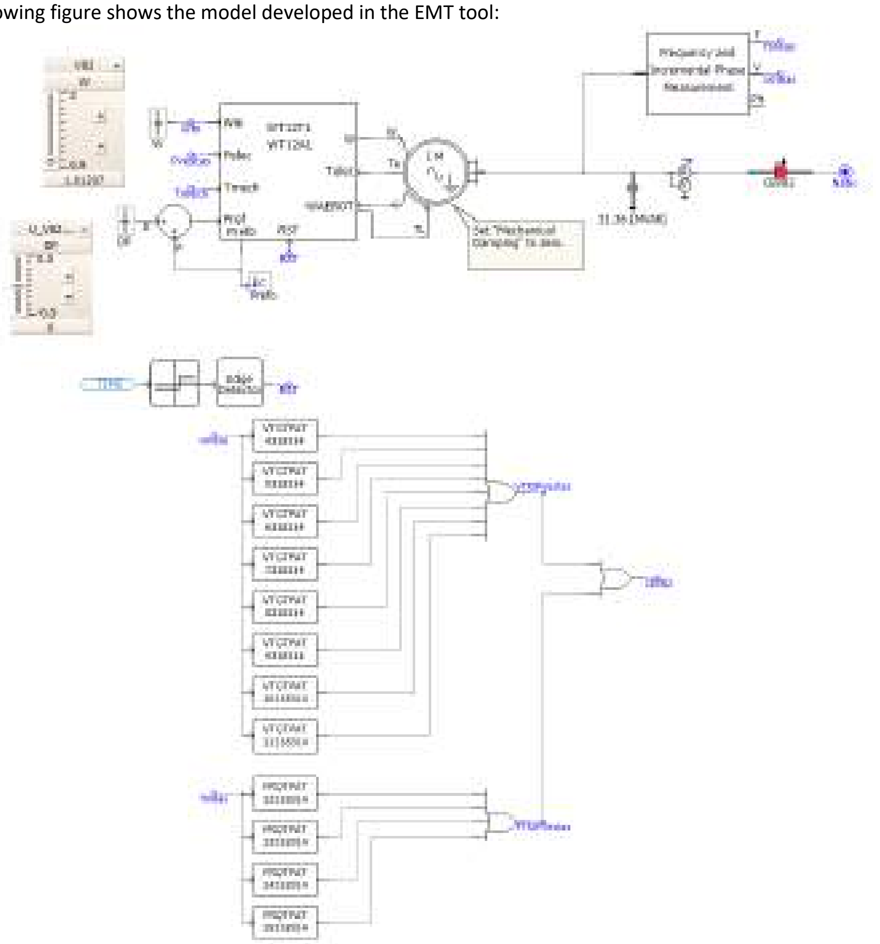

Figure A.1: Details of the EMT ~~model~~Model

Model Initialization

Initialization of an EMT simulation differs from software to software. The steps described here are for ~~one~~a single piece of the EMT software and ~~maybe~~may not be applicable in other software.

After building the model, its initialization is presented to match a solved power flow. The induction generator in the power flow program is treated the same as a synchronous generator. The active and reactive powers from the machine are calculated based on the specified values and the capability given by Qmax and Qmin. In the dynamic simulation, ~~then~~ the positive-~~-~~sequence tool then adds a shunt reactance at the terminals of the machine to account for the difference between the reactive power absorbed by the induction machine (determined by the applied voltage and the slip~~),~~) and the reactive power calculated when the power flow was solved. The value of this added reactance is given in VAR(L) of the WT1G1 model and should be added in the EMT model to maintain consistency. To obtain the value of VAR(L), a no-disturbance positive-sequence dynamic simulation is required in addition to solving the power flow.

Next, the initial speed of the machine must be specified in the EMT model. This value is also obtained from a no-disturbance positive-sequence simulation and is equal to (1 + SPEED) of the induction generator. When an EMT simulation is started, the speed of the machine is kept constant at this given value~~, then~~ before the machine is released at a user-specified time instant. **Figure A.2** shows the locations in the model where the user needs to enter the data for initialization.

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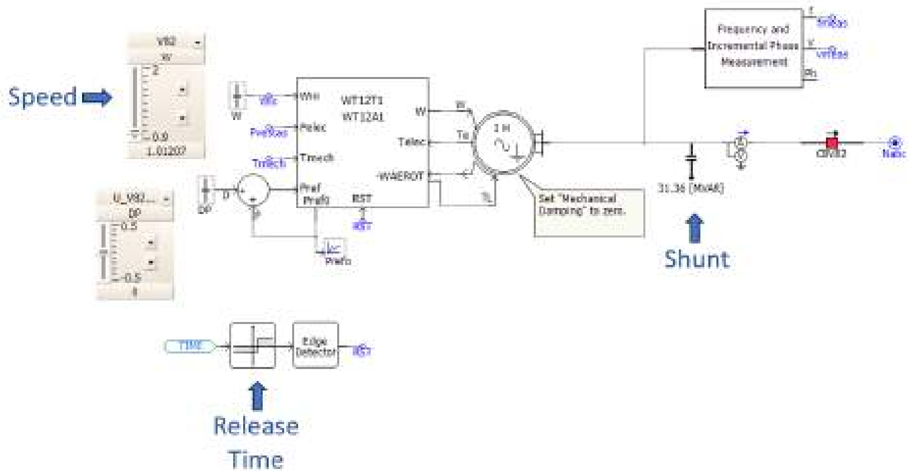

Figure A.2: Initialization of the EMT ~~model~~Model

Benchmarking the EMT ~~model~~Model against ~~positive-sequence model:~~the Positive-Sequence Model

Once the model was initialized to the same power flow as that in positive-sequence dynamic simulation, the developed EMT model modules for WT12T1 and WT12A1 were individually tested by playing back positive-sequence dynamic simulation waveforms to their inputs and comparing their outputs to the corresponding curves from the same positive-sequence dynamic simulation. A voltage step test was also used to compare the behavior of the overall EMT model against the positive-sequence model. Results show the comparison of the two simulations where the EMT model behaves similarly to the positive-sequence model.

The following figures show the benchmarking results using a playback test.

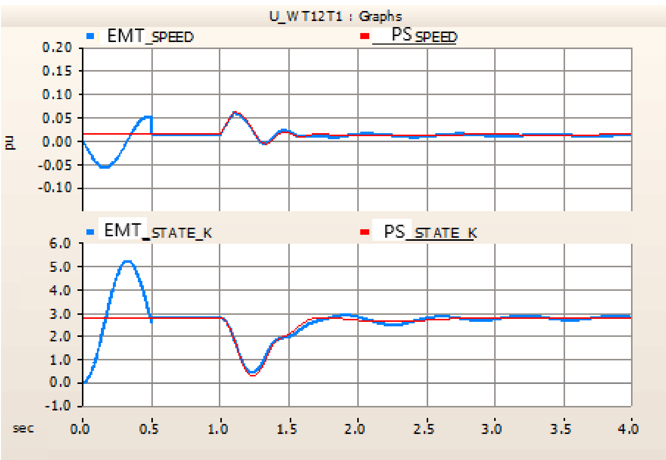

Figure A.3: Comparison of WT12T1 ~~responses between~~Responses Between EMT and Positive~~-~~-Sequence ~~simulation~~Simulation

Figure A.4:- Comparison of WT12A1 ~~responses between~~Responses Between EMT and Positive -Sequence ~~simulation~~Simulation

~~The following figures~~Figure A.5, Figure A.6, and Figure A.7 show the benchmarking results using a voltage step test in which a voltage disturbance was introduced at the POI by dropping the voltage down to 0.05 pu for 0.1 seconds and brought back to 1 pu.

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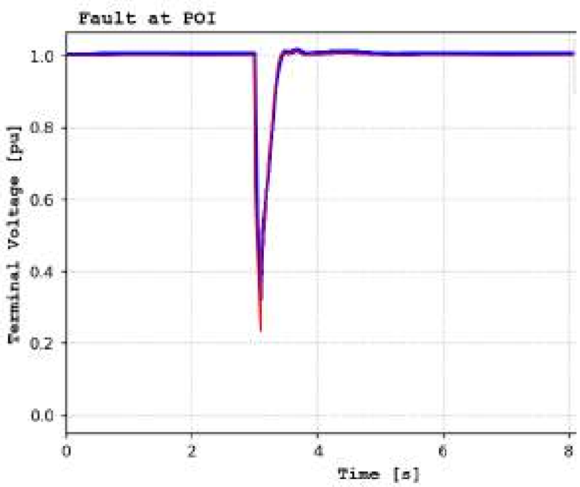

Figure A.5: Comparison of ~~terminal voltages between~~Terminal Voltages Between EMT (~~blue~~Blue) and ~~positive sequence (red) models~~Positive-Sequence (Red) Models

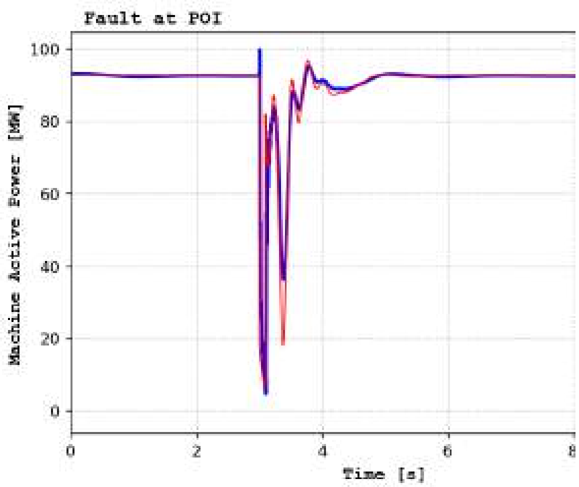

Figure A.6: Comparison of ~~active powers between~~Active Powers Between EMT (~~blue~~Blue) and ~~positive sequence (red) models~~Positive-Sequence (Red) Models

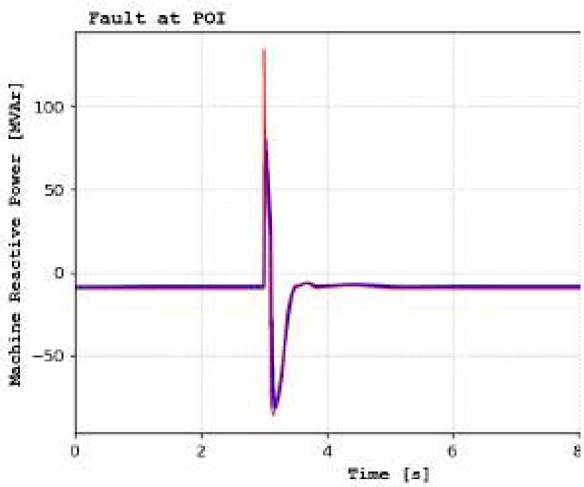

Figure A.7: Comparison of ~~reactive powers between~~Reactive Powers Between EMT (~~blue~~Blue) and ~~positive sequence (red) models~~Positive-Sequence (Red) Models

In summary, legacy plants can be modeled in EMT using generic models if no other option is available and it is acceptable by TOs and ISOs. Although these generic models will lack the detailed control system features of legacy units, they still provide a good representation of plants' behaviors within the validity and accuracy range of the original positive~~-~~-sequence model.

Tuning and Validating Generic EMT Models ~~using~~Using Field Disturbance Data

There ~~exists~~exist generic EMT models with enough flexibility to be tuned to represent a given equipment with some degree of accuracy. It has been shown that they ~~could~~can be tuned and validated to represent legacy IBR plant. For example, a generic EMT-type model for a type-IV WTG considering a gearless externally excited synchronous generator and a three-stage full converter was benchmarked against the measurements from a wind turbine.[77]~~.~~ This model implemented protection and ~~Follow-Ride-Through Control~~follow-ride-through control to be consistent with ~~Grid Codes~~grid codes in North America and Europe and included a mixture of average values ~~model~~modeling and equivalent circuits for the power electronic switching stages that allowed the use of longer calculation intervals (i.e~~.~~., around 50 µs for specific cases to speed up the simulation time to the point that it could eventually make it suitable for real-time simulations~~.~~). The proposed model developed for individual representations could also handle aggregate WTG groupings to simulate the entire generation plant operating at maximum power. The generic model was able to mimic the fault-ride-through calculations from a WTG field test involving a 365 MW wind power plant in Québec. The results are shown in ~~Figures 7~~**Figure A.8** and **A.**~~,~~**8**. A good correlation between calculations and measurements is observed. The deviations that occurred at fault clearing were partially attributed to the approximations in the representation of the distribution grid, particularly of the collector system due to the absence of real data and to the use of generic ~~WT~~WTG parameters and controllers instead of OEM-specific data. The results could improve if ~~there were~~ OEM-specific data were available.

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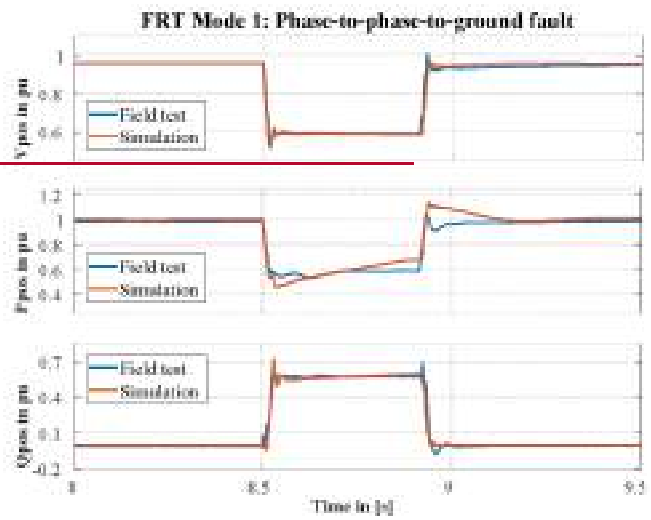
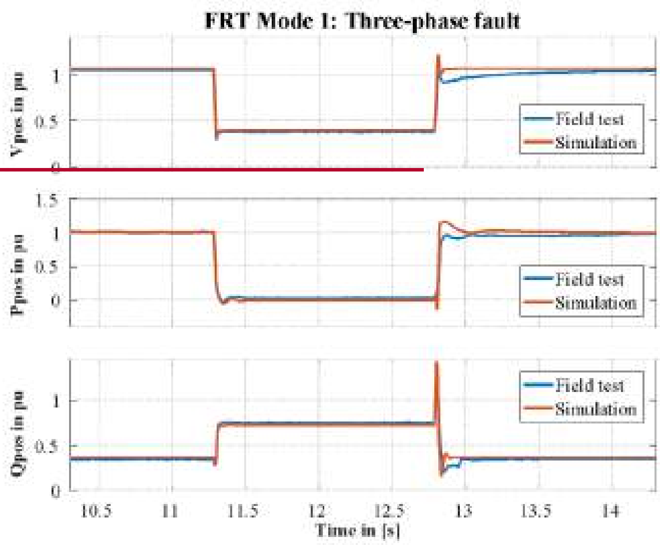
[77] Trevisan, A.S., El-Deib, A.A., Gagnon, R., Mahseredjian, J., Fecteau, M., Field Validated Generic EMT-Type Model of a Full Converter Wind Turbine Based on a Gearless Externally Excited Synchronous Generator, IEEE Trans. on Power Delivery, Vol 33, No. 5, October 2018.



~~Figure A.7: Simulations and field test validation for an unsymmetrical fault~~



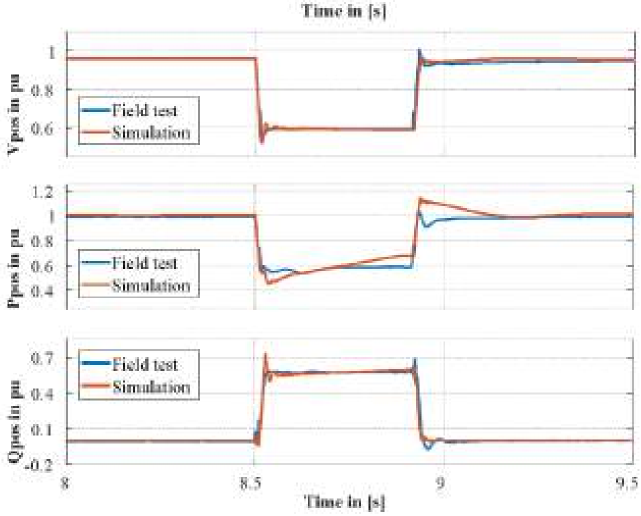


Figure A.8: Simulations and Field Test Validation for an Unsymmetrical Fault

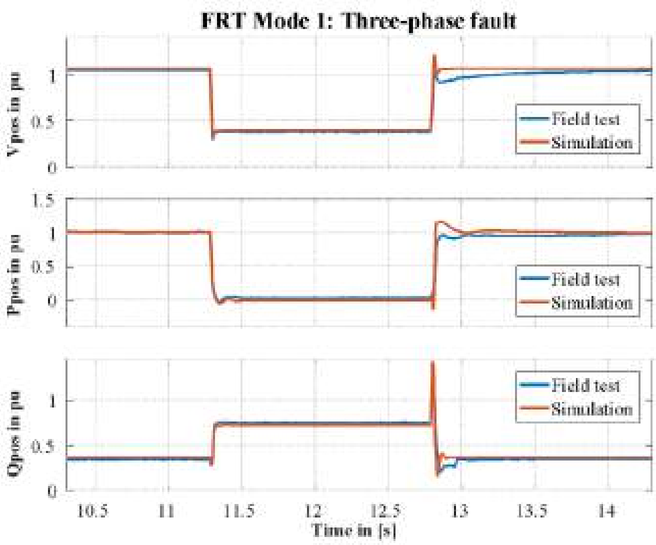


Figure A.9: Simulations and ~~field test validation~~Field Test Validation for a ~~symmetrical fault~~Symmetrical Fault

Similarly, there exist generic EMT models to represent PV plants. One specific example features the required flexibility to be tuned to suit the design of specific PV ~~Inverter~~inverters and ~~specific~~ PV plants[78]~~. It~~.[79] The example implements the control architecture developed by WECC. The model features both a detailed (switching model) representation of a PV inverter as a current source inverter (CSI) and the average model ~~where~~in which the controlled IGBT switching was replaced by an infinite switching frequency leading to a pure sinusoidal output from the CSI, which also allowed the use of a large solution ~~time step~~timestep, resulting in much shorter simulation times. With careful tuning, the model was able to replicate the field measured response, showcasing a good application of generic models to represent legacy plants without equipment-specific models. The current waveforms from the detailed model were very similar to the current waveforms from the average model with only higher order harmonics showing up on the detailed model~~,~~ but with the fundamental components matching very closely.

The use of field data captured during system disturbances looks promising as an effective resource to tune and validate generic EMT models to represent legacy plants for which there are no equipment-specific models.

~~[78] https://www.esig.energy/wiki-main-page/user-guide-for-pv-dynamic-model-simulation-written-on-pscad-platform/~~
[79] https://www.esig.energy/wiki-main-page/user-guide-for-pv-dynamic-model-simulation-written-on-pscad-platform/

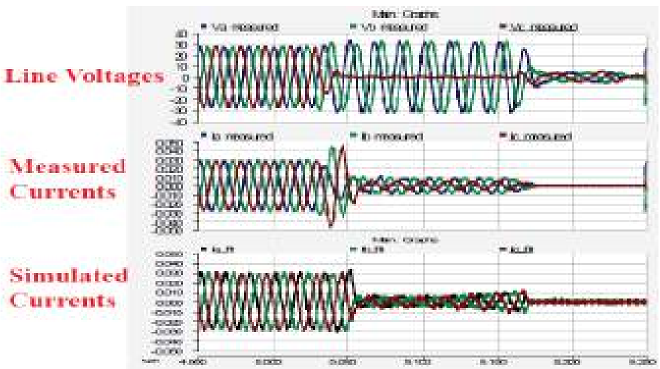


Figure A.10: Comparisons ~~between calculated~~Between Calculated and ~~measured parameters using~~Measured Parameters Using a ~~detailed, switching model~~Detailed Switching Model [3]

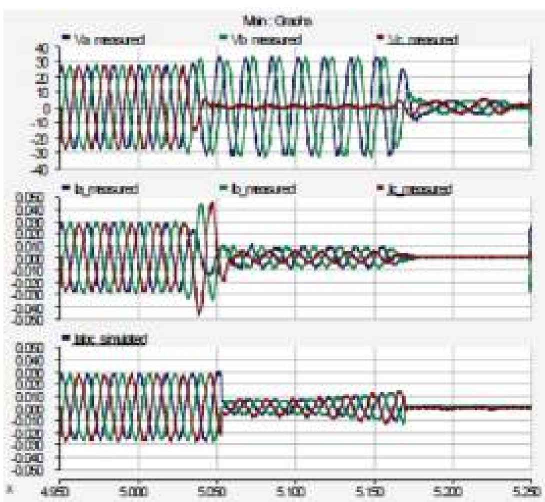


Figure A.11: Comparisons ~~between calculated~~Between Calculated and ~~measured parameters using~~Measured Parameters Using an ~~average converter model~~Average Converter Model

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In summary, based on the referred work, the use of field data captured during system disturbances looks promising as an effective resource to tune and validate generic EMT models for type-IV WTGs and Average PV dynamic simulation models to represent legacy plants for which there are no equipment-~~-~~specific models.

~~Appendix B: Example~~

Appendix B: ~~More Details on~~Limitations of Aggregated ~~and Non-aggregated~~ Representation of IBR

~~Model Use Cases~~

It is important to note that, while compliance with ride-through capability is mandated at the plant level, it must also be validated at the individual device level. Consequently, the aggregated model can be employed to evaluate the ~~plant's~~plant's adherence to power-frequency standards~~,~~ but ~~it cannot be utilized~~not to verify if the power plant satisfies the voltage ride-through criteria.

In the context of modeling large-scale IBR plants (~~Wind, Solar~~wind, solar, BESS) in a wide-area system study, there are different levels of fidelities (detailed inverter-level models, semi-aggregated plant models, aggregated plant models) when it comes to the representation of the entire plant itself. ~~While a~~A typical plant consists of several ~~hundreds of~~hundred individual units~~ be it~~, such as several wind turbines in the case of a wind plant with its own inverter, filters, and transformers interconnected through collector systems to the point of interconnection. Similarly, in the context of a solar plant, there are individual PV modules with their own ~~DC/DC~~dc-dc converters and inverters along with their filters~~,~~ and transformers~~,~~ and the collector systems to interconnect them. As detailed representations of the entire IBR plant model with their constituent components require a significant amount of computational resources for performing detailed EMT studies, they are typically aggregated to have an equivalent behavior at the plant-level for several use cases.[80,81,82,83]

In some cases, instead of aggregating the entire plant into a single equivalent inverter, multiple units are utilized to aggregate the plant. This is typically the case when the IBR plant has inverters from different OEMs or has inverters with different operating characteristics or controllers or when ~~there has been an upgrade to~~ an existing plant has been upgraded to increase capacity. Under these cases, the method used to obtain the multi-inverter equivalent of the IBR plant is extremely important. This typically includes the following steps: clustering of related units or identifying groups within the plant, aggregation of units within an identified cluster, equivalencing the collector network, and validating the multi-unit aggregated plant model[84]~~. A~~.[85] There exist a variety of clustering algorithms including ~~(~~k-means, fuzzy-based, dynamic time-warping distance, etc~~.,)~~. The selection of appropriate indices to cluster could also be based on several categories, such as unit features, operating conditions, controller parameters, and dynamic responses. Obtaining the equivalent parameters for the aggregated inverter includes the application of one of the following: weighting methods based on capacities, central parameter substitution method, or optimization methods. Similarly, for the equivalent collector network model, there are four main approaches~~:~~, namely the voltage deviation~~ method~~, current injection~~ method~~, power loss~~ method~~~~,~~, and circuit transformation ~~method~~methods. The most critical part of the equivalencing process as indicated above is the model validation step with field test data or at least with a detailed plant model for a selected set of use case scenarios and comparing dynamic responses to

[80] WECC REMTF Generic solar photovoltaic system dynamic simulation model specification, September 2012.

[81] IEC, 2012. Grid integration of large-capacity renewable energy sources and use of large capacity electrical energy storage, International Electrotechnical Commission (IEC) White Paper, Geneva.

[82] Ackermann, T., Ellis, A., Fortmann, J., Matevosyan, J., et al., 2013. Code shift: grid specifications and dynamic wind turbine models. IEEE Power Energ. Mag. 11 (6),
72–82.

[83] WECC, 2015. WECC central station photovoltaic power plant model validation guideline, WECC Renewable Energy Modeling Task Force. [Online]. ~~Available: https://www.wecc.biz/Administrative/150616.~~Available here: https://www.wecc.biz/Administrative/150616.

~~[84] Pupu Chao, Weixing Li, Xiaodong Liang, Yong Shuai, Feng Sun, Yangyang Ge, "A comprehensive review on dynamic equivalent modeling of large photovoltaic power plants," Solar Energy, Volume 210, 2020, Pages 87-100, ISSN 0038-092X, https://doi.org/10.1016/j.solener.2020.06.051.~~

[85] Pupu Chao, Weixing Li, Xiaodong Liang, Yong Shuai, Feng Sun, Yangyang Ge, "A comprehensive review on dynamic equivalent modeling of large photovoltaic power plants," Solar Energy, Volume 210, 2020, Pages 87-100, ISSN 0038-092X, https://doi.org/10.1016/j.solener.2020.06.051.

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assess the overall performance match. In the context of wind plants, an approach to obtain a semi-aggregated, multi-machine model for a large wind power plant with an equivalent representation of the collector system obtained based on the power loss method ~~had been~~was developed several years ago.[86]~~.~~ Similar to the criteria described above for PV plants, several methods ~~to~~for grouping wind turbines exist~~ as follows:~~, namely based on the diversity of the wind speeds, turbine types, impedances, control algorithms, transformer sizes, and ~~based on the~~ short~~-~~-circuit capacity.

Overall, ~~it is to be noted that~~ any type of aggregated IBR plant ~~models need~~model needs to be appropriately validated for the use cases ~~that they are~~ for which it is used as there are some specific use cases~~ like~~, such as protection and fault ride-through studies~~ where~~, in which they do not produce similar behavior as a fully detailed plant-level EMT model due to ~~various~~ factors, such as inverter configuration variations, geographical variations in irradiances or wind speeds within the plant, and variation of collector cable impedances. These factors could result in variation of power produced by the various units ~~as well as~~and cause differences in transient voltages at different locations within the plant, causing individual inverters to behave slightly differently and potentially trip on various conditions like ~~over-voltages~~overvoltages or imbalances.[87,88]~~.~~

One of the use cases for the use of detailed models of all IBRs in a region is to understand the impact of unbalanced faults in the ~~power~~ grid and the responses observed in each IBR present in the region. This assumes significance upon observing the impact of transient events recorded in ~~North American Electric Reliability Corporation (~~NERC~~)~~ reports from 2016 ~~onwards~~onward that have shown that an unbalanced fault has affected several IBRs in a region and many IBRs have shown partial reduction in power generation. An example large PV plant is shown in **Figure B.1**. The large PV plant is composed of ~~50s-100s~~50–100 seconds of PV systems (PV inverters connected to one distribution transformer) in the medium-voltage (34.5 kV) distribution system, which is connected to the high-voltage (230 kV) transmission system. The PV system consists of PV arrays, PV inverter modules (dc-dc converters and dc-ac inverters), and inverter firmware. ~~Additionally, there~~There is a ~~power plant controller (~~PPC~~)~~ present in the PV plant.

[86] E. Muljadi, S. Pasupulati, A. Ellis and D. Kosterov, "Method of equivalencing for a large wind power plant with multiple turbine representation," 2008 IEEE Power and Energy Society General Meeting - Conversion and Delivery of Electrical Energy in the 21st Century, Pittsburgh, PA, USA, 2008, pp. 1-9, doi: 10.1109/PES.2008.4596055.

[87] WECC, 2014. WECC solar plant dynamic modeling guidelines, WECC Renewable Energy Modeling Task Force. [Online].

[88] Han, P., Lin, Z., Wang, L., Fan, G., et al., 2018. A survey on equivalence modeling for large-scale photovoltaic power plants". Energies. 11, 1–14.

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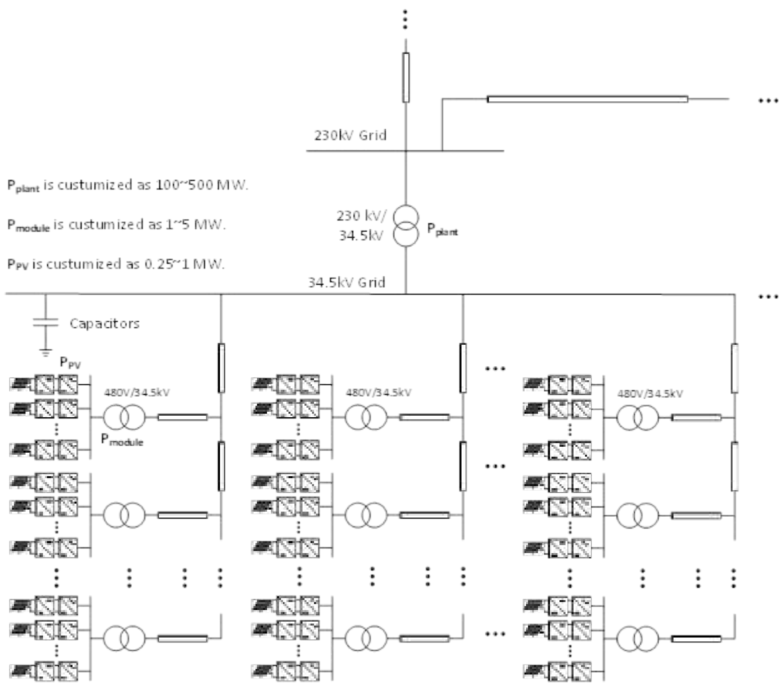
230kV Grid
Pplant is custumized as 100~500 MW.
Pmodule is custumized as 1~5 MW.
PPV is custumized as 0.25~1 MW.
230 kV/
34.5kV
Pplant
34.5kV Grid
Capacitors
PPV
480V/34.5kV
480V/34.5kV
480V/34.5kV
Pmodule

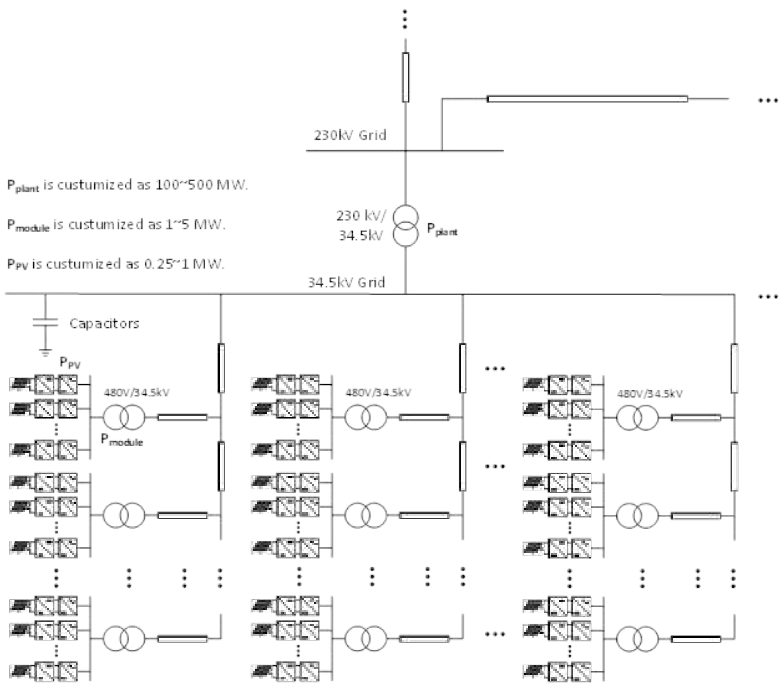

Figure B.1: Configuration of a ~~large~~Large PV ~~plant~~Plant in ~~medium-voltage~~Medium-Voltage (e.g., 34.5 kV) ~~distribution system connected~~Distribution System Connected to ~~high-voltage~~High-Voltage (e.g., 230 kV) ~~transmission system.~~Transmission System

PV Inverter Module Model

The high-fidelity model of a PV inverter module consists of a PV array, a dc-dc boost converter, an ac-dc three-phase voltage source inverter, and ~~a~~an LCL filter. The PV inverter module is illustrated in **Figure B.2**. ~~Additionally, different~~Different types of inverters have been considered in the models ~~(that is typically~~to be representative of inverters from different vendors and/or from different generations of inverters from the same vendor~~)~~. The controller used in dc-dc converter and dc-ac inverters ~~are~~is implemented in a multi-rate implementation, similar to the field implementation ~~where~~in which the controller is implemented in 50~~-~~–100 µs.

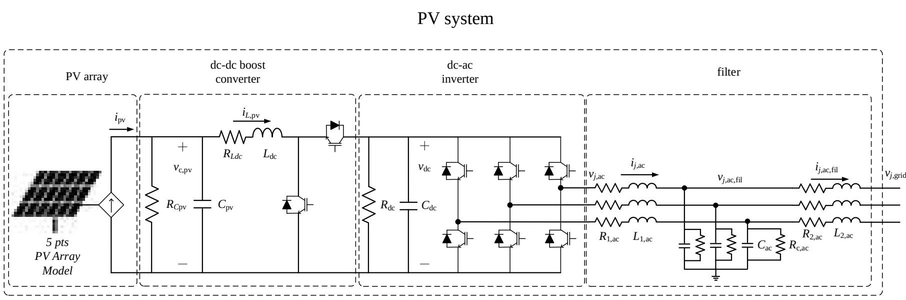

Figure B.2: Configuration of PV ~~inverter module.~~Inverter Module

PV System Model

A number of PV inverter modules are connected to a distribution transformer in a PV system. In the high-fidelity model, up to ~~5~~five inverter modules may be connected. The PV system is shown in **Figure B.3**.

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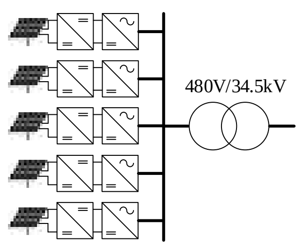

Figure B.3: Configuration of ~~multiple~~Multiple PV ~~inverter modules through~~Inverter Modules Through a ~~distribution transformer~~Distribution Transformer (PV ~~system~~System)

Collector System Model

The collector system[89] within the PV plant is modeled considering the lines, cables, shunts, and transformers that may be present. The lines and cables are modeled using the pi-section model, and the transformers are modeled using the T-type model. A detailed model of the PV plant models includes the collector ~~sytem~~system with all the PV systems present.[90]~~.~~

To replicate the Angeles Forest 2018 event, the region of the power grid from the fault to the location of the one affected PV plant is modeled in the EMT domain as a simple test case to showcase the utility of EMT simulations and the use of detailed (or high-fidelity) models. ~~Please note that this~~This analysis should be extended to the ~~region~~area affected by the fault and to all the affected PV plants.

Event Replication

The integrated EMT model of the power grid with the detailed model of one of the affected PV plants is evaluated for a line-to-line fault incident that replicates the Angles Forest disturbance scenario. The line-to-line fault is incepted

[89] Sometimes referred to as *plant distribution grid*.

[90] S. Debnath and J. Choi. 2022. "Electromagnetic Transient (EMT) Simulation Algorithms for Evaluation of Large-Scale Extreme Fast Charging Systems (T & D Models)." In *IEEE Transactions on Power Systems*, doi: 10.1109/TPWRS.2022.3212639.

at t = 1.99 s. The simulation results of the voltages and currents at the local and remote ends of the faulted line in the integrated model are shown in **Figure B.4**. These results are very similar to ~~the results~~those observed in the NERC report on the event. Subplot (a) and (b) show voltages and currents, respectively, at the near end of the ~~event~~faulted line; subplot (c) and (d) show voltages and currents, respectively, at the remote end of the faulted line.

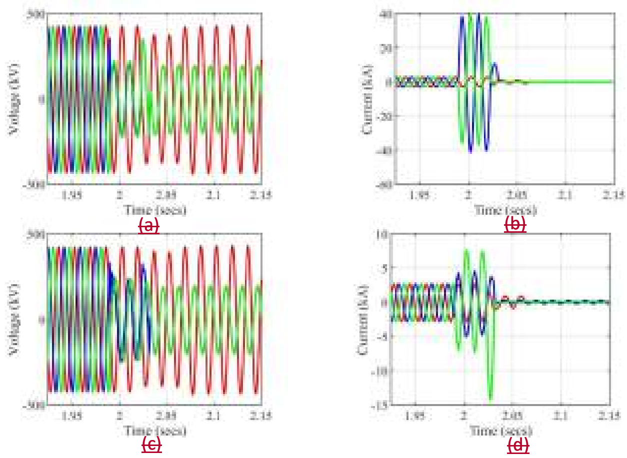

Figure B.4~~: Simulation results from the integrated EMT high-fidelity model (grid-plant) during line-to-line fault: (a) voltages at the near end of the faulted line; (b) currents at the near end of the faulted line; (c) voltages at the remote end of the faulted line; and (d) currents at the remote end of the faulted line.~~: Simulation Results from the Integrated EMT High-Fidelity Model (Grid-Plant) During Line-to-Line Fault

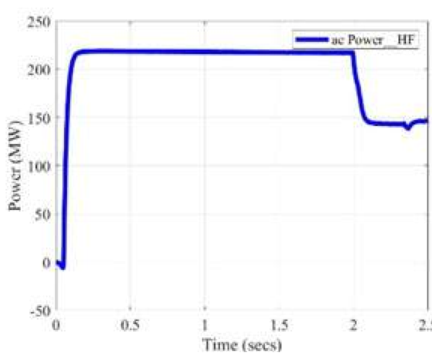

Figure B.5: Active ~~power~~Power (in ~~megawatts~~Megawatts) from ~~simulation~~Simulation of a ~~high-fidelity switched model~~High-Fidelity Switched Model of a PV ~~plant~~Plant with ~~all~~All the ~~inverters represented~~Inverters Represented in ~~electromagnetic transient simulations.~~Electromagnetic Transient Simulations

The simulation result of active power from the plant is shown in **Figure B.5**. From the figure, it is observed that the active power from the plant reduces in response to the line-to-line fault incepted. The observed reduction ~~observed~~

in the power ~~arises~~is due to a transient ~~operating~~ condition observed at only some of the inverters within the plant, thereby~~,~~ reducing their corresponding power generations to zero. The rest of the inverters within the PV plant continue to operate. This is a ~~replication of~~ first-of-its-kind replication using EMT simulations to replicate a field event with trips in IBRs recurrently being observed in the field.[91]~~.~~ Different average-valued aggregated single inverter models of the PV plant do not replicate the behavior observed in the field.

This type of analysis needs to be expanded to the region typically affected by the unbalanced faults and ~~needs~~ to incorporate the detailed (high-fidelity) models of all the affected PV plants to accurately reflect the partial reduction in power generation at each affected PV plant during these events. Changes are needed to the contingency analysis performed in planning to accommodate this new behavior observed in planning that may assist with minimizing such behavior being observed in operations moving forward.

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[91] Suman Debnath, et. al. April 2020 – September 2023, *Library of Advanced Models of Large-scale PV*. Project Team: ORNL, SCE, PSU, CAISO, GIT, SPP, OGE.

Appendix C: Real-World Case Studies for Leveraging Parallel Computing to Accelerate EMT Simulations

~~In the~~The following sections~~, we~~ present several practical case studies of how parallel computing has been leveraged to accelerate EMT simulations for large or complex power systems.

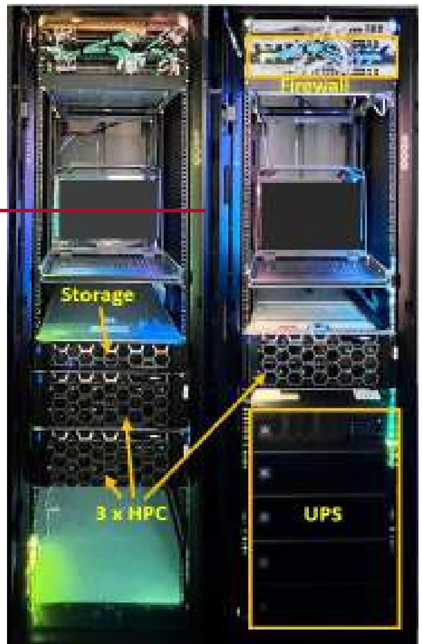
Example 1: Modeling ~~A~~a Full Wind Farm: An Example with Large Number of IBRs

The detailed EMT model of a full wind farm consists of ~~1)~~ multiple wind turbines, ~~2)~~a switching model of each wind turbine converter, ~~3)~~a detailed MV collector grid model with cables, ~~4)~~ MV/HV transformer(s~~)~~), and ~~5)~~ detailed HV cable/line models for collecting to grid side. As discussed earlier, the bottleneck of the simulation time and the main sources of the computational burden are the nonlinear switching of power electronic devices. ~~-~~The length of any detailed line/cable model is also very important to enable parallel computations if any such line propagation delay is larger than the ~~time-step~~timestep of the simulation. Therefore, the full wind farm simulations can be divided into multiple sections based on the number of available CPU cores in the machine. To optimize the speed of simulation, all available CPU cores should be equally loaded with the simulation of switching power electronics, detailed electrical circuits, and the decoupling enabled by short lines/cables. The system can be decoupled with the TLM-based approach when the shortest line propagation delay is greater (typically 10 times) than the simulation ~~time-step~~timestep.

Parallel computing is very efficient with the use of the ~~High-Performance Computer~~high-performance computer (HPC~~)~~), which consists of dozens of CPU cores. The HPC can efficiently simulate~~ a~~ detailed wind farms and large-scale grids. As an example, the Iberdrola Innovation Middle East (IBME) lab is equipped with three HPCs and ~~a~~ storage that has the capability to solve high computational and time-consuming simulations. The specs and the setup of the HPCs are shown in **Table C.1** and **Figure C.1**, respectively. ~~Figure 2~~**Figure C.2** shows a comparison between the simulation time of a full wind farm of more than ~~one hundred~~100 wind turbines using different numbers of CPU cores. The HPC is able to reduce the computing time by a factor of 15 when compared to a single-core simulation.

Table C.1: Hardware ~~specs~~Specs for HPC and ~~storage units~~Storage Units [Source: IBME]

Specs	HPC unit	Storage unit
CPU	128 cores (2x64 AMD 7763, 2.45GHz)	2 Intel Xeon CPUs 24 cores, 2.2 GHz
RAM	1024 GB (RDIMM)	192 GB (RDIMM)
Storage	19.2 TB (SSD vSAS)	38.4 TB (SSD vSAS)
GPU	4x NVIDIA HGX A100	-



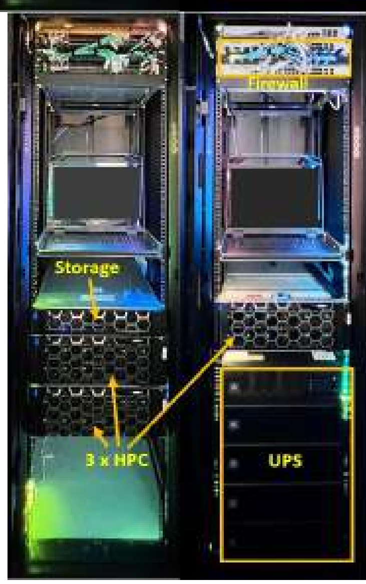
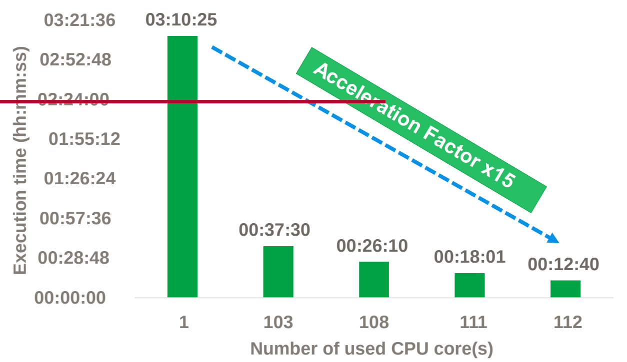


Figure C.1: HPC ~~setup~~Setup in IBME ~~lab~~Lab [Source: IBME]



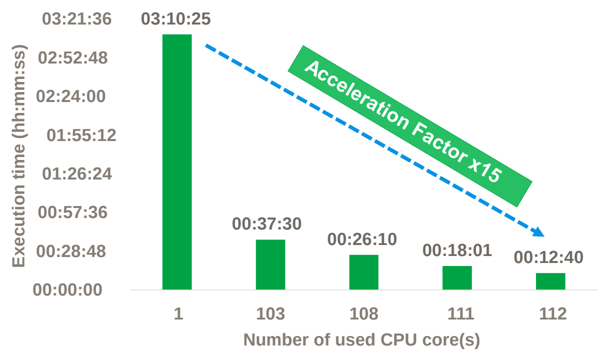


Figure C.2: ~~The simulation time using different numbers~~Simulation Time Using Different Numbers of ~~cores~~Cores [Source: IBME]

Another Wind Farm Example

This test case illustrates the simulation of a detailed wind park using the compensation method for parallel computations. In this case, due to the short cables in the collector grid of the wind park, it is not possible to use TLM-based decoupling. The cables are ~~modelled~~modeled as PI-sections (without propagation delay). There is a total of 45 full converter wind turbines of 1.5 MW each represented by average-value models. They are distributed on three feeders. The nonlinear magnetization branches of individual transformers are included and require iterations. Each wind turbine generic model contains ~~1500~~1,500 components. The computing time with a ~~time-step~~timestep of ~~50 µs~~50µs for ~~1s~~1 seconds of simulation on a single core is 275 s. It reduces to 55 ~~s~~seconds with 9 cores. Although the implementation of the iterative compensation method is more complex, it allows to ~~achieve~~ parallelization in the absence of transmission line delays.

Example 2: Modeling Hydro-Québec High-Voltage Transmission Network

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Method 1: Accelerating EMT Simulation ~~using~~Using Offline EMT Tool

The following example presents the simulation of the very large Hydro-~~Quebec~~Québec grid. A top-level view is presented below.

Figure C.3: Hydro-Québec Power System Example in EMT (~~Offline~~Off-Line)

The EMT model includes all voltage levels from 735 kV down to 25 kV loads in some places. The main case data is as follows:

- ~~2098~~2,098 transformers, ~~23181~~23,181 RLC branches
- 860 PI-line models, 398 CP-line models
- ~~3675~~3,675 ideal switches (e.g. circuit breakers)
- 174 arresters, 99 nonlinear inductances
- 349 synchronous machines with magnetization, exciter, and governor controls
- ~~2701~~2,701 PQ loads
- 10 static var compensators
- ~~56202~~56,202 control diagram blocks (e.g~~.~~., each gain is considered as a block)
- Total number of electric nodes: ~~29803~~29,803

The computing time for 1 ~~s~~seconds with a ~~time-step~~timestep of 50~~-~~ µs on a single core is only 3 minutes, including load-flow solution and automatic initialization. This remarkable performance is due to the usage of sparse matrices with fast convergence using Newton's method[92]. With 8 cores, the computing time reduces to 75 s. TLM-based decoupling is used to achieve these results on a basic laptop, i7-12800H, 2.4 GHz. No artificial lines are added in the grid for creating more decoupling~~,~~ since that requires user intervention and impacts ~~on~~ accuracy. Discontinuity treatment is enabled for switching devices.

It ~~is remarkable~~should be noted that this simulation does not require any user intervention. What is drawn in the schematic diagram is what is simulated~~. It starts~~, starting with an integrated load-flow solution that initializes immediately the time-domain computations. ~~Perfectly flat~~Flat frequency trace is achieved~~. A~~ and a fully iterative solver is used for nonlinear models. The control block diagrams are solved directly with an algebraic loop solver~~. No~~, and no user intervention is required.

[92] A. Abusalah, O. Saad, J. Mahseredjian, U. Karaagac and I. Kocar, "Accelerated Sparse Matrix-Based Computation of Electromagnetic Transients," in IEEE Open Access Journal of Power and Energy, vol. 7, pp. 13-21, 2020, doi: 10.1109/oajpe.2019.2952776.

Method 2: Reaching Real-Time Speed with 56 ~~processors~~Processors with 6 12-~~pulse HVDC converters~~Pulse HVdc Converters and 10 ~~static var compensators~~Static Var Compensators

Table C.1 delineates the components of a modified Hydro-Québec power system model that was introduced earlier. This categorization includes both the type and quantity of components, providing a thorough insight into the ~~system's~~system's architecture. ~~Furthermore,~~ Table C.2 highlights the variation in simulation speed as a function of the number of processors deployed. The data unequivocally demonstrates that substantial gains in performance efficiency are achievable through the incremental addition of CPU cores. This enhancement extends from offline simulations to real-time simulations executed at 40 µs, utilizing 56 CPU cores for an extensive system that encompasses roughly ~~1666~~1,666 three-phase buses. The possibility of utilizing additional processors indicates the potential for achieving speeds that exceed real~~-~~ time. This capability is exceptionally beneficial for the swift analysis of various contingencies within a constrained timeframe, offering a significant improvement in the ~~system's~~system's analytical efficiency and operational reliability.

Table C.2: Real-~~time simulation~~Time Simulation of Hydro-Québec ~~grid~~Grid on 56 CPU ~~cores~~Cores at 40 ~~us~~µs

Components	Quantity
Three-phase buses	~~1666~~1,666
Electrical Machines	111
Lines and Cables	432
Three-phase Transformers	338
Governors, Exciters, and Stabilizers	221
Static Compensators	10
Wind Power Plants	10
HVDC Converters	6
Dynamic Loads	165

Table C.3: Simulation ~~time~~Time for a ~~15s event~~15 Seconds Event

CPU Type	# of CPUs	Measured Simulation Time (s)	Theoretical Simulation Time with 100% Efficiency (s)	Actual Efficiency (%)
i9-10900X	1	2565	NA	NA
i9-10900X	4	786	641	82%
Xeon Gold 6144	56	15	46	305%

The previous examples for the Hydro-~~Quebec~~Québec grid model clearly demonstrate the scalability of parallel EMT simulations[93]. The prospect of conducting several parallel simulation runs on vast cloud computing platforms further amplifies this potential, underscoring the scalable nature of the ~~system's~~system's simulation capacity.

[93] B. Bruned, J. Mahseredjian, S. Dennetière, J. Michel, M. Schudel and N. Bracikowski, "Compensation Method for Parallel and Iterative Real-Time Simulation of Electromagnetic Transients," in IEEE Transactions on Power Delivery, vol. 38, no. 4, pp. 2302-2310, Aug. 2023, doi: 10.1109/TPWRD.2023.3238422.

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Example 3: Modeling the Chilean Grid

In the second case, parallel computations are achieved for the Chilean grid for studying the integration of renewable energies. The increasing penetration of ~~Variable Renewable Energy~~variable renewable energy (VRE) generation along with the decommissioning of conventional power plants in Chile~~,~~ has raised several operational challenges in the Chilean National Power Grid (NPG), including transmission congestion and VRE curtailment. To mitigate these limitations, an innovative virtual transmission solution based on ~~battery energy storage systems (~~BESS~~)~~, known as Grid Booster (GB), has been proposed to increase the capacity of the main ~~500kV~~500 kV corridor of the NPG. A top-level view of the NPG characterized by five voltage control areas (VCA), corresponding to distinct geographical regions~~:~~ (Big North, Small North, Center, and Center South), is shown ~~below.~~in **Figure C.4**. This system has been studied ~~using~~with a wide-area EMT model.

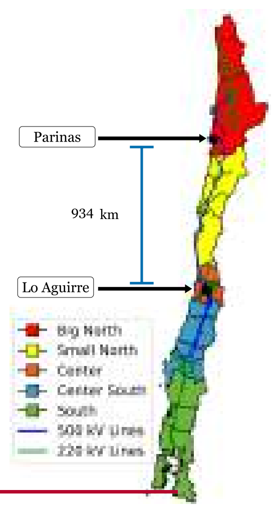
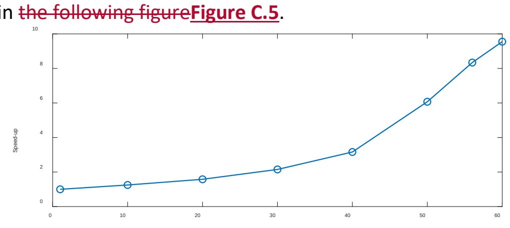


Figure C.4: Chilean Power System Example in EMT

~~Due to~~The large numbers of IBRs made it ~~was~~ necessary to simulate this grid in parallel using a co-simulation technique where several instances of EMT solvers are used to run on separate cores and in parallel[94]. This TLM-based approach allowed ~~to achieve~~ a performance of 13 ~~s~~seconds for 1 ~~s~~seconds of simulation with a ~~time-step~~timestep of 50 µs. A total of 60 CPUs were used on a basic desktop computer (AMD Ryzen Threadripper PRO 5995WX, 2.7 GHz). Scalability can be observed in ~~the following figure~~**Figure C.5**.



[94] M. Ouafi, J. Mahseredjian, J. Peralta, H. Gras, S. Dennetière, B. Bruned, "Parallelization of EMT simulations for integration of inverter-based resources," Electric Power Systems Research, Vol. 223, Oct. 2023, 8 pages, DOI: 10.1016/j.epsr.2023.109641.

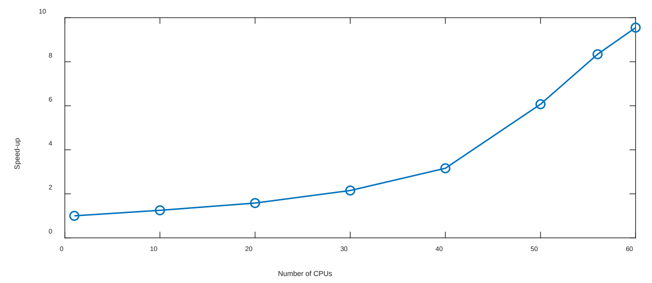


Figure C.5: 1.15 Scalability with ~~increasing~~Increasing # of CPUs

The complete network includes the following:

- ~~1.~~ 27 wind parks and 32 photovoltaic parks, generic models
- ~~2.~~ 307 PI-line models, 297 CP-line models
- ~~3.~~ 57 synchronous generators with magnetization data when available~~,~~ with governor and exciter controls
- ~~4.~~ 48 transformers with nonlinear magnetization branches
- ~~5.~~ ~~5770~~57,708 control diagram blocks
- ~~6.~~ ~~Total number of~~6,785 total electric nodes~~: 6785~~

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Example 4: Modeling Very Large ~~4000~~4,000-Bus Australian System

A recent case study ~~of~~considered a ~~4000~~4,000-bus EMT benchmark that was developed based on a synthetic model of the Australian electricity ~~network[1]~~network[95]. In this case study, the setup (as shown in Figure 4) interconnected multiple multi-core CPU real-time simulators together with a fast communication link over optical fiber. In this architecture, the entire EMT simulation of the network and its associated elements (including main grid models, controls, protection, measurement, black-box control, and plant model~~ etc.,~~)) were distributed between various multi-core CPUs ~~to accelerate the overall performance of the EMT simulation. In~~(in particular, a ~~High-Performance~~ high-performance 128-core Windows computer interconnected to 22 high-performance 18-core computers~~.~~) to accelerate the overall performance of the EMT simulation. Overall, 100 cores were used for the computation of the network solution while about 300 cores were used for detailed simulations of OEM controller codes for various IBR plants. The details about the components of the model are shown in **Table C.2**.

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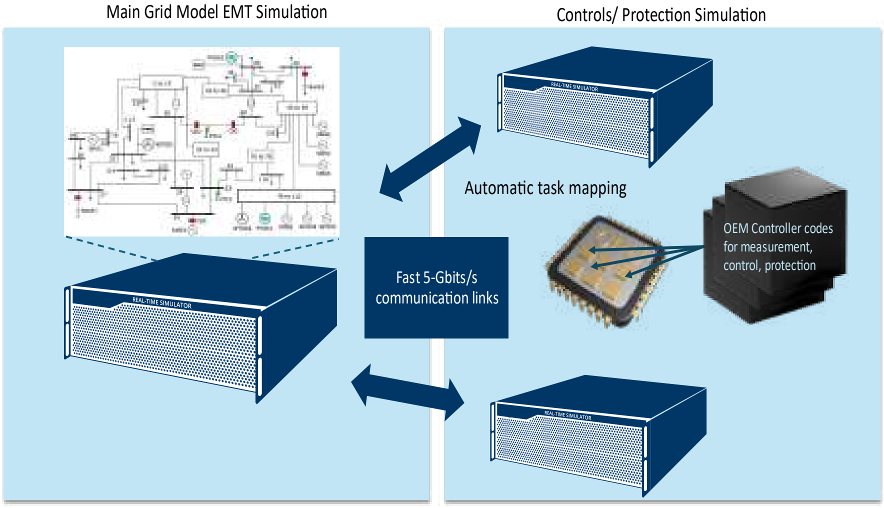

Figure C.6: Multiple Simulator, Multi-Core CPU Real-Time Simulation Architecture for Accelerating EMT Simulation

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[95] S. Li et al., "Fast and real-time EMT simulations for Hardware-in-the-Loop controller performance testing and for on-line transient stability analysis of large-scale low-inertia power systems." Paper CIGRE-689, CIGRE Canada, Vancouver, BC, Sept. 25 – 28 2023. [Online] Available: https://cigreconference.ca/papers/2023/paper_689.pdf

~~It is to be noted in~~The goal of this case study~~, the goal~~ was to achieve real-time simulation speeds for a large-scale system. However, the actual speed of simulation was limited by several OEM black-box controller codes that were not implemented efficiently, ~~which~~ negatively ~~affected~~affecting the potential for reaching real-time performance. Regardless, this setup showed a significant performance improvement (30 ~~s~~seconds of simulation in 90 ~~s~~seconds of wall-clock time) to reduce the time taken to perform EMT studies while including detailed OEM black-box models. Overall, in the interest of accelerating EMT simulations with detailed site-specific models, it is crucial for the industry to not only establish standards for model interoperability, such as the Functional Mock-~~up~~Up Interface (FMU) or the guidelines provided by CIGRE, but also to mandate that the implementations of OEM controller codes can achieve, or ~~exceeding~~exceed, real-time speeds. Adopting this comprehensive approach is imperative for accelerating EMT simulation performance at scale to support the need for detailed system studies.

Table C.4: ~~4000-bus synthetic~~4,000-Bus Synthetic EMT ~~benchmark components list~~Benchmark Components List

Component	Approximate # of components
Buses (3-phase)	~~4000~~4,000
Lines, loads, switched shunt reactors	~~6700~~6,700
Transformers and synchronous machines	~~2000~~2,000
Protection relay models	100
IBR plants (Solar, Wind)	150
OEM Controllers (precompiled DLLs)	300
FACTS and HVDC converters	70

Summary

The examples presented in the case studies underscore the efficacy of parallel computation in facilitating rapid EMT simulation of extensive power grids with minimal user intervention.

It is acknowledged that, particularly for large power systems, a hybrid EMT-Phasor simulation might be applicable. Nonetheless, the selection of appropriate EMT and phasor-~~-~~domain zones to accurately assess transient stability remains a formidable challenge and an area of active research. Best accuracy is achieved with EMT-only simulation mode.

EMT Analysis in Operations

The rapid growth of ~~Inverter-Based Resources (IBR)~~IBRs and ~~Distributed Energy Resources (~~DER~~) pose a~~ challenge ~~to~~ existing power system reliability assessment processes. These resources and their software-defined behaviors expose the limitations of conventional phasor-domain simulation techniques~~,~~ across all aspects of power system engineering, including system operations. There are unique challenges presented by EMT analysis~~,~~ and the associated engineering processes~~,~~ when carried out within the operations planning time horizon. This ~~chapter~~section briefly explores challenges and solutions for study methodologies and model management processes for successful EMT analysis in operations space.

- Why is EMT analysis needed in the operations space?
  - EMT analysis in interconnection studies may typically cover a limited set of potential topology conditions and generation patterns~~,~~ since they necessarily make assumptions about a future system state.~~-~~ The operations planning time horizon is typically much nearer to the real-time system topology and operating conditions than planning studies, so there is less uncertainty when assessing for example a planned maintenance outage condition, unique expected generation pattern, or other system

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conditions. This may allow for a deeper analysis of a specific topology condition than could otherwise be justified in an interconnection study.

- Operations engineering analysis typically revolves around the need for testing the boundary conditions and testing hypothetical and real~~-~~-time scenarios with a wide variety of operating conditions involving topology and generation patterns. The goal is to provide operating guidance for the system operators, identifying the most limiting factors and describing the mechanisms to prevent adverse outcomes following a criteria contingency. Due to the complexity of IBR behaviors~~,~~ and~~ therefore~~ the EMT models representing these resources, these operating studies can be atypical compared to conventional resources.

- What are the necessary processes that need to be in place for successful EMT analysis pipeline in operations?
  - (What are the attributes of) A complete IBR model life cycle management process that produces a repository of accurate, ready-to-use EMT models~~.~~:
    - As-studied model evolution into an as-built model, changes tracked and validated.
    - Repository contains EMT models that passed model accuracy and usability acceptance tests~~,~~ and whose performance benchmarks well against real system events.
    - Model documentation that covers relevant simulation prerequisites and particulars
  - (What are the attributes of) A mature study and simulation pipeline for EMT analysis~~.~~:
    - Process for conveying initial steady-state conditions and disturbance characteristics into test case~~.~~
    - Process for executing simulations in a performant manner (enhance ability for study engineer to iterate)
    - Process for extracting meaningful results from the simulation output (plotting)
- Why are these processes so important to EMT analysis in operations?
  - Timelines~~ – Operations~~: An operations engineer may need to return an answer to a reliability question in a matter of weeks, days, or even hours, which does *not* allow time for:
    - Chasing down model quality or usability issues
    - ~~Collect~~Collecting EMT models from potentially disparate sources~~,~~ or ~~extract~~extracting them from prior studies.
    - ~~Verify~~Verifying that the models to be used represent the most up~~-~~-to~~-~~-date configuration of the projects that fall within the scope of the study area.
    - ~~Chase~~Chasing down model documentation
    - ~~Manual~~Undertaking manual intervention to achieve an EMT simulation initial condition that matches a known steady-state starting point~~.~~
- What are the challenges of performing EMT analysis in operations time horizon?
  - Impact of contingencies on neighboring areas due to ~~Interconnected Reliability Operating Limit~~Interconnection reliability operating limit (IROL) impact, which may expand the study area model, making it challenging for EMT tools~~.~~

Establishing mature processes to support EMT analysis in the operations space has knock-on benefits that extend to any point in the ~~life cycle~~lifecycle of an ~~inverter-based resource~~IBR that requires EMT analysis. For example, an actively managed EMT model repository can benefit the generation interconnection process by reducing the time and effort required to collect, process, and validate EMT models of resources near a future project under study.

~~Additional References~~

~~[1] M. Ouafi, J. Mahseredjian, J. Peralta, H. Gras, S. Dennetière, B. Bruned, "Parallelization of EMT simulations for integration of inverter-based resources", Electric Power Systems Research, Vol. 223, Oct. 2023, 8 pages, DOI: 10.1016/j.epsr.2023.109641.~~

~~[2] A. Abusalah, O. Saad, J. Mahseredjian, U. Karaagac and I. Kocar, "Accelerated Sparse Matrix-Based Computation of Electromagnetic Transients," in IEEE Open Access Journal of Power and Energy, vol. 7, pp. 13-21, 2020, doi: 10.1109/oajpe.2019.2952776.~~

~~[3] J. Mahseredjian, M. Naidjate, M. Ouafi and J. A. O. Wilches, "Electromagnetic Transients Simulation Program: A unified simulation environment for power system engineers," in IEEE Electrification Magazine, vol. 11, no. 4, pp. 69-78, Dec. 2023, doi: 10.1109/mele.2023.3320511.~~

~~[4] S. Li, J. Bélanger, M. Cervantes, M. Kazemtabrizi, J.N. Paquin, V. Lapointe, W. Li, J. Paez-Alvarez, "OPAL-RT Technologies Inc Fast and real-time EMT simulations for Hardware-in-the-Loop controller performance testing and for on-line transient stability analysis of large-scale low-inertia power systems", CIGRE CANADA, 2023 Conference, Vancouver, B.C.~~

~~[5] S. Li et al., "Fast and real-time EMT simulations for Hardware-in-the-Loop controller performance testing and for on-line transient stability analysis of large-scale low-inertia power systems". Paper CIGRE-689, CIGRE Canada, Vancouver, BC, Sept. 25 – 28 2023. [Online] Available: https://cigreconference.ca/papers/2023/paper_689.pdf~~

~~[6] B. Bruned, J. Mahseredjian, S. Dennetière, J. Michel, M. Schudel and N. Bracikowski, "Compensation Method for Parallel and Iterative Real-Time Simulation of Electromagnetic Transients," in IEEE Transactions on Power Delivery, vol. 38, no. 4, pp. 2302-2310, Aug. 2023, doi: 10.1109/TPWRD.2023.3238422.~~

~~[7] B. Bruned, J. Mahseredjian, S. Dennetière and N. Bracikowski, "Optimized Reduced Jacobian Formulation for Simultaneous Solution of Control Systems in Electromagnetic Transient Simulations," in IEEE Transactions on Power Delivery, vol. 38, no. 5, pp. 3366-3374, Oct. 2023, doi: 10.1109/TPWRD.2023.3275221.~~

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Guideline Information and Revision History

Guideline Information	
Category/Topic: EMTTF	**Reliability Guideline/Security Guideline/Hybrid:** Reliability Guideline: Recommended Practices for Performing EMT System Studies ~~– When, How, and What~~for Inverter-Based Resources
Identification Number: [NERC use only]	**Subgroup:** EMTTF

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

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~~report and ~~Long Term Reliability Assessments~~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:

- Number of TPs and PCs that have implemented screening methods and criteria for EMT modeling
- Number of TPs and PCs performing select EMT studies recommended herein

Effectiveness Survey

On January 19, 2021, the Federal Energy Regulatory Commission (FERC) accepted the NERC proposed approach for evaluating ~~Reliability Guidelines.~~reliability guidelines. This evaluation process takes place under the leadership of the RSTC and includes the following:

- ~~industry~~Industry survey on effectiveness of ~~Reliability Guidelines;~~reliability guidelines
- ~~triennial~~Triennial review with a recommendation to NERC on the effectiveness of a ~~Reliability Guideline~~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~~that use reliability and security guidelines to respond to the short survey provided in the link below.

Guideline Effectiveness Survey [insert hyperlink to survey]

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Errata

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Technical Reference Document: Considerations for Performing an Energy Reliability Assessment – Volume 2

Action
Approve

Background
Energy reliability assessments are critical for assuring the reliable operation of the bulk power system (BPS) as the penetrations of variable generation resources and/or just-in-time energy supplies increase. In turn, dispatchable and quick start units are relied upon for flexibility, where sources such as energy storage and natural gas-fired generation deliver energy to support intra-hour and inter-hour ramping to match variations in demand and energy production from the rest of the fleet. Energy reliability assessments account for the finite nature of stored fuels and their replenishment characteristics. In addition, the availability of natural gas to supply electric generation can impact reliability during high natural gas demand periods throughout the year. Energy reliability assessments provide assurance to planners and operators that resources can supply both electrical energy and ancillary services needs across a span of time.

Summary
The Energy Reliability Assessments Working Group is requesting that the RSTC approve the Technical Reference Document: Considerations for Performing an Energy Reliability Assessment – Volume 2.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Technical Reference Document: Considerations for Performing an Energy Reliability Assessment

Volume 2

December 2024

RELIABILITY | RESILIENCE | SECURITY

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Table of Contents

Preface

Electricity is a key component of the fabric of modern society and the Electric Reliability Organization (ERO) Enterprise serves to strengthen that fabric. The vision for the ERO Enterprise, which is comprised of 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

Considerations for Performing an Energy Reliability Assessment, Volume 1[1] (Volume 1), which provided an overview of the basic elements of an energy reliability assessment (ERA) and general considerations for performing an ERA, was published in March 2023. Volume 2 details how to perform an ERA, including different methods for building analysis tools, how metrics can be defined in terms of energy, and approaches to corrective actions when those metrics cannot be met. **The purpose of this technical reference document was not to dictate how to perform an ERA but rather to highlight inputs that should be considered when performing an ERA.**

Several key pieces of prerequisite knowledge, including Volume 1, *NERC Reliability Guideline: Fuel Assurance and Fuel-Related Reliability Risk Analysis*,[2] and the *NERC Special Report on Maintaining Bulk Power System Reliability While Integrating Variable Energy Resources (VER)*, lead into the topics discussed in this document.[3] The fuel assurance reliability guideline discusses the individual risks associated with specific fuel types, helping the reader understand how upstream fuel supplies may impact power generation—a key input to any energy analysis. Likewise, the need for flexibility in a committed fleet to maintain reliability is discussed in greater detail in this document.

This technical reference document is organized into eight chapters. Chapters 1 through 4 outline the considerations and recommended data needed to perform an ERA in the NERC-defined[4] time horizons. Chapter 1 highlights general elements that are applicable to all time horizons. Chapters 2, 3, and 4 are more specific to the near-term, seasonal, and planning ERAs, respectively. To get the full picture of an ERA in a specific time horizon, the reader is encouraged to review Chapter 1 before reading the applicable chapter for the time horizon being assessed. Later chapters cover methods (Chapter 5), case development and scenario modeling (Chapter 6), and metrics (Chapter 7). The discussion of methods will help in the development and design of tools. The chapter on case development and scenario modeling discusses a recommended approach for base case and scenario development. Chapter 7 discusses existing metrics that can be used to compare the results of an ERA. Lastly, Chapter 8 enumerates remedies available when energy shortfalls are identified on corrective actions.

As factors that may play a role in promoting energy reliability differ significantly across North America, this document proposes an array of solutions that may apply to each particular system that could be considered under certain situations. Factors that are known to introduce this variety include the following:

- Generating capacity and density (e.g., how much and where) of wind and solar resources are a primary driver for the high degree of generation diversity among areas, including the performance characteristics for each (e.g., certain areas, such as the southwestern United States, are more likely to support highly productive solar resources than those in the north).
- Storage capabilities and capacities for fuels like oil, coal, natural gas, and fissile nuclear material differ across areas but also within areas depending on their geographic size. For instance, if an area has only limited reliance on stored fuels, it may be able to model energy reliability as a series of capacity assessments and rely on more general assumptions for impact of one hour to the next.
- Fuel replenishment delay times and diversity of supply and delivery options impact specific factors of an ERA. For example, anticipated long delays between arranging and receiving fuel deliveries could require longer ERA study periods to produce meaningful results.
- Available natural gas pipeline capacity, gas pipeline network topology and the diversity of the available gas supply to the pipeline network from production or storage areas can impact an ERA's input assumptions.

[1] https://www.nerc.com/comm/RSTC_Reliability_Guidelines/CLEAN_ERATF_Vol_1_WhitePaper_17MAY2023.pdf
[2] https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Fuel_Assurance_and_Fuel-Related_Reliability_Risk_Analysis_for_the_Bulk_Power_System.pdf
[3] https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC-CAISO_VG_Assessment_Final.pdf
[4] https://www.nerc.com/pa/Stand/Resources/Documents/Time_Horizons.pdf

These differences would factor into scenario selection. A high degree of diversity in supply and transportation options is likely to render single points of failure less extreme and more likely to be mitigated with fewer actions.

- Regulatory considerations differing from one area to the next may play a role not only in the options available for correcting energy deficiencies but could also change how input assumptions are accounted.

These are just some of the factors that make ERAs non-universal; however, the general concepts can be consistently applied across different systems.

The appropriate actions resulting from deficiencies identified by ERAs may also differ based on the points discussed above. Longer lead times may be required to address potential energy deficiencies than capacity deficiencies. For example, shifting the way planners consider storage in analyses would be a required consideration for an energy assessment even if this may be one of the actions that should not be considered for capacity. Storage optimization over periods of time becomes part of the solution as VER output fluctuates throughout a day, a week, or longer.

Chapter 1: Inputs to Consider When Performing an ERA in Any Time Horizon

The information needed to perform an ERA is similar to what is required for capacity assessments but with the additional component of time. The time component of an ERA accounts for the impact of operating conditions and actions that occur at one point in time and their impact on future intervals.

Volume 1 discussed the differences between capacity and energy assessments. Capacity assessments are performed today in nearly every time horizon, from operations to long-term planning. Connecting the hours and transforming operations at one point into future availability is what expands a capacity analysis into an energy analysis.

Supply

Supply resources can be categorized into generation, electric storage,[5] and load-modifying resources[6]. They can be modeled as either supply additions or demand reductions as decided by the analyst. Accurately modeling the energy availability of generation resources requires an understanding and representation of the underlying fuel supply and the generator system.

Fuel supply will be categorized in this document as either stored fuels or just-in-time fuels. Tangible inventory and replenishment strategies should be considered for stored fuels. Just-in-time fuels require considerations for transportation capacity, fuel deliverability, and the immediate impact of disruptions. Furthermore, just-in-time fuels include weather-dependent fuel sources such as solar irradiance and wind, that introduce significant volatility for which an analyst should account.

Power generation is not the only sector that consumes fuel. Fuels like oil and natural gas are directly used in other applications. For example, the U.S. Census Bureau's *American Community Survey*[7] includes information on the types of fuel used to heat homes broken down by individual U.S. states. This information is one of many inputs that would guide an analyst in building future profiles of fuel demand for input into an ERA. Competing fuel demands should be considered when looking holistically at an interconnected and interdependent energy system.

A more detailed introduction to fuel assurance that is specific to a variety of fuel types is provided in *Reliability Guideline: Fuel Assurance and Fuel-Related Reliability Risk Analysis for the Bulk Power System*.[8]

Stored Fuels

Power generators with stored fuels are those where fuel inventory is on site or reasonably close to the generator so that fuel transportation risks are minimal. Fuels are most commonly stored in tanks, reservoirs or piles and have a measurable inventory. Examples include, but are not limited to, nuclear fissile material, fuel oil, coal, water for hydro facilities, and natural gas as liquefied natural gas (LNG) or in subsurface geological formations.

Once inventory information is gathered and/or estimated, it must then be converted into electric energy based on the specific generator that uses the fuel. For thermal generators, that calculation requires two additional pieces of information: fuel heat content and generator heat rate. Generator heat rate is typically expressed in terms of Btu/kWh or MMBtu/MWh. Heat rates range from less than 6,000 Btu/kWh (6 MMBtu/MWh) to over 20,000 Btu/kWh

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[5] For the purpose of the discussions in this technical reference document, *electric storage* is a device or facility with electric power as an input, a storage medium of some kind that stores that energy, and electric power as an output. This is in contrast to stored fuel in that the source of stored fuel is external to the power system. Both electric storage and stored fuel can be labeled *energy storage*.

[6] Load-modifying resources are (behind-the-meter) generators that modify demand rather than provide additional supply.

[7] https://data.census.gov/table/ACSDT1Y2019.B25040?q=heat

[8] https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Fuel_Assurance_and_Fuel-Related_Reliability_Risk_Analysis_for_the_Bulk_Power_System.pdf

(20 MMBtu/MWh) and can vary across the operating range of a resource, with considerations for efficiency at various output levels. Oil heat content varies slightly by the type of oil and how it was refined and ranges between 135,000 Btu/gallon to 156,000 Btu/gallon. The example below walks through a conversion from gallons of oil to MWh of electric energy and the amount of time that a generator would continue to operate at a specific power output. A similar calculation could be completed for other types of stored fuels using the respective fuel-specific heat contents and generator heat rates.

Calculate the energy production capability (MWh total and hours at maximum output) of a 135 MW oil generator with a heat rate of 9,700 Btu/kWh and 1,000,000 gallons of fuel oil with a heat content of 135,000 Btu/gallon.

$$1{,}000{,}000\ gallons * \frac{135{,}000\ Btu}{gallon} * \frac{kWh}{9{,}700\ Btu} * \frac{MWh}{1{,}000\ kWh} = 13{,}918\ MWh$$

$$\frac{13{,}918\ MWh}{135\ MW} = 103\ hours, at\ maximum\ output$$

In an ERA, once this specific generator produces 13,918 MWh of energy, it must be set as unavailable for all remaining hours or fuel replenishment must occur.

Figure 1.1: Converting Stored Fuel to Available Electric Energy

Multiple generators at a single site often share a fuel inventory, meaning that more than one generator could deplete fuel during operations. This is further complicated when different generator technologies with different efficiencies are operating on the same fuel and by the fact that efficiencies of a given unit may vary based on its operating point. For this reason, discrete modeling of generators and their individual demands on the common fuel supplies at sites provides for a more accurate solution than a generalized approach.

Stored fuel replenishment is a key consideration in an ERA that is impacted by a number of factors. Proximity to additional storage affects assumptions for replenishment, as power generator stations that are adjacent to larger storage facilities have fewer obstacles to replenishment than generators far from supply sources or in residential areas. Transportation mechanisms also affect the ability to replenish stored fuels. Generators are typically replenished by pipeline, truck, barge, or train, each of which has its own set of advantages and/or disadvantages. The experts on each generator fuel supply arrangement are the owner/operator of the generator and their fuel suppliers. Performing an ERA requires communication with the Generator Owners and Operators to ensure that the modeling for fuel supplies is accurate. Once the analyst becomes familiar with the information needed from the Generator Owner/Operators, the specific fuel information can be obtained and properly accounted for through routine surveys.

The following table is useful for modeling stored fuels in an ERA for any time horizon:

Table 1.1: Information Useful for Modeling Stored Fuels in an ERA in Any Time Horizon		
Data	**Potential Sources**	**Notes/Additional Considerations**
Specific, usable[9] inventory of each generation station	Generator surveys Assumptions based on historical performance	Inventory is often shared for a group of generators located at a single station. Surveys should be performed as often as necessary to initialize an assessment with accurate information. It is recommended to start each iteration of an assessment with updated data. Hydroelectric resources may need to consider the availability of water as a fuel input – change over the course of the year or vary by year. Environmental limitations: water flows/rights priority, dissolved oxygen (DO) limitations, etc. Stored fuels may be used for unit start-up with a portion embargoed for blackstart service provision.
Minimum consumption requirements of fuels that have shelf-life limitations	Surveys of Generator Owners or Operators Assumptions based on historical performance	May result in a fuel being consumed at a time when it is less than optimal.
Replenishment assumptions	Generator surveys Assumptions based on historical performance	Replenishment is key to modeling inventory at any point during the study period. Replenishment restrictions are also an important aspect of an ERA.
Shared resources	Generator surveys or registration data	Modeling the sharing of fuel between multiple resources allows for precise modeling of fuel availability.
Global shipping constraints	Industry news reports	Stored fuel supply is often impacted by world events that cause supply chain disruptions, including port congestion, international conflict, shipping embargoes, and confiscation.
Localized shipping constraints	Weather forecasts or assumptions, direct communication with local transportation providers, emergency declarations[10]	Considerations for local trailer transportation of fuels over wet/snow-covered roads, rail route disruptions due to weather or debris, as well as seaport weather when docking ships or river transportation route restrictions for barge movements.

[9] Usable inventory is the amount of fuel that is held in inventory after subtracting minimum tank levels that are required for quality control and fuel transfer equipment limitations.
[10] https://www.fmcsa.dot.gov/emergency-declarations

Specific Considerations by Generator Type

Fuel Oil Generators

Fuel oil for generators, diesel fuel for transportation, and home heating oil all share supply chain logistics. Though there are subtle differences between each type, they are nearly identical at the supply side. As such, stresses on supply from one mechanism can lead to deficiencies in supply to a seemingly unrelated mechanism. A likely scenario is that cold weather that increases demand on home heating oil creates a need for an accelerated replenishment to residential and commercial heating oil tanks, resulting in reduced availability of replenishment stocks for power generation. In an ERA, this should be considered as a limitation on the inventory available for replenishment when conditions are cold, and oil heating is prevalent in the area.

Fuel oil delivered by truck can face a number of obstacles. For example, truck drivers are legally allowed to drive only a set number of hours,[11] and trucking can be susceptible to delays caused by snow and debris. Both scenarios may cause delays in fuel delivery to generators that should be considered. However, waivers to some rules during specific conditions have been granted by state and federal agencies during emergencies.[12]

Delivery by ship or barge may be available to resources with access to waterways, typically allowing larger cargoes than truck delivery. Oil trucks can typically transport 5,000–12,000 gallons of fuel per truck. River barges have capacities ranging between 800,000 gallons and nearly 4 million gallons. The largest oil tankers can transport over 50 million gallons of fuel.[13] Challenges in delivering by water include rough seas and waterway freezing.

Fuel replenishment in an ERA can be modeled as a multiplier or an adder to initial fuel supply expectations from the start or can be more precisely modeled at an hourly granularity. The simpler calculation ignores the specific constraints surrounding replenishment and assumes that the total amount of fuel will be available when it is needed. The following simple example sets the initial tank level equal to the actual (or assumed) starting inventory plus all replenishments throughout the study period. For example, if a 1 million gallon tank starts with 500,000 gallons and is expected to replenish that quantity twice, start with 1.5 million gallons and ignore the constraint of the tank size and deplete the oil inventory from the new starting point. A more complex refinement of this approach would account for replenishment strategies, time constraints from the decision to replenish to the time of delivery, rate of refill, individual delivery amount, and transportation mechanisms. More effort is required to apply the specific constraints of a fuel oil tank and the associated replenishment infrastructure. While modeling more granular replenishment will be more precise, it may not result in significant improvements in accuracy depending on the time horizon of the study. Both methods can be employed in the same study. Analysts should consider the appropriate levels of constraints on the replenishment capabilities of various oil tanks depending on the attributes of the system under consideration.

Dual-Fuel Generators

Dual-fuel generators can lessen the risk of outages caused by a lack of a specific fuel supply but require additional information to perform ERAs and develop appropriate Operating Plans. Consideration should be given to formulating operational models that include the decisions that lead to the use of each fuel, the time required to swap fuels, limitations of the generator during a fuel swap, and output reductions or environmental restrictions while operating on the alternate fuel. Some generators can operate on multiple fuels simultaneously, and some can swap fuels while continuing to operate, perhaps at a lower output for a controlled swap. Other generators are required to shut down before swapping fuel. Since each generator is different, the specific processes should be understood when developing an ERA.

[11] https://www.ecfr.gov/current/title-49/subtitle-B/chapter-III/subchapter-B/part-395/subpart-A/section-395.3

[12] https://www.fmcsa.dot.gov/emergency-declarations

[13] https://response.restoration.noaa.gov/about/media/how-much-oil-ship.html#:~:text=Inland%20tank%20barge%20(200%E2%80%93300,7%20million%E2%80%9314%20million%20gallons

Dual-fuel capability auditing and reporting is the most comprehensive method of obtaining fuel switching information. However, surveys can provide similar information if auditing cannot be accomplished and the survey information is dependable or vetted for accuracy. Generator Owner/Operators are the experts in the logistics of fuel swapping and should be consulted when performing an ERA.

Coal Generators

Coal storage capacity is usually larger than fuel oil storage capacity but comes with its own unique challenges. When stored outdoors and exposed to the elements, causing frozen or wet coal, coal's outage mechanisms can differ from other generator types. Given the relatively large storage volumes and replenishment options associated with coal-fired generators, an analyst performing an ERA may assume that the fuel supply is unlimited, simplifying the overall process. However, care should be taken to ensure that this assumption is prudent and will not result in unexpected conditions when the fuel supply is depleted or unable to be replenished.

Nuclear Generators

Nuclear fuel (e.g., uranium or plutonium) is stored in a reactor. Nuclear replenishment is a well-planned process that is scheduled months or years in advance. Depletion of nuclear fuel is measured in effective full power hours (EFPH), where a given supply of fuel is depleted based on the percent of full power at which the plant is operated over time. Refueling typically requires the reactor to shut down and be opened to replace fuel assemblies. Although advancements in reactor technologies that could change how a nuclear generator would be modeled in an ERA are regularly proposed, most of the operating plants in North America remain generally the same. The key points for modeling nuclear power in an ERA focus on long durations of operation and outages and typically a considerable amount of energy produced in comparison to generators with similar footprints.

Hydroelectric Generators

Pondage water available for hydroelectric generation is a function of past precipitation. Considerations should be made for environmental requirements for minimum and maximum flows at specific times, which would impact the quantity of water that is available for power generation throughout an ERA. Forecasting hydroelectric availability and demand is among the first parameters for power system operations and planning, and significant experience has been gathered over the last century.

Just-in-Time Fuels

Various types of natural gas, run-of-river hydro, solar, and wind generators rely on just-in-time fuels, which are consumed immediately upon delivery. Each generator type has its own specific considerations for fuel constraints that should be well understood while building an energy model and performing an ERA. Just-in-time fuels are delivered immediately prior to, or within moments of, conversion to electric energy, either by combustion in a gas turbine or boiler, conversion through photovoltaics, or directly applying force to spin a wind turbine for generation.

Natural Gas

Natural gas-fired generators rely on the delivery of fuel at the time of combustion in a turbine or boiler. Natural gas is a compressible fluid, primarily transported by pipelines. Gas pipeline operators can typically operate their pipelines with a range of operating pressure, which provides some level of flexibility by, in effect, storing natural gas in the very pipelines that are used for transportation. This flexibility allows for some intraday mismatches between natural gas supply and natural gas demand, so long as mismatches do not preclude operating within specifications. The minimum pressure needed for generator operation is typically lower than the main pipeline pressure, and regulator(s) are used to maintain proper inlet pressure to the generator. For generators that require pressure that is higher than pipeline pressure, on-site compression is typically included in the site design.

For natural gas delivery to be scheduled to a generator, there are two required components. The first major component is procurement of the physical gas, the commodity. The commodity can be procured through natural gas marketplaces, directly from producers through bilateral arrangements, or via marketers holding bulk quantities. Shippers may elect to schedule natural gas from storage locations. Natural gas volumes typically would be scheduled in advance according to the specific pipeline rules and requirements (usually gas-day ahead) to allow pipelines to assess their ability to supply the nomination.

Secondly, there must be transportation arranged for the gas to ensure delivery at the desired location. Gas transportation can be firm or non-firm. Firm transportation usually must be acquired well in advance of the anticipated need, usually months or seasons, and most often years in advance, but can be released for others to use when it is not needed by the primary firm transportation holder. In addition to firm transportation, there are other varying degrees of firmness. Interruptible contracts may also be available, and the pipelines decide when to allow each level of transportation firmness to flow based on conditions and demands on the pipeline. Also, there can be periods where even firm transportation can be curtailed based on pipeline conditions. Understanding each generator's specific situation and gas contract requirements is crucial for performing an ERA. Pipeline flexibility to accommodate unscheduled receipts and deliveries is at the discretion of the pipeline operators and should be accounted for in an ERA. Communication and coordination with pipeline operators, as well as historic observations, can give the analyst the information necessary to model the expected flexibility.

Natural gas pipelines that deliver to power generators usually serve multiple generators as well as other types of demand. Competing demand must be accounted for in an ERA in order to produce an accurate solution. Depending on the contractual arrangements that have been made by different natural gas customers, demand will be served in a specific order. Higher levels of firm transportation arrangements provide more certainty and come with higher fixed costs. It is important to understand the individual arrangements for commodity and transportation for each generator when modeling the amount of natural gas that would be available for power generation. It is also imperative that an analyst understand transportation constraints and non-power-generation demands when calculating the remaining quantity of gas available for power generation. Operating generators when there is no fuel available produces an infeasible solution.

Natural gas is scheduled daily (i.e., the gas day). The gas day is defined by the North American Energy Standards Board (NAESB)[14] as 9 a.m. to 9 a.m. (Central Clock Time). Quantities of gas are scheduled in terms of MMBtu per day, fitting the construct of the 24-hour gas day. Electric energy is scheduled on a more granular basis (usually hourly) that relies on a daily allotment of fuel to be profiled over that 24-hour period. An ERA should consider the limitations that could be created by this misalignment between the gas and electric day and the magnitude of hourly gas flow imbalances that are allowed by the individual pipelines serving the generators in the study area.

Depending on the constraints that are in place on the gas pipeline network for a given area, the model can be simple or it can be more granular, as determined by the analyst. In a system where the gas demand is distributed similarly to the gas supply capabilities, a homogeneous gas model can be used. Homogeneous models consider a single energy balance of gas supply and gas demand. Homogeneous models require less effort to model and likely will solve faster but could miss potential constraints if not evaluated properly.

Additional information concerning the natural gas supply chain is provided in Chapter 2 of *NERC Reliability Guideline: Fuel Assurance and Fuel-Related Reliability Risk Analysis for the Bulk Power System*.

In its simplest form, the gas supply/demand balance equation is similar to the electric supply/demand equation.

$$Gas\ Supply = Gas\ Demand$$

[14] https://www.naesb.org//pdf/idaywk3.pdf

More complex calculations can help an analyst determine the availability of natural gas for generation.

$$Gas\ Supply = Gas\ Demand_{Heat} + Gas\ Demand\ _{Industrial} + Gas\ Demand\ _{Generation}$$

For this example, assuming that natural gas demand for heat and industry has a higher priority level for their gas transportation service (e.g., primary firm) than generation, the equation can be rearranged to solve for gas available for generation, a proxy for gas demand for generation.

$$Gas\ Available\ _{Generation} = Gas\ Supply - Gas\ Demand_{Heat} - Gas\ Demand\ _{Industrial}$$

Typically, natural gas supply would be a fixed daily quantity, based on the transportation of the pipeline network. In a more complex system, it would also be a function of production assumptions. In the most complex form, the gas pipeline network may require nodal modeling, similar to the electric system, in order to solve for specific conditions, operations, or disruptions, but that level of complexity would come with a steeper computational price.

Natural gas demand for heating is a function of weather, usually temperature and wind speed, and will differ for every geographic area. A simple form of modeling natural gas demand for heating could use a linear function of average temperature, or heating degree days.[15] On the other end of the spectrum, complex gas heating demand modeling could employ artificial neural network forecasting methods with inputs like temperature, wind speed, day of week, time of year, and any other pertinent inputs that would drive gas demand. A simple example of calculating natural gas available for power generation is shown in the following example.

[15] https://forecast.weather.gov/glossary.php?word=heating%20degree%20day

In the following example, assume that a given natural gas pipeline system can transport 1,000,000 MMBtu/day and has adequate supply injections at that level with no additional supply sources in the area. Also, assume a fixed quantity of industrial demand of 100,000 MMBtu/day and that heating demand is a linear function of heating degree days defined by the points 0 MMBtu/day at 0 HDD and 600,000 MMBtu/day at 75 HDD.

Calculate the quantity of natural gas that would be available for power generation at 40 heating degree days under these assumptions.

$$Gas\ Available_{\ Generation} = Gas\ Supply - Gas\ Demand_{Heat} - Gas\ Demand_{\ Industrial}$$

$$Gas\ Available_{\ Generation} = 1{,}000{,}000\ \frac{MMBtu}{day} - \left(600{,}000 * \frac{40\ HDD}{75\ HDD}\right)\frac{MMBtu}{day} - 100{,}000\ \frac{MMBtu}{day}$$

$$Gas\ Available_{\ Generation} = (1{,}000{,}000\ - 320{,}000 - 100{,}000)\ \frac{MMBtu}{day}$$

$$Gas\ Available_{\ Generation} = 580{,}000\ \frac{MMBtu}{day}$$

Given that 580,000 MMBtu/day is available for power generation, calculate the MWh that would be available using an average heat rate of 8,000 Btu/kWh.

$$Generation\ (MWh) = Gas\ Available / \ Heat\ Rate\ (MMBtu/MWh)$$

$$Generation\ (MWh) = \frac{580{,}000\ MMBtu}{8.0\ MMBtu/MWh} = 72{,}500\ MWh$$

Convert 72,500 MWh to hourly MW, evenly distributed across all hours

$$\frac{72{,}500\ MWh}{24\ hours} = 3{,}020\ MW$$

The graph below shows how the amount of available natural gas will vary based on this specific model of non-power demand and remaining availability.

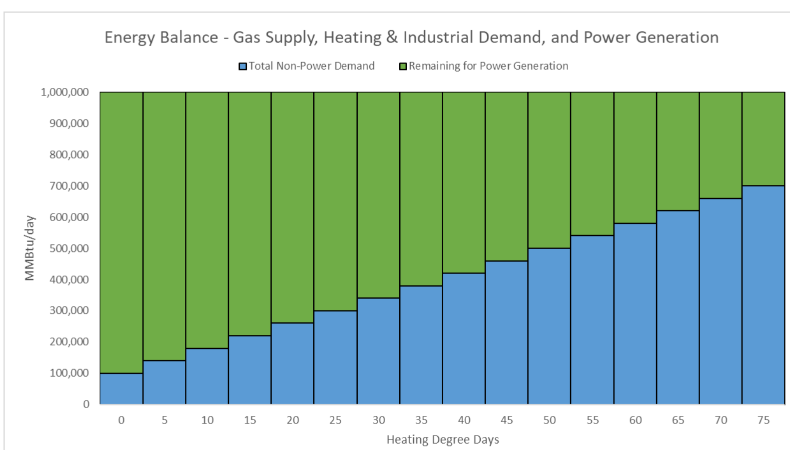

Figure 1 – Energy Balance – Gas Supply, Heating & Industrial Demand, and Power Generation

Figure 1.2: Fuel Availability Calculation (Natural Gas)

While a single event or set of conditions may cause disruptions on a pipeline that could impact several delivery points, internal line pack storage capacity of pipelines could reduce the downstream effects of interruptions are not necessarily immediate as pipeline operators work to control the changes in operating pressure. Studies[16] have shown that there may be significant time between pipeline disruptions and resulting generator outages. ERAs can account for disruptions by staggering outages according to the expected rate of pressure drop and/or operator decisions to operate valves and shut-in gas customers (specifically generators). In the first few hours of a disruption, studies focus on the replacement of natural gas generation by the remaining fleet that is unaffected by the disruption. This includes start-up times and ramping capability of generators from off-line to high utilization. After the first few hours, once generation is replaced, ERAs should focus on the long-term (i.e., several hours to several days) effects of major disruptions and the impact that will have on the generation fleet that would otherwise be unused. ERAs would generally be focused on the longer-term effects of disruptions rather than the initial events themselves.

Basic mapping of generators to pipelines is key to assessing the impact of disruptions. This information can be gathered from pipeline maps, generator surveys, contract information and registration data. Research is required to place the generators on pipelines in the correct location in reference to injection and receipt points, compressor stations, and other pipeline demand. An ERA can then use this information for scenario development and analysis. There are instances in which a generator's proximity to a pipeline is irrelevant to the pipeline from which it has actually contracted the gas. In these cases, mapping based on contractual counterparties would be more precise.

The following table useful for modeling natural gas supply in an ERA for any time horizon:

Table 1.2: Information Useful for Modeling Natural Gas Supply in an ERA in Any Time Horizon

Data	Potential Sources	Notes/Additional Considerations
Pipeline transportation capacity	Pipeline Electronic Bulletin Boards (EBB), open season postings, firm transportation contracts	Interstate pipeline information is readily available through public sources, usually directly from the pipeline company itself.
Gas pipeline constraints	EBB postings of operationally available capacity and planned service outages, pipeline maps	Starting with pipeline maps or one-line diagrams, pinpointing the location of specific constraint points requires research. Communication with pipeline operators is helpful when specific locations are in question or difficult to find.
Generator location on pipelines	Pipeline maps, generator surveys, registration data	Research is required to properly place generators on pipelines in the correct location.
Non-generation demand estimates	Historical scheduled gas to city gates and end users, historic weather data, weather assumptions based on historic weather and climatology	Similar to load forecasting on the electric system, gas estimates play a crucial role in developing a holistic energy solution. Assuming that more gas is available than physically possible could lead to inaccurate study results.
Heating and end-user demand assumptions	Filings with state regulators, historical demand data	Regulated utilities will file their expected needs for natural gas with their respective state regulators.

[16] https://www.nerc.com/pa/RAPA/Lists/RAPA/Attachments/310/2018_NERC_Technical_Workshop_Presentations.pdf

Table 1.2: Information Useful for Modeling Natural Gas Supply in an ERA in Any Time Horizon		
Contractual arrangements	EBB index of customers, generator surveys, FERC Form 549B	Some information can be obtained via the EBB Index of Customers; however, nuanced data would need to be queried directly from generators. Non-public information includes generator arrangements with gas marketers and participation in capacity release agreements.
Generator heat rates	Registration data, generator surveys	Converting electric energy to fuel consumption and vice versa requires the heat rate of a generator, typically expressed in Btu/kWh or MMBtu/MWh.

Variable Energy Resources

Run-of-river hydro, solar, and wind resources generate electricity when the fuel is available and conditions permit. The amount of energy produced by these resources at any given time is uncertain, and operators cannot require that the generators produce more power when conditions do not allow for it. Forecasts are available for expected variable generation outputs and have improved over time; however, longer-range (from seasonal to several years out) ERAs must make assumptions for inputs that would be difficult to predict. Historical data is a good starting point for developing assumptions; this can be further augmented by known or anticipated conditions, such as drought, and adjusted for additional buildout since the historical conditions were recorded. The resulting input to an ERA is an hourly profile or set of profiles that portrays VER output. For areas where VERs make up a small percentage of the total nameplate of generation, resources may not need to be as specific when building energy models. The model could assume a fixed output over the course of the study period based on historical performance (e.g., capacity factor) and nameplate capability. A simple model is easier to build, maintain, and understand but may fall short when attempting to reveal deficiencies once the resources become a larger producer of electric power for the area.

Energy Supply Variability

Energy supply variability means that ramping capability is needed. Just-in-time fuels or input energy are subject to large- and small-scale energy supply interruptions (in this context, including clouds over solar panels, calm winds, and gas network outages). Variability of one fuel supply stresses other fuel supplies or requires drawdown of storage when replacement energy is sought. The rate of increase or decrease of the production from a resource with a variable fuel supply (e.g., wind or solar) has the potential to overwhelm the infrastructure and capabilities of the replacement generators. An ERA should consider the ability of balancing resources to replace fast-moving variable resources when production wanes and the ability to back down when production returns. Both increases and decreases in generation or demand pose risks.

The two figures below show an example of actual solar and wind production, respectively, for seven consecutive days in March 2023. As shown, the hourly production of solar or wind can change by thousands of MW for the same hour between consecutive days. To account for the uncertainty associated with VER production, analysts may have to use probabilistic analysis in a near-term ERA to best evaluate the energy reliability risk. Probabilistic methods can allow the assessment to ensure that the flexible capacity is available across a range of scenarios and combine the results to evaluate the risk. Alternatively, to use deterministic methods, specific variable energy production scenarios should be chosen as a design basis that stresses the system to determine if sufficient energy is available in the time horizon being studied. The ability to produce variable production curves based on weather forecasts, forecast errors, and resource characteristics—or, at least, historical production data—is necessary to support near-term ERAs.

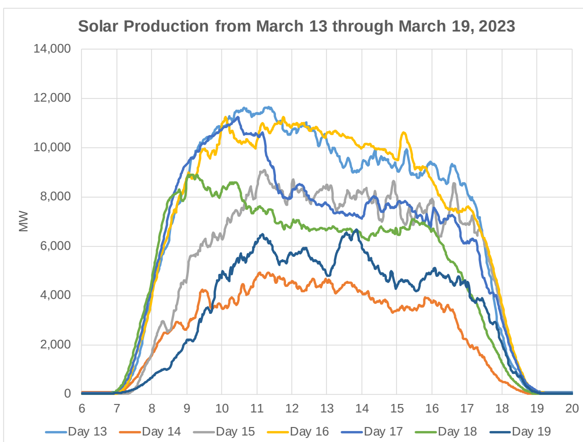

Figure 1.3: Actual Solar Production for Seven Consecutive Days

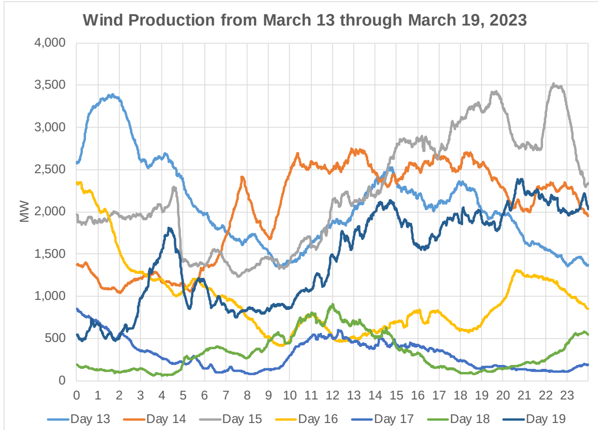

Figure 1.4: Actual Wind Production for Seven Consecutive Days

Evaluating that capability requires knowledge of fuel supply constraints and specific generator capabilities. For example, when solar production has peaked on a system with significant solar power, the evaluation would start by modeling the ramping capability of the resources that are replacing that power. Once the physical capabilities of replacement resources are known, the next layer to consider is the upstream infrastructure that is necessary to support their operation. For example, when replacing solar power as part of the daily cycle of operations, natural-gas-fired generation could ramp up to replace the solar power. Consideration should be made to determine if the natural gas pipeline system has the capability to maintain established gas system tolerances while ramping generation up. Assumptions would need to be made for the initial pipeline pressure, and the analyst will need to know the minimum and maximum allowable operating pressures. Pipeline operators maintain pipeline pressure by limiting the rate at which the demand is allowed to fluctuate and modulating operations of compressor stations along the pipeline. These constraints may limit the flexibility of natural gas resources beyond what is expected without factoring in gas pipeline operational practices. If fuel systems are unable to keep up with ramping generation, ramping generation should be discounted accordingly in an ERA. This type of assessment can get complicated quickly and should be coordinated with natural gas pipeline operators to ensure that accurate information is used.

On the other side of the spectrum is when VERs begin to ramp their production from low to high. This situation is likely not as dire , as conventional resources can generally ramp their output down faster than ramping up, and some variable resources can be curtailed if a system reliability risk emerges. However, the considerations for pipeline pressures and energy storage still apply, just on the opposite side of the spectrum. Using solar power ramping as the example again: when solar production starts to ramp up while demand increases at a lower rate, in the morning, solar over-generation results in a need to back down other supply resources. However, generation problems can arise if gas pipeline pressures are already high and storage is full, resulting in pipeline constraints caused by unused fuel in the pipe. Coordinated operation of the gas and electric systems should provide for multiple mechanisms to ensure that this can be minimized or avoided altogether. Electric System Operators would need to ensure that there is room to charge/pump the storage resources as necessary through the periods of ramping, and an ERA would provide the information necessary to set those plans.

The following table contains information useful for modeling energy supply variability in an ERA for any time horizon:

Table 1.3: Information Useful for Modeling Energy Supply Variability in an ERA in Any Time Horizon

Data	Potential Sources	Notes/Additional Considerations
VER assumptions	VER forecasts as described in the VER sections of this document	VER production drives the need for flexible generation to be available or online. Additionally, the ability to curtail VER production should be considered as a mitigating option.
Generation ramping capability	Registration data, market offers	Balancing resources would be used to maintain system frequency from moment to moment.
Fuel supply dynamic capabilities	Fuel supply network models, market-based models to determine volumes delivered to specific sectors or historic observations	The key to including ramping capability in an ERA is focusing on the capabilities of the fuel delivery network (e.g., gas pipelines, fuel oil or coal delivery systems at specific generators) and how that network responds to the ramping needs of the system.

Emissions Constraints on Generator Operation

Emissions from all industries, including power generation, are being increasingly restricted, limiting generator capability or operating durations and windows. Emissions limitations are more nuanced than inventory limitations; one additional complexity is that waivers can be granted under emergency declarations, meaning that the limits are not necessarily fixed and require evaluation before becoming binding. Emission limitations may potentially be shared across several generating stations. Results of ERAs can be used to show a need for emissions waivers. Emissions information should be available from Generator Owner/Operators and should be included in routine surveys. Analysts will need to be able to apply an emissions limitation to the operation of a generator or generating station. The information obtained must be in a format that is usable by the analysts performing the ERA (e.g., MWh remaining until emissions constrained rather than tons of CO_2 remaining without a conversion from emissions to electric energy remaining). Emissions limitations will differ by jurisdiction (e.g., state or province), can be on a variety of time scales (e.g., annual, seasonal, or rolling 12-month limits), and can be shared by portfolio within a specific state. They can also have multiple components (e.g., NOx, SOx, and CO_2), all of which should be evaluated, but only the most limiting would likely be modeled in an ERA. Again, relevant information would be provided by the resource owners/operators and, while the analyst performing the ERA should be familiar with the concepts of emissions limitations, they will likely not be the expert who would derive the associated limits. Generators may be further constrained by the lack of availability of emissions credits or offsets during extreme conditions.

Other potential constraints that may impact generation from an environmental point of view, specifically entities with hydro resources, include limitations like required minimum water flows and downstream dissolved oxygen levels. Such regulations could impact desired operation related to scheduling energy from hydro or pumped storage facilities located on non-isolated reservoirs and should be considered for modeling in an ERA.

The following table is useful for modeling emissions constraints on generator operation in an ERA for any time horizon:

Table 1.4: Information Useful for Modeling Emissions Constraints on Generator Operation in an ERA in Any Time Horizon		
Output limitations for a set of generators	Generator surveys	Each Generator Owner/Operator may know their own operational information, but when determining when a collection of generators will reach a limit would require gathering information that each owner/operator has but not as a collective. The analyst performing the ERA would be the centralized collection point of the information required to accurately model the limit.

Outage Modeling

A common method for modeling generator outages in an ERA is to multiply the generator's maximum output by a function of outage rate (e.g., 1 - EFORd) and assign that as the new maximum output for the duration of the study period. Applying this method consistently to the entire fleet of generators results in a set of input assumptions that is agnostic of how outages occur but accounts for outages in a fairly accurate manner. However, this method will only show the average outage impact from all units, not the risks posed by concurrent outages, especially if there is any degree of correlation in outage patterns.

Alternately, dynamic outage modeling methods assign a probability of occurrence, impact, and duration to each failure mechanism of a specific outage of a specific generator and run a probabilistic analysis, or outage draw. The probability of occurrence would be compared to a random number generator in the software and implement the outage with the associated impact and duration from that point in the study period. This method is much more complex to model than the simpler methods and requires that each type of failure be evaluated for the correct parameters but is more closely aligned with actual conditions. It should be noted, however, that even probabilistic approaches to outage modeling can exhibit significant variability, both in implementation and subsequent accuracy. Understanding the nuances present in probabilistic outage modeling is important for any resource adequacy assessment but especially so for an ERA.[17]

Information on generator outages is available through historical data analysis, specifically operator logs, operational data, or the NERC Generation Availability Data System (GADS).[18]

An ERA should take into consideration the impacts of previous hours on the next hour. For this reason, methods that consider temporal impacts—such as two-state Markov modeling or state transition matrices—are beneficial. In addition to considering mechanical failure of equipment, it is also beneficial to consider a wide range of failure causes, such as fuel availability or ambient air and water temperature.

[17] https://www.epri.com/research/products/000000003002027832
[18] https://www.nerc.com/pa/RAPA/gads/Pages/GeneratingAvailabilityDataSystem-(GADS).aspx

In reality, Forced Outages are a more complex phenomenon than typical modeling techniques have been able to predict. Model fidelity can be improved by gathering data and incorporating the following:

- Foresight on failures (e.g., start-up failures have limited foresight and therefore may require faster response times from other resources)
- Uncommon causes (e.g., battery cell balancing)
- Time-varying forced-outage rates (e.g., seasonality, hourly variation)
- Common cause failures

Most reliability assessments consider generator outages as independent events, where each generator is modeled separately with its own forced-outage rate that applies for the entire study horizon.

The following table is useful for modeling energy supply outages in an ERA for any time horizon:

Table 1.4: Information Useful for Modeling Energy Supply Outages in an ERA in Any Time Horizon

Data	Potential Sources	Notes/Additional Considerations
Forced-outage rates	NERC GADS, assumptions based on historical performance	NERC requires outages and reductions to be reported with associated cause codes and makes that information available to registered entities. Alternatively, analysts can observe historical unplanned outage information to determine similar assumptions.

Distributed Energy Resources

Distributed energy resources (DER) are primarily made up of the same types of resources discussed in prior sections (e.g., VERs) but have different considerations associated with their distributed nature:

- DERs generally use just-in-time fuels, are variable in nature, and do not respond to dispatch instructions; however, some DER installations are being installed with integrated storage systems that serve to distribute production more evenly, resulting in a behavior that is less like a just-in-time resource.
- DERs are usually installed on lower-voltage systems (i.e., distribution-level systems) that are not modeled by Transmission Operators and can be subject to unknown constraints.
- DERs can be subject to unanticipated operation in response to faults on the transmission or distribution systems.[19]
- Modeling DERs in an ERA can be done on either the supply side of the energy balance equation or on the demand side, to be determined by the analyst and the defined process.

Market-Based Resources and Market Conditions

Market-based resources are those that are registered with an Independent System Operator/Regional Transmission Organization (ISO/RTO), generate revenue for their owner by participating in the area's organized market, and are typically governed by an agreement between the resource owner and the ISO/RTO. The development of an ERA should consider these market rules and understand how market participants will behave in certain situations. These

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

resources are expected to perform in the market (e.g., no economic withholding) but occasionally must make decisions that would impact their availability.
For example, a generator's revenue and dispatch expectations under market conditions may change how a generator is positioned for dispatch, such as increasing its notification-to-start time to avoid staffing its facilities 24/7. Another example would be if a given area's agreements have severe penalties or reduced revenue for generators that are not running during a constraint period. To avoid incurring penalties, non-variable generators may take proactive actions to self-schedule on these days with the intention of mitigating potential operational issues if given enough notice of these availability conditions.

Contracts, both out-of-market and non-power, held by generating units that impose take-or-pay or force majeure penalties may also impact entities. These contracts typically impact co-generation facilities and those that provide power, steam, and/or other services to adjacent facilities, such as refineries and heavy industry, and may reduce the available output and operational responsiveness of impacted units.

Demand

Demand is significantly more complex today than it ever has been. Today's demand is composed of actual demand adjusted by varying types of demand response (including the impact of time-of-use rates) and distributed generation that is considered load-reducing.

Actual demand (i.e., gross demand) can be thought of as loads that are drawing power from the interconnected electric systems. Lighting, environmental controls like heating and air conditioning, household and commercial electronics, and industrial loads all comprise the actual demand on the system. These concepts have been consistent since the power grid was first developed. The specifics may change over time, with energy efficiency and changes to lifestyles, but the concepts remain the same.

The behavior of demand is becoming more difficult to predict due to factors, such as energy efficiency, demand response, and price-responsive loads, which can significantly vary the shape of typical hourly demand. The expansion of electrification (e.g., electric vehicles and heating) within a specific footprint requires the analyst to make assumptions of the electric vehicle charging patterns and other changes to load profile due to electrification of heating or industry. Like air-conditioning units and heating sources, electric vehicle charging assumptions would differ by season, but would be different from assumptions made for those other end-uses leading to changes in techniques for predicting demand.

Demand itself is more versatile than it once was. Demand-response programs have been designed to preempt the buildout of additional, or the retention of existing, generation capacity resources by lowering demand during peak hours. Impact on energy will depend on how each program is implemented. For example, interrupting air-conditioning systems for a few hours on peak days may reduce Peak Demand but may not change the total energy demand on the system. Loss of load diversity without a longer-duration change to temperature setpoints may eventually require a similar energy demand to restore temperatures after the peak is shaved. When restored, systems will run longer and more consistently, drawing nearly the same amount of energy as if no demand response was initiated. Voltage reductions may also fall into the same type of construct, depending largely on the makeup of demand in a specific area. These concepts will factor into the decisions that are made to manage energy when situations arise that require actions.

Finally, in some applications, DERs are considered in the demand side of an energy balance equation, while others may include DERs in supply. Both methods have their advantages and disadvantages.

$$Supply + Imports = Demand + Exports + Losses$$

Where

$$Supply = Generators + Distributed\ Energy\ Resources$$

Or

$$Demand = Load - Distributed\ Energy\ Resources$$

Deconstructing demand into its individual components may be helpful in solving for the variability of distributed generation or for building future demand curves. This process may require significant effort and potentially some assumptions in the absence of actual data. The impact of variability can be addressed by reconstituting actual demand (i.e., adding the distributed generation production back into the measured load). Once the components are separated, actual demand forecasts or assumptions can be developed as one input variable and distributed generation can be modeled separately. The same concept applies to electrification. Start with the current demands and the projected growth of existing demand types, then add the assumed incremental demand that is expected from electric heating—then add the assumed incremental demand that is expected from transportation electrification. However, demand will be modeled in an ERA, the analyst should ensure that all aspects are accounted for and not double counted.

Electric Storage

Classification of Electric Storage

As discussed earlier, *electric storage* refers to a device or facility with electric power as an input, a storage medium of some kind that stores that energy, and electric power as an output. Before energy can be supplied by an electric storage device, it needs to be generated somewhere and then stored in the device. Electric storage cannot itself generate energy but can provide electric energy to the grid to the extent it has been charged. An ERA can show when energy storage needs to be charged and when it should be discharged to support energy sufficiency needs. It may also indicate when there may not be enough energy stored to keep the system balanced with variable supply or volatile demand.

Electric storage can be classified as short-duration energy storage (SDES) or long-duration energy storage (LDES),[20] depending on the needs of the system where the storage is built. This technical reference document uses the terms *SDES, Inter-day LDES, Multi-day/Week LDES, and Seasonal Shifting LDES* to describe the types of electric storage and considerations for each. However, an analyst with more extensive knowledge of electric storage systems and a need to model electric storage more precisely may categorize the resources differently. Each area may have a specific need (or set of needs) for storage and, quite possibly, multiple types simultaneously. When performing an ERA, all known electric storage resources should be included as supply resources when they are discharging or as demand when they are charging.

SDESs can be used for frequency regulation, energy arbitrage, and peaking capacity. These resources include smaller batteries,[21] less than four hours of storage, and flywheels. These electric storage types can cycle, charge, and discharge quickly and often in response to signals defined to maintain a balanced Area Control Error (ACE).[22] SDESs with duration closer to four hours can be used to arbitrage demand from the low-load periods to the higher-load periods by, for example, charging overnight or when PV production is high and using that energy to serve peak hourly loads. Inter-day LDES includes resources able to store energy for up to 36 hours, such as pumped hydro storage stations and some developing battery storage. These resources fill the upper pondage or charge when net demand is low and generate or discharge energy when demand is high. Inter-day LDESs can be called on when renewable resources (solar and wind) cannot produce power for several hours. For example, inter-day LDESs can be dispatched to cover nighttime demand when solar generation ceases in the evening after the sun sets. In simplified models, the operation of inter-day LDES resources is sometimes modeled as a fixed charge/pump load at normally lower-demand periods and as a fixed discharge/generation at normally higher-demand periods. The more standard and

[20] https://liftoff.energy.gov/long-duration-energy-storage/

[21] As with all inverter-based resources, it is critical to know if the storage resource functions under grid-forming or grid-following technology.

[22] ACE is defined by NERC in BAL-001-2 (https://www.nerc.com/pa/Stand/Reliability%20Standards/BAL-001-2.pdf)

recommended option for modeling inter-day LDES is to include the specific capabilities as part of the energy balance from hour to hour and optimize the charge/discharge decisions. This effectively tells the analyst when to charge/pump and discharge/generate based on the resource's state of charge or other specific system conditions. Multi-day LDES is made up of electric storage resources (e.g., larger batteries and pumped storage hydro stations) that can provide several days to a week of electricity and is intended to be held for longer time periods. Multi-day LDES can be called upon when a natural-gas-fired plant is unable to receive fuel or when renewable resources are not able to produce power for many hours, such as when wind or solar resources are unable to generate energy due to weather systems that reduce wind speeds or solar irradiance for extended periods.

Seasonal shifting LDES, storage that holds energy produced in one period to be used weeks or months later, is currently focused on "Power-to-X"[23] pathways, such as hydrogen, ammonia, and synthetic fuels. Seasonal shifting LDES is in the early developmental process and is not necessarily the focus of this technical reference document.

Electric Storage Configuration

Electric storage can be standalone or co-located or consist of hybrid/storage resources, further complicating modeling. Solar or wind generators with storage devices at the same location as the generation allow the production of electricity to exceed interconnection limitations. The excess energy is then stored at the associated storage device and withdrawn from storage when generation drops off. Additional complication comes from a potential lack of visibility of the generation resource, as the energy may be supplied by the generation or the storage resource. Metering at the output of a co-located storage facility adds a layer of obfuscation between the weather conditions and the production of the renewable resource, or when the electric storage portion of the facility is used to store energy from the grid rather than from the renewable resource. Metering the individual components can remove that obfuscation but potentially at the cost of adding to a project or retrofitting. Modeling these resources in an ERA as individual components may give the analyst more flexibility with modeling tools and a better understanding of the production from the facility.

Reliability Optimization

A charge/discharge cycle usually incurs losses and, thus, electric storage creates a net energy demand when averaged over longer periods of time. This "round-trip efficiency of storage" is an important consideration for performing an ERA, primarily for accuracy, but also for deciding on action plans when energy supplies are inadequate. Both supply and demand implications of storage resources should be considered when formulating action plans when facing an energy shortfall.

Optimization of energy in electric storage devices across several hours or several days is a complicated process that requires consideration for how it would be modeled in an ERA. Electric storage is used in many cases to shift available energy from low-demand periods to high-demand periods or to provide Ancillary Services, and an ERA should model that operation accurately according to how electric storage devices would operate in real life. If the actual dispatch and operation would be optimized to meet a certain objective or set of objectives, the ERA should optimize it toward the same objective over the same period. If an electric storage device is not normally optimized and an ERA were to optimize the dispatch and operation to minimize reliability risk, it could mask indications of a shortfall to the analyst.

The following table is useful for modeling electric storage in an ERA for any time horizon:

[23] Power-to-X is described by NETL in Technology in Focus: Power-to-X (https://doi.org/10.2172/2336708)

Table 1.5: Information Useful for Modeling Electric Storage in an ERA in Any Time Horizon		
Data	**Potential Sources**	**Notes/Additional Considerations**
Maximum charge/discharge rates (in MW or kW) and total storage capability (in MWh or kWh)	Registration data	These two parameters combined define the primary characteristics of a storage device.
Usable Capacity	Registration data, operational data	Battery storage may not operate well above and below a specific charged percentage. For example, batteries charged above 80% or below 20% may underperform. Therefore, the storage capacity may be less than intended.
Transition time between charge and discharge cycles	Registration data, operational data, market offers	
Cycling efficiency	Operational data	Calculating the cycling efficiency of storage can be done using operational data, dividing the sum of output energy by the sum of input energy over some period. A longer duration will yield a more accurate efficiency value. All storage requires more input energy than the output that will be produced.
Co-located/hybrid or standalone configuration. Charging source – primary and secondary	Registration data	Scenario studies may remove a generation type (e.g., solar), which may eliminate the energy supply source.
Ambient temperature limits	Registration data, operational data	This refers to the ambient temperature limitations at the storage facility, which are part of the formula for calculating cell temperature limitations. There are high- and low-temperature requirements for charging and discharging batteries at a normal rate. Outside that band, the rate of charge could be reduced, potentially to 0.
No-load losses	Registration data, operational data	Electric storage facilities may experience a loss of energy even when not delivering energy to the grid.
Emergency limits		Can the storage resource run below the P-Min or above the P-Max, and if so, for how long?

Transmission

Transmission moves power from supply to demand on the Bulk Electric System. Transmission constraints limit how much power can be transferred. ERAs should account for transmission constraints to accurately model transfers, which can occur within and between constrained areas. Inter-area transmission constraints can be modeled as imports and exports while intra-area transmission constraints could be modeled as reductions in supply capability or by dividing the area zonally. Calculation of specific transfer limits are required by NAESB standards and are a well-known quantity. This information may be available through various Open-Access Same-Time Information System (OASIS) postings. These limits are one aspect of determining the available energy that can be transferred over the transmission system. Once the limitations for transfers between areas are known, there should be coordination between areas to determine if the energy is available to use that transmission capability. Coordinating ERAs between neighboring areas is crucial to formulating accurate input assumptions.[24]

Other considerations for transmission capability include grid-enhancing technologies, such as ambient adjusted ratings, dynamic line ratings,[25] controllable ties, transmission and distribution losses, priority to access, and recallable Transactions/cutting assistance. These considerations will change how imports, exports, and additional transmission usage are modeled in an ERA. Ambient adjusted ratings (AAR) will potentially allow for greater Transfer Capability within and between areas, enabling higher energy usage.

ERAs can also be used to determine if transmission outages would cause or worsen shortfalls. Transmission outages can create conditions that constrain or curtail fuel-secure or high-energy production resources. These constraints or Curtailments can be represented to accurately portray the impact of the transmission outage. Conversely, system conditions (including transmission outages) that create must-run conditions for generators should be incorporated into the ERA. For example, a must-run condition of hydroelectric generation (to mitigate thermal overloads or undervoltage conditions) could reduce the available energy from that resource to meet the needs of the ERA. The ERA would inform the System Operator and Operational Planning Analysis when resources are not available due to energy constraints. Using limitations on imports and exports would factor into the neighboring area ERAs as well.

The following table is useful for modeling transmission in an ERA for any time horizon:

Table 1.6: Information Useful for Modeling Transmission in an ERA in Any Time Horizon

Data	Potential Sources	Notes/Additional Considerations
Planned outages and Maintenance	Transmission Operators (TOP), Transmission Planners (TP), or other transmission planning entities	
Import/export transfer limits	Engineering studies	
Import/export resource limits	Coordinated ERA with neighboring areas	Aligning input assumptions between areas would be necessary for ensuring that energy is not ignored or double counted in multiple areas.
Transmission topology and characteristics	Transmission and distribution models	Potentially, using a simplified or dc-equivalent circuit for probabilistic or similar analysis. Considerations for including planned transmission expansion projects.
Transmission outage rates	NERC TADS	Ideally, weather-dependent and facility-specific outage rates could be used to reflect energy scenarios.

[24] FERC Order 896 [elibrary.ferc.gov] directed NERC to develop a new standard to address the reliability and resilience impacts of extreme heat or extreme cold events on the BPS. A NERC Standards Authorization Request [nerc.com] to address transmission planning energy scenarios was approved by the NERC Standards Committee [nerc.com] in December 2023

[25] To draw distinction between ambient adjusted ratings and dynamic line ratings, ambient adjusted ratings are a function of forecasted temperatures that can be used in real-time and near-term operations planning and are defined in FERC Order 881. Dynamic line ratings are a function of real-time environmental conditions to determine the capability of a transmission system element.

Other Considerations

Across all portions of the power sector, inventories of replacement equipment, mean time to repair (MTTR), and lead times for non-inventoried equipment represent critical limitations that should be considered during the application of contingencies in ERAs. Some of these factors may restrict response pathways across all ERA time horizons. Additional factors that may require consideration include component sourcing (domestic material requirements, nuclear “N-Stamp” certification, etc.), tariff and import restrictions, and government policy and regulatory interventions/restrictions/limitations. While these considerations may improve the accuracy of an ERA, the details may be unavailable or unable to be implemented in a model.

Labor availability may also need to be considered during ERAs depending on the variable of concern; for instance, in a short-term horizon, Contingency recovery time may be governed by the availability of skilled labor and trade personnel over a holiday weekend. In longer time horizons, labor availability may drive uncertainty in both maintenance and construction scheduling, potentially leading to increased outages at existing units and delays in synchronization of new units.

Chapter 2: Inputs to Consider When Performing a Near-Term ERA

An ERA in the near-term horizon addresses a time frame that starts about 1–2 days out and then continuously through the following several days or weeks. It effectively starts at the end of the Operating Plan that covers today and perhaps tomorrow as outlined in NERC Standard TOP-002.[26] That said, the period assessed in a near-term ERA can start earlier (i.e., today, or even in the past) if the analyst needs to set up accurate initial conditions. The near-term ERA then looks into future days or weeks to provide the analyst with a representation of what the energy-constrained conditions would be. Considerations for inputs to a near-term ERA are described below.

Supply

Modeling supply in a near-term ERA relies on an analyst gathering information from an existing fleet of generators. This information is usually fairly static in the near term and can be included in registration data or gathered through generator surveys. Additionally, forecast information may be necessary for Balancing Authorities (BA) with high levels of VERs who will use that information to make more informed decisions on required VERs that would be committed on any given day.

Stored Fuels

Stored fuel information in a near-term ERA should start with current inventories and be updated throughout the assessment based on operations and expected replenishment.

The following table is useful for modeling stored fuels in a near-term ERA:

Table 2.1: Information Useful for Modeling Stored Fuels in a Near-Term ERA

Data	Potential Sources	Notes/Additional Considerations
Current inventory, inventory management plans, and replenishment assumptions	Generator surveys, assumptions based on historic performance, or annually variable conditions specific to the resource type	Replenishment is key to modeling inventory at any point during the study period. Replenishment restrictions are also an important aspect of an ERA. Performance expectations for hydroelectric resources may be informed by seasonal runoff conditions.

Just-in-Time Fuels

Modeling just-in-time fuels in a near-term ERA relies on the existing fuel supply infrastructure and assumptions of the operation of those facilities.

[26] https://www.nerc.com/pa/Stand/Reliability%20Standards/TOP-002-4.pdf

Natural Gas

Modeling natural gas availability in a near-term ERA requires an understanding of the pipeline infrastructure that is in place.

The following table is useful for modeling natural gas supply in a near-term ERA:

Table 2.2: Information Useful for Modeling Natural Gas Supply in a Near-Term ERA

Data	Potential Sources	Notes/Additional Considerations
Natural gas scheduling timelines	Pipeline tariffs, NAESB	Timelines may differ between pipelines. The NAESB sets five standard cycles that are to be followed by Federal Energy Regulatory Commission (FERC) jurisdictional entities (which generally excludes intrastate pipelines and local distribution networks).
Natural gas commodity pricing and availability	Intercontinental Exchange (ICE),[27] Platts[28]	Natural gas commodity pricing is an indicator of its availability. Continuously monitoring pricing will allow an analyst to estimate the availability of natural gas into a near-term ERA.

Variable Energy Resources

VERs are modeled in a near-term ERA using the technical specifications of the existing fleet and a forecast of weather conditions translated into power (production) forecasts. Developing an ERA that is highly dependent on VERs requires consideration of the uncertainty of the energy available. The forecast error of VER production can be high even over a near-term horizon. The energy available from VERs is based on the following factors:

- VER capacities
- Geographical location of installed VERs
- Typical forecast errors of wind, solar, and weather
- The capacity, configuration, and transmission capacity of co-located energy storage
- Outage rates of resources
- Amount of VERs connected to distribution or transmission

For most BAs with high levels of VER installations, conducting a near-term ERA with deterministic production values beyond 7–10 days may require the use of averaged production assumptions rather than forecasts due to accuracy concerns.

Near-term ERAs will generally use forecasts rather than assumptions and historical observations. These forecasts are available through a variety of weather vendors and national weather service providers that are derived from global models allowing for specific localized weather to be extracted. Model downscaling, blending and improvement efforts generally produce higher accuracy and/or precision. The analyst can interpret the output of weather models coordinated with VER production forecasts and apply the results to generator performance assumptions in an ERA.

The following table is useful for modeling VERs in a near-term ERA:

[27] https://www.ice.com/index
[28] https://www.spglobal.com/en/

Table 2.3: Information Useful for Modeling Variable Energy Resources in a Near-Term ERA		
Data	**Potential Sources**	**Notes/Additional Considerations**
Weather forecasts	Vendor supplied but could be developed using weather service models	There could be differences between one or multiple central forecast(s) and the aggregation of independent forecasts. Forecast error analysis of historical data would provide a measure of the performance of available options.
	In-house models or vendor-supplied data	Wind/solar profiles can be modified to capture uncertainty associated with rainy, windy, and/or cloudy days. It is important to maintain the correlation between wind, solar, and load in conducting these analyses.
VER production forecasts	Vendor supplied but could be developed using weather service models	Significant research and development have been done in the last decade to create and improve VER/DER forecasts for use in power system operations and analysis, including ERAs. Hourly or sub-hourly profiles of actual production from VERs can be scaled up or down to fit specific scenarios in an ERA.

Emissions Constraints on Generator Operation

Modeling constraints on generator operation in a near-term ERA can be done using the characteristics of the existing fleet, adjusting for any new resources that are expected to become available during the period being studied.

The following table is useful for modeling emissions constraints on generator operation in a near-term ERA:

Table 2.4: Information Useful for Modeling Emissions Constraints on Generator Operation in a Near-Term ERA		
Data	**Potential Sources**	**Notes/Additional Considerations**
Output limitations by specific generators	Generator surveys	For short-term assessments, generator surveys would be the best source of emissions limitation information. Generator Owner/Operators should be aware of what their limits would be and the plans to abide by those limits.

Table 2.4: Information Useful for Modeling Emissions Constraints on Generator Operation in a Near-Term ERA		
Data	**Potential Sources**	**Notes/Additional Considerations**
Output limitations for a set of generators	Generator surveys	Each Generator Owner/Operator may know their own operational information, but when determining when a collection of generators will reach a limit would require gathering information that each owner/operator has but not as a collective. The analyst performing the ERA would be the centralized collection point of the information required to accurately model the limit.

Outage Modeling

Near-term ERAs have the benefit of scheduled maintenance plans. These plans are usually set months in advance and give the analyst an indication of the work expected to occur, leaving only unplanned outages as a major source of uncertainty.

The following table is useful for modeling energy supply outages in a near-term ERA:

Table 2.5: Information Useful for Modeling Energy Supply Outages in a Near-Term ERA		
Data	**Potential Sources**	**Notes/Additional Considerations**
Planned outages and maintenance	Maintenance schedules and outage coordination tools	ERAs can use planned maintenance as an input but can also be used to advise the shifting of planned maintenance to minimize energy-related risks.

Distributed Energy Resources

Most area operators do not have real-time telemetry of DER within their footprint but may be able to work with their local energy commissions or local utility operators to get installed DER capacity at a suitably granular level, such as substation or ZIP code, as well as other useful information (e.g., tilt, direction for solar panels). Creating time series data of DER production for near-term ERAs can be challenging. The results of a near-term ERA can show a high degree of uncertainty when DER installation exceeds a certain point (e.g., a few thousand MW for a small- to medium-demand area; more for larger areas). The point where the amount of DER has significant impact on the power system is not clearly standardized and should be understood and defined by the analyst performing the ERA. A lack of visibility and ability to benchmark the DER forecast against actual production creates an additional level of complexity, and the analyst may need to rely on a variety of scenarios to determine the probability of deficiencies.

The following table is useful for modeling DERs in a near-term ERA:

Table 2.6: Information Useful for Modeling Distributed Energy Resources in a Near-Term ERA		
Data	**Potential Sources**	**Notes/Additional Considerations**
Installation data	Electric utility companies (i.e., Distribution Providers, or DPs), production incentive administrators	DERs are likely to be required to coordinate with the distribution System Operator before interconnecting. Additionally, any DER that is participating in a renewable energy credit program will likely need to register with and provide production information to a program administrator.
Forecasted DER production	Vendor supplied but could be developed using weather service models	Significant research and development have been done in the last decade to create and improve DER/VER forecasts for use in power system operations and analysis, including ERAs.
Historical performance, observations of net load	Historical patterns of demand compared to a longer history	Comparing a similar-day demand curve from a more recent year to one from a year prior can give a sense of the difference in DER that was installed year-over-year.
Estimated performance of DERs	Based on limited samples of a subset of the DER type	Modern DERs may have advanced measurement devices that could be made available through vendor aggregation services. Smaller, evenly distributed samples could be used to scale to the full amount. Testing should be done to validate whether the conceived process is accurate.

Demand

In a near-term ERA, demand profiles should be well understood and can be forecasted accurately, reducing the need to make assumptions. The ever-changing demand profiles that are discussed in other chapters of this technical reference document do not really change overnight, and the recent past should be very indicative of the near future, adjusted for weather.

The following table is useful for modeling demand in a near-term ERA:

Table 2.7: Information Useful for Modeling Demand in a Near-Term ERA

Data	Potential Sources	Notes/Additional Considerations
Weather forecasts or projections	Numerical weather prediction (NWP) models, weather forecast vendors	Weather information is the primary variable input to demand forecasts. Near-term assessments can use weather forecasts.
Actual demand forecasts or projections	Load forecast models using weather information as an input	Historical weather and demand may be useful for projecting future conditions; however, caution should be exercised to ensure that interrelated parameters remain interrelated. Decoupling weather and load could result in implausible outcomes.
Demand-response capabilities	Electric utilities or other organizations (e.g., demand-response aggregation service providers) that manage participation in demand-response programs	

Electric Storage

Primary considerations for electric storage when performing a near-term ERA are that electric storage resources are less than 100% efficient, and modeling how the expected state of charge (i.e., how much energy is stored) of the resource may impact the operation of the storage facility. In the near-term ERA, electric storage may be used to provide ramping flexibility as solar generation drops off as the sun sets. Understanding of the state of charge facilitates this critical service. Specific storage inputs are needed to perform an ERA.

The following table is useful for modeling electric storage in a near-term ERA:

Table 2.8: Information Useful for Modeling Electric Storage in a Near-Term ERA

Data	Potential Sources	Notes/Additional Considerations
State of charge	Resource owner	Additional considerations may be given to state of charge in a near-term ERA that reflect the recent operation of the electric storage facility.
Ramp Rate (up/down) MW/minutes	Resource owner	Rate that the electric storage resource can discharge or absorb energy when electric demand or supply changes.
Cell balancing	Resource owner	This describes the change-out of cells within a storage device. Specifically, this would apply to faulty cells that could limit the capability of a battery plant. Balancing takes a few days to accomplish once cells are replaced.
Project-specific incentives (e.g., investment tax credits)	Resource owner	Investment tax credits, either production or investment, may indicate how the electric storage resource will run.
Cell temperature limits[29]	Resource owner	This is the ambient temperature at the storage facility. There are high- and low-temperature requirements for charging and discharging batteries at a normal rate. Outside that band, you may reduce the rate of charge, potentially to 0.

[29] Lithium-ion battery: Charge temperature at 32°F to 113°F; Discharge temperature at -4°F to 140°F
Lead acid battery: Charge temperature at -4°F to 122°F; Discharge temperature at -4°F to 122°F
Nickel-based battery: Charge temperature at 32°F to 113°F; Discharge temperature at -4°F to 149°F

Chapter 3: Inputs to Consider When Performing a Seasonal ERA

A seasonal ERA considers an upcoming season, focusing on energy-related risks that are exposed in that season. The term *season* is used more as a generic term that means a time period longer than a few weeks but not a full year. Seasons, and their associated risks, are unique across areas and do not necessarily fit into the classic definitions. The analyst should have a good idea of what seasons are experienced by the area where they are performing a seasonal ERA and should apply that definition to the input assumptions. Partial seasons (e.g., three weeks of a winter period) may offer a vantage point that captures the representative risks of a full season without requiring the overhead of performing three-month-long assessments. Winter and summer peak periods are traditionally the focal point of seasonal capacity assessments, but there may be unexpected risks in Off-Peak times (including Off-Peak hours within days) that would be identified by an ERA and should not be overlooked. Considerations for inputs to a seasonal ERA are described below.

Supply

Modeling supply in a seasonal ERA relies on an analyst gathering information from an existing fleet of generators plus any generators that are expected to be added prior to the start of the season being assessed. This information is usually fairly static for a single season and can be included in registration data or gathered through generator surveys. VER production assumptions may be necessary for BAs with high levels of VERs. These BAs will use that information to make more informed decisions on required VERs that would be committed on any given day.

Stored Fuels

Stored fuel information in a seasonal ERA is likely similar to the current inventories plus adjustments for replenishment and usage plans between the time that the ERA is performed and the period being assessed. However, there may be season-specific constraints that affect these factors for the study period in a seasonal ERA.

The following table is useful for modeling stored fuels in a seasonal ERA:

Table 3.1: Information Useful for Modeling Stored Fuels in a Seasonal ERA

Data	Potential Sources	Notes/Additional Considerations
Current inventory, inventory management strategies, and replenishment assumptions	Generator surveys, formal or informal generator outreach, assumptions based on historical performance, or annually variable conditions specific to the resource type	Replenishment is key to modeling inventory at any point during the study period. Replenishment restrictions are also an important aspect of an ERA. Performance expectations for hydroelectric resources may be informed by seasonal runoff conditions. Generator surveys can still be useful just prior to a specific season; however, this information may still introduce some uncertainty at the time that the ERA is being performed. Communication with the entities deciding on replenishment strategies would result in more accurate assumptions for starting inventories.

Table 3.1: Information Useful for Modeling Stored Fuels in a Seasonal ERA		
Data	**Potential Sources**	**Notes/Additional Considerations**
Availability of overall fuel storage	U.S. Energy Information Administration (EIA) reports	The U.S. EIA reports weekly inventories for five Petroleum Administration for Defense Districts (PADD). This can be an indicator of whether fuel may be available for generator fuel replenishment.
Shipping constraints	Industry news reports	Seasonal ERAs could be impacted by weather patterns and world events that cause supply chain disruptions, including port congestion, international conflict, shipping embargoes, and confiscation.

Just-in-Time Fuels

Modeling just-in-time fuels in a seasonal ERA relies on the existing fuel supply infrastructure and assumptions of the operation of those facilities as well as expected changes (e.g., expansion or planned outages) prior to the start of the upcoming season.

Natural Gas

Natural gas supply infrastructure is a fairly predictable input to a seasonal ERA. Pipeline expansion and demand growth are usually planned far in advance and are implemented prior to peak-usage seasons. Planned outages of interstate natural gas pipelines are posted publicly.

The following table is useful for modeling natural gas supply in a seasonal ERA:

Table 3.2: Information Useful for Modeling Natural Gas Supply in a Seasonal ERA		
Data	**Potential Sources**	**Notes/Additional Considerations**
Pipeline, production, import, and export expansion projects	Pipeline websites, filings with state and federal agencies, advertising for open seasons	This includes new pipelines, compressor enhancements and expansions, and LNG import and export projects that will increase or reduce the amount of natural gas that is available.
Pipeline Planned Service Outages	EBB	Interstate natural gas pipelines are required[30] by FERC to post maintenance plans on their public-facing EBBs.
Natural gas commodity futures pricing	Several internet sources that monitor futures pricing	Futures pricing can give a sense of what pricing pressures the commodity is facing in the coming year(s). It may not be a fully accurate picture of what the pricing will be but gives an analyst some direction for a starting point for a seasonal ERA.

Variable Energy Resources

The existing fleet with minor adjustments for outages and expected expansions can be used to model VERs in a seasonal ERA. The variability presents an unknown risk that may require analysis from multiple perspectives. Multiple

[30] See U.S. Code of Federal Regulations Chapter I, Subchapter I, Part 284, Subpart A, § 284.13.(d).(1) - https://www.ecfr.gov/current/title-18/chapter-I/subchapter-I/part-284/subpart-A/section-284.13

profiles should be considered because times of low production from VERs could also coincide with high demand or unplanned outages of other resources.

The following table useful for modeling VERs in a seasonal ERA:

Table 3.3: Information Useful for Modeling Variable Energy Resources in a Seasonal ERA		
Data	**Potential Sources**	**Notes/Additional Considerations**
Weather outlook	NOAA (for the United States), Environment and Climate Change Canada, historical observations, weather models	Seasonal outlooks can provide a direction on which historical observations to select when performing a seasonal ERA.
VER production assumptions	Historical observations adjusted for weather outlooks	Historical observations can set a starting point for what can be expected in upcoming seasons. This would need to be adjusted for other known factors, such as drought conditions or temperature expectations.
New VER installations	Installation queues	New VERs installed between the time that an ERA is performed, and the start of the upcoming season can be large enough to impact the outcome and should be included as accurately as possible. The seasonal horizon should have more certainty on what will be commissioned or not.

Emissions Constraints on Generator Operation

Modeling constraints on generator operation in a seasonal ERA can be done using the characteristics of the existing fleet, adjusting for any new resources that are expected to become available during the study period.

The following table for modeling emissions constraints on generator operation in a seasonal ERA:

Table 3.4: Information Useful for Modeling Emissions Constraints on Generator Operation in a Seasonal ERA		
Data	**Potential Sources**	**Notes/Additional Considerations**
Output limitations by specific generators	Generator surveys	For short-term assessments, generator surveys would be the best source of emissions limitation information. Generator Owner/Operators should be aware of what their limits would be and the plans to abide by those limits.

Outage Modeling

When performing a seasonal ERA, the expectation for outages is somewhat clearer than a planning ERA, but there is more uncertainty than in the near term. Well-developed outage coordination processes have provisions to schedule and coordinate generation and transmission outages as far out in the future as possible, which would likely include the time period being addressed by seasonal ERAs.

The following table is useful for modeling energy supply outages in seasonal ERAs:

Table 3.5: Information Useful for Modeling Energy Supply Outages in a Seasonal ERA

Data	Potential Sources	Notes/Additional Considerations
Weather-dependent outage rates	Surveys, registration information, assumptions based on historic performance	GADS will provide average outage rates. The information from GADS can be combined with weather information to derive correlations with weather conditions that could be modeled in an ERA.
Outage mechanisms	NERC GADS, operator logs	Outage mechanisms can be used to determine outage duration and impact.
Planned outage schedules	Outage coordination records	Planned outages are a good start for modeling the unavailability of resources, but considerations should be given to the accuracy of plans. Not every outage goes according to plan, and they may finish early or overrun.

Distributed Energy Resources

Seasonal ERAs would depend more on historical performance from DERs while assuming that the resources are distributed similarly to how they are when the ERA is being developed and performed. Some scaling may be needed to account for some rapid new development.

The following table is useful for modeling DERs in a seasonal ERA:

Table 3.6: Information Useful for Modeling Distributed Energy Resources in a Seasonal ERA

Data	Potential Source	Notes/Additional Considerations
Installation data coupled with expansion assumptions	Electric utility companies (i.e., DPs), production incentive administrators	Like the information needed for a near-term ERA, DERs are likely to coordinate with distribution System Operators, providing a path to make information available. Future information may also be available through those same channels but may also need to be inferred based on trends, growth forecasts, or legislative goals.
Historical DER production data	Operations data, assumptions based on past performance	The analyst may choose to model DER explicitly as a supply resource or as a demand reduction. Modeling the DER separately and incorporating it to the resource mix will allow the analyst to vary the assumptions without impacting other facets of the ERA.

Demand

When considering demand on a long enough time horizon, forecasts are unavailable or unreliable. To supplement forecasts, assumptions should be made based on historical demand and projected load growth or contraction based on factors, such as climate change and economic factors.

The following table is useful for modeling demand in a seasonal ERA:

Table 3.7: Information Useful for Modeling Demand in a Seasonal ERA		
Data	**Potential Sources**	**Notes/Additional Considerations**
Weather forecasts or projections	Historical data, seasonal weather projections (e.g., the National Weather Service, Climate Prediction Center outlooks)[31], Environment and Climate Change Canada,	Weather information is the primary variable input to demand forecasts. Near-term assessments can use weather forecasts. Longer-term assessments, including seasonal assessments, typically require assumptions or projections of weather due to forecast accuracy.
Actual demand forecasts or projections	Load forecast models using weather information as an input	Historical weather and demand may be useful for projecting future conditions; however, caution should be exercised to ensure that interrelated parameters remain interrelated. Decoupling weather and load could result in implausible outcomes.
DER production forecasts or projections	Weather-based prediction models using the assumed weather as an input, which are available from a variety of vendors	This may or may not be considered in the demand side of the energy balance equation. Correlation with modeled weather conditions should be considered.
Demand-response capabilities and expectations	Electric utilities or other organizations (e.g., demand-response aggregation service providers) that manage participation in demand-response programs	Not all demand response operates at the command of the entity responsible for dispatching resources.

Electric Storage

Charging and discharging patterns for electric storage devices may change depending on the season being studied. During summer, electric storage may be used to store excess solar generation to be used during nighttime hours while storage may be used to inject energy into the grid during periods of high demand due to extreme cold during winter. Additionally, storage devices may also be providing Ancillary Services and, as such, would be charging and discharging when required by the System Operator.

The following table is useful for modeling electric storage in a seasonal ERA:

[31] https://www.cpc.ncep.noaa.gov/products/predictions/long_range/

Table 3.8: Information Useful for Modeling Electric Storage in a Seasonal ERA		
Data	**Potential Sources**	**Notes/Additional Considerations**
Cell temperature limits[32]	Resource owner	This is the ambient temperature at the storage facility. There are high- and low-temperature requirements for charging and discharging batteries at a normal rate. Outside that band, you may reduce the rate of charge, potentially to 0.
Ramp Rate (up/down) MW/minutes	Resource owner	Rate that the electric storage resource can discharge or absorb energy when electric demand or supply changes.
Project-specific incentives (e.g., investment tax credits)	Resource owner	Investment tax credits, either production or investment, may indicate how the electric storage resource will run.

Transmission

Transmission constraints in a seasonal ERA can be modeled using the existing system with any anticipated changes that would occur before the time being studied, including planned outages and new construction.

[32] Typically, today's battery technologies are constrained to the following temperature bands:
Lithium-ion battery: Charge temperature at 32°F to 113°F; Discharge temperature at -4°F to 140°F;
Lead acid battery: Charge temperature at -4°F to 122°F; Discharge temperature at -4°F to 122°F;
Nickel-based battery: Charge temperature at 32°F to 113°F; Discharge temperature at -4°F to 149°F

Chapter 4: Inputs to Consider When Performing a Planning ERA

Planning ERAs are generally performed in the 1-to-10-year time horizon, beyond Operations Planning. The planning horizon offers more uncertainty but also more options to explore for correcting or minimizing shortfalls. The analyst performing a planning ERA will likely need to look at a wider array of possible inputs, resulting in an even wider array of outputs. The methods will be up to the analyst performing the ERA. Considerations for inputs to a planning ERA are described below and would generally apply to any type of analysis.

Supply

Modeling supply in a planning ERA leans heavily on assumptions due to the volatility of future resource mix possibilities. Variability in new construction, retirements, legislative goals, and possible emissions limitations drive a need to assess a variety of outcomes.

Stored Fuels

Electrification of heating is expected to replace oil, natural gas, and other unabated carbon-emitting combustible fuels over time with vast differences between state goals, shifting competing demands for fuel into additional electric demand. Electrification may not necessarily eliminate the need for combustible fuels but just move the combustion from inside each individual building (i.e., at the furnace or boiler) to centralized generating stations. Modeling long-term impacts of electrification of heating and fuel transportation networks will depend on the types of fuels being replaced and be driven by policy, economics, and technical complications.

The following table is useful for modeling stored fuels in a planning ERA.

Table 4.1: Information Useful for Modeling Stored Fuels in a Planning ERA

Data	Potential Sources	Notes/Additional Considerations
Inventory management and replenishment assumptions	Assumptions based on historical performance and/or commodity market evaluations.	Replenishment is key to modeling inventory at any point during the study period. Replenishment restrictions are also an important aspect of an ERA.
Availability of overall fuel storage	EIA reports	The U.S. EIA reports weekly inventories for five PADDs. Trending PADD inventories over time may provide insight into how replenishment may occur over longer periods of time.
Intra-annual hydro availability	Historical drought or high-runoff conditions	Since drought and high-runoff hydro forecasts may not cover an extensive enough period to depend on for a planning ERA, assumptions would need to be made based on historical information.

Just-in-Time Fuels

Natural Gas

Modeling natural gas availability in a planning ERA may require more extensive research of infrastructure projects and assumptions for competing demands for fuel. Natural gas pipeline and production expansion tend to require long lead times and have tended to become more uncertain in recent years.

The following table is useful for modeling natural gas supply in a planning ERA:

Table 4.2: Information Useful for Modeling Natural Gas Supply in a Planning ERA

Data	Potential Sources	Notes/Additional Considerations
Pipeline, production, import, and export expansion projects	Pipeline websites, filings with state and federal agencies, advertising for open seasons	This includes new pipelines, compressor enhancements and expansions, and LNG import and export projects that will increase or reduce the amount of natural gas that is available.

Variable Energy Resources

Modeling VERs in a planning ERA requires a set of assumptions that depend on several factors. First, the expansion of installed facilities drives the magnitude of available energy. Profitability of VERs is the primary consideration, which is a function of the cost of materials, labor, shipping, and interconnecting to the transmission system. With that information, assumptions can be made on the scaling factors to be used.

The following table is useful for modeling VERs in a planning ERA:

Table 4.3: Information Useful for Modeling Variable Energy Resources in a Planning ERA

Data	Potential Sources	Notes/Additional Considerations
Expected installed resources	Interconnection queue, economic analysis and forecasts	
Renewable energy goals	State legislature dockets	These goals drive the rate at which renewable (and likely variable energy) resources are built, including target years and amounts.
Production assumptions	Historical observations, weather models, climate trends	Profiling the expanded fleet across some historical dataset, adjusted for expected trends in climate, gives an ERA plausible inputs.

Emissions Constraints on Generator Operation

Modeling constraints on generator operation in a planning ERA can be done partially by using the characteristics of the existing fleet but also requires an evaluation of planned new construction and retirements. Planning ERAs that go beyond the next few years may require the analyst to make assumptions on state or national policies, retirements, and new construction where final decisions have not yet been made.

The following table is useful for modeling emissions constraints on generator operations in a planning ERA:

Table 4.4: Information Useful for Modeling Emissions Constraints on Generator Operation in a Planning ERA		
Data	**Potential Sources**	**Notes/Additional Considerations**
Output limitations by specific generators	Generator surveys	For short-term assessments, generator surveys would be the best source of emissions limitation information. Generator Owner/Operators should be aware of what their limits would be and the plans to abide by those limits.
Trends in individual state carbon emissions goals	State government or public utility commission (PUC) websites	When assessing the probability of long-term retirements and new construction, emissions goals may provide insight to the analysts to decide whether a specific resource or a subset of the entire fleet may or may not be viable under the expected rules.

Outage Modeling

While past performance is not a perfect indicator for future performance, it can serve as a guide for the analyst to make assumptions about generation outages.

The following table is useful for modeling energy supply outages in a planning ERA:

Table 4.4: Information Useful for Modeling Energy Supply Outages in a Planning ERA		
Data	**Potential Sources**	**Notes/Additional Considerations**
Forced-outage rates	NERC GADS, assumptions based on historical performance	NERC requires outages and reductions to be reported with associated cause codes and makes that information available to registered entities. Alternatively, analysts can observe historical unplanned outage information to determine similar assumptions.
Weather-dependent outage rates	Surveys, registration information, assumptions based on historical performance	GADS will provide average outage rates. The information from GADS can be combined with weather information to derive correlations with weather conditions that could be modeled in an ERA.
Assumed outage rates for newly constructed supply resources	Fleet averages using existing resources, when possible	New construction using existing plans means that there is likely a similar resource somewhere that has some performance data that can be used to estimate the performance of a new resource.

Table 4.4: Information Useful for Modeling Energy Supply Outages in a Planning ERA		
Data	**Potential Sources**	**Notes/Additional Considerations**
Outage mechanisms	NERC GADS, operator logs	Outage mechanisms can be used to determine outage duration and impact.

Distributed Energy Resources

In a planning ERA, DERs are modeled similarly to a seasonal ERA but with more uncertainty in installed capacity. Past a certain point, the assumptions being made would overshadow the fact that the supply resources are connected in such a way that they would be less visible to the operator. There is also some uncertainty in whether each resource, once finally built, would even be distributed or not. That uncertainty supports a method of modeling DERs that can accommodate either outcome.

The following table is useful for modeling DERs in a planning ERA:

Table 4.5: Information Useful for Modeling Distributed Energy Resources in a Planning ERA

Data	Potential Sources	Notes/Additional Considerations
Growth estimates, renewable energy goals	State government and PUCs, directly or via their websites	

Demand

Demand is expected to become more complicated than ever in the coming years. Today's demand has components of actual demand (e.g., lighting, heating and air conditioning, appliances, industrial demand), varying types of demand response (including the impact of time-of-use rates), and distributed generation that is considered load-reducing. Future demand will change throughout the evolution to decarbonize the power system.

Further expected changes will continue to transform the actual demand profiles and the need for electric energy. Electrification of heating and transportation will likely shift demand curves away from traditional energy supplies of oil, natural gas, and gasoline to electricity. The shifts will result in net load profiles that, although not necessarily less predictable from a day-to-day point of view, are more difficult to predict through the transition when looking several years into the future and making assumptions. ERAs require modeling of multiple hours and should consider the expected changes brought about by changes in demand.

The following table is useful for modeling demand in a planning ERA:

Table 4.6: Information Useful for Modeling Demand in a Planning ERA

Data	Potential Sources	Notes/Additional Considerations
Weather forecasts or projections	Historical data, adjusted using climate models	Weather information is one of the primary inputs to longer-term demand forecasts. Longer-term assessments typically require assumptions or projections of weather due to forecast accuracy concerns.

Table 4.6: Information Useful for Modeling Demand in a Planning ERA		
Data	**Potential Sources**	**Notes/Additional Considerations**
Actual demand projections	Historical actual demand modified by the expected impact of demand changes, load forecast models using weather information as an input	Historical weather and demand may be useful for projecting future conditions; however, caution should be exercised to ensure that interrelated parameters remain interrelated. Decoupling weather and load could result in implausible outcomes. Performing an energy assessment still requires a profiled demand curve over a period of time. Most legacy long-term forecasts produce a set of seasonal peak values.
Projected changes in actual demand magnitude and profile (e.g., load growth)	Analysis of economic factors, governmental policy, and technical considerations	This should include the impact on demand magnitude as well as changes in demand profiles. This includes energy efficiency and electrification. Electrification of heat is a function of local temperatures. Electrification of transportation will be more linked to commute distances and time of day.
DER production forecasts or projections	Historical production data, scaled to future capability	This may or may not be considered in the demand side of the energy balance equation. Correlation with modeled weather conditions should be considered.
Demand-response capabilities	Electric utilities or other organizations (e.g., demand-response aggregation service providers) that manage participation in demand-response programs.	

Electric Storage

As noted in Chapter 1, when performing a planning ERA, it is important to know the source that will charge or fill the electric storage resource. It is expected that electric storage will become a critical resource for maintaining system balance as coal- and natural gas-fired generation retire and are replaced by VERs. Knowing how the electric storage resource is charged/filled, either a direct resource or off the grid, increases the value of the ERA. Information that would be useful for performing a planning ERA is similar to near-term and seasonal ERAs but with more uncertainty.

Transmission

In a planning ERA, transmission can be significantly more variable than the near-term or seasonal ERAs. This time horizon presents an opportunity to build out or upgrade the transmission systems to relieve constraints or for other purposes.

Chapter 5: Methods

Introduction/Overview

The modeling items described in the prior chapters are foundational for performing comprehensive ERAs. Many of these are also considered when performing capacity assessments with a key difference for ERAs being the finite amount of energy available from fuel and energy-limited resources. For example, a hydroelectric power plant with a capacity of 100 MW can only generate a total energy output over time equivalent to the amount of water in storage, and energy generated in one hour is not available to be used in a later period. Capacity assessments historically would count this hydro plant as having 100 MW available in every hour. Most modern capacity assessments instead attempt to account for energy limitations with various probabilistic methods that derate nominal capacity toward an expectation at the time of peak hour or greatest risk. An energy assessment constrains the total energy available, not the capacity. This is achieved through an explicit modeling and enforcing of all energy constraints on the system through the full study horizon.

An additional element of an energy assessment is identifying not only that enough energy is available to meet expected demand for all hours of the study period but also that it is available to ensure that necessary essential reliability service requirements are met, primarily ramping capability and reserves. As more variable generation is added to the system, the need for additional flexible or ramping resources should be evaluated. Ramping resources that can quickly raise or lower their output are essential to the Reliable Operation of the BPS. Certain demand also provides ramping capability, and an understanding of how these demand-side resources operate is essential for modeling and performing energy assessments.

Many methods can be used to perform an ERA and may require the use of both probabilistic and deterministic models to identify when the system may be at risk of energy shortages. Probabilistic vs. deterministic methods are defined in Volume 1. Succinctly, the probabilistic method considers at a high level many possible combinations of supply and demand to screen for potential reliability risks to the BPS. This method can be used to identify periods and conditions under which the system's energy supply and demand are stressed and could lead to unserved load.

A deterministic approach involves modeling one set of events for a given scenario. Running certain iterations of the supply and demand conditions identified in the probabilistic model through a deterministic model allows for a detailed analysis in which increased operational detail is modeled for the identified scenarios. Such a detailed analysis may not be computationally feasible in a probabilistic analysis. As such, deterministic and probabilistic approaches can be used in conjunction with one another to identify and explore high-risk scenarios in greater depth. Many different modeling tools can be used to perform energy assessments, but all fall into a handful of tool families with cross-family integration leading to more robust results.

Tool Families Overview

This section describes the families of tools that an analyst can use to perform an ERA. The subsections are not meant to be comprehensive but to provide the reader with a high-level understanding of the different tool families. By reading the materials presented, the reader can hope to learn at a high level what each family of tools can do, what functionality each family has (i.e., the kinds of questions each family can answer), what each family does well, what each family does not do or does less than optimally, what level of system topology detail is captured, what time horizon each family can study and how time is represented, and where to find models of each family type. The section does not provide recommendations for or names of any specific tools within the described families., The reader should be cognizant of any regulatory requirements that require the provision of filings using a specified file format that may be vendor or program specific (e.g., FERC requires Form 715 power flow cases to be filed in one of six specific formats).[33]

The tools described below can be used separately for some assessments but are recommended to be used in combination with each other (or with other tools that may not be described) to set up the assumptions and initial conditions needed to perform ERAs. The analyst will need to evaluate the value of each tool and employ sound judgment in selecting the proper tools. In the end, a reasonable set of initial conditions is subjective and requires the analyst to understand what each individual component means.

Resource Adequacy

Resource Adequacy (RA) tools are the core set of tools used to perform an ERA.[34] They allow for resource capacity and energy Adequacy to be evaluated probabilistically for a range of possible scenarios. Risk metrics, such as loss of load expectation (LOLE) or expected unserved energy (EUE), are calculated using an RA tool.

Historically, many RA assessments used a convolution algorithm, an analytical method that calculates total available capacity distribution by convolving together the distributions associated with available capacity for each unit in the system. In this method, each time interval is assessed independently of all others, meaning that the intertemporal nature of power systems operations is ignored.

Most RA assessments and tools today instead use a Monte Carlo algorithm, which simulates hundreds or thousands of scenarios using different outage and/or weather patterns to understand the likelihood of load shedding. There are further nuances across Monte Carlo algorithms, with some algorithms considering chronological system operations and others considering every time interval independently. Some methods use a heuristics-based method, while others use a dispatch-based method. A heuristics-based method is simpler and less computationally intensive than a dispatch-based method but may not fully capture all energy constraints on the system. A dispatch-based method provides the most accurate representation of power system operations within the RA framework. Indeed, highly detailed dispatch-based Monte Carlo approaches closely resemble production cost modeling tools.

RA models can answer or provide guidance to determine if the system meets the required reliability level while considering outage probabilities, reserve margins, and load and weather uncertainty. Some of items for consideration when applying an RA model to an ERA are described in the following table.

[33] Part 2: Power Flow Base Cases https://www.ferc.gov/industries-data/electric/electric-industry-forms/form-no-715-annual-transmission-planning-and-evaluation-report-instructions

[34] Further information on RA tools can be found in the EPRI "Resource Adequacy Assessment Tool Guide: EPRI Resource Adequacy Assessment Framework" https://www.epri.com/research/products/000000003002027832

Table 5.1: Considerations for Applying Resource Adequacy Models to ERAs

Consideration	Description
Availability of Stored Fuel	Certain RA models can be used to model the availability of stored fuel by considering inventory levels and replenishment rates. For example, for thermal power plants (coal, natural gas), the model should track fuel inventory levels and factor in delivery schedules to ensure that the plants have sufficient fuel to operate when needed to meet demand. The cost associated with fuel procurement and storage may also be included in the model's calculations. This may not be possible in all RA tools, and such an analysis comes at a computational cost that should be balanced against other modeling decisions within the probabilistic framework.
Just-in-Time Fuel Modeling	RA models may incorporate fuel consumption and delivery schedule forecasts. These forecasts, created externally to the RA model framework, may be based on historical data, demand projections, and market conditions. Just-in-time fuel modeling ensures that power plants receive fuel deliveries precisely when needed to optimize operational efficiency and minimize costs.
Variable Energy Resources	For VERs like wind and solar, RA models incorporate probabilistic forecasting methods to consider a range of possible generation outputs based on weather forecasts, historical data, and geographic characteristics.
Power-Specific Limits and Emission Modeling	Certain RA models can incorporate generator operating constraints and emissions constraints in the algorithms. The level of constraints that can be incorporated will be dependent on the type of RA tool used (for example, tools with convolution algorithms and certain heuristics-based algorithms may not allow for these constraints) and the computational tractability of the model.
Energy Supply Availability	RA models can assess energy supply availability by considering the availability of generation resources, transmission capacity, and fuel availability. They analyze generation unit availabilities, scheduled maintenance outages, and unplanned downtime to determine the overall energy supply Adequacy in meeting demand requirements. This is done over multiple weather years and/or outage draws and is used to assess RA metrics, such as LOLE and EUE.
Electric Vehicles (EV)	RA models should include representations of EVs by incorporating EV charging demand profiles, vehicle-to-grid (V2G) interactions, and the impact of EV penetration on electricity demand patterns. The model should evaluate the effects of EV charging behavior on load profiles, including the potential for EVs to provide demand-response services to the grid.
Non-Transportation Electrification	Models should consider the uptake and usage patterns associated with electrification technologies in non-transportation sectors. They should assess the impact on system Adequacy of the shifts in timing and seasonality of load profiles and usage patterns.
Energy Storage	RA models vary substantially in the amount of detail included in energy storage modeling. At their most detailed, RA tools allow for consideration of parameters, such as cycling limitations, charging/discharging efficiencies, and transmission constraints. Storage may be dispatched to reduce overall system costs, maximize unit profit, reduce peak or net peak load, or reduce load shortfall events; careful consideration of the dispatch objectives is required to accurately represent storage operations.

Table 5.1: Considerations for Applying Resource Adequacy Models to ERAs	
Consideration	**Description**
T&D Export/Import and Deliverability	Many RA models leverage a zonal consideration of their systems, with major interface limits between areas enforced. Some tools have the capability for nodal modeling, although this should be carefully balanced against the computational cost of implementation. A careful analysis of important transmission and Stability constraints to consider should be undertaken in other analyses (such as production cost modeling and power flow models), and this information should be reflected in RA models as appropriate.
Essential Reliability Services and other Ancillary Needs	Essential reliability services, such as Spinning Reserves, Non-Spinning Reserves, and Frequency Regulation, can be modeled in RA assessments either as an increase to the effective demand, or explicitly modeled. It is important to consider which Ancillary Services would be maintained in a load-shed situation, as this distinction will affect reliability assessment results.

Production Cost

Electricity production cost models (PCM), sometimes referred to as rank-order security-constrained models, are a family of tools that provide insights into current and potential future market and system operating conditions. They are used to understand electricity market dynamics and future operational issues, identify potential reliability challenges, and perform economic and environmental benefit assessments. In an ERA context, they can be used to evaluate deterministic scenarios that were identified as high interest in the RA model or to run extreme weather scenarios that were not represented in the probabilistic analysis.

At a high level, PCMs mimic the real-time operation (commitment and dispatch) of resources, considering factors, such as power generation, transmission, and demand. PCMs can answer or provide guidance to answer various questions, including the following:

- What is the total production cost of the resources meeting electricity demand while subject to system constraints?
- What is the optimal commitment and dispatch of energy resources considering factors, such as fuel costs and deliverability, environmental regulations, and technology constraints?
- What is the impact of policy changes (e.g., carbon pricing, renewable energy mandates) on the operation and economics of the power system?

The underlying capabilities of PCMs include the following features by model:

- **Unit Commitment (UC) Models:** Optimize the scheduling of power generation units over a specified time horizon, typically ranging from hours to days. The unit commitment problem considers detailed generation operational constraints, such as minimum unit run/down times, ramp rates, start-up/shut-down durations, and energy storage volume, along with load profiles to schedule the selection of generators that may be committed to operate based on cost, deliverability, and condition in the preceding time step.
- **Economic Dispatch Models:** Further resolves the schedule by determining the level of production from each scheduled resource and unscheduled resources on a rolling basis to satisfy the load in each hour or sub-hourly period at least-cost while satisfying imposed constraints, such as emissions limitations or Ancillary Service constraints. They ensure that the total generation output matches the system load while minimizing fuel and operating expenses.
- **Security-Constrained Unit Commitment/Economic Dispatch Models:** Models extend unit commitment and Economic Dispatch by allowing for transmission constraints to be enforced through a nodal representation

of the system. They optimize the dispatch of generating units while representing the reliability and Stability constraints of the power system under normal and Contingency conditions.

- **Ancillary Services Market Models:** Extend the unit commitment and Economic Dispatch models to also simulate the procurement and provision of Ancillary Services, such as regulation, Spinning Reserve, and Non-Spinning Reserve, to maintain grid reliability and Stability. They co-optimize the allocation of resources across Ancillary Services and energy to ensure the availability of essential reliability services in real time.
- **Price Forecasting Tools:** Using PCM tools (unit commitment/Economic Dispatch (UC/ED)) or other approaches to predict electricity prices in wholesale energy markets based on supply and demand fundamentals, market dynamics, weather forecasts, regulatory policies, and other relevant factors. They help market participants make informed decisions regarding generation scheduling, bidding strategies, and risk management.

PCMs historically assumed perfect foresight and are solved using a two-step security-constrained algorithm that first resolves unit commitment for each simulation time step on a rolling basis before determining the unit dispatch in each simulation time step. PCMs are often used to assess issues, such as the integration of large amounts of variable renewable energy (like wind and solar) into the grid and determine the need for storage or other flexibility options to balance supply and demand. They can also be used to evaluate the potential for demand-side measures (like energy efficiency or load shifting) to reduce the cost of electricity production.

PCMs can be complex and require significant computational resources and expertise to develop, calibrate, and interpret. Results from PCMs can be sensitive to input parameters and assumptions, which may introduce uncertainties in the analysis. While PCMs can simulate various scenarios, they may not fully capture the complexities of extreme events or rare system failures.

PCMs operate at different time resolutions, ranging from hourly to sub-hourly time steps based on the level of detail required. The time horizon of analysis can span from short-term operational planning to long-term investment decisions.[35] Unlike capacity expansion models (CEM), which use aggregated representative time slices across each year, PCMs use sequential hourly or sub-hourly time slices to generate a least-cost solution across the simulated time horizon. PCMs incorporate extensive detail on electricity generating unit operating characteristics, transmission grid topology (typically represented as a dc representation of the ac network), operating characteristics and constraints, and market system operations to support economic system operation and detailed planning.

The results of PCMs provide valuable information on the system and market operations by determining the effects of transmission congestion, fuel costs, generator availability, bidding behavior, and load growth on market prices. PCMs provide forecasts of hourly/sub-hourly energy prices, unit generation, revenues and fuel consumption, external market Transactions, transmission flows and congestion, and loss prices. In non-market-based areas, these models are still applicable as they can be used to understand future operations, provision of Ancillary Services and transmission congestion, and other factors impacting reliability and economics.

Electricity PCMs are built on robust data structures, including the ability to enter time-based data changes at the hourly and sub-hourly granular level and detailed generator data inputs. In addition to unit capacity changes, users can enter data describing future changes to generator and transmission operational data. While PCMs rely heavily upon detailed generator specification, the level of transmission detail is determined by the user and can be aggregated into zonal representations or highly detailed nodal representations. The level of transmission detail included in a PCM simulation significantly influences the rigor of the simulation results, but this comes at the expense of non-trivial increases in simulation run times as more transmission detail is included. While very detailed

[35] Although CEMs are traditionally leveraged to make long-term investment decisions, PCMs can be used as a complement to this analysis to obtain a more accurate picture of a plant's operating costs.

transmission representations can be included, PCMs do not fulfill the role of the detailed power flow operational analysis tools as they typically use a dc representation of the ac power flow (i.e., no voltage constraints or Stability issues represented) and may produce infeasible power flow results. Many different PCM options are available to an analyst performing an ERA, including both open-source and commercial options. The selection of a PCM, as with all the tools described in this section, should consider the needs of the assessment, the veracity and availability of data within the model, licensing and maintenance costs, and ease of use.

The boundary between PCM and RA tools is blurring given the increased need for RA analyses to represent a greater level of operational detail than ever before. As such, PCM tools are sometimes leveraged for probabilistic analysis by simulating hundreds or thousands of scenarios and calculating RA risk metrics in post-processing.

Table 5.2: Considerations for Applying Production Cost Models to ERAs

Consideration	Description
Availability of Stored Fuel	PCMs can be used to model the availability of stored fuel by considering inventory levels and replenishment rates. For example, for thermal power plants (coal, natural gas), the model should track fuel inventory levels and factor in delivery schedules to ensure that the plants have sufficient fuel to operate when needed to meet demand. The cost associated with fuel procurement and storage may also be modeled as an additional generator cost impacting unit commitment and dispatch decisions.
Just-in-Time Fuel Modeling	PCMs may incorporate fuel consumption and delivery schedule forecasts. These forecasts, created externally to the PCM framework, may be based on historical data, demand projections, and market conditions. Just-in-time fuel modeling ensures that power plants receive fuel deliveries precisely when needed to optimize operational efficiency and minimize costs.
Variable Energy Resources	PCMs can be used to study the impacts of uncertainty, where a plan (e.g., day-ahead commitment) is based on one forecast and the system then needs to react as different wind, solar and demand show up in the dispatch.
Power-Specific Limits and Emission Modeling	PCMs account for off-power specific limits, such as emission constraints and Contingency modeling, by incorporating regulatory requirements and operational constraints into the optimization algorithms. For example, emission limits for pollutants like sulfur dioxide, nitrogen oxides, and carbon dioxide are integrated into the model to ensure compliance with environmental regulations while optimizing generation dispatch and scheduling.
Energy Supply Availability	PCMs assess energy supply availability by considering the availability of generation resources, transmission capacity, and fuel availability in the market.
Electric Vehicles (EV)	PCMs should include representations of EVs by incorporating EV charging demand profiles, V2G interactions, and the impact of EV penetration on electricity demand patterns. The model should evaluate the effects of EV charging behavior on load profiles, helping utilities plan for EV integration and infrastructure upgrades.
Non-Transportation Electrification	Models should consider the uptake and usage patterns associated with electrification technologies in non-transportation sectors. They should assess the shifts in timing and seasonality of load profiles and usage patterns.

Table 5.2: Considerations for Applying Production Cost Models to ERAs	
Consideration	**Description**
Energy Storage	PCMs model energy storage systems by considering parameters, such as cycling limitations, charging/discharging efficiencies, and transmission constraints. They optimize the dispatch of energy storage resources to reduce overall system costs, manage Peak Demand, and provide Ancillary Services, such as Frequency Regulation; careful consideration of the optimization objectives is required to represent storage operations. Cycling effects, including degradation over time due to charge-discharge cycles, should also be considered in the model's analysis.
T&D Export/Import and Deliverability	PCM model allows for transmission constraints to be enforced through a nodal representation of the system. However, PCMs do not fulfill the role of the detailed power flow operational analysis tools as they typically use a dc representation of the ac power flow (i.e., no voltage constraints or Stability issues represented) and may produce infeasible power flow results. A careful analysis of important transmission and Stability constraints to consider should be undertaken in other analyses (such as power flow models), and this information should be reflected in PCM models as appropriate.
Essential Reliability Services and other Ancillary Needs	PCMs can explicitly model procurement of essential reliability services, such as Spinning Reserves, Non-Spinning Reserves, and Frequency Regulation, to maintain grid reliability. They optimize the allocation of reserve resources to respond to sudden changes in demand or generation outages, ensuring sufficient capacity to restore system balance and prevent Cascading failures during contingencies. They do not analyze the response after contingencies.

Capacity Expansion Models

CEMs are a family of tools used in long-term system planning to inform investment decisions and potential future system designs through least-cost optimization of system resources given assumptions about future electricity demand, fuel prices, technology cost and performance, policy and regulation, and reliability targets. The output of a CEM would provide an analyst performing an ERA with a resource buildout to which energy constraints would then be applied. The CEM would not provide information on the nature of these energy constraints: This would need to be implemented by the analyst using their knowledge of the system. Many CEM options, including both open-source and commercial options, are available to an analyst. The selection of a CEM, as with all the tools described in this section, should consider the needs of the assessment, the veracity and availability of data within the model, licensing and maintenance costs, and ease of use. Capacity expansion tools excel in providing insights into long-term infrastructure investment decisions by considering multiple factors and scenarios. They help policymakers, regulators, and utilities identify cost-effective strategies to maintain energy reliability while meeting environmental and sustainability goals. These tools can assess the tradeoffs between different investment options and optimize the allocation of resources over time. CEMs can answer various questions related to long-term energy planning, such as the following:

- What is the optimal mix of generation technologies to meet future demand while minimizing costs?
- When and where should new power plants be built or retired?
- What transmission and distribution infrastructure upgrades are necessary to accommodate the future resource buildout? (Many CEM models do not yet have this capability.)

The CEM family of tools typically includes at least a generation capacity expansion capability to help determine the type and quantity of power generation facilities that should be built in a specific time frame to meet future energy demand at the lowest cost. In some cases, CEMs may also represent transmission capacity expansion in a co-optimized or coordinated manner with generation expansion, focusing less on specific transmission lines but more on upgrades between the zones represented in the model. Additionally, several commercially available CEMs have recently started to include high-level representations of distribution upgrade needs to accommodate load growth and DERs. Integrated generation, transmission, and distribution planning assessments may require several levels of tools, including CEMs as well as more detailed transmission and/or distribution analysis, though efforts are underway to improve the existing CEMs to better represent transmission or distribution for a more fully integrated capability. All these tools can be used to produce a starting point of generation and transmission that would be used to set initial conditions for ERAs.

CEMs rely on assumptions and input data that may not fully capture the complexities and uncertainties of the energy landscape. There is significant uncertainty regarding changes in technology characteristics and cost attributes, fuel prices, regulatory policies, operational flexibility needs, and consumer behavior. These uncertainties in input data translate to a resource buildout that is itself very uncertain. Additionally, these tools may have limitations for representing certain aspects of the power system, such as the dynamic interactions between generation, transmission, and distribution networks during extreme events or emergencies. Scenario analysis can support investigation of these issues.

Unlike the other model families described in this section, CEMs use high-level aggregate assumptions to reduce solve times given the length of time horizon considered. These tools typically operate over a long-term planning horizon, ranging from 10 to 30 years or more, depending on the specific needs and objectives of the analysis. They may use annual or sub-annual time steps to capture seasonal variations in demand, renewable energy availability, and other factors influencing system operations. CEMs typically use a structure built upon the use of time slices reflecting a handful of representative days each year consisting of blocks of hours with similar characteristics. A typical CEM includes fewer than 50 total time slices to represent each simulated year, which may or may not be simulated in time sequential order. Most CEMs include a planning reserve margin as an input or constraint to the simulation to ensure that solutions include sufficient resources to cover for variation from the 50/50 conditions of the representative days and operational experiences such as generator Forced Outages.

Capacity expansion tools can be customized to specific areas or jurisdictions to account for differences in energy resources, demand patterns, regulatory frameworks, and infrastructure constraints. They allow stakeholders to tailor the analysis to reflect the unique characteristics and priorities of their respective areas. Since CEMs sometimes consider transmission solutions as an investment choice, it can be intimated that they are quasi-transmission constrained, but these constraints are only as detailed as the system representation used by the CEM. Since most CEMs use a zonal approximation of the system, the level of transmission constraint reflected is at the zonal interface, meaning that copperplate deliverability is assumed within the zone. Because of the number of simplifying assumptions, level of aggregation, and assumption of perfect foresight reflected in a CEM, it is possible for it to produce a least-cost solution that is infeasible for dispatch and operations or that is not adequate when evaluated probabilistically for a wider range of possible scenarios.

CEM results are normally used in integrated resource plans and regulatory analyses. Advanced CEMs may consider the interdependencies between generation investments and the corresponding transmission upgrades necessary to deliver electricity from remote generation sites to load centers efficiently.

Although CEMs are not directly used to assess energy reliability, a robust analysis that incorporates energy constraints where computationally feasible will allow for a recommended resource buildout that is more likely to be energy adequate than if these constraints were not incorporated. CEMs should be run in combination with other types of models (“round-trip analysis”) when direct inclusion of constraints is not computationally or technically feasible. Other types of models can be used to guide a choice of simplified pseudo-constraints that allow for some representation of energy constraints within the CEM in a simplified manner.

Table 5.3: Considerations for Applying Capacity Expansion Models to ERAs	
Consideration	**Description**
Availability of Stored Fuel	CEMs can incorporate assumptions about the availability and cost of stored fuel, such as coal, natural gas, or uranium, based on historical data and market projections. They can also consider storage capacities and inventory management strategies to ensure a reliable fuel supply for thermal power plants over the planning horizon. One possible approach to incorporating this into a CEM would be to impose operational limits on fuel-limited resources. These operational limits could be informed by a PCM.
Just-in-Time Fuel Modeling	Models should simulate the logistics and transportation infrastructure required for delivering fuel to power plants, including pipelines, railroads, and storage facilities. They can account for lead times, delivery schedules, and supply chain disruptions to assess the reliability of just-in-time fuel delivery systems. One possible approach to incorporating this into a CEM would be to impose forced derates or Forced Outages for resources in time periods where their output is forecast to be limited.
Variable Energy Resources	CEMs should account for the variability and intermittency of renewable energy sources, such as wind and solar, in their analysis. One approach to incorporating weather shape diversity would be to incorporate rolling weather years in the CEM analysis: This would allow for some of the variability of renewables to be reflected in the analysis while maintaining computational tractability. Additionally, CEMs should be run in coordination with RA models, which can allow the Adequacy of the proposed resource buildout to be evaluated across multiple weather years.
Power-Specific Limits and Emission Modeling	Models should incorporate technical constraints and environmental regulations governing power plant operations, including emission limits, generator operating constraints, heat rate curves, and outage schedules, as is computationally feasible. The models have the capability to assess the impact of compliance costs, emissions trading schemes, and regulatory changes on investment decisions. Including important generator operating constraints allows for the flexibility needs of the system to be captured within the CEM framework. One possible approach to incorporating emissions constraints and other energy-based constraints into a CEM would be to impose operational limits on affected resources that are informed by a previous PCM analysis. Emissions constraints in particular may sometimes be overridden during high-risk load-shed periods, so it is important to be aware of the specific area's regulations when modeling this process.
Energy Supply Adequacy	CEM buildouts should be evaluated using RA models to ensure a reliable energy supply for scenarios that minimize costs and environmental impacts. This may require pairing these CEM tools with related tools, as described in earlier parts of this section, or even tools specifically designed to perform ERAs.

Table 5.3: Considerations for Applying Capacity Expansion Models to ERAs	
Consideration	**Description**
Electric Vehicles (EV)	Models should account for the growth of EVs and their impact on electricity demand patterns, grid congestion, and infrastructure requirements. They should analyze charging behaviors, load profiles, and grid integration challenges to ensure that the selected resource buildout is reflective of the needs of the electric transportation system.
Non-Transportation Electrification	Models should consider the uptake and usage patterns associated with electrification technologies in non-transportation sectors. They should assess the shifts in timing and seasonality of load profiles and usage patterns to optimize resource deployments.
Energy Storage	Capacity expansion models should consider the role of energy storage technologies, such as batteries, pumped hydro, and thermal storage, in enhancing grid flexibility and reliability. They should optimize the sizing, placement, and operation of energy storage systems to address intermittency, ramping requirements, and system balancing needs.
T&D Export/Import and Deliverability	CEMs should model the interconnection capacity and transmission constraints between different areas or neighboring systems, considering import/export capabilities and congestion management strategies, as is computationally feasible. In a traditional CEM model, including key interfaces through a zonal constraint model is recommended. Interface limits should be set to account for thermal limits as well as voltage Stability Limits and line losses. In a more advanced CEM model, nodal analysis may be possible, or transmission expansion may be co-optimized with generation expansion. A full analysis of T&D systems is likely an external process but would be useful to gauge the validity of the results from a CEM.
Essential Reliability Services and Other Ancillary Needs	Capacity expansion models should incorporate the provision of essential reliability services, such as Frequency Regulation, voltage support, reserves, and blackstart capability, from diverse sources in the generation mix. Analysts should consider including provisions to evaluate the cost effectiveness and technical feasibility of providing these services through various generation, storage, and demand-response options.

Power System Operational Modeling Tools

At the opposite end of the spectrum from CEM and PCM are power system physical simulation tools. This family of tools is used to study very short-term transient periods, typically only a few cycles (or seconds) in duration, on the system. These tools simulate the physical behavior of power systems under various operating conditions, including Disturbances, contingencies, and dynamic responses. While it may not be readily apparent, these tools may play an important part in the successful execution of an ERA. While not necessarily incorporated directly into an ERA process, these tools would help an analyst gain an understanding of the fundamental engineering-driven equipment responses that are not captured in lower time resolution models (PCMs, CEMs, RAs). Operational modeling tools may provide insights into different concerns and solutions (e.g. fault ride through) and allow them to create more precise models when needed to assess energy reliability.

Operational models can address a variety of questions crucial for ERAs, including the following:

- Can the system maintain synchronism and Stability following Disturbances, such as Faults or sudden changes in load or generation, and what assumptions would be applied in an ERA to such a Disturbance?

- How do the different components of the power system, including generators, transformers, and control systems, respond to changes in operating conditions, resulting in how they would be modeled in an ERA?
- Can the system maintain voltage and frequency within acceptable limits under varying conditions, or is a different set of resources needed to supplement the expected commitment and dispatch?
- How do equipment failures or other contingencies impact system reliability and performance?

Operational modeling tools excel at providing detailed insights into the dynamic behavior of power systems during transient events. They accurately capture the interactions between various system components and can simulate complex scenarios with high fidelity. These tools are valuable for identifying potential vulnerabilities and assessing system resilience under different operating conditions. This family of tools includes the most detailed representation of the transmission system but at the expense of a lesser representation of generator constraints.

Operational models encompass various software packages and computational techniques designed to simulate the dynamic behavior of power systems during operational conditions. Some of the key tools are listed as follows:

- **Transient Stability Analysis Tools:** Simulate the dynamic response of power systems following Disturbances such as Faults, sudden changes in load, or contingencies. They assess the system's ability to maintain synchronism and Stability over short time frames, typically ranging from a few cycles to a few seconds.
- **Dynamic Simulation Software:** Model the behavior of power system components, including generators, transformers, transmission lines, and control systems, under varying operating conditions. They provide insights into voltage and frequency dynamics, system oscillations, and response to control actions.
- **Contingency Analysis Packages:** Evaluate the impact of equipment failures, line outages, or other contingencies on system reliability and performance. They identify critical contingencies and assess the effectiveness of mitigation strategies, such as Remedial Action Schemes and automatic load shedding.
- **Voltage and Frequency Regulation Tools:** Focus on analyzing the system's ability to maintain voltage and frequency within acceptable limits under normal and abnormal operating conditions. They assess the effectiveness of automatic voltage control devices, governor systems, and other control mechanisms.
- **Wide-Area Monitoring and Control Systems (WAMS):** Use real-time measurement data from synchronized phasor measurement units (PMU) to monitor and control power system dynamics over large geographic areas. They provide situational awareness, early Fault detection, and system-wide Stability analysis capabilities that can be used to detect unexpected dependencies that can then be modeled in an ERA.

While these tools offer valuable insights, they have limitations, including computational intensity, complexity, data dependencies, and scalability. Simulating short-term dynamic events requires significant computational resources and time, therefore limiting the scope of analysis. The complexity of power system dynamics can make it challenging to model all interactions accurately. Simplifications and assumptions may be necessary, which can affect the accuracy of results. Operational models rely heavily on accurate data inputs, including system parameters, network topology, and equipment models. Inaccurate or incomplete data can compromise the reliability of simulation results. These tools may struggle to scale up to large, interconnected power systems or to incorporate detailed representations of DERs effectively. They may also be unable to capture impacts of certain issues, such as control interactions between inverter-based resources, for which electromagnetic transient (EMT) tools would be necessary. These issues are well covered by other NERC activities related to modeling for IBRs, including the Inverter-Based Resource Planning Subcommittee (IRPS). Additionally, these tools can only analyze one operational condition at a time and, as such, are not well suited to analyze a large number of uncertainty scenarios for a full study horizon. Since they can only model one system snapshot at a time, they also are not well adapted to analyzing energy sufficiency issues.

Operational models offer flexible resolution capabilities, allowing users to adjust time steps and time horizons based on the specific requirements of the analysis. Shorter time steps enable more detailed simulation of fast transients, while longer time horizons facilitate assessment of system behavior over extended periods.

Operational models typically represent generation and transmission (G&T) components in detail, including generators, transformers, transmission lines, and control systems. These components are modeled using mathematical equations and algorithms that capture their dynamic behavior accurately during transient events. However, the level of detail and complexity in G&T representations may vary based on the specific objectives and constraints of the reliability assessment. Demand is also represented in various ways, with more detailed models that can cover different types of loads, as well as DER, being increasingly represented in such models.

This is currently the only family of tools that is directly covered by established NERC standards—the MOD family of standards. These tools are used directly in the study of power system reliability through the performance of power flow simulation to assess system dynamics, Stability, optimal power flow, and many other short-term transient conditions. Unlike the prior families of tools that produce solutions driven by economic least-cost optimization, power flow tools are not economically constrained. This family offers many tool options to an analyst performing an ERA, including both open-source and commercial options; however, industry has primarily settled around a small handful of mature commercial tools in this space driven by regulatory requirements. Application in an ERA would be limited to having a better understanding of dependencies, which would then be modeled in ERA-specific tools or other modeling tools that feed the ERA process.

Screening Tools

In addition to the detailed tools described above, specialized simple tools covering one or more items are often needed to create a narrowed set of scenarios or considered variables. These may include Contingency screening tools, probabilistic screening tools to identify likely energy reliability risk scenarios for deeper exploration, and/or covariance of inputs (e.g., load dependence on weather, outage dependence on the same weather input, and higher generator capability with cold air input). The choice to use these tools is often narrowed by the need to supplement experience-based judgments.

Interdependence Tools

The family of models in this category are those that simulate items that intersect or impinge on electric system planning and operation that may be used to inform the performance of an ERA or mitigation plan development, including commodity, supply chain, transportation, weather, and economic sector models. Since these models can vary in complexity, cost, and availability to the analyst or entity performing an ERA, performers are advised to closely consider the needs and benefits for including these types of models in an ERA over the use of engineering judgment. Often, it is only feasible for the entities to include these types of models in a planning ERA because of the major differences in modeled time domains compared to the electric sector; however, this is not always the case as information from these models may be available through collaborations with partners and other industries. Examples of benefits from including non-electric sector models in the performance of an ERA include establishing feedback loops to capture the dynamic interdependency concerns that may not otherwise be captured. For instance, inclusion of detailed natural gas models can significantly improve an entity's ability to mitigate against natural gas-electric interdependency concerns as these models can be used to develop price and congestion forecasts, which can be integrated with or used to inform electricity models, such as a PCM, to determine re-dispatch or fuel switching solutions. Similarly, rail and truck transport models can be used over a longer-term horizon, enabling an entity to assess whether mitigating actions are needed to accommodate fuel and consumables stockpile replenishment timelines.

Implementation

Any analyst performing an ERA would need to evaluate the benefits and shortcomings of each model and consider the needs and objectives of the ERA when determining what model, or models, should be employed in the performance of their assessment. Models can feed bi-directionally to inform each other, as binding constraints from one family may not be captured or identifiable in another. For example, it may be desirable to move from a low level of detail to a higher level of detail to evaluate identified periods of concern or to pass constraints identified in higher-detail models to the lower-detail model (i.e., congestion constraints identified in a power flow that are not captured in a first-pass PCM or CEM). Implementation and performance of an ERA may be iterative within and between tools depending on the scenario design and desired outcomes. Figure 4 illustrates the interdependencies of tools involved in the ERA process, including some of the tools detailed above.

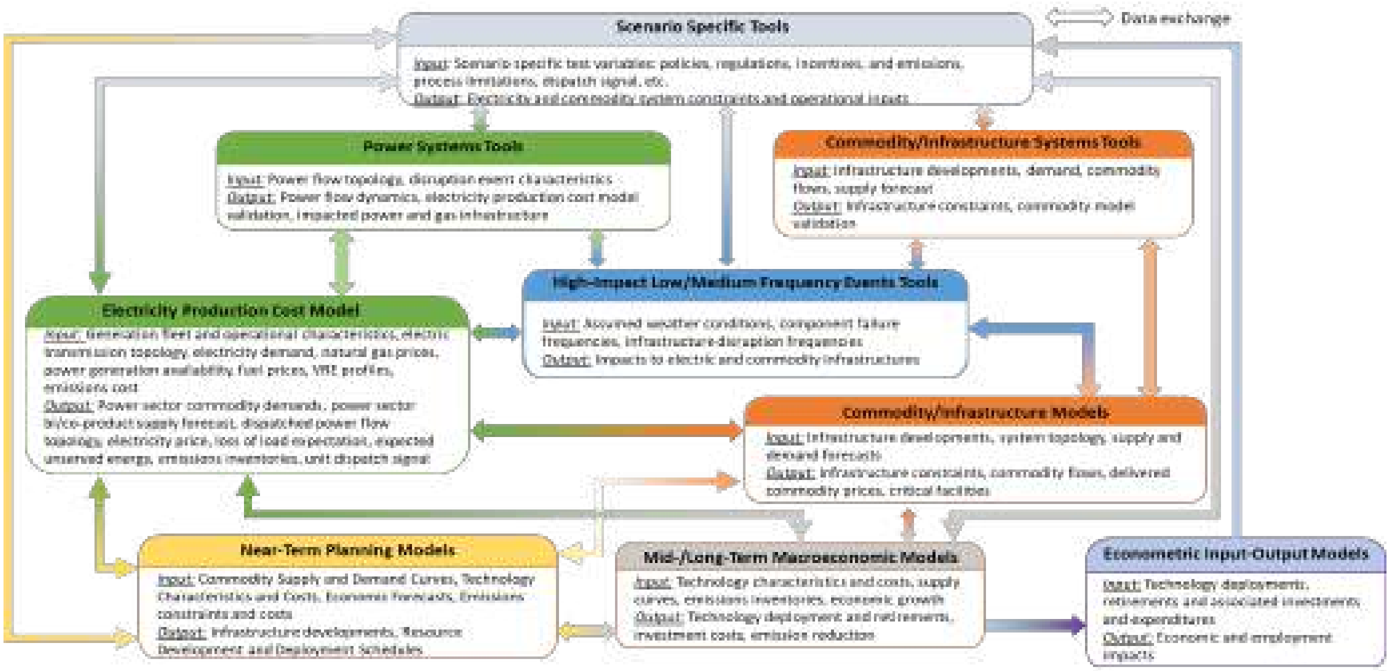

Figure 5.1: Illustrations of the Interdependence of Tools as They Relate to the ERA Process

Chapter 6: Base Case and Scenario Modeling

Base Case

The base case for an ERA is a model of projected power system conditions for a specific point in time. From the base case, additional scenarios and contingencies can be applied for further analysis of risks. Studying the base case will give an analyst a view of a standard starting point. Since ERA is a look at a certain time period, a base case would include the most-likely-to-occur series of conditions over the defined period.

Several input considerations should be included in an ERA. Ultimately, the base case represents the *expected* quantity for all the input considerations in each interval (e.g., hour, day, week) of the assessment. The contributing factors that the analyst will associate with are their contribution to energy, either from the supply or demand point of view. Starting with demand, and the input factors that contribute to demand. All the contributing factors that drive demand (e.g., weather, behind-the-meter generation, industrial processes, seasonal considerations, electrification) would be modeled as the *expected* value for each, resulting in an *expected* demand value. Likewise, for supply capabilities and availabilities, the analyst would use the *expected* values for production capabilities, fuel supply factors without Contingency, and any other factor that would contribute to the availability of supply resources.

The term "base case" in an ERA is used generically, meaning that it is a set of baseline assumptions that define a reference point by which scenarios and contingencies would be applied. The term base case is **not** intended to draw any similarities to transmission base cases that are used for transmission planning studies; however, it is also not intended to disallow transmission studies to be coupled with ERAs. How a base case is defined may depend on the time horizon of the ERA. Near-term, seasonal, and planning base cases have a variety of differences in how particular inputs are modeled or formulated.

Near-term base cases will likely start with a forecast set of conditions or verified known quantities. Near-term base cases start off with higher certainty in weather, demand, planned outages, fuel availability, transmission capability, etc. In a deterministic analysis, a median forecast or known quantity would serve as the base case for all parameters and then be varied using specific scenarios as needed. In a probabilistic analysis, a number of probabilistically weighted replications representing operational uncertainties (primarily due to Forced Outages and weather uncertainty) would be used to create a base case, with various specific scenarios relating to other system risks being subsequently analyzed as needed.

Seasonal base cases introduce some uncertainty over near-term base cases due to the longer time horizon but still require the outlining of an appropriate set of system conditions representative of the time horizon modeled. These system conditions need to be determined by the analyst using the tools and information available but are intended to be similar in nature to near-term base cases. Longer time horizons will likely depend more on scenarios than shorter-term base cases, but a base case should be established to introduce uncertainty. With enough scenarios, emphasis on the accuracy of a base case gives way to a variety of possibilities. There will be seasonal considerations for both supply and demand. Seasonality will have a different impact depending on what system is being assessed. The intent of modeling the *expected* conditions does not change based on the season being studied; it just changes what the literal assumptions are.

Planning base cases again should outline an appropriate set of system conditions, even given the increased uncertainty associated with a more distant study time horizon. As such, planning ERAs will depend much more heavily on a comprehensive scenario analysis to form a complete picture of future risk as compared to short-term ERAs, where a base case analysis may be sufficient.

While scenarios and contingencies gain importance as the horizon increases, it remains necessary to define a reasonable base case. The results of the ERA on the base case will be important in conveying risk. If base-case assumptions result in energy shortfall or other unfavorable conditions, the base case may not be defined properly, or the proposed system may not be prepared to reliably serve energy demands and require corrective actions sooner than anticipated. It is also helpful when applying scenarios to have a base case to compare results, which allows an analyst to point to specific parameters and convey trends.

All base cases should be defined as part of a repeatable process, especially if the ERA is intended to be performed routinely, to allow for comparison and metric tracking and trending. That process can be updated over time as knowledge and experience dictates. There is some likelihood that base cases will be developed in accordance with stakeholder-approved processes and may not have the flexibility to change frequently. Provisions for updating assumptions in the base case and then again in subsequent sensitivities and scenarios should be included in the process for when large, unexpected changes happen that were not included in the original base case or new methods become available that make for more robust modeling in a base case. Examples would include large resource unplanned outages (e.g., nuclear power station trips) or major transmission system element failures.

One last consideration for base-case assumptions is the verification of the reasonability of assumptions, after the time that was assessed has passed and actual observations are available. Items that were identified in prior scenario models may influence an evolution in base case modeling. It is impossible to forecast energy assessment conditions with 100% accuracy. However, with a large enough sample size and a series of assessments, they can be benchmarked against actual conditions and the analyst can detect and minimize or eliminate biases.

Scenarios and Risk Assessment

Risk is a product of three primary components:

- The events or scenarios considered
- Their likelihood of occurrence
- Their associated impact

Choosing the scenarios (or method of generating scenarios) appropriately is critical to a robust risk assessment and tolerance definition because these choices determine the outcome of an ERA, either implicitly or explicitly by their likelihood of occurrence. While defining an objective standard is not easy, the analyst should consider the expected or likely, credible, and even worst credible scenarios with their associated risk metrics or criteria based on their inherent risk tolerance to fully assess risk through an ERA. Chapter 7 discusses how to use metrics and criteria to evaluate risk and communicate that risk based on the method and scenarios used.

Sensitivity and Scenario Modeling

Sensitivities and scenarios are not new concepts to industry planners but are looked at from a different angle in an ERA.

The following is an excerpt from page 13 of the NERC Probabilistic Assessment Technical Guideline Document:[36]

Sensitivity Modeling: Sensitivity analyses are run to assess the impact of a change in an input (either load, transmission, or resource-related) on resource Adequacy metrics. The runs are performed by changing one input at a time to isolate the potential impact of each input. Ideally, the change in each input should be accompanied by an associated probability.

Scenario Modeling: In its most general form, a scenario analysis is performed to assess the impact of changes in multiples inputs (either load, transmission, or resource-related) on resource Adequacy metrics. The runs are performed by changing multiple inputs at the same time. Ideally, each scenario should have an associated probability calculated based on the changes in inputs included within the scenario. Scenarios are likely to be identified in the

[36] https://nerc.com/comm/pc/pawg%20dl/proba%20technical%20guideline%20document_08082014.pdf

NERC *Long-Term Reliability Assessment* or by sensitivity analysis results. In some cases, scenario analysis may require additional inputs (not included in the Core Probabilistic Assessment) relevant to address a specific reliability concern.

While these descriptions are specific to the NERC Probabilistic Assessment (ProbA), application to an ERA is similar. Sensitivity modeling adjusts one input parameter and scenario modeling adjusts multiple input parameters.

In probabilistic ERAs, each uncertainty will have an associated probability of occurrence. The analyst should understand what the appropriate probability is and what it means for an ERA's outcome. Some inputs may have equal chances of occurrence (e.g., weather assumptions for upcoming seasons), while others may have a higher chance to a specific value (e.g., weather forecasts for the next seven days). Further, some inputs may have a lesser chance of occurrence but a larger impact on the outcome of an ERA. However, it is challenging to assign a probability of occurrence to certain uncertainty pathways. This is particularly true for the evaluation of macro risks, such as policy changes and shifts in macroeconomic conditions. A sensitivity or scenario analysis would be particularly useful for analyzing the risk associated with these types of uncertainties.

Scenarios should be selected to analyze certain conditions, either simple or complex, with a reasonable risk of occurring that stress the system beyond the conditions modeled in the base case to examine risks that the system may experience. This is especially important for conditions for which the entity wants to be prepared. Scenarios in an ERA would have varying levels of severity. Consideration should be given for how the results of a scenario will be compared to specified criteria. For example, low-impact scenarios should not result in outcomes with unacceptable consequences (e.g., a scenario similar to the base case probably should not result in a relatively large-magnitude energy shortfall). Conversely, it may be appropriate to get results with large-magnitude energy shortfall when the worst-case scenario for all inputs is selected. The analyst would need to determine the degree of variance that would be needed to create that stress and approach shortfall. It is likely that multiple iterations would be required when initially setting up multiple scenarios (e.g., if the first attempt adds no stress, more variances may be required).

Credible risks are events that are plausible to occur and would have a severe impact. The choice of scenarios, paired with the selection of metrics and criteria (discussed in Chapter 7), helps set the level of risk or reliability around which an entity plans and designs a system and expects reliability to be maintained. Scenarios should be chosen such that the entity can describe and document the scenarios that have some risk of occurring, and their system should be designed to operate reliability through that occurrence.

As the term "credible" is inherently subjective, formulating conditions that would be considered credible may require research and effort to ensure that a scenario would be accepted as "credible." Some examples that will lend credibility to scenarios include industry assessments, academic research papers, documented historical event reports, verified analyst experience, the judgment of subject matter experts, and statistical evaluations. Conditions that have happened before, locally or in other similar locations, also lend credibility in terms of historical events. Nevertheless, just because an event has happened before does not necessarily mean that it will happen again. Similarly, just because an event has not happened in the recorded past does not mean that it cannot happen in the future.

Finally, scenarios will have inputs that are co-dependent on a similar driving factor, such as demand, variable supply (e.g., solar and wind), outage assumptions, and fuel availability all being co-dependent on weather. These inputs should be coupled together when modeling input assumptions. Decoupling related co-dependent assumptions can result in impossible scenarios. Including these scenarios in a solution set and comparing the results of that solution set to a criterion can give biased results, potentially triggering actions to be taken for a scenario with a 0% probability of occurrence. Worse, these impossible scenarios dilute the pool of results and can potentially mask indications of real problems in ERAs. Additionally, certain severe events that are only present when weather outputs are properly correlated could fail to be captured within the analysis.

Near-term scenarios will likely have less variability than seasonal or planning scenarios. Higher certainty in data allows for the use of forecasted conditions rather than assumptions in the base case and can limit the variability in scenarios. Demand, fuel supply availability, generation and transmission outages, stored fuel inventories, emissions limitations, and most other input assumptions present some level of clarity in the near term, and a high degree of variability may not be necessary. Resources that inherently operate with a high degree of variability (e.g., wind and solar) are exceptions, and the variability of some inputs may not change from near-term to planning ERAs.

Scenarios in seasonal ERAs may need to offer more variability than those in the near term. Some variability would remain similar, as mentioned before with wind and solar supplies. Some inputs (e.g., weather, demand, planned outages) would introduce some additional variability and should be understood by the analyst to define scenarios that would be considered credible. Further, some inputs would remain predictable with limited variability (e.g., which generators and transmission capabilities are built). Weather scenarios in seasonal assessments can be limited by long-range forecasts (e.g., NOAA outlooks, El Niño conditions and forecasts), which should be used with caution to avoid overlooking potential real conditions. Long-range forecasts provide a general direction over a long period of time (i.e., month or months) but may not capture the possibility of shorter-duration spell of more extreme weather embedded within the outlook period.

Scenarios in planning ERAs are completely based on assumptions rather than forecasts. Historical information coupled with assumptions for expected changes gives the analyst information that can be used to determine credible scenarios. For example, historical demand could be used to represent future demand, so long as it is adjusted for any known changes in climate, coupled with growth/contraction assumptions. For longer-term ERAs, this becomes even more critical given the anticipated greater reliance on weather-dependent resources on the BPS. Supply resources are more uncertain in long-term ERAs but are not completely uncertain. A variety of factors need to be considered when creating long-term scenarios. For example, the future resource mix will be influenced by economics, technological advances, environmental policy and regulations, and other incentives to build new resources. Many of those factors will impact all infrastructure expansion and would need to be researched to be plausibly varied in a longer-term ERA.

Chapter 7: Study Metrics and Criteria

Purpose of Metrics and Criteria

An ERA will show an analyst what the outcome of a range of events or operating conditions would look like. To determine what the risk is and whether that risk is acceptable, there must be some metrics and associated criteria (or minimum thresholds) for comparison and evaluation of risk. The evaluation of system Adequacy using these metrics and criteria will drive when and what corrective actions may be required to minimize the impact of the perceived risks. Metrics are measurements derived from deterministic or probabilistic Adequacy analysis to indicate the reliability or risk to the system while criteria are a set standard to determine if the level of a metric is acceptable. In the case of ERAs, a criterion for a metric might be set such that if it is not met, some mitigation activities need to be performed.

Metrics and criteria are useful for four purposes: quantifying the risk, setting a risk tolerance or identifying what risk is acceptable, evaluating whether the risk of the system is acceptable, and comparing potential risk-reduction activities. Based on these purposes, the method and scenarios of the ERA should quantify the current risk, the analyst should have defined a risk tolerance specific to the scenarios based on evaluation criteria, and the analyst should use those criteria or metrics to evaluate whether and what interventions are needed.

Traditional RA processes, metrics, and tools may not be fully able to evaluate Adequacy requirements and properly articulate risks in the context of an evolving resource mix, changes to demand profiles, and extreme weather scenarios. The evaluation criteria and associated metrics should be based on the methods used in ERAs, the level of risk that entities can tolerate, and how entities want to quantify and present the risk. Considerations for stakeholder involvement in the development of metrics will be a key input to the process. Expertise, responsibility, and authority to address deficiencies will all likely fall with different entities and should be coordinated for all stakeholders. A significant challenge is to identify appropriate ERA metrics that provide a comprehensive picture of system risk to planners, operators, regulators, and policymakers and to set minimum Adequacy criteria that reflect both the costs and benefits of avoiding excessive unserved energy, the frequency and duration of loss-of-load events, and the risk of energy deficiency that areas can accept. The names of some of the metrics are not different whether used in a capacity- or an energy-based assessment but represent the specific capacity or energy risk depending on the methods and quality of the analysis method used to calculate the metrics.

Existing Metrics

Many reliability and Adequacy metrics used within the capacity assessment framework can be directly used in an energy assessment framework. To understand the risk of losing load, an analyst needs to consider the duration of events, the magnitude of the loss of load, and frequency of the loss of load.

Deterministic Metrics and Criteria

Deterministic metrics can be useful in examining a specific forecasted scenario or set of scenarios that the analyst expects to occur, including, in certain situations, tail-risk events (high impact/low frequency [HILF]) that can provide a system design basis for planning purposes. Using deterministic scenarios is especially helpful if the analyst wants to stress test an electrical system model to understand if the system can reliably meet certain minimum thresholds with respect to criteria including unserved energy, Energy Emergency alert (EEA) levels, or a higher reserve margin under extreme weather or system conditions.

Creating credible lower-probability but high-impact events and assigning a deterministic criterion to them allows the analyst to set a risk tolerance for those events and what their expectations are for handling severe events. The analysis of these high-impact events is useful to understand how the system may behave during these events and allow for planning that is more resilient even if the expectation is that the system may experience some adverse or abnormal conditions if those events occur.

Unserved Energy
Unserved energy is the amount of load that is not served in terms of energy for a given time period, generally expressed in MWh. Unserved energy can be determined for individual deterministic scenarios with a limit in the amount that you will accept during severe contingencies for a given time period, generally expressed in MWh.

Forecasted Energy Emergency Alert
EEAs are defined in NERC Standard EOP-011-1,[37] Attachment 1 as follows:

- **EEA 1**: All available generation resources in use
- **EEA 2:** Load management procedures in effect
- **EEA 3:** Firm load interruption is imminent or in progress

These thresholds are useful for connecting the forecasted or possible Energy Emergency that might be observed in an ERA to the actual Energy Emergency events that the analyst is trying to avoid. These thresholds indicate system conditions that would be considered energy emergencies even if load loss is not expected to occur. Using the increasing level of impact of the EEAs as criteria may be useful to setting criteria for increasingly less probable but impactful events.

For example, ISO New England uses Forecasted EEAs[38] (FEEA) in near-term ERAs, leveraging the existing and well-understood EEA definitions. FEEAs can be used as an indication that available resources during any hour of an ERA are forecasted to be less than the quantity defined by EEAs. The EEA metrics have been used consistently for many years in ERAs.

Reserve Margins
Reserve margins requirements can be set as criteria to have a sufficient amount of excess energy or capacity available beyond generation levels needed to meet demand. This threshold provides an additional buffer before expected load loss and therefore a lower expectation of impact in any scenarios that are simulated. These reserve margin requirements could be based on a fixed value or a set percent of energy demand or be related to Ancillary Service requirements or uncertainty of supply or demand variables.

Probabilistic Metrics and Criteria
Probabilistic methods allow the analyst to assess risk based on a wider range of scenarios and better incorporate the likelihood of the events occurring than individual deterministic scenarios. The resulting probabilistic metrics are based on all the events simulated or statistical calculations and combined into statistical values of shortfall events. The metrics more explicitly reflect risk across a range of operating conditions instead of a design around a specific defined scenario's result. However, individually the metrics may not reflect as clearly the frequency, durations, and magnitude of expected events.[39]

All the following metrics can potentially be calculated based on the same set of ERA simulations and may not necessarily require separate probabilistic analyses to be performed.

Loss of Load ExpectationError! Bookmark not defined.
LOLE is the expected number of days per periods (generally studied for a year) for which the available generation is insufficient to serve demand. The calculation is based on whether shortfalls are observed during individual scenarios and the likelihood of those events occurring. As a result, the metric reflects the frequency of events or at least the

[37] https://www.nerc.com/pa/Stand/Reliability%20Standards/EOP-011-1.pdf
[38] https://www.iso-ne.com/static-assets/documents/rules_proceds/operating/isone/op21/op21_rto_final.pdf
[39] See: Probabilistic Adequacy and Measures Report - 2018

number of days with loss-of-load events but does not give any information of the expected duration or magnitude of these events or even if multiple events occur on the same day.

In an ERA, LOLE would be tailored to the defined study period but would effectively mean the same as in capacity assessments, event-days per period. LOLE would not show depth of shortfall, only the likelihood of the occurrence of a shortfall. Used in combination with the EUE metric, this metric can have criteria defined to trigger corrective actions. For example, a threshold for the number of shortfall days you are willing to risk loss of load for a given time period, such as 0.1 days per year (similar to the 1 day-in-10 year reliability metric that is often cited across the industry), might be useful.

Loss of Load Events

Loss of load events (LOLEv) is the number of events per period (generally on a per-year basis) when load is lost. This metric differs from the LOLE metric in that LOLEv takes into account days with multiple loss of load events and records one event for multi-day loss of load events. Using LOLE alone will obscure multiple events occurring during a single day. Multiple events in a single day may be different magnitudes and may occur at different times of day, reflecting inherent differing system conditions and associated risk.

Loss of Load Hours

Loss of load hours (LOLH) is the expected number of hours per period (generally on a per-year basis) when a system's hourly demand is projected to exceed the available generating capacity. This metric is calculated using each hourly load in the given period instead of using only the daily peak in the classic LOLE calculation.

With LOLH reflecting the duration of energy shortfalls better than LOLE, LOLH can be used in an ERA in combination with EUE, and perhaps LOLE, to set a limit on the number of LOLH. Limits could be conditional as well by including system conditions with the metric, for example, limiting LOLH to 12 hours as long as no more than 2 of the hours are below 32°F.

One caution to this approach is that higher precision does not necessarily lead to higher accuracy. When working in a longer-duration energy space, actions are available to move some shortfall from one period of time to another. LOLH may not be an appropriate metric for this reason.

Expected Unserved Energy

EUE[40] is the measure of the resource availability to continuously serve all loads at all delivery points while satisfying all planning criteria. EUE is energy-centric and analyzes all hours over a period of time. Results are calculated in MWh or can be normalized to expected demand. EUE can be normalized (NEUE) as a percentage of total energy demand. In an ERA, EUE can be used to show the expected energy shortfall over the duration of a study period. The study period would be carefully defined to examine the impact of a specific risk (e.g., the duration of a long-duration cold spell or heat wave or duration of a drought). EUE would be cumulative over the selected duration but could also be combined with LOLE or LOLH. For example, a limit can be placed on the total MWh of EUE while also satisfying a limit on the number of days or hours where a shortfall may occur throughout the study period.

Limits on EUE could then be used to inform and/or trigger corrective actions to be taken to maintain reliability.

Loss of Load Probability

Loss of load probability (LOLP) is the probability of system daily peak or hourly demand exceeding the available Electrical Energy during a given period.

LOLP can be useful for probabilistic ERAs when defining risk associated with EUE or LOLE/LOLH.

[40] https://nerc.com/comm/pc/pawg%20dl/proba%20technical%20guideline%20document_08082014.pdf

Value at Risk and Conditional Value at Risk

Value at risk (VaR) and conditional value at risk (CVaR) are risk metrics that evaluate the tail Adequacy risk instead of an average or expected risk. VaR and CVaR are used in the finance industry to measure risk, especially related to tail risk or the magnitude of impact of lower-probability but higher-impact events. VaR is the maximum loss at given probability or confidence interval and can be calculated as the loss for a given percentile of scenarios. CVaR is similar to VaR but is the average risk of losses above a given percentile of losses (e.g., average losses of the 95th percentile or higher losses). These metrics are not specific to any energy concept but can be applied to many energy metrics, such as LOLE, LOLH, or EUE. These metrics differ from the other probabilistic methods discussed in this document as the VaR results are based on a percentile or confidence level, while CvaR is based on a conditional metric. These metrics are therefore good indicators of tail risk and the impact of lower-probability and higher-impact events. LOLE95 and LOLH95 are currently used examples of these metrics.

Figure 5 illustrates an example of VaR and CVaR of energy deficiencies based on a probabilistic ERA. The figure is a histogram of the energy deficiency results calculated from the assessment. The 95% VaR of energy deficiencies (shown by the black line) is 236.6 MWh, which means that the assessment expects that 95% of scenarios will have 236.6 MWh or less of load loss.

The 99% CVaR of energy deficiency of 485.3 MWh loss means that the average load loss for the worst 1% of scenarios is 485.3 MWh.

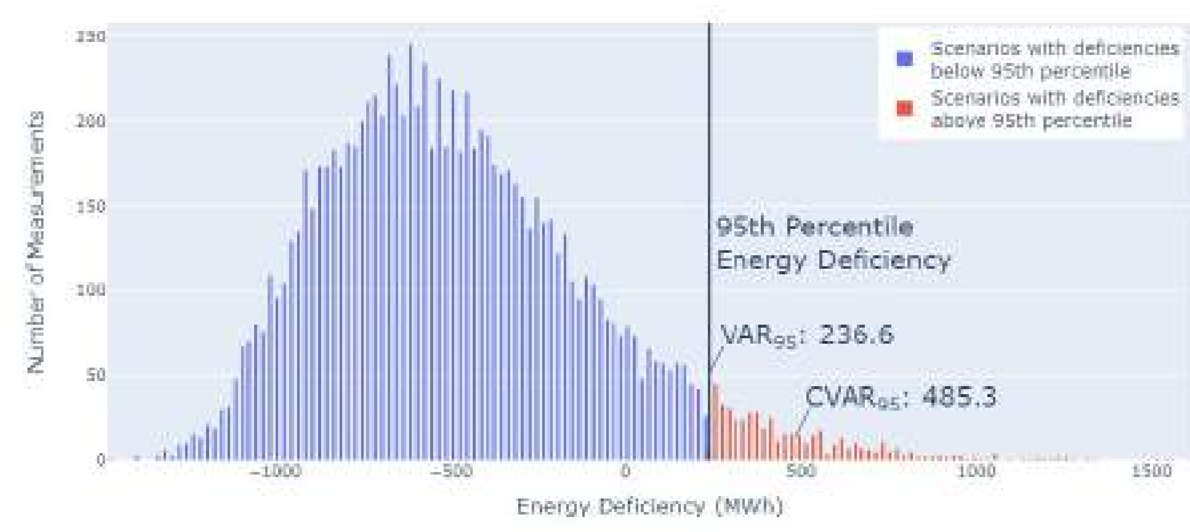

Figure 7.1: Example of VaR and CVaR for the 95th percentile of energy deficiency. VAR is 236.67 since it is the 95th percentile of the measurements and CVAR is the mean of the values greater than the 95th percentile (shown in red).

Selecting the Right Metrics and Criteria

The methods used to perform an ERA should be decided on in the early stages of development and will drive subsequent decisions and/or potential corrective actions. Methods and metrics would likely be developed in tandem with one another and are inherently subject to the risk tolerance of stakeholders. Considerations for scenario-dependent, deterministic metrics would also be part of that development. Probabilistic ERAs will have different metrics and criteria than deterministic ERAs. Similarly, scenarios with varying levels of supply loss or additional demand will have different minimum criteria than “all-facilities-in” or “normal conditions” ERAs.

It is also necessary to decide what parameters are important for measuring while staying in alignment with existing standards or other requirements. For example, the decision point on either maintaining some amount of Operating Reserves[41] or avoiding energy shortfall (i.e., load shed) comes early in the process and may vary by scenario simulated. Considerations for operations procedures or actions should also be taken into account when establishing criteria. This decision will also guide the analysts on what information is needed to come out of the ERA.

Using Deterministic Metrics

Deterministic ERAs and associated scenarios imply that a small set of discrete possibilities are examined. These scenarios make it easier to inspect and determine what mitigation activities would lower the risk of specific scenarios. This facilitates communication of the choice of mitigation activities and identified problems.

Using Probabilistic Metrics

Probabilistic metrics can be similar to those used in deterministic ERAs, with the addition of an associated probability, resulting in a metric that is defined as a criteria curve rather than a single point. The criteria curve would be on axes of the metric and probability, and the results of the ERA could be plotted against the criteria curve. The result of the defined criteria would then be a curve showing the results of the ERA versus a curve showing the pass/fail criteria.

Using Multiple Metrics and Criteria

Given that each metric represents an aspect of risk (frequency, duration, or magnitude), combining metrics is likely necessary to achieve the specified goals in performing the ERA. The use of multiple metrics will evolve and may even include using both probabilistic and deterministic methods to enable a better understanding of resource and energy Adequacy conditions.[42]

The reliability or risk thresholds can be set by a number of entities, not always the one performing the ERA or implementing the corrective or preventive actions. Criteria should be set through some stakeholder process, formal or otherwise, to ensure that affected parties are able to contribute and convey their concerns.

Table 7.1: Representation of Metrics in ERAs

Metrics	**Type of Metric**	**Can Represent Duration**	**Can Represent Frequency of Event**	**Can Represent Magnitude or Impact of Events**	**Can Represent Tail Risk**
Forecasted EEA	Deterministic			X	X*
Energy Reserve Margin	Deterministic			X	X*
Unserved Energy	Deterministic			X	X*
Loss of Load Probability (LOLP)	Expected or Average	X	X		
Expected Unserved Energy	Expected or Average			X	

[41] Note, for one example, that NERC Standard *BAL-002-3 – Disturbance Control Standard – Contingency Reserve for Recovery from a Balancing Contingency Event* may provide useful guidance on developing an ERA-based criteria for maintaining operating reserves throughout the duration of an ERA.

[42] See "New Resource Adequacy Criteria for the Energy Transition" for more discussion on choosing and using multiple criteria. https://www.esig.energy/new-resource-adequacy-criteria/

Table 7.1: Representation of Metrics in ERAs					
Metrics	**Type of Metric**	**Can Represent Duration**	**Can Represent Frequency of Event**	**Can Represent Magnitude or Impact of Events**	**Can Represent Tail Risk**
Loss of Load Events (LOLEv)	Expected or Average		X		
Loss of Load Expectation	Expected or Average		X		
Loss of Load Hours	Expected or Average	X			
Value at Risk	Conditional or Percentile	X**	X**	X**	X
Conditional Value at Risk	Conditional or Percentile	X**	X**	X**	X

* Deterministic metrics can represent tail risk if being applied to a stress test or “extreme” scenario

** VaR and CVaR metrics can represent duration, frequency, or magnitude depending on whether they are applied to LOLH, LOLE/LOLEv, or EUE

Chapter 8: Considerations for Corrective Actions

After performing an ERA and comparing the results to a set of defined criteria, if it is determined an energy shortfall is forecasted, the following actions could delay, reduce, or eliminate a potential realization of the forecasted energy shortfall or forecasted conditions that exceed the pass/fail criteria. Likely, the pass/fail criteria will be more conservative than a real-life situation that would cause an energy shortfall, ensuring that there is some level of Contingency Reserve or energy reserve to manage the uncertainty associated with the conditions being studied. However, there may be some allowable shortfall depending on the risk tolerance, reiterating the importance of understanding, and establishing the appropriate criteria when developing a response. A set of corrective actions can be formulated into an operating plan, Operating Process, Operating Procedure, Corrective Action Plan (all of which are NERC-defined terms),[43] or any number of documented or undocumented actionable steps to minimize the impact of an energy shortfall.

Possible corrective actions can range from some fairly limited in scope (e.g., enhanced communication and/or more frequent assessments) to widely expansive (e.g., controlled power outages across a Wide Area to conserve fuel that can be used when system conditions are at their worst), depending on the time horizon of the ERA. Near-term ERAs provide fewer options for mitigation than planning ERAs. Actions should be commensurate with the forecasted risk. Care should be taken to maintain reliability and minimize the impact on the BPS and the general public whenever possible. For example, public appeals should be considered before firm load shedding, when the option is available. Low-probability events may not require extreme responses. Awareness and outreach with regulators and other stakeholders will help define the acceptable and proper responses to energy shortfalls and may also help with the establishment of more defined criteria commensurate with the risk tolerance. For longer-term planning purposes, corrective actions would include actions targeted at addressing the specific deficiencies noted in the ERA, such as enhancements to market structures, delaying planned retirements, or increasing the projected new builds on the system.

Examples of and considerations for possible actions, along with the time horizon where the actions would be appropriate, are outlined in the table below. This is not intended to be an all-inclusive list and may not apply in every situation. The responsible party performing these steps should use caution to ensure that they are effective and practical. It is becoming increasingly apparent that there is no single authority that can take action to remediate all energy reliability issues. Responsibility and authority depend on the actions being taken and can be assigned to the federal government (i.e., legislatures and agencies/regulators), state and/or provincial governments (e.g., legislatures and regulators), and registered entities (e.g., resource owners, independent System Operators). Sound judgment, awareness, and collaboration between all entities and organizations, coupled with a well-defined problem and a range of options for practical solutions, is the most appropriate path to finding a solution to the forecasted energy reliability problem.

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

Table 8.1: Considerations for Recommended Corrective Actions in Response to Energy Shortfalls		
Corrective Action	**Time Horizon(s)** [44]	**Considerations**
Enhanced Communication	NT S P	For many actions that can prevent or minimize an energy shortfall, the entity performing the assessment may not have the authority to take all the necessary corrective actions. Communicating early with parties that do have that authority allows for time to implement actions in the most efficient and successful manner. Pre-deficient communications should be considered as well. Depending on the time horizon, this can be in the form of seasonal workshops and tabletop exercises or simply holding meetings to inform parties of what indications they may receive and what actions they could take.
Perform more frequent ERAs	NT S	In a situation where highly variable inputs are driving the studied system into an energy shortfall, more accurate forecasts may be the solution. An assessment for several months or years in the future with a low to moderate probability of an energy shortfall may require more frequent assessments that refine the inputs as they become more certain. This allows the analyst to formulate plans with more concrete impact.
Capacity deficiency actions	NT	There are several capacity deficiency actions that would occur at the time when load shed is being used, in accordance with capacity-deficiency procedures. For an energy shortfall, there should be an understanding of what impact those actions will have to reduce or remedy the reliability issue. One example is using demand-response programs that target thermostats, hot or cold. When the setpoint of a thermostat is changed in response to a capacity deficiency, the temperature of a building is allowed to drift further away from comfortable settings. Unless those setpoints are maintained indefinitely, the energy requirement would remain relatively unchanged. Lowering the temperature setpoint on a cold day will draw less power over time but restoring the setpoint within only a few hours of lowering it will cause a temperature recovery, drawing the same amount of overall energy, just at different times.

Time Horizon definitions:

- NT = Near Term Operations Planning
- S = Seasonal Operations Planning
- P = Planning

Table 8.1: Considerations for Recommended Corrective Actions in Response to Energy Shortfalls		
Corrective Action	**Time Horizon(s)** [44]	**Considerations**
Replenishment of fuel supplies	NT S P	ERAs will show when generators are expected to run out of fuel. Fuel replenishment is key to extending the operations of stored fuel resources. Replenishment actions are highly dependent on how the power system is operated in a given area. Vertically integrated utilities can procure and schedule fuel directly, where power market operators are limited in the actions that they can take, mostly to providing more information to those responsible for operating generators
Outage coordination	NT S	Outages can cause or worsen energy reliability issues. When detected, rescheduling planned outages of energy resources may be the solution to deficiencies.
Dispatch to preserve limited fuel inventory	NT	Models may dispatch resources based on cost order, but if a shortfall in energy results, one alternative may be to dispatch resources in the order of fuel inventory to maximize reliability (e.g., capacity, energy, Ancillary Services) in future periods.
Targeted appeals for conservation	NT	Appeals for conservation should be considered and focused on *when* conservation would make an impact. To target conservation at the right time, the analyst should understand what is causing the shortfall. For example, if the shortfall is caused by a lack of just-in-time fuels (solar, wind, natural gas), the time to conserve is at the moment of shortfall. If the cause of the shortfall is diminishing quantities of stored fuels, conservation should be targeted to when those fuels are in use so that the depletion rate is slowed.
Targeted controlled power outages (i.e., rolling blackouts)	NT	Controlled power outages can be a last resort or a preemptive action. When energy is unavailable to serve load, then that load must be shed. When facing a loss of stored fuels with conservation actions insufficient to prolong the availability of that fuel, controlled power outages may conserve the fuel. This does not seem different than controlled power outages during an Energy Emergency but does offer the option to shift when the power outages occur, such that fuel is available when it is needed most. For instance, shedding load would be done on a moderately cold day to conserve fuel so that load shed is not required on the coldest day. This consideration is highly situational and would require significant analysis, documentation, and coordination between multiple parties, specifically state and local authorities, and regulatory agencies. This should not be taken lightly.

Table 8.1: Considerations for Recommended Corrective Actions in Response to Energy Shortfalls		
Corrective Action	**Time Horizon(s)** [44]	**Considerations**
Operational strategies for electric storage	NT S P	No storage is 100% efficient. Therefore, energy storage devices (e.g., batteries, pumped storage) are a net draw on energy supplies. Once energy shortfalls are occurring, changes to how storage is operated should be considered. Accounting for the operational aspects of storage in planning ERAs would inform the analyst of what shortfalls can be mitigated by optimizing electric storage.
Infrastructure expansion	P	While likely not feasible in most cases, additional infrastructure may be needed to minimize energy shortfalls that are detected far enough in advance. While the entity performing ERAs may not have the authority to build infrastructure for energy reliability, informing the entities that do have that authority may yield positive results.
Retention of resources	P	After a resource or infrastructure is built, there are more opportunities to retain that resource to maintain energy reliability compared to building new resources.
Market rule enhancements	P	Enhancing market rules to account for future energy needs can be one option for market operators. Market rules with an emphasis on energy can incentivize the right type of products that would serve as solutions to energy problems.

Chapter 9: Conclusion

ERAs are a necessary component in the suite of tools used by power system planners and operators as more VERs and stored fuel dependencies gain prevalence. Gaps in traditional capacity assessment methods, when applied to energy-related issues, present risks where potential shortfalls can go undetected before a reliability event occurs. Efforts are underway to bolster assessment requirements and provide some clarity to industry such that these gaps can be better understood and undergo assessments that will allow planners and operators to take actions to reduce the impact of energy shortfalls or eliminate them altogether.

This technical reference document provides the reader with a framework that can be used to perform ERAs. From input assumptions and tools/methods to criteria and corrective action considerations, the audience has a better understanding of how to perform an ERA. With more experience, and as the resource mix continues to evolve away from resources with relatively assured fuels to those with a wider degree of variability, there will be opportunities to develop new methods to perform assessments with new tools, build models to enhance corrective actions, and more clearly define criteria and metrics such that ERAs are meaningful to stakeholders. The assessments described here are not intended to replace existing study work but to supplement that work and address energy-related assessment gaps necessary for understanding power system reliability.

Appendix A: Summary of Available and Suggested Data

This appendix is a summary of all the tables in Chapters 1 through 4 delineating what information may be useful in performing ERAs and where that information might be available to the analyst to retrieve.

Table A.1: Abbreviations for Summary of Potential Information Sources in All ERAs	
Category	**Abbreviation**
Stored Fuels	SF
Natural Gas	NG
Energy Supply Variability	ESV
Electric Storage	ES
Variable Energy Resources	VER
Emissions Constraints on Generator Operations	ECGO
Energy Supply Outages	ESO
Distributed Energy Resources	DER
Demand	D
Transmission	T

Table A.2: Summary of Potential Information Sources in All ERAs						
Near Term	**Seasonal**	**Planning**	**Topic**	**Data**	**Potential Sources**	**Notes / Additional Considerations**
X	X	X	SF	Specific, usable[45] inventory of each generation station	Generator surveys Assumptions based on historical performance	Inventory is often shared for a group of generators located at a single station. Surveys should be performed as often as necessary to initialize an assessment with accurate information. It is recommended to start each iteration of an assessment with updated data. Hydroelectric resources may need to consider the availability of water as a fuel input – change over the course of the year or vary by year. Environmental limitations: water flows/rights priority, dissolved oxygen (DO) limitations, etc. Stored fuels may be used for unit start-up with a portion embargoed for blackstart service provision.
X	X	X	SF	Minimum consumption requirements of fuels that have shelf-life limitations	Surveys of Generator Owners or Operators Assumptions based on historical performance	May result in a fuel being consumed at a time when it is less than optimal.
X	X	X	SF	Replenishment assumptions	Generator surveys Assumptions based on historical performance	Replenishment is key to modeling inventory at any point during the study period. Replenishment restrictions are also an important aspect of an ERA.
X	X	X	SF	Shared resources	Generator surveys or registration data	Modeling the sharing of fuel between multiple resources allows for precise modeling of fuel availability.

[45] Usable inventory is the amount of fuel that is held in inventory after subtracting minimum tank levels that are required for quality control and fuel transfer equipment limitations.

Table A.2: Summary of Potential Information Sources in All ERAs						
Near Term	**Seasonal**	**Planning**	**Topic**	**Data**	**Potential Sources**	**Notes / Additional Considerations**
X	X	X	SF	Global shipping constraints	Industry news reports	Stored fuel supply is often impacted by world events that cause supply chain disruptions, including port congestion, international conflict, shipping embargoes, and confiscation.
X	X	X	SF	Localized shipping constraints	Weather forecasts or assumptions, direct communication with local transportation providers, emergency declarations[46]	Considerations for local trailer transportation of fuels over wet/snow-covered roads, rail route disruptions due to weather or debris, as well as seaport weather when docking ships or river transportation route restrictions for barge movements.
X	X	X	NG	Pipeline transportation capacity	Pipeline Electronic Bulletin Boards (EBB), open season postings, firm transportation contracts	Interstate pipeline information is readily available through public sources, usually directly from the pipeline company itself.
X	X	X	NG	Gas pipeline constraints	EBB postings of operationally available capacity and planned service outages, pipeline maps	Starting with pipeline maps or one-line diagrams, pinpointing the location of specific constraint points requires research. Communication with pipeline operators is helpful when specific locations are in question or difficult to find.
X	X	X	NG	Generator location on pipelines	Pipeline maps, generator surveys, registration data	Research is required to properly place generators on pipelines in the correct location.
X	X	X	NG	Non-generation demand estimates	Historical scheduled gas to city gates and end users, historic weather data, weather assumptions based on historic weather and climatology	Similar to load forecasting on the electric system, gas estimates play a crucial role in developing a holistic energy solution. Assuming that more gas is available than physically possible could lead to inaccurate study results.

[46] https://www.fmcsa.dot.gov/emergency-declarations

Table A.2: Summary of Potential Information Sources in All ERAs						
Near Term	**Seasonal**	**Planning**	**Topic**	**Data**	**Potential Sources**	**Notes / Additional Considerations**
X	X	X	NG	Heating and end-user demand assumptions	Filings with state regulators, historical demand data	Regulated utilities will file their expected needs for natural gas with their respective state regulators.
X	X	X	NG	Contractual arrangements	EBB index of customers, generator surveys, FERC Form 549B	Some information can be obtained via the EBB Index of Customers; however, nuanced data would need to be queried directly from generators. Non-public information includes generator arrangements with gas marketers and participation in capacity release agreements.
X	X	X	NG	Generator heat rates	Registration data, generator surveys	Converting electric energy to fuel consumption and vice versa requires the heat rate of a generator, typically expressed in Btu/kWh or MMBtu/MWh.
X	X	X	ESV	VER assumptions	VER forecasts as described in the VER sections of this document	VER production drives the need for flexible generation to be available or online. Additionally, the ability to curtail VER production should be considered as a mitigating option.
X	X	X	ESV	Generation ramping capability	Registration data, market offers	Balancing resources would be used to maintain system frequency from moment to moment.
X	X	X	ESV	Fuel supply dynamic capabilities	Fuel supply network models, market-based models to determine volumes delivered to specific sectors or historic observations	The key to including ramping capability in an ERA is focusing on the capabilities of the fuel delivery network (e.g., gas pipelines, fuel oil or coal delivery systems at specific generators) and how that network responds to the ramping needs of the system.

Table A.2: Summary of Potential Information Sources in All ERAs						
Near Term	**Seasonal**	**Planning**	**Topic**	**Data**	**Potential Sources**	**Notes / Additional Considerations**
X	X	X	ECGO	Output limitations for a set of generators	Generator surveys	Each Generator Owner/Operator may know their own operational information, but when determining when a collection of generators will reach a limit would require gathering information that each owner/operator has but not as a collective. The analyst performing the ERA would be the centralized collection point of the information required to accurately model the limit.
X	X	X	ESO	Forced-outage rates	NERC GADS, assumptions based on historical performance	NERC requires outages and reductions to be reported with associated cause codes and makes that information available to registered entities. Alternatively, analysts can observe historical unplanned outage information to determine similar assumptions.
X	X	X	ES	Maximum charge/discharge rates (in MW or kW) and total storage capability (in MWh or kWh)	Registration data	These two parameters combined define the primary characteristics of a storage device.
X	X	X	ES	Usable Capacity	Registration data, operational data	Battery storage may not operate well above and below a specific charged percentage. For example, batteries charged above 80% or below 20% may underperform. Therefore, the storage capacity may be less than intended.
X	X	X	ES	Transition time between charge and discharge cycles	Registration data, operational data, market offers	

Table A.2: Summary of Potential Information Sources in All ERAs						
Near Term	Seasonal	Planning	Topic	Data	Potential Sources	Notes / Additional Considerations
X	X	X	ES	Cycling efficiency	Operational data	Calculating the cycling efficiency of storage can be done using operational data, dividing the sum of output energy by the sum of input energy over some period. A longer duration will yield a more accurate efficiency value. All storage requires more input energy than the output that will be produced.
X	X	X	ES	Co-located/hybrid or standalone configuration. Charging source – primary and secondary	Registration data	Scenario studies may remove a generation type (e.g., solar), which may eliminate the energy supply source.
X	X	X	ES	Ambient temperature limits	Registration data, operational data	This refers to the ambient temperature limitations at the storage facility, which are part of the formula for calculating cell temperature limitations. There are high- and low-temperature requirements for charging and discharging batteries at a normal rate. Outside that band, the rate of charge could be reduced, potentially to 0.
X	X	X	ES	No-load losses	Registration data, operational data	Electric storage facilities may experience a loss of energy even when not delivering energy to the grid.
X	X	X	ES	Emergency limits		Can the storage resource run below the P-Min or above the P-Max, and if so, for how long?
X	X	X	T	Planned outages and Maintenance	Transmission Operators (TOP), Transmission Planners (TP), or other transmission planning entities	
X	X	X	T	Import/export transfer limits	Engineering studies	

Table A.2: Summary of Potential Information Sources in All ERAs						
Near Term	Seasonal	Planning	Topic	Data	Potential Sources	Notes / Additional Considerations
X	X	X	T	Import/export resource limits	Coordinated ERA with neighboring areas	Aligning input assumptions between areas would be necessary for ensuring that energy is not ignored or double counted in multiple areas.
X	X	X	T	Transmission topology and characteristics	Transmission and distribution models	Potentially, using a simplified or dc-equivalent circuit for probabilistic or similar analysis. Considerations for including planned transmission expansion projects.
X	X	X	T	Transmission outage rates	NERC TADS	Ideally, weather-dependent and facility-specific outage rates could be used to reflect energy scenarios.
X			SF	Current inventory, inventory management plans, and replenishment assumptions	Generator surveys, assumptions based on historic performance, or annually variable conditions specific to the resource type	Replenishment is key to modeling inventory at any point during the study period. Replenishment restrictions are also an important aspect of an ERA. Performance expectations for hydroelectric resources may be informed by seasonal runoff conditions.
X			NG	Natural gas scheduling timelines	Pipeline tariffs, NAESB	Timelines may differ between pipelines. The NAESB sets five standard cycles that are to be followed by Federal Energy Regulatory Commission (FERC) jurisdictional entities (which generally excludes intrastate pipelines and local distribution networks).
X			NG	Natural gas commodity pricing and availability	Intercontinental Exchange (ICE),[47] Platts[48]	Natural gas commodity pricing is an indicator of its availability. Continuously monitoring pricing will allow an analyst to estimate the availability of natural gas into a near-term ERA.

47 https://www.ice.com/index
48 https://www.spglobal.com/en/

Table A.2: Summary of Potential Information Sources in All ERAs						
Near Term	**Seasonal**	**Planning**	**Topic**	**Data**	**Potential Sources**	**Notes / Additional Considerations**
X			VER	Vendor supplied but could be developed using weather service models In-house models or vendor-supplied data	There could be differences between one or multiple central forecast(s) and the aggregation of independent forecasts. Forecast error analysis of historical data would provide a measure of the performance of available options. Wind/solar profiles can be modified to capture uncertainty associated with rainy, windy, and/or cloudy days. It is important to maintain the correlation between wind, solar, and load in conducting these analyses.	Vendor supplied but could be developed using weather service models In-house models or vendor-supplied data
X			VER	Vendor supplied but could be developed using weather service models	Significant research and development have been done in the last decade to create and improve VER/DER forecasts for use in power system operations and analysis, including ERAs. Hourly or sub-hourly profiles of actual production from VERs can be scaled up or down to fit specific scenarios in an ERA.	Vendor supplied but could be developed using weather service models

Table A.2: Summary of Potential Information Sources in All ERAs						
Near Term	Seasonal	Planning	Topic	Data	Potential Sources	Notes / Additional Considerations
X			ECGO	Output limitations by specific generators	Generator surveys	For short-term assessments, generator surveys would be the best source of emissions limitation information. Generator Owner/Operators should be aware of what their limits would be and the plans to abide by those limits.
X			ECGO	Output limitations for a set of generators	Generator surveys	Each Generator Owner/Operator may know their own operational information, but when determining when a collection of generators will reach a limit would require gathering information that each owner/operator has but not as a collective. The analyst performing the ERA would be the centralized collection point of the information required to accurately model the limit.
X			ESO	Planned outages and maintenance	Maintenance schedules and outage coordination tools	ERAs can use planned maintenance as an input but can also be used to advise the shifting of planned maintenance to minimize energy-related risks.
X			DER	Installation data	Electric utility companies (i.e., Distribution Providers, or DPs), production incentive administrators	DERs are likely to be required to coordinate with the distribution System Operator before interconnecting. Additionally, any DER that is participating in a renewable energy credit program will likely need to register with and provide production information to a program administrator.
X			DER	Forecasted DER production	Vendor supplied but could be developed using weather service models	Significant research and development have been done in the last decade to create and improve DER/VER forecasts for use in power system operations and analysis, including ERAs.

Table A.2: Summary of Potential Information Sources in All ERAs						
Near Term	Seasonal	Planning	Topic	Data	Potential Sources	Notes / Additional Considerations
X			DER	Historical performance, observations of net load	Historical patterns of demand compared to a longer history	Comparing a similar-day demand curve from a more recent year to one from a year prior can give a sense of the difference in DER that was installed year-over-year.
X			DER	Estimated performance of DERs	Based on limited samples of a subset of the DER type	Modern DERs may have advanced measurement devices that could be made available through vendor aggregation services. Smaller, evenly distributed samples could be used to scale to the full amount. Testing should be done to validate whether the conceived process is accurate.
X			D	Weather forecasts or projections	Numerical weather prediction (NWP) models, weather forecast vendors	Weather information is the primary variable input to demand forecasts. Near-term assessments can use weather forecasts.
X			D	Actual demand forecasts or projections	Load forecast models using weather information as an input	Historical weather and demand may be useful for projecting future conditions; however, caution should be exercised to ensure that interrelated parameters remain interrelated. Decoupling weather and load could result in implausible outcomes.
X			D	Demand-response capabilities	Electric utilities or other organizations (e.g., demand-response aggregation service providers) that manage participation in demand-response programs	
X			ES	State of charge	Resource owner	Additional considerations may be given to state of charge in a near-term ERA that reflect the recent operation of the electric storage facility.

Table A.2: Summary of Potential Information Sources in All ERAs						
Near Term	**Seasonal**	**Planning**	**Topic**	**Data**	**Potential Sources**	**Notes / Additional Considerations**
X			ES	Ramp Rate (up/down) MW/minutes	Resource owner	Rate that the electric storage resource can discharge or absorb energy when electric demand or supply changes.
X			ES	Cell balancing	Resource owner	This describes the change-out of cells within a storage device. Specifically, this would apply to faulty cells that could limit the capability of a battery plant. Balancing takes a few days to accomplish once cells are replaced.
X			ES	Project-specific incentives (e.g., investment tax credits)	Resource owner	Investment tax credits, either production or investment, may indicate how the electric storage resource will run.
X			ES	Cell temperature limits[49]	Resource owner	This is the ambient temperature at the storage facility. There are high- and low-temperature requirements for charging and discharging batteries at a normal rate. Outside that band, you may reduce the rate of charge, potentially to 0.

[49] Lithium-ion battery: Charge temperature at 32°F to 113°F; Discharge temperature at -4°F to 140°F
Lead acid battery: Charge temperature at -4°F to 122°F; Discharge temperature at -4°F to 122°F
Nickel-based battery: Charge temperature at 32°F to 113°F; Discharge temperature at -4°F to 149°F

Table A.2: Summary of Potential Information Sources in All ERAs

Near Term	Seasonal	Planning	Topic	Data	Potential Sources	Notes / Additional Considerations
	X		SF	Current inventory, inventory management strategies, and replenishment assumptions	Generator surveys, formal or informal generator outreach, assumptions based on historical performance, or annually variable conditions specific to the resource type	Replenishment is key to modeling inventory at any point during the study period. Replenishment restrictions are also an important aspect of an ERA. Performance expectations for hydroelectric resources may be informed by seasonal runoff conditions. Generator surveys can still be useful just prior to a specific season; however, this information may still introduce some uncertainty at the time that the ERA is being performed. Communication with the entities deciding on replenishment strategies would result in more accurate assumptions for starting inventories.
	X		SF	Availability of overall fuel storage	U.S. Energy Information Administration (EIA) reports	The U.S. EIA reports weekly inventories for five Petroleum Administration for Defense Districts (PADD). This can be an indicator of whether fuel may be available for generator fuel replenishment.
	X		SF	Shipping constraints	Industry news reports	Seasonal ERAs could be impacted by weather patterns and world events that cause supply chain disruptions, including port congestion, international conflict, shipping embargoes, and confiscation.
	X		NG	Pipeline, production, import, and export expansion projects	Pipeline websites, filings with state and federal agencies, advertising for open seasons	This includes new pipelines, compressor enhancements and expansions, and LNG import and export projects that will increase or reduce the amount of natural gas that is available.

Table A.2: Summary of Potential Information Sources in All ERAs						
Near Term	**Seasonal**	**Planning**	**Topic**	**Data**	**Potential Sources**	**Notes / Additional Considerations**
	X		NG	Pipeline Planned Service Outages	EBB	Interstate natural gas pipelines are required[50] by FERC to post maintenance plans on their public-facing EBBs.
	X		NG	Natural gas commodity futures pricing	Several internet sources that monitor futures pricing	Futures pricing can give a sense of what pricing pressures the commodity is facing in the coming year(s). It may not be a fully accurate picture of what the pricing will be but gives an analyst some direction for a starting point for a seasonal ERA.
	X		VER	Weather outlook	NOAA (for the United States), Environment and Climate Change Canada, historical observations, weather models	Seasonal outlooks can provide a direction on which historical observations to select when performing a seasonal ERA.
	X		VER	VER production assumptions	Historical observations adjusted for weather outlooks	Historical observations can set a starting point for what can be expected in upcoming seasons. This would need to be adjusted for other known factors, such as drought conditions or temperature expectations.
	X		VER	New VER installations	Installation queues	New VERs installed between the time that an ERA is performed, and the start of the upcoming season can be large enough to impact the outcome and should be included as accurately as possible. The seasonal horizon should have more certainty on what will be commissioned or not.

[50] See U.S. Code of Federal Regulations Chapter I, Subchapter I, Part 284, Subpart A, § 284.13.(d).(1) - https://www.ecfr.gov/current/title-18/chapter-I/subchapter-I/part-284/subpart-A/section-284.13

Table A.2: Summary of Potential Information Sources in All ERAs						
Near Term	**Seasonal**	**Planning**	**Topic**	**Data**	**Potential Sources**	**Notes / Additional Considerations**
	X		ECGO	Output limitations by specific generators	Generator surveys	For short-term assessments, generator surveys would be the best source of emissions limitation information. Generator Owner/Operators should be aware of what their limits would be and the plans to abide by those limits.
	X		ESO	Weather-dependent outage rates	Surveys, registration information, assumptions based on historic performance	GADS will provide average outage rates. The information from GADS can be combined with weather information to derive correlations with weather conditions that could be modeled in an ERA.
	X		ESO	Outage mechanisms	NERC GADS, operator logs	Outage mechanisms can be used to determine outage duration and impact.
	X		ESO	Planned outage schedules	Outage coordination records	Planned outages are a good start for modeling the unavailability of resources, but considerations should be given to the accuracy of plans. Not every outage goes according to plan, and they may finish early or overrun.
	X		DER	Installation data coupled with expansion assumptions	Electric utility companies (i.e., DPs), production incentive administrators	Like the information needed for a near-term ERA, DERs are likely to coordinate with distribution System Operators, providing a path to make information available. Future information may also be available through those same channels but may also need to be inferred based on trends, growth forecasts, or legislative goals.

Table A.2: Summary of Potential Information Sources in All ERAs						
Near Term	Seasonal	Planning	Topic	Data	Potential Sources	Notes / Additional Considerations
	X		DER	Historical DER production data	Operations data, assumptions based on past performance	The analyst may choose to model DER explicitly as a supply resource or as a demand reduction. Modeling the DER separately and incorporating it to the resource mix will allow the analyst to vary the assumptions without impacting other facets of the ERA.
	X		D	Weather forecasts or projections	Historical data, seasonal weather projections (e.g., the National Weather Service, Climate Prediction Center outlooks)[51], Environment and Climate Change Canada,	Weather information is the primary variable input to demand forecasts. Near-term assessments can use weather forecasts. Longer-term assessments, including seasonal assessments, typically require assumptions or projections of weather due to forecast accuracy.
	X		D	Actual demand forecasts or projections	Load forecast models using weather information as an input	Historical weather and demand may be useful for projecting future conditions; however, caution should be exercised to ensure that interrelated parameters remain interrelated. Decoupling weather and load could result in implausible outcomes.
	X		D	DER production forecasts or projections	Weather-based prediction models using the assumed weather as an input, which are available from a variety of vendors	This may or may not be considered in the demand side of the energy balance equation. Correlation with modeled weather conditions should be considered.

[51] https://www.cpc.ncep.noaa.gov/products/predictions/long_range/

Table A.2: Summary of Potential Information Sources in All ERAs						
Near Term	**Seasonal**	**Planning**	**Topic**	**Data**	**Potential Sources**	**Notes / Additional Considerations**
	X		D	Demand-response capabilities and expectations	Electric utilities or other organizations (e.g., demand-response aggregation service providers) that manage participation in demand-response programs	Not all demand response operates at the command of the entity responsible for dispatching resources.
	X		ES	Cell temperature limits[52]	Resource owner	This is the ambient temperature at the storage facility. There are high- and low-temperature requirements for charging and discharging batteries at a normal rate. Outside that band, you may reduce the rate of charge, potentially to 0.
	X		ES	Ramp Rate (up/down) MW/minutes	Resource owner	Rate that the electric storage resource can discharge or absorb energy when electric demand or supply changes.
	X		ES	Project-specific incentives (e.g., investment tax credits)	Resource owner	Investment tax credits, either production or investment, may indicate how the electric storage resource will run.
		X	SF	Inventory management and replenishment assumptions	Assumptions based on historical performance and/or commodity market evaluations.	Replenishment is key to modeling inventory at any point during the study period. Replenishment restrictions are also an important aspect of an ERA.
		X	SF	Availability of overall fuel storage	EIA reports	The U.S. EIA reports weekly inventories for five PADDs. Trending PADD inventories over time may provide insight into how replenishment may occur over longer periods of time.

[52] Typically, today's battery technologies are constrained to the following temperature bands:
Lithium-ion battery: Charge temperature at 32°F to 113°F; Discharge temperature at -4°F to 140°F;
Lead acid battery: Charge temperature at -4°F to 122°F; Discharge temperature at -4°F to 122°F;
Nickel-based battery: Charge temperature at 32°F to 113°F; Discharge temperature at -4°F to 149°F

Table A.2: Summary of Potential Information Sources in All ERAs						
Near Term	**Seasonal**	**Planning**	**Topic**	**Data**	**Potential Sources**	**Notes / Additional Considerations**
		X	SF	Intra-annual hydro availability	Historical drought or high-runoff conditions	Since drought and high-runoff hydro forecasts may not cover an extensive enough period to depend on for a planning ERA, assumptions would need to be made based on historical information.
		X	NG	Pipeline, production, import, and export expansion projects	Pipeline websites, filings with state and federal agencies, advertising for open seasons	This includes new pipelines, compressor enhancements and expansions, and LNG import and export projects that will increase or reduce the amount of natural gas that is available.
		X	VER	Expected installed resources	Interconnection queue, economic analysis and forecasts	
		X	VER	Renewable energy goals	State legislature dockets	These goals drive the rate at which renewable (and likely variable energy) resources are built, including target years and amounts.
		X	VER	Production assumptions	Historical observations, weather models, climate trends	Profiling the expanded fleet across some historical dataset, adjusted for expected trends in climate, gives an ERA plausible inputs.
		X	ECGO	Output limitations by specific generators	Generator surveys	For short-term assessments, generator surveys would be the best source of emissions limitation information. Generator Owner/Operators should be aware of what their limits would be and the plans to abide by those limits.
		X	ECGO	Trends in individual state carbon emissions goals	State government or public utility commission (PUC) websites	When assessing the probability of long-term retirements and new construction, emissions goals may provide insight to the analysts to decide whether a specific resource or a subset of the entire fleet may or may not be viable under the expected rules.

Table A.2: Summary of Potential Information Sources in All ERAs						
Near Term	Seasonal	Planning	Topic	Data	Potential Sources	Notes / Additional Considerations
		X	ESO	Forced-outage rates	NERC GADS, assumptions based on historical performance	NERC requires outages and reductions to be reported with associated cause codes and makes that information available to registered entities. Alternatively, analysts can observe historical unplanned outage information to determine similar assumptions.
		X	ESO	Weather-dependent outage rates	Surveys, registration information, assumptions based on historical performance	GADS will provide average outage rates. The information from GADS can be combined with weather information to derive correlations with weather conditions that could be modeled in an ERA.
		X	ESO	Assumed outage rates for newly constructed supply resources	Fleet averages using existing resources, when possible	New construction using existing plans means that there is likely a similar resource somewhere that has some performance data that can be used to estimate the performance of a new resource.
		X	ESO	Outage mechanisms	NERC GADS, operator logs	Outage mechanisms can be used to determine outage duration and impact.
		X	DER	Growth estimates, renewable energy goals	State government and PUCs, directly or via their websites	
		X	D	Weather forecasts or projections	Historical data, adjusted using climate models	Weather information is one of the primary inputs to longer-term demand forecasts. Longer-term assessments typically require assumptions or projections of weather due to forecast accuracy concerns.

Table A.2: Summary of Potential Information Sources in All ERAs						
Near Term	**Seasonal**	**Planning**	**Topic**	**Data**	**Potential Sources**	**Notes / Additional Considerations**
		X	D	Actual demand projections	Historical actual demand modified by the expected impact of demand changes, load forecast models using weather information as an input	Historical weather and demand may be useful for projecting future conditions; however, caution should be exercised to ensure that interrelated parameters remain interrelated. Decoupling weather and load could result in implausible outcomes. Performing an energy assessment still requires a profiled demand curve over a period of time. Most legacy long-term forecasts produce a set of seasonal peak values.
		X	D	Projected changes in actual demand magnitude and profile (e.g., load growth)	Analysis of economic factors, governmental policy, and technical considerations	This should include the impact on demand magnitude as well as changes in demand profiles. This includes energy efficiency and electrification. Electrification of heat is a function of local temperatures. Electrification of transportation will be more linked to commute distances and time of day.
		X	D	DER production forecasts or projections	Historical production data, scaled to future capability	This may or may not be considered in the demand side of the energy balance equation. Correlation with modeled weather conditions should be considered.
		X	D	Demand-response capabilities	Electric utilities or other organizations (e.g., demand-response aggregation service providers) that manage participation in demand-response programs.	

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NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Technical Reference Document: Considerations for Performing an Energy Reliability Assessment

Volume 2

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~~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~~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~~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

Considerations for Performing an Energy Reliability Assessment, Volume 1[1] ~~(“~~(Volume 1~~”) was published in March 2023. It~~), which provided an overview of the basic elements of an ~~Energy Reliability Assessment~~energy reliability assessment (ERA) and general considerations for performing an ERA~~. In this volume,~~, was published in March 2023. Volume 2 details ~~of~~ how to perform an ERA ~~are introduced and discussed~~, including different methods ~~that can be used to build~~for building analysis tools, how metrics can be defined in terms of energy, and approaches to corrective actions when those metrics cannot be met. **The purpose of this technical reference document ~~is~~was not to dictate how to perform an ERA ~~is to be performed~~ but rather to highlight inputs that should be considered when performing an ERA.**

~~There are several~~Several key pieces of prerequisite knowledge ~~that lead into the topics being discussed in this document~~, including~~:~~ Volume 1, ~~the~~ *NERC Reliability Guideline: Fuel Assurance and Fuel-Related Reliability Risk Analysis*,[2] and the *NERC Special Report on Maintaining Bulk Power System Reliability While Integrating Variable Energy Resources (VER*~~)~~~~[3]. In~~), lead into the ~~Reliability Guideline,~~topics discussed in this document.[4] The fuel assurance reliability guideline discusses the individual risks associated with specific fuel types ~~are thoroughly discussed~~, helping the reader understand how upstream fuel supplies may impact power generation ~~–~~—a key input to any energy analysis. Likewise, ~~in maintaining reliability,~~ the need for flexibility in a committed fleet to maintain reliability is discussed in greater detail in this document.

This technical reference document is organized into eight chapters. Chapters 1 through 4 outline the considerations and recommended data needed to perform an ERA in ~~different,~~the NERC-defined[5] time horizons. Chapter 1 highlights general elements that are applicable to all time horizons. Chapters 2, 3, and 4 are more specific to the near-term, seasonal, and planning ERAs, respectively. To get the full picture of an ERA in a specific time horizon, the reader is encouraged to review Chapter 1 ~~first, then~~before reading the applicable chapter for the time horizon being assessed. ~~Following Chapters 1 through 4, there are separate discussions on~~Later chapters cover methods (Chapter 5), case development and scenario modeling (Chapter 6), and metrics (Chapter 7). The discussion ~~on~~of methods will help in the development and design of tools. ~~Case~~The chapter on case development and scenario modeling discusses a recommended approach for ~~Base Case~~base case and ~~S~~scenario development. ~~Further,~~ Chapter 7 discusses existing metrics that can be used to compare the results of an ERA. Lastly, Chapter 8~~, on corrective actions,~~ enumerates remedies available when energy shortfalls are identified on corrective actions.

~~It is acknowledged that, throughout this technical reference document, there are significant differences across North America in terms of available~~As factors that may play a role in promoting energy reliability~~. To that point,~~ differ significantly across North America, this document proposes an array of ~~suggested~~ solutions ~~are proposed~~ that may apply to each particular system that could be considered under certain situations. Factors that are known to introduce this variety ~~are as follows, but may extend beyond this list~~include the following:

- Generating capacity and density (e.g., how much and where) of wind and solar resources are a primary driver for the high degree of generation diversity among ~~regions~~areas, including the performance characteristics for each (e.g., certain areas, such as the southwestern United States, are more ~~amenable~~likely to support highly productive solar resources than those in the north).
- ~~Fuel storage~~Storage capabilities and capacities ~~of fuel~~for fuels like oil, coal, ~~liquefied~~ natural gas ~~(LNG),~~, and fissile nuclear ~~fuels~~material differ across ~~regions,~~areas but also within ~~regions~~areas depending on their

[1] https://www.nerc.com/comm/RSTC_Reliability_Guidelines/CLEAN_ERATF_Vol_1_WhitePaper_17MAY2023.pdf
[2] https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Fuel_Assurance_and_Fuel-Related_Reliability_Risk_Analysis_for_the_Bulk_Power_System.pdf
~~[3] https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC-CAISO_VG_Assessment_Final.pdf~~
[4] https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC-CAISO_VG_Assessment_Final.pdf
[5] https://www.nerc.com/pa/Stand/Resources/Documents/Time_Horizons.pdf

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geographic size. ~~By having~~For instance, if an area has only limited reliance on stored fuels, ~~a region~~it may be able to model energy reliability as a series of capacity assessments and rely on more general assumptions for impact of one hour to the next.

- Fuel replenishment delay times and diversity of supply and delivery options impact specific factors of an ERA. ~~Longer time~~For example, anticipated long delays between arranging and receiving fuel deliveries ~~would drive a need for a~~could require longer ~~period of time~~ERA study periods to ~~be studied, and vice versa, so that reaction to the results can be~~produce meaningful results.
- ~~Capacity~~Available natural gas pipeline capacity, gas pipeline network topology and the diversity of the available gas supply to the pipeline network from ~~pipeline natural gas to generation~~production or storage areas can impact ~~the~~an ERA's input assumptions ~~to an ERA~~. These differences would factor into scenario selection. ~~With a~~A high degree of diversity in supply~~,~~ and transportation options is likely to render single points of failure ~~are likely to be~~ less extreme and more likely to be mitigated with fewer actions.
- Regulatory considerations differing from one ~~region~~area to the next may play a role not only in the options available for correcting energy deficiencies but ~~w~~could also change how input assumptions are accounted.

These are just some of the factors that make ERAs non-universal~~,~~; however, the general concepts can be ~~fairly~~ consistently applie~~s~~d across different systems.

The appropriate actions resulting from ~~identified~~ deficiencies ~~found in~~identified by ERAs may also differ~~,~~ based on the poi~~n~~n~~tem~~s discussed above. Longer lead times may be required ~~for~~to address potential energy deficiencies than capacity deficiencies. ~~Shifting~~For example, shifting the way planners consider storage in analyses ~~may be one of the actions that shouldn't be considered for capacity but~~ would be a required consideration for an energy assessment~~.~~ even if this may be one of the actions that should not be considered for capacity. Storage optimization over periods of time becomes part of the solution as ~~VERs fluctuate outputs~~VER output fluctuates throughout a day, a week, or ~~a~~ longer ~~period.~~.

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Chapter 1: Inputs to Consider When Performing an ERA in Any Time Horizon

The information needed to perform an ERA is similar to ~~the information that~~what is ~~used to perform~~required for capacity assessments~~,~~ but with the additional component of time~~ included~~. The time component of an ERA accounts for the impact of operating conditions and actions that occur at one point in time and their impact on future intervals.

Volume 1 ~~talked about~~discussed the differences between capacity and energy assessments. Capacity assessments are performed today in nearly every time horizon, from operations to long-term planning. Connecting the hours and transforming operations at one point into future availability is what expands a capacity analysis into an energy analysis.

Supply

Supply resources can be categorized into generation, electric storage,[6]~~,~~ and load-modifying resources~~.~~[7]. They can be modeled as either supply additions or demand reductions as decided by the analyst. Accurately modell~~l~~ing the energy availability of generation resources requires an understanding and representation of the underlying fuel supply and the generator system.

Fuel supply will be ~~described~~categorized in this document as either stored fuels or just-in-time fuels. ~~Stored fuels have a tangible~~Tangible inventory and replenishment strategies ~~to consider.~~should be considered for stored fuels. Just-in-time fuels require considerations for transportation capacity, fuel deliverability, and the immediate impact of disruptions. Furthermore, just-in-time fuels include weather-dependent fuel sources such as solar irradiance and wind, that introduce significant volatility for which an analyst ~~to~~should account~~ for~~.

Power generation is not the only ~~consumer of fuel. Specific fuels (e.g.,~~sector that consumes fuel. Fuels like oil and natural gas~~)~~ are directly used in other applications~~, without modification of the fuel to adapt to a different use. Competing demands must be considered when looking more holistically at an interconnected and interdependent system. .~~. For example, the U.S. Census ~~Bureau publishes the results of the~~Bureau's *American Community Survey*[8]~~, which~~ includes information on the types of fuel~~ that is~~ used to heat homes~~,~~ broken down by individual U.S. states. This information is one of many inputs that would ~~help~~guide an analyst ~~guide the~~in building ~~of~~ future profiles of fuel demand for input into an ERA. Competing fuel demands should be considered when looking holistically at an interconnected and interdependent energy system.

~~For a~~A more detailed introduction to fuel assurance that is specific to a variety of fuel types~~, refer to~~ is provided in *Reliability Guideline: Fuel Assurance and Fuel-Related Reliability Risk Analysis for the Bulk Power System*.[9]

Stored Fuels

Power generators with stored fuels are those where fuel inventory ~~of fuel~~ is on ~~-~~site or reasonably close to the generator ~~such~~so that ~~risks to the~~fuel transportation ~~of that fuel to the generator~~ risks are minimal. Fuels are most commonly stored in tanks, reservoirs or piles and have a measurable inventory. Examples include, but are not limited to, nuclear fissile material, fuel oil, coal, water for hydro facilities~~ with pondage~~, and natural gas as liquefied natural gas (LNG) or in subsurface geological formations.

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[6] For the purpose of the discussions in this technical reference document, *electric storage* is a device or facility with electric power as an input, a storage medium of some kind that stores that energy, and electric power as an output. This is in contrast to stored fuel in that the source of stored fuel is external to the power system. Both electric storage and stored fuel can be labeled *energy storage*.

[7] Load-modifying resources are (behind-the-meter) generators that modify demand rather than provide additional supply.

[8] https://data.census.gov/table/ACSDT1Y2019.B25040?q=heat

[9] https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Fuel_Assurance_and_Fuel-Related_Reliability_Risk_Analysis_for_the_Bulk_Power_System.pdf

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Once inventory information is gathered and/or ~~assumed~~estimated, it must then be converted into electric energy based on the specific generator that uses the fuel. For thermal generators, that calculation requires two additional pieces of information: fuel heat content and generator heat rate. Generator heat rate is typically expressed in terms of Btu/kWh or MMBtu/MWh. Heat rates range from less than 6,000 Btu/kWh (6 MMBtu/MWh) to over 20,000 Btu/kWh (20 MMBtu/MWh) and can vary across the operating range of a resource, with considerations for efficiency at various output levels. Oil heat content varies slightly by the type of oil and how it was refined~~,~~ and ranges between 135,000 Btu/gallon to 156,000 Btu/gallon. ~~Example 1~~The example below walks through a conversion from gallons of oil to MWh of electric~~al~~ energy and the amount of time that ~~it~~a generator would continue to operate at a specific power output. A similar calculation could be completed for other types of stored fuels using the respective fuel-specific heat contents and generator heat rates.

Calculate the energy production capability (MWh total and hours at maximum output) of a 135 MW oil generator with a heat rate of 9,700 Btu/kWh and 1,000,000 gallons of fuel oil with a heat content of 135,000 Btu/gallon.

$$1{,}000{,}000\ gallons * \frac{135{,}000\ Btu}{gallon} * \frac{kWh}{9{,}700\ Btu} * \frac{MWh}{1{,}000\ kWh} = 13{,}918\ MWh$$

$$\frac{13{,}918\ MWh}{135\ MW} = 103\ hours, at\ maximum\ output$$

In an ERA, once this specific generator produces 13,918 MWh of energy, it must be set as unavailable for all remaining hours or fuel replenishment must occur.

Figure 1.1: Converting Stored Fuel to Available Electric~~al~~ Energy

Multiple generators at a single site often share a fuel inventory~~ where~~, meaning that more than one generator could deplete fuel during operations. This is further complicated when ~~there are~~ different generator technologies with different efficiencies are operating on the same fuel~~,~~ and by the fact that efficiencies of a given unit may vary based on its operating point. For this reason, discrete modeling of generators and their individual demands on the common fuel supplies at sites provides for a more accurate solution than ~~generalizing that relationship~~a generalized approach.

Stored fuel replenishment is a key consideration in an ERA that is impacted by a number of factors. Proximity to additional storage affects assumptions for replenishment~~. Power~~, as power generator stations that are adjacent to larger storage facilities have fewer obstacles to replenishment tha~~t~~n generators far from supply sources or in residential areas. Transportation mechanisms~~ will~~ also affect the ability to replenish stored fuels. Generators are typically replenished by pipeline, truck, barge, or train~~. Each transportation mechanism~~, each of which has its own set of advantages and/or disadvantages. The experts on each generator fuel supply arrangement are the owner/operator of the generator and their ~~counterparties for~~ fuel ~~and other supplies.~~suppliers. Performing an ERA requires communication with the ~~generator owners~~Generator Owners and ~~o~~Operators to ensure that the modeling for fuel supplies is accurate. Once the analyst becomes familiar with the information needed from ~~generator owner/operators~~the Generator Owner/Operators, the specific fuel information can be obtained and properly accounted for through routine surveys.

The following ~~information~~table is useful for modeling stored fuels in an ERA for any time horizon~~.~~:

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Table 1.1: Information Useful for Modeling Stored Fuels in an ERA in Any Time Horizon		
Data	**Potential Sources**	**Notes/Additional Considerations**
Specific, usable[10] inventory of each generation station	Generator surveys Assumptions based on historical performance	Inventory is often shared for a group of generators located at a single station. Surveys should be performed as often as necessary to initialize an assessment with accurate information. It is recommended to start each iteration of an assessment with updated data. Hydroelectric resources may need to consider the availability of water as a fuel input – change over the course of the year or vary by year. Environmental limitations~~—~~: water flows/rights priority, dissolved oxygen (DO) limitations, etc. Stored fuels may be used for unit start-up with a portion embargoed for ~~black start~~blackstart service provision.
Minimum consumption requirements of fuels that have shelf-life limitations	Surveys of ~~generator owners~~Generator Owners or ~~o~~Operators Assumptions based on ~~H~~historical performance	May result in a fuel being consumed at a time when it is less ~~-~~than ~~-~~optimal.
Replenishment assumptions	Generator surveys Assumptions based on historical performance	Replenishment is key to modeling inventory at any point during the study period. Replenishment restrictions are also important aspect of an ERA.
Shared resources	Generator surveys or registration data	Modeling the sharing of fuel between multiple resources allows for precise modeling of fuel availability.
Global shipping constraints	Industry news reports	Stored ~~energy~~fuel supply is often impacted by world events that cause supply chain disruptions~~.~~ ~~This includes~~, including port congestion, international conflict, shipping embargoes, and confiscation.

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[10] Usable inventory is the amount of fuel that is held in inventory after subtracting minimum tank levels that are required for quality control and fuel transfer equipment limitations.

Table 1.1: Information Useful for Modeling Stored Fuels in an ERA in Any Time Horizon		
Data	**Potential Sources**	**Notes/Additional Considerations**
Localized shipping constraints	Weather forecasts or assumptions, direct communication with local transportation providers, emergency declarations[11]	Considerations for local trailer transportation of fuels over wet/snow-covered roads, rail route disruptions due to weather or debris, as well as seaport weather when docking ships or river transportation route restrictions for barge movements.

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~~Fuel Oil~~ Specific Considerations by Generator Type

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Fuel Oil Generators

Fuel oil for generators, diesel fuel for transportation, and home heating oil all share supply chain logistics. ~~There~~Though there are subtle differences between each type, ~~but at the supply side,~~ they are nearly identical~~. Since they are~~ at the ~~same~~supply side. As such, stresses on supply from one mechanism can lead to deficiencies in supply to a seemingly unrelated mechanism. ~~The most~~A likely scenario is that cold weather ~~requires higher~~that increases demand on home heating oil~~,~~ creat~~ing~~es a need for an accelerated replenishment to residential and commercial heating oil tanks, resulting in reduced availability of replenishment stocks for power generation. In an ERA, this should be considered as a limitation on the inventory available for replenishment when conditions are cold, and oil heating is prevalent in the ~~region~~area.

Fuel oil ~~that is~~ delivered by truck can face a number of obstacles. ~~Truck~~ For example, truck drivers are ~~limited to the number of hours that they are~~ legally allowed to drive~~[12]. Trucking~~ only a set number of hours,[13] and trucking can ~~also~~ be susceptible to delays caused by ~~impassible roads after storms caused by~~ snow and debris. Both scenarios may cause ~~for possible~~ delays in fuel delivery to generators that should be considered. However, ~~during emergencies,~~ waivers to ~~specific~~some rules ~~with~~during specific conditions have been ~~requested and~~ granted by state and federal agencies~~[14].~~ during emergencies.[15]

Delivery by ship or barge may be available to resources with access to waterways~~. Waterborne cargoes are~~, typically allowing larger cargoes than truck delivery. Oil trucks can typically transport ~~between~~ 5,000 ~~and~~ –12,000 gallons of fuel per truck. River barges have capacities ranging between 800,000 gallons ~~to~~and nearly 4 million gallons. The largest oil tankers can transport over 50 million gallons of fuel.[16]~~.~~ Challenges in delivering by water include rough seas and waterway freezing.

~~Representing fuel~~Fuel replenishment in an ERA can be modeled as a multiplier or ~~as~~ an adder to initial fuel supply expectations from the start or can be more precisely modeled at an hourly granularity. The simpler calculation ignores the specific constraints surrounding replenishment and assumes that the total amount of fuel will be available when it is needed. ~~This~~The following simple example sets the initial tank level equal to the actual (or assumed) starting inventory plus all replenishments throughout the study period. For example, if a 1 -million -gallon tank starts with

[11] https://www.fmcsa.dot.gov/emergency-declarations
~~[12] https://www.ecfr.gov/current/title-49/subtitle-B/chapter-III/subchapter-B/part-395/subpart-A/section-395.3~~
[13] https://www.ecfr.gov/current/title-49/subtitle-B/chapter-III/subchapter-B/part-395/subpart-A/section-395.3
~~[14] https://www.fmcsa.dot.gov/emergency-declarations~~
[15] https://www.fmcsa.dot.gov/emergency-declarations
[16] https://response.restoration.noaa.gov/about/media/how-much-oil-ship.html#:~:text=Inland%20tank%20barge%20(200%E2%80%93300,7%20million%E2%80%9314%20million%20gallons

500,000 gallons and is expected to replenish that quantity twice, start with 1.5 million gallons and ignore the constraint of the tank size and deplete the oil inventory from the new starting point. ~~The~~A more complex ~~method accounts~~refinement of this approach would account for replenishment strategies, time constraints from the decision to replenish to the time of delivery, rate of refill, individual delivery amount, and transportation mechanisms. More effort is required to apply the specific constraints of a fuel oil tank and the associated replenishment infrastructure. While modeling more granular replenishment will be more precise, it may not ~~be more accurate~~result in significant improvements in accuracy depending on the time horizon of the study. Both methods can ~~coexist~~be employed in the same study. Analysts should consider the appropriate levels of constraints on the replenishment capabilities of various oil tanks depending on the attributes of ~~a~~the system under consideration.

Dual-Fuel ~~Generator Specific Considerations~~Generators

Dual-fuel generators can lessen the risk of outages caused by a lack of a specific fuel supply but require additional information to perform ERAs and develop ~~the~~ appropriate ~~operating plans.~~Operating Plans. Consideration should be given to formulat~~e~~ing operational models that include the decisions that lead to ~~operations on~~the use of each fuel, the time required to swap fuels, limitations of the generator during a fuel swap, and output reductions or environmental restrictions while operating on the alternate fuel. Some generators ~~are capable of operating~~can operate on multiple fuels simultaneously, and some can swap fuels while continuing to operate, perhaps at a lower output for a controlled swap~~, while there are also~~. Other generators ~~that~~ are required to shut down before swapping fuel. ~~Each~~Since each generator is different~~ and~~, the specific processes should be understood when developing an ERA.

Dual-fuel capability auditing and reporting is the most comprehensive method of obtaining fuel switching information. However, surveys can provide similar information if auditing ~~is unable to~~cannot be accomplished and the survey information ~~provided via survey~~ is dependable or vetted for accuracy. Generator ~~owner/operators~~Owner/Operators are the experts in the logistics of fuel swapping and should be consulted when performing an ERA.

Coal ~~Generator Specific Considerations~~Generators

Coal storage capacity is usually larger than ~~the~~fuel oil storage capacity ~~of fuel oil and~~but comes with its own unique challenges. When stored outdoors and exposed to the elements, ~~coal can have different~~causing frozen or wet coal, coal's outage mechanisms ~~than~~can differ from other generator types~~ (e.g., frozen or wet coal).~~. Given the relatively large storage volumes and replenishment options associated with coal-fired generators, an analyst performing an ERA may assume that the fuel supply is unlimited, simplifying the overall process. ~~Care must~~However, care should be taken to ensure that this assumption is prudent and ~~won't~~will not result in unexpected conditions when the fuel supply is depleted or unable to be replenished.

Nuclear ~~Specific Considerations~~Generators

Nuclear fuel (e.g., uranium or plutonium) is stored in a reactor. Nuclear replenishment is a well-planned process that is scheduled months or years in advance. Depletion of nuclear fuel is measured in effective full power hours (EFPH), where a given supply of fuel is depleted based on the percent of full power ~~that~~at which the plant is operated over time. Refueling ~~is a process that~~ typically requires the reactor to shut down and be opened to replace fuel assemblies. ~~There are always new~~Although advancements in ~~proposed~~ reactor technologies that could change how a nuclear generator would be modeled in an ERA~~, however~~ are regularly proposed, most of the operating plants in North America ~~are~~remain generally the same. The key points for modeling nuclear power in an ERA focus on long durations of operation and outages~~,~~ and typically a considerable amount of energy produced in comparison to generators with similar footprints.

Hydroelectric ~~Specific Considerations~~ Generators

Pondage water available for hydroelectric ~~"fuel" availability~~generation is a function of past precipitation. Considerations should be made for environmental requirements for minimum and maximum flows at specific times, which would impact the quantity of water that is available for power generation throughout an ERA. Forecasting hydroelectric availability and demand ~~are~~is among the first parameters for power system operations and planning, and significant experience has been gathered over the last century.

Just-in-Time Fuels

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Various types of natural gas, run-of-river hydro, solar, and wind generators rely on just-in-time fuels, which are consumed immediately upon delivery. Each generator type has its own specific considerations for fuel constraints ~~which must~~that should be well understood while building an energy model and performing an ERA. Just-in-time fuels are delivered immediately prior to, or within moments of, conversion to electric~~al~~ energy, either by combustion in a gas turbine or boiler, conversion through photovoltaics, or directly applying force to spin a wind turbine for generation.

Natural Gas

Natural gas-fired generators rely on the delivery of fuel at the time of combustion in a turbine or boiler. Natural gas is a compressible fluid, primarily transported by pipelines. Gas ~~controllers are~~pipeline operators can typically ~~able to~~ operate their pipelines with a range of operating pressure, which provides some level of flexibility by, in effect, storing natural gas in the very pipelines that are used for transportation. This flexibility allows for some intraday mismatches between natural gas supply and natural gas demand, so long as mismatches do not preclude operating within specifications. The minimum pressure needed for generator operation is typically lower than the main pipeline pressure, and regulator(s) are used to maintain proper inlet pressure to the generator. For generators that require pressure that is higher than pipeline pressure, on-site compression is typically included in the site design. ~~This flexibility allows for intraday mismatches between natural gas supply and natural gas demand, so long as mismatches don't preclude operating within specifications.~~

For natural gas delivery to be scheduled to a generator, there are two required components. The first major component is procurement of the physical gas, the commodity. The commodity can be procured through natural gas marketplaces, directly from producers through bilateral arrangements, or via marketers holding bulk quantities. Shippers may elect to schedule natural gas from storage locations. Natural gas volumes typically would be scheduled in advance according to the specific pipeline rules and requirements (usually gas-day ahead) to allow pipelines to assess their ability to supply the nomination.

Secondly, there must be transportation arranged for the gas to ensure delivery at the desired location. Gas transportation can be firm or non-firm. Firm transportation usually must be acquired well in advance of the anticipated need, usually months or seasons, and most often years in advance, but can be released for others to use when it is not needed by the primary firm transportation holder. In addition to firm transportation, there are other varying degrees of firmness. Interruptible contracts may also be available, and the pipelines decide when to allow each level of transportation firmness to flow based on conditions and demands on the pipeline. Also, there can be periods~~,~~ where even firm transportation can be curtailed based on pipeline conditions. Understanding each generator's specific situation and gas contract requirements is crucial for performing an ERA. Pipeline flexibility to accommodate unscheduled receipts and deliveries is at the discretion of the pipeline operators and should be accounted for in an ERA. Communication and coordination with pipeline operators, as well as historic observations, can give the analyst the information necessary to model the expected flexibility.

Natural gas pipelines that deliver to power generators usually serve multiple generators as well as other types of demand. Competing demand must be accounted for in an ERA in order to produce an accurate solution. Depending on the contractual arrangements that have been made by different natural gas customers, demand will be served in a specific order. Higher levels of firm transportation arrangements provide more certainty and come with higher fixed costs. It is important to understand the individual arrangements for commodity and transportation for each generator when modeling the amount of natural gas that would be available for power generation. It is also imperative that an analyst understand transportation constraints and non-power-generation demands when calculating the remaining quantity of gas available for power generation. Operating generators when there is no fuel available produces an infeasible solution.

Natural gas is scheduled ~~on a~~ daily ~~boundary,~~ (i.e., the gas day~~.)~~). The gas day is defined by the North American Energy Standards Board (NAESB)[17] ~~to be~~as 9 a.m. to 9 a.m. (Central Clock Time). Quantities of gas are scheduled in terms of MMBtu per day, fitting the construct of the 24-hour gas day. Electric energy is scheduled on a more granular basis (usually hourly) ~~which~~that relies on a daily allotment of fuel to be profiled over that 24-hour period. An ERA ~~must~~should consider the limitations that could be ~~imposed~~created by ~~that inconsistency~~this misalignment between the gas and electric day and the magnitude of hourly gas flow imbalances that are allowed by the individual pipelines serving the generators in the study area.

Depending on the constraints that are in place on the gas pipeline network for a given ~~region~~area, the model can be simple or it can be more granular, as determined by the analyst. In a system where the gas demand is distributed similarly to the gas supply capabilities, a homogeneous gas model can be used. Homogeneous models consider a single energy balance of gas supply and gas demand. Homogeneous models require less effort to model and likely will solve faster~~,~~ but could miss potential constraints if not evaluated properly.

~~For additional~~Additional information concerning the natural gas supply chain~~, chapter~~ is provided in Chapter 2 of ~~the~~ *NERC Reliability Guideline: Fuel Assurance and Fuel-Related Reliability Risk Analysis for the Bulk Power System*~~, is a valuable reference~~.

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In its simplest form, the gas supply/demand balance equation is similar to the electric supply/demand equation.

$$Gas\ Supply = Gas\ Demand$$

More complex calculations can help an analyst determine the availability of natural gas for generation.

$$Gas\ Supply = Gas\ Demand_{Heat} + Gas\ Demand_{\ Industrial} + Gas\ Demand_{\ Generation}$$

~~Assuming~~For this example, assuming that natural gas demand for heat and industr~~ial~~y has a higher priority level ~~of~~for their gas transportation service (e.g., primary firm) than generation, the equation can be rearranged to solve for gas available for generation, ~~the equivalent of~~a proxy for gas demand for generation.

$$Gas\ Available_{\ Generation} = Gas\ Supply - Gas\ Demand_{Heat} - Gas\ Demand_{\ Industrial}$$

Typically, natural gas supply would be a fixed daily quantity, based on the transportation of the pipeline network. In a more complex system, it would also be a function of production assumptions. In the most complex form, the gas pipeline network may require nodal modeling, similar to the electric system, in order to solve for specific conditions, operations, or disruptions, but that level of complexity would come with a steeper computational price.

Natural gas demand for heating is a function of weather, usually temperature and wind speed, and will ~~be different~~differ for every ~~region. The simplest~~geographic area. A simple form of modeling natural gas demand ~~would~~

[17] https://www.naesb.org//pdf/idaywk3.pdf

~~be~~for heating could use a linear function of average temperature, or heating degree days~~[18]. In its most~~.[19] On the other end of the spectrum, complex ~~form,~~ gas heating demand modeling ~~can require~~could employ artificial neural network forecasting m~~eth~~od~~el~~s with inputs ~~that include temperatures~~like temperature, wind speed~~s~~, day of week, time of year, and any other pertinent inputs that would drive gas demand. A simple example of calculating ~~available~~ natural gas available for power generation is shown in ~~Example 2.~~the following example.

~~[18] https://forecast.weather.gov/glossary.php?word=heating%20degree%20day~~

[19] https://forecast.weather.gov/glossary.php?word=heating%20degree%20day

In the following example, assume that a given natural gas pipeline system ~~is capable of transporting~~can transport 1,000,000 MMBtu/day~~,~~ and has adequate supply injections at that level with no additional supply ~~within~~sources in the area~~,~~. Also, assume a fixed quantity of industrial demand of 100,000 MMBtu/day~~,~~ and that heating demand is a linear function of heating degree days ~~from~~defined by the points 0 MMBtu/day at 0 HDD and 600,000 MMBtu/day at 75 HDD.

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Calculate the quantity of natural gas that would be ~~assumed to be~~ available for power generation at 40 heating degree days under these assumptions.

$$Gas\ Available_{\ Generation} = Gas\ Supply - Gas\ Demand_{Heat} - Gas\ Demand_{\ Industrial}$$

$$Gas\ Available_{\ Generation} = 1{,}000{,}000\ \frac{MMBtu}{day} - \left(600{,}000 * \frac{40\ HDD}{75\ HDD}\right)\frac{MMBtu}{day} - 100{,}000\ \frac{MMBtu}{day}$$

$$Gas\ Available_{\ Generation} = (1{,}000{,}000\ - 320{,}000 - 100{,}000)\ \frac{MMBtu}{day}$$

$$Gas\ Available_{\ Generation} = 580{,}000\ \frac{MMBtu}{day}$$

Given that 580,000 MMBtu/day is available for power generation, calculate the MWh that would be available using an average heat rate of 8,000 Btu/kWh.

$$Generation\ (MWh) = Gas\ Available /\ Heat\ Rate\ (MMBtu/MWh)$$

$$Generation\ (MWh) = \frac{580{,}000\ MMBtu}{8.0\ MMBtu/MWh} = 72{,}500\ MWh$$

Convert 72,500 MWh to hourly MW, evenly distributed across all hours

$$\frac{72{,}500\ MWh}{24\ hours} = 3{,}020\ MW$$

The graph below shows how the amount of available natural gas will vary based on this specific model of non-power demand and remaining availability.

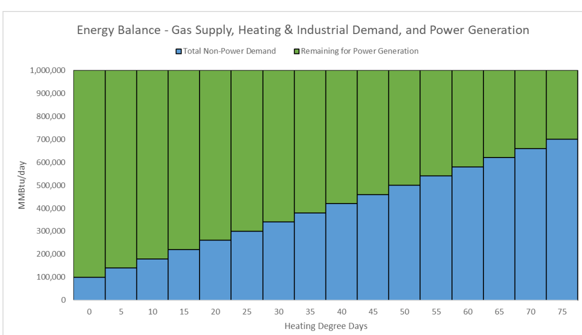

Figure 1 – Energy Balance – Gas Supply, Heating & Industrial Demand, and Power Generation

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~~Given that 580,000 MMBtu/day is available for power generation, calculate the MWh that would be available using an average heat rate of 8,000 Btu/kWh.~~

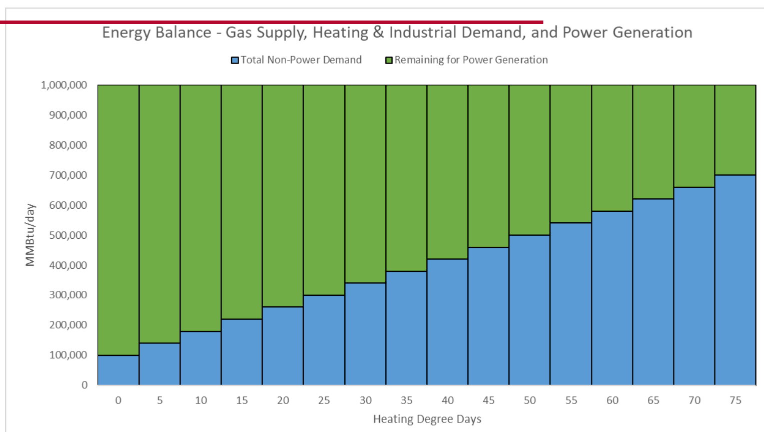
$$\cancel{Generation\ (MWh) = Gas\ Available/\ Heat\ Rate\ (MMBtu/MWh)}$$

$$\cancel{Generation\ (MWh) = \frac{580{,}000\ MMBtu}{8.0\ MMBtu/MWh} = 72{,}500\ MWh}$$

~~Convert 72,500 MWh to hourly MW, evenly distributed across all hours~~

$$\cancel{\frac{72{,}500\ MWh}{24\ hours} = 3{,}020\ MW}$$

~~Figure 1 below shows how the amount of available natural gas will vary based on this specific model of non-power demand and remaining availability.~~



~~1. Figure 1 – Energy Balance – Gas Supply, Heating & Industrial Demand, and Power Generation~~

Figure 1.2: Fuel Availability Calculation (Natural Gas)

~~Disruptions~~While a single event or set of conditions may cause disruptions on a ~~network of pipelines will have the potential to~~ pipeline that could impact ~~a number of~~several delivery points, ~~caused by the same event or set of conditions. However, because of the compressibility of natural gas,~~internal line pack storage capacity of pipelines could reduce the downstream effects of interruptions are not necessarily immediate~~.~~ as pipeline operators work to control the changes in operating pressure. Studies[20] have shown that there may be significant time between pipeline disruptions and resulting generator outages~~ caused by pipeline disruptions~~. ERAs can account for disruptions by staggering outages according to the expected rate of pressure drop~~,~~ and/or operator decisions to operate valves and shut-in gas customers (specifically generators). In the first few hours of a disruption, studies focus on the replacement of natural gas generation by the remaining fleet that is unaffected by the disruption. This includes ~~startup~~start-up times and ramping capability of generators from ~~offline~~off-line to high utilization. After the first few hours, once generation is replaced, ERAs should ~~tend to~~ focus on the long~~ term~~-term (i.e., several hours to several days) effects

[20] https://www.nerc.com/pa/RAPA/Lists/RAPA/Attachments/310/2018_NERC_Technical_Workshop_Presentations.pdf

of major disruptions and the impact that will have on ~~a~~the generation fleet that would otherwise be unused. ERAs would generally be focused on the longer-term effects of disruptions~~,~~ rather than the initial events themselves.

~~Key information to have available to assess the impact of disruptions includes basic~~Basic mapping of generators to pipelines~~.~~ is key to assessing the impact of disruptions. This information can be gathered from pipeline maps, generator surveys, contract information and registration data. Research is required to place the generators on pipelines in the correct location in reference to ~~interconnects~~injection and receipt points, compressor stations, and other pipeline demand. An ERA can then use this information for scenario development and analysis. There are instances in which a generator's proximity to a pipeline is irrelevant to the pipeline from which it has actually contracted the gas. In these cases, mapping based on contractual counterparties would be more precise.

The following ~~information is~~table useful for modeling natural gas supply in an ERA for any time horizon~~.~~:

Table 1.2: Information Useful for Modeling Natural Gas Supply in an ERA in Any Time Horizon

Data	Potential Sources	Notes/Additional Considerations
Pipeline transportation capacity	Pipeline Electronic Bulletin Boards (EBB), open season postings, firm transportation contracts	Interstate pipeline information is readily available through public sources, usually directly from the pipeline company itself.
Gas pipeline constraints	EBB postings of operationally available capacity and planned service outages, pipeline maps	Starting with pipeline maps or one-line diagrams, pinpointing the location of specific constraint points requires research. Communication with pipeline operators is helpful when specific locations are in question or difficult to find.
Generator location on pipelines	Pipeline maps, generator surveys, registration data	Research is required to properly place generators on pipelines in the correct location.
Non-generation demand estimates	Historical scheduled gas to ~~citygates~~city gates and end users, historic weather data, weather assumptions based on historic weather and climatology	Similar to load forecasting on the electric system, gas estimates play a crucial role in developing a holistic energy solution. Assuming that more gas is available than physically possible could lead to inaccurate study results.
Heating and end-user demand assumptions	Filings with state regulators, historical demand data	Regulated utilities will file their expected needs for natural gas with their respective state regulators.
Contractual arrangements	EBB index of customers, generator surveys, FERC Form 549B	Some information can be obtained via the EBB Index of Customers~~,~~; however ~~there are~~, nuanced data ~~that~~ would ~~be needed~~need to be queried directly from generators. Non-public information includes generator arrangements with gas marketers and participation in capacity release agreements.

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Table 1.2: Information Useful for Modeling Natural Gas Supply in an ERA in Any Time Horizon		
Generator heat rates	Registration data, generator surveys	Converting electric energy to fuel consumption and vice versa requires the heat rate of a generator, typically expressed in Btu/kWh or MMBtu/MWh.

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Variable Energy Resources

Run-of-river hydro, solar, and wind resources generate electricity when the fuel is available and conditions permit. ~~There is no certainty to the~~The amount of energy produced by these resources at any given time is uncertain, and operators cannot require that the generators produce more power when ~~limited fuel will~~conditions do not allow for it. Forecasts are available for expected variable generation outputs and have improved over time~~.~~; ~~H~~however, longer-range (from seasonal to several years out) ERAs must make assumptions for inputs that would be difficult to predict. Historical data is a good starting point for developing assumptions~~, which would~~; this can be further augmented by known or anticipated conditions, such as drought ~~for one example~~, and adjusted for additional buildout since the historical conditions were recorded. The resulting input to an ERA is an hourly profile~~,~~ or set of profiles~~,~~ that ~~portray the~~portrays VER output ~~of VERs~~. For ~~regions~~areas where VERs make up a small percentage of the total nameplate of generation, resources may not need to be as specific when building energy models. The model could assume a fixed output over the course of the study period~~,~~ based on historical performance (e.g., capacity factor) and nameplate capability. A simple model is easier to build, maintain, and understand but may fall short when attempting to reveal deficiencies once the resources become a larger producer of electric power for the ~~region~~area.

Energy Supply Variability

~~Several components of energy~~ Energy supply variability ~~have been mentioned already in this technical reference document, stressing the need for~~means that ramping capability is needed. Just-in-time fuels or input energy are subject to large- and small-scale ~~fuel~~energy supply interruptions (in this context, including clouds over solar panels, calm winds, and gas network outages). Variability of one fuel supply ~~creates a stress on~~stresses other fuel supplies or requires drawdown of storage when replacement energy is sought. The rate of increase or decrease of the production from a resource with a variable fuel supply (e.g., wind or solar) has the potential to overwhelm the infrastructure and capabilities of the ~~generators being used as~~ replacement generators. An ERA should consider the ability of balancing resources to replace fast-moving variable resources when production wanes~~,~~ and the ability to back down when production returns. Both increases and decreases in generation or demand pose ~~certain~~ risks.

~~Figure 2 and Figure 3~~The two figures below show an example of actual solar and wind production, respectively, for seven consecutive days in March 2023. As shown, the hourly production of solar or wind can change by thousands of MW for the same hour between consecutive days. To account for the uncertainty associated with VER production, analysts may have to use probabilistic analysis ~~to conduct~~in a near-term ERA to best evaluate the energy reliability risk. ~~Using probabilistic~~Probabilistic methods can ~~enable~~allow the assessment to ensure that the flexible capacity is available across a range of scenarios and combine the results to evaluate the risk. Alternatively, to use deterministic methods, specific variable energy production scenarios should be chosen as a design basis ~~which stress~~that stresses the system to determine if sufficient energy is available in the time horizon being studied. ~~To support near-term ERAs, the~~The ability to produce variable production curves based on weather forecasts, forecast errors, and resource characteristics ~~is necessary~~ —or, at least, ~~being able to use~~ historical production data—is necessary to support near-term ERAs.

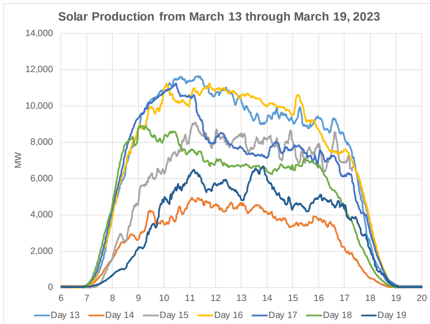

Figure 1.3: Actual ~~solar production~~Solar Production for ~~seven consecutive days~~Seven Consecutive Days

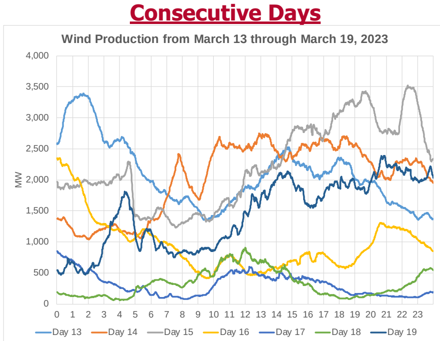

Figure 1.4: Actual ~~wind production~~Wind Production for ~~seven consecutive days~~Seven Consecutive Days

Evaluating that capability requires knowledge of fuel supply constraints and specific generator capabilities. For example, ~~in a situation~~ when ~~the~~ solar production has peaked on a system with significant solar power, the evaluation would start by modeling the ramping capability of the resources that are replacing that power. Once the physical capabilities of replacement resources are known, the next layer to consider is the upstream infrastructure that is necessary to support their operation. For example, when replacing solar power as part of the daily cycle of operations, natural-gas-fired generation ~~ramps~~could ramp up to replace the solar power. Consideration should be made to determine if the natural gas pipeline ~~pressure would remain in tolerance~~system has the capability to maintain established gas system tolerances while ramping generation up. Assumptions would need to be made for the initial pipeline pressure, and the analyst will need to know the ~~limits on~~ minimum and maximum allowable operating pressures. Pipeline ~~pressure will be maintained by pipeline~~ operators maintain pipeline pressure by limiting the rate at which the~~ir~~ demand is allowed to fluctuate~~. This constraint~~ and modulating operations of compressor stations along the pipeline. These constraints may limit the flexibility of natural gas resources beyond what is expected~~.~~ without factoring in gas pipeline operational practices. If fuel systems are unable to keep up with ramping generation, ~~the~~ ramping generation should be discounted ~~at that point~~accordingly in an ERA. This type of assessment can get complicated quickly and should be coordinated with natural gas pipeline operators to ensure that accurate information is used.

On the other side of the spectrum is when VERs begin to ramp their production from low to high. This situation is likely not as dire , as conventional resources can generally ~~can~~ ramp their output down faster than ~~it can ramp~~ramping up, and some variable resources can be curtailed if a system reliability risk emerges. However, the considerations for pipeline pressures and ~~electric~~energy storage still apply, just on the opposite side of the spectrum. Using solar power ramping as the example again~~, in the morning~~: when solar production starts to ramp up while demand increases at a lower rate, in the morning, solar over~~-~~generation results in ~~the~~a need to back down other supply resources. ~~Additionally~~However, generation problems can arise if gas pipeline pressures are already high~~,~~ and storage is full, resulting in pipeline constraints caused by unused fuel in the pipe. Coordinated operation of the gas and electric systems should provide for multiple mechanisms to ensure that this can be minimized or avoided altogether~~, allowing gas system operators to plan ahead.~~. Electric ~~system operators~~System Operators would need to ensure that there is room to charge/pump the storage resources as necessary through the periods of ramping, and an ERA would provide the information necessary to set those plans.

The following table contains information ~~is~~ useful for modeling energy supply variability in an ERA for any time horizon~~.~~:

Table 1.3: Information Useful for Modeling Energy Supply Variability in an ERA in Any Time Horizon

Data	Potential Sources	Notes/Additional Considerations
VER assumptions	VER forecasts as described in the ~~variable energy resources~~VER sections of this document	VER production drives the need for flexible generation to be available or online. Additionally, the ability to curtail VER production should be considered as a mitigating option.
Generation ramping capability	Registration data, market offers	Balancing resources would be used to maintain system frequency from moment to moment.
Fuel supply dynamic capabilities	Fuel supply network models, market-based models to determine volumes delivered to specific sectors or historic observations	The key to including ramping capability in an ERA is focusing on the capabilities of the fuel delivery network (e.g., gas pipelines, fuel oil or coal delivery systems at specific generators) and how that network responds to the ramping needs of the system.

Emissions Constraints on Generator Operation

~~An increasing number of restrictions are being placed on emissions~~ Emissions from all industries, including power generation, ~~which can limit~~are being increasingly restricted, limiting generator capability ~~completely~~ or ~~concentrated at specific times.~~operating durations and windows. Emissions limitations are more nuanced than inventory limitations~~.~~; ~~O~~one additional complexity is that waivers can be granted under emergency declarations, meaning that the limits are not necessarily fixed ~~points~~ and require ~~evaluations prior to~~evaluation before becoming binding ~~on the constraint. Also, emission~~. Emission limitations may potentially be shared across several generating stations. Results of ERAs can be used to show a need for emissions waivers. Emissions information should be available from ~~generator owner/operators~~Generator Owner/Operators and should be included in routine surveys. Analysts will need to be able to apply an emissions limitation to the operation of a generator or generating station. The information obtained must be in a format that is usable by the analysts performing the ERA (e.g., MWh remaining until emissions constrained rather than tons of CO_2 remaining without a conversion from emissions to electric~~al~~ energy remaining). Emissions limitations will differ by jurisdiction (e.g., state or province~~). Emissions limits~~), can be on a variety of time scales (e.g., annual, seasonal, or rolling 12-month limits), and can be shared by portfolio within a specific state. They can also have multiple components ~~to them~~ (e.g., NOx, SOx, and CO_2), all of which ~~must~~should be evaluated, but only the most limiting would likely be modeled in an ERA. Again, relevant information would be provided by the resource owners/operators and, while the analyst performing the ERA should be familiar with the concepts of emissions limitations, they will likely not be the expert who would derive the associated limits. ~~Additionally, generators~~Generators may be further constrained by the lack of availability of emissions credits or offsets during extreme conditions.

Other potential constraints that may impact generation from an environmental point of view, specifically entities with hydro resources, ~~are~~include limitations ~~such as~~like required minimum water flows and downstream dissolved oxygen levels. Such regulations could impact desired operation ~~as it~~ related to scheduling energy from hydro or pumped storage facilities located on non-isolated reservoirs and should be considered for modeling in an ERA.

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The following ~~information~~table is useful for modeling emissions constraints on generator operation in an ERA for any time horizon~~.~~:

Table 1.4: Information Useful for Modeling Emissions Constraints on Generator Operation in an ERA in Any Time Horizon		
Output limitations for a set of generators	Generator surveys	Each ~~generator owner/operator~~Generator Owner/Operator may know their own operational information, but when determining when a collection of generators will reach a limit would require gathering information that each owner/operator has but not as a collective. The analys~~is~~t performing the ERA would be the centralized collection point of the information required to accurately model the limit.

Outage Modeling

~~Outage Modeling~~

A common method for~~ statically~~ modeling generator outages in an ERA is to multiply the generator's maximum output by a function of outage rate (e.g., 1 - EFORd) and assign that as the new maximum output for the duration of the study period. Applying this method consistently to the entire fleet of generators results in a set of input assumptions that is agnostic of how outages occur~~,~~ but accounts for outages in a fairly accurate manner. However, this method will only show the average outage impact from all units, not the risks posed by concurrent outages, especially if there is any degree of correlation in outage patterns.

Alternately, dynamic outage modeling methods assign a probability of occurrence, impact, and duration to each failure mechanism of a specific outage of a specific generator and run a probabilistic analysis, or outage draw. The probability of occurrence would be compared to a random number generator in the software and implement the outage with the associated impact and duration from that point in the study period. This method is much more complex to model than the simpler methods and requires that each type of failure be evaluated for the correct parameters but is more ~~precise when comparing to real-life~~closely aligned with actual conditions. It should be noted, however, that even probabilistic approaches to outage modeling can exhibit ~~a large amount of~~significant variability, both in implementation and subsequent accuracy. Understanding the nuances present in probabilistic outage modeling is important for any resource adequacy assessment~~,~~ but especially so for an ERA.[21]

Information on generator outages is available through historical data analysis, ~~either through~~specifically operator logs, operational data, or the NERC Generation Availability Data System (GADS~~)~~).[22]~~.~~

[21] https://www.epri.com/research/products/000000003002027832

[22] https://www.nerc.com/pa/RAPA/gads/Pages/GeneratingAvailabilityDataSystem-(GADS).aspx

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~~In an~~An ERA~~, it is important to~~ should take into consideration the impacts of previous hours on the next hour. For this reason, methods that consider temporal impacts~~–~~—such as two-state Markov modeling or state transition matrices ~~–~~—are beneficial. In addition to considering mechanical failure of equipment, it is also beneficial to consider a wide range of failure causes, such as fuel availability or ambient air and water temperature.

In reality, ~~forced outages~~Forced Outages are a more complex phenomenon than typical modeling techniques ~~allow~~have been able to predict. Model fidelity can be improved by gathering data and incorporating the following:

- Foresight on failures ~~–~~(e.g., start-up failures have limited foresight and therefore may require faster response times from other resources)
- Uncommon causes (e.g., battery cell balancing)
- Time-varying forced-outage rates (e.g~~.~~., seasonality, hourly variation~~); and~~)
- Common cause failures

Most reliability assessments consider generator outages as independent events, where each generator is modeled separately with its own forced-outage rate that applies for the entire study horizon. ~~In reality, this may not be the case and one might need to consider this issue.~~

The following ~~information~~table is useful for modeling energy supply outages in an ERA for any time horizon~~.~~:

Table 1.4: Information Useful for Modeling Energy Supply Outages in an ERA in Any Time Horizon

Data	Potential Sources	Notes/Additional Considerations
Forced ~~Outage Rates~~ outage rates	NERC GADS, assumptions based on historical performance	NERC requires outages and reductions to be reported with associated cause codes and makes that information available to registered entities. Alternatively, analysts can observe historical unplanned outage information to determine similar assumptions.

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Distributed Energy Resources

Distributed energy resources (DER) are ~~comprised~~ primarily made up of the same types of resources ~~that were~~ discussed in prior sections (e.g., VERs~~),~~) but have different considerations associated with ~~them being~~their distributed~~.~~ nature:

- DERs generally use just-in-time fuels, are variable in nature, and do not respond to dispatch instructions~~,~~; however, some DER installations are being installed with integrated storage systems that serve to distribute production more evenly, resulting in a behavior that is less like a just-in-time resource.
- DERs are usually installed on lower-voltage systems (i.e., distribution-level systems) that are not modeled by ~~transmission operators,~~Transmission Operators and can be subject to unknown constraints.
- DERs can be subject to unanticipated operation in response to faults on the transmission or distribution systems.[23]
- ~~-~~Modeling DERs in an ERA can be done on either the supply side of the energy balance equation or on the demand side, to be determined by the analyst and the defined process.

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

Market-Based Resources and Market Conditions

Market-based resources are those that are registered with an Independent System Operator~~ / ~~/Regional Transmission Organization (ISO/RTO), ~~receive market~~generate revenue for their owner by participating in the ~~regions~~area's organized market, and are typically governed by an agreement between the ~~participant~~resource owner and the ISO/RTO. The development of an ERA ~~must~~should consider these market rules and understand how market participants will behave in certain situations. These resources ~~have an expectation~~are expected to perform in the market (e.g~~.~~., no economic withholding) but occasionally must make decisions that would impact their availability.

For example, ~~in regions with locational marginal pricing, by nature there will be some resources who tend to be closer to the marginal unit who ultimately profit less,~~a generator's revenue and ~~there will be other resources who tend to profit more if they're priced further away from the marginal unit. This profitability~~dispatch expectations under market conditions may change ~~the way~~how a generator is positioned for dispatch, such as increasing ~~their~~its notification-to-start time to avoid staffing ~~their~~its facilities 24/7. Another example would be if a given are~~gion~~a's agreements have severe penalties or reduced revenue for generators ~~who~~that are not running during a constraint period. To avoid incurring penalties, non-~~intermittent~~variable generators may take proactive actions to self-schedule on these days with the intention of mitigating potential operational issues if given enough notice of these availability conditions.

~~Other constraints that may impact entities are contracts~~Contracts, both out-of-market and non-power, held by generating units that impose take-or-pay or force majeure penalties~~.~~ may also impact entities. These contracts typically impact co-generation facilities and those that provide power, steam, and/or other services to adjacent facilities, such as refineries and heavy industry, and may reduce the available output and operational responsiveness of impacted units.

Demand

Demand is significantly more complex today than it ever has been. ~~Modern~~Today's demand ~~has components~~is composed of actual demand~~,~~ adjusted by varying types of demand response (including the impact of time-of-use rates~~,~~) and distributed generation that is considered load-reducing.

Actual demand~~,~~ (i.e., gross demand~~,~~) can be th~~r~~ought of as loads that are drawing power from the interconnected electric systems. Lighting, environmental controls like heating and air conditioning, household and commercial electronics, and industrial loads all comprise the actual demand on the system. These concepts have been consistent since the power grid was first developed. The specifics may change over time, with energy efficiency and changes to lifestyles, but the concepts remain the same.

The behavior of demand is becoming more difficult to predict due to ~~several ~~factors, such as energy efficiency, demand response, and price-responsive loads~~ etc.,~~, which can significantly vary the shape of typical hourly demand. ~~Also, as~~The expansion of electrification (e.g., electric vehicles and heating) ~~expands ~~within a specific footprint~~,~~ requires the analyst ~~would need ~~to make assumptions of the ~~EV~~electric vehicle charging patterns and other changes to load profile due to electrification of heating or industry. ~~Charging assumptions would differ by seasons and would be different from assumptions made for air condition~~Like air-conditioning units and heating sources, ~~which are season specific. Electric vehicles and~~electric vehicle charging assumptions would ~~also have an impact on~~differ by season, but would be different from assumptions made for those other end-uses leading to changes in techniques for predicting demand.

Demand itself is more versatile than it once was. Demand-response programs have been designed to preempt the buildout of additional, or the retention of existing, generation capacity resources by lowering demand during peak hours. Impact on energy will depend on how each program is implemented. For example, interrupting air-conditioning systems for a few hours on peak days may reduce ~~the peak demand~~Peak Demand but may not change the ~~overall~~total energy demand on the system. Loss of load diversity without a longer-duration change to temperature ~~set points~~setpoints may eventually require a similar energy demand to restore temperatures after the peak is shaved. When restored, systems will run longer and more consistently, drawing nearly the same amount of energy ~~than~~as if no demand response was initiated. Voltage reductions may also fall into the same type of construct, depending largely on the makeup of demand in a specific ~~region~~area. These concepts will factor into the decisions that are made to manage energy when situations arise that require actions.

Finally, in some applications, DERs are considered in the demand side of an energy balance equation, while others may include DERs in supply. Both methods have their advantages and disadvantages.

$$Supply + Imports = Demand + Exports + Losses$$

Where

$$Supply = Generators + Distributed\ Energy\ Resources$$

Or

$$Demand = Load - Distributed\ Energy\ Resources$$

Deconstructing demand into its individual components may be helpful in solving for the variability of distributed generation or for building future demand curves. This process may require significant effort and potentially some assumptions in the absence of actual data. The impact of variability can be addressed by reconstituting actual demand~~,~~ (i.e., adding the distributed generation production back into the measured load~~.~~). Once the components are separated, actual demand forecasts or assumptions can be developed as one input variable and distributed generation can be modeled separately. The same concept applies to electrification. Start with the current demands and the projected growth of existing demand types, then add the assumed incremental demand that is expected from electric heating~~; –~~—then add the assumed incremental demand that is expected from transportation electrification. However, demand will be modeled in an ERA, the analyst should ensure that all aspects are accounted for and not double counted.
~~However it is decided that demand will be modeled in an ERA, the analyst must ensure that all aspects are accounted for and not double counted. From there, where each piece goes in the equation is irrelevant.~~

Electric Storage

Classification of Electric Storage

As discussed earlier, *electric storage* ~~is~~refers to a device or facility with electric power as an input, a storage medium of some kind that stores that energy, and electric power as an output. Before energy can be supplied by an electric storage device, it needs to be generated somewhere and then stored in the device. Electric storage ~~is not a resource that generates~~cannot itself generate energy but ~~is a resource that~~ can provide electric energy to the grid to the extent it has been charged. An ERA can ~~be used to~~ show when energy storage needs to be charged~~,~~ and when it should be discharged to support energy sufficiency needs. It may also indicate when there may not be enough energy stored to keep the system balanced with variable supply or volatile demand.

Electric storage can be classified as ~~Short-Duration Energy Storage~~short-duration energy storage (SDES) or ~~as Long-Duration Energy Storage~~long-duration energy storage (LDES~~)~~),[24]~~,~~ depending on the needs of the system where the storage is built. This technical reference document uses the terms *SDES, Inter-day LDES, Multi-day/Week LDES, and Seasonal Shifting LDES* to describe ~~different~~the types of electric storage and considerations for each. However, an analyst with more extensive knowledge of electric storage systems and a need to model electric storage more precisely may categorize the resources differently. Each ~~region~~area may have a specific need (or set of needs) for storage~~,~~ and, quite possibly, multiple types simultaneously. When performing an ERA, all known electric storage resources should be included as supply resources when they are discharging or as demand when they are charging.

[24] https://liftoff.energy.gov/long-duration-energy-storage/

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SDESs can be used for frequency regulation, energy arbitrage, and peaking capacity. These resources include smaller batteries,[25]~~,~~ less than ~~4~~four hours of storage, and flywheels. These electric storage types can cycle, charge, and discharge~~,~~ quickly and often in response to signals defined to maintain a balanced Area Control Error (ACE~~)~~).[26]~~. For SDES~~ SDESs with duration closer to ~~4~~four hours~~, they~~ can be used to arbitrage demand from the low-load periods to the higher-load periods by, for example, charging overnight or when PV production is high and using that energy to serve peak hourly loads. Inter-~~D~~day LDES includes resources ~~with capability~~able to store energy for up to 36 hours, such as pumped hydro storage stations and some developing battery storage. These resources fill the upper pondage or charge when net demand is low and generate or discharge energy when demand is high. Inter-~~Day LDES~~day LDESs can be called on when renewable resources (solar and wind) ~~are not able to~~cannot produce power for several hours. For example, ~~Inter-Day LDES~~inter-day LDESs can be dispatched to cover nighttime demand when solar generation ceases in the evening after the sun sets. In simplified models, the operation of ~~Inter-Day~~inter-day LDES resources is sometimes modeled as a fixed charge/pump load at normally lower-demand periods and as a fixed discharge/generation at normally higher-demand periods. The more standard and recommended option for modeling ~~I~~inter-day LDES is to include the specific capabilities as part of the energy balance from hour to hour and optimize the charge/discharge decisions. This effectively tells the analyst when to charge/pump and discharge/generate~~,~~ based on the resource's state of charge~~,~~ or other specific system conditions. Multi-~~D~~day LDES is ~~comprised~~made up of electric storage resources (e.g., larger batteries and pumped storage hydro stations) that can provide several days to a week of electricity and is intended to be held for longer time periods. Multi-~~D~~day LDES can be called upon when a natural-gas-fired plant is unable to receive fuel~~,~~ or when renewable resources are not able to produce power for many hours, ~~for example,~~such as when wind or solar resources are unable to generate energy due to weather systems that reduce wind speeds or solar irradiance for extended periods~~ of time~~.

Seasonal ~~S~~shifting LDES~~ is~~, storage that holds energy produced in one period to be used weeks or months later~~. Currently, Seasonal Shifting LDES is~~, is currently focused on "Power-to-X"[27] pathways, such as hydrogen, ammonia, and synthetic fuels. Seasonal ~~S~~shifting LDES is in the early developmental process and is not necessarily the focus of this technical reference document.

Electric Storage Configuration

Electric storage can be standalone~~,~~ or co-located~~,~~ or consist of hybrid/storage resources, ~~which can~~ further complicat~~e~~ing modeling. Solar or wind generators with storage devices at the same location as the generation allow the production of electricity to exceed interconnection limitations. The excess energy is then stored at the associated storage device and withdrawn from storage when generation drops off. Additional complication comes from a potential lack of visibility of the generation resource, as the energy may be supplied by the generation or the storage resource. Metering at the output of a co-located storage facility adds a layer of obfuscation between the weather conditions and the production of the renewable resource, or when the electric storage portion of the facility is used to store energy from the grid rather than from the renewable resource. Metering the individual components can remove that obfuscation but ~~may be costly to add~~potentially at the cost of adding to a project or ~~to retrofit~~retrofitting. Modeling these resources in an ERA as individual components may give the analyst more flexibility with modeling tools and a better understanding of the production from the facility.

Reliability Optimization

A charge/discharge cycle usually incurs losses and, thus, electric storage creates a net energy demand when averaged over longer periods of time. This "round-trip efficiency of storage" is an important consideration for performing an ERA, primarily for accuracy, but also for deciding on action plans when energy supplies are inadequate. Both supply

[25] As with all inverter-based resources, it is critical to know if the storage resource functions under ~~Grid-Forming~~grid-forming or ~~Grid-Following~~grid-following technology.

[26] ACE is defined by NERC in BAL-001-2 (https://www.nerc.com/pa/Stand/Reliability%20Standards/BAL-001-2.pdf)

[27] Power-to-X is described by NETL in Technology in Focus: Power-to-X (https://doi.org/10.2172/2336708)

and demand implications of storage resources should be considered when formulating action plans when facing an energy shortfall.

Optimization of energy in electric storage devices across several hours or several days is a complicated process that requires consideration for how it would be modeled in an ERA. Electric storage is ~~being~~ used in many cases to shift available energy from low-demand periods to high-demand periods~~,~~ or to provide ~~ancillary services~~Ancillary Services, and an ERA should model that operation accurately~~,~~ according to how electric storage devices would operate in real life. If the actual dispatch and operation would be optimized~~,~~ to meet a certain objective or set of objectives, the ERA should optimize it toward~~s~~ the same objective over the same period. If an electric storage device is not normally optimized and an ERA were to optimize the dispatch and operation to minimize reliability risk, it could mask indications of a shortfall to the analyst.

The following ~~information~~table is useful for modeling electric storage in an ERA for any time horizon~~.~~:

Table 1.5: Information Useful for Modeling Electric Storage in an ERA in Any Time Horizon		
Data	**Potential Sources**	**Notes/Additional Considerations**
Maximum charge/discharge rates (in MW or kW) and total storage capability (in MWh or kWh)	Registration data	These two parameters combined define~~d~~ the primary characteristics of a storage device.
Usable Capacity	Registration data, operational data	Battery storage may not operate well above and below a specific charged percentage. For example, batteries charged above 80% or below 20% may ~~under perform.~~underperform. Therefore, the storage capacity may be less tha~~t~~n intended.
Transition time between charge and discharge cycles	Registration data, operational data, market offers	
Cycling efficiency	Operational data	Calculating the cycling efficiency of storage can be done using operational data, dividing the sum of output energy by the sum of input energy over some period. A longer duration will yield a more accurate efficiency value. All storage requires more input energy than the output that will be produced.
Co-located/~~H~~hybrid or ~~stand-alone~~standalone configuration. Charging source – primary and secondary	Registration data	Scenario studies may remove a generation type (~~i.~~e.g., solar~~)~~), which may eliminate the energy supply source.
Ambient temperature limits	Registration data, operational data	This ~~is~~refers to the ambient temperature limitations at the storage facility, which are part of the formula for calculating cell temperature limitations. There are high- and low-temperature requirements for charging and discharging batteries at a normal rate. Outside that band, the rate of charge could be reduced, potentially to 0.
No-~~L~~load losses	Registration data, operational data	Electric storage facilities may experience a loss of energy even when not delivering energy to the grid.
Emergency ~~L~~limits		Can the storage resource run below the P-Min or above the P-Max, and if so, for how long?

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Transmission

Transmission moves power from supply to demand~~.~~ on the Bulk Electric System. Transmission constraints ~~place limits on~~ limit how much power can be transferred. ERAs ~~must~~should account for transmission constraints to accurately model transfers, which can occur within and between constrained areas. Inter-area transmission constraints can be modeled as imports and exports~~,~~ while intra-area transmission constraints could be modeled as reductions in supply capability or by dividing the ~~region~~area zonally. Calculation of specific transfer limits are required by NAESB ~~S~~standards and are a well-known quantity. This information may be available through various Open-Access Same-Time Information System (OASIS) postings. These limits are one aspect of determining the available energy that can be transferred over the transmission system. Once ~~it is known what~~ the limitations ~~are~~ for transfers between areas are known, there ~~must~~should be coordination between areas to determine if the energy is available to use that transmission capability. Coordinating ERAs between neighboring areas is crucial to formulating accurate input assumptions.[28]

Other considerations for transmission capability include grid-enhancing technologies, such as ambient adjusted ratings, dynamic line ratings,[29]~~,~~ controllable ties, transmission and distribution losses, priority to access, and recallable ~~t~~Transactions/cutting assistance. These considerations will change ~~the way that import~~how imports, exports, and additional transmission usage ~~is~~are modeled in an ERA. Ambient ~~Adjusted Ratings (AARs~~adjusted ratings (AAR) will potentially allow for greater ~~transfer capability~~Transfer Capability within and between areas, enabling higher energy usage.

ERAs can also be used to determine if transmission outages would cause or worsen shortfalls. Transmission outages can create conditions ~~which~~that constrain or curtail fuel-secure or high-energy production resources. These constraints or ~~c~~Curtailments can be represented to accurately portray the impact of the transmission outage. Conversely, system conditions (including transmission outages) ~~which~~that create must-run conditions for generators should be incorporated into the ERA. For example, a must-run condition of hydroelectric generation (to mitigate thermal overloads or ~~under-voltage~~undervoltage conditions) could reduce the available energy from that resource to meet the needs of the ERA. The ERA would inform the ~~system operator~~System Operator and Operational Planning Analysis ~~for~~ when resources are not available due to energy constraints. ~~Additionally, using~~Using limitations on imports and exports would factor into the neighboring area ERAs as well.

The following ~~information~~table is useful for modeling transmission in an ERA for any time horizon~~.~~:

Table 1.6: Information Useful for Modeling Transmission in an ERA in Any Time Horizon

Data	Potential Sources	Notes/Additional Considerations
Planned ~~O~~outages and Maintenance	~~TOPs, TPs,~~Transmission Operators (TOP), Transmission Planners (TP), or other transmission planning entities	
Import/~~Export Transport Limits~~export transfer limits	Engineering studies	
Import/~~Export Resource Limits~~export resource limits	Coordinated ERA with neighboring areas	Aligning input assumptions between areas would be necessary for ensuring that energy is not ignored or double counted in multiple ~~regions~~areas.

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[28] FERC Order 896 [elibrary.ferc.gov] directed NERC to develop a new standard to address the reliability and resilience impacts of extreme heat or extreme cold events on the ~~bulk power system.~~BPS. A NERC Standards Authorization Request [nerc.com] to address transmission planning energy scenarios was approved by the NERC Standards Committee [nerc.com] in December 2023

[29] To draw distinction between ~~Ambient Adjusted Ratings~~ambient adjusted ratings and ~~Dynamic Line Ratings, Ambient Adjusted Ratings~~dynamic line ratings, ambient adjusted ratings are a function of forecasted temperatures ~~which~~that can be used in real-time and near-term operations planning~~,~~ and are defined in FERC Order 881~~ and~~. Dynamic ~~Line Ratings~~line ratings are a function of real-time environmental conditions to determine the capability of a transmission system element.

Table 1.6: Information Useful for Modeling Transmission in an ERA in Any Time Horizon		
Data	**Potential Sources**	**Notes/Additional Considerations**
Transmission ~~T~~topology and ~~C~~characteristics	Transmission and distribution models	Potentially, using a simplified or ~~DC~~ dc-equivalent circuit for probabilistic or similar analysis. Considerations for including planned transmission expansion projects.
Transmission ~~Outage Rates~~outage rates	NERC ~~G~~TADS	Ideally, weather-dependent and ~~unit~~ facility-specific outage rates could be used to reflect energy scenarios.

Other Considerations

Across all portions of the power sector, inventories of replacement equipment, mean time to repair (MTTR), and lead ~~-~~times for non-inventoried equipment ~~are a~~represent critical limitations that should be considered during the application of contingencies in ERAs. Some of these factors may restrict response pathways across all ERA time horizons. Additional factors that may require consideration ~~or govern along different time horizons~~ include component sourcing (domestic material requirements, nuclear "N-Stamp" certification, etc.), tariff and import restrictions, and government policy and regulatory interventions/restrictions/limitations. While these considerations may improve the accuracy of an ERA, the details may be unavailable or unable to ~~implement~~be implemented in a model.

Labor availability ~~is~~may also ~~an item that may~~ need to be considered ~~at various points in the performance of~~during ERAs depending on the variable of concern~~,~~; for instance, in a short-term horizon, ~~c~~Contingency recovery time may be governed by the availability of skilled labor and trade~~s~~ personnel over a holiday weekend. In longer time horizons, labor availability may drive uncertainty in both maintenance and construction scheduling, potentially leading to ~~the potential of~~ increased outages at existing units and delays in synchronization of new units.

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Chapter 2: Inputs to Consider When Performing a Near-Term ERA

An ERA in the near-term horizon ~~is considered to look at~~addresses a ~~timeframe~~time frame that starts about 1~~-~~–2 days out and ~~look~~then continuously through the following several days or weeks. It effectively starts at the end of the Operating Plan that covers today and perhaps tomorrow~~,~~ as outlined in NERC Standard TOP-002~~[30]. The~~.[31] That said, the period~~ being~~ assessed in a near-term ERA can start earlier (i.e., today, or even in the past) if the analyst needs to set up accurate initial conditions. The near-term ERA then looks into future days or weeks to provide the analyst with a representation of what the energy-constrained conditions would be. Considerations for inputs to a near-term ERA are described below.

Supply

Modeling supply in a near-term ERA relies on an analyst gathering information from an existing fleet of generators. This information is usually fairly static in the near term and can be included in registration data or gathered through generator surveys. Additionally, forecast information may be necessary for ~~BAs~~Balancing Authorities (BA) with high levels of VERs~~,~~ who will use that information to make more informed decisions on required VERs that would be committed on any given day.

Stored Fuels

Stored fuel information in a near-term ERA should start with current inventories and be updated throughout the assessment based on operations and expected replenishment.

The following ~~information~~table is useful for modeling stored fuels in a near-term ERA~~.~~:

Table 2.1: Information Useful for Modeling Stored Fuels in a Near-Term ERA

Data	Potential Sources	Notes/Additional Considerations
Current inventory, inventory management plans, and replenishment assumptions	Generator surveys, assumptions based on historic performance, or annually variable conditions specific to the resource type	Replenishment is key to modeling inventory at any point during the study period. Replenishment restrictions are also an important aspect of an ERA. Performance expectations for hydroelectric resources may be informed by seasonal runoff conditions.

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Just-in-Time ~~f~~Fuels

Modeling just-in-time fuels in a near-term ERA relies on the existing fuel supply infrastructure and assumptions of the operation of those facilities.

~~[30] https://www.nerc.com/pa/Stand/Reliability%20Standards/TOP-002-4.pdf~~

[31] https://www.nerc.com/pa/Stand/Reliability%20Standards/TOP-002-4.pdf

Natural Gas

Modeling natural gas availability in a near-term ERA requires an understanding of the pipeline infrastructure that is ~~currently~~ in place.

The following ~~information~~table is useful for modeling natural gas supply in a near-term ERA~~.~~:

Table 2.2: Information Useful for Modeling Natural Gas Supply in a Near-Term ERA

Data	Potential Sources	Notes/Additional Considerations
Natural gas scheduling timelines	Pipeline tariffs, NAESB	Timelines may differ between pipelines. The NAESB sets five standard cycles that are to be followed by Federal Energy Regulatory Commission (FERC) jurisdictional entities (which generally excludes intrastate pipelines and local distribution networks~~)~~).
Natural gas commodity pricing and availability	Intercontinental Exchange (ICE~~)~~),[32]~~,~~ Platts[33]	Natural gas commodity pricing is an indicator of its availability. Continuously monitoring pricing will allow an analyst to estimate the availability of natural gas into a near-term ~~energy reliability assessment.~~ ERA.

Variable Energy Resources

~~Modeling~~ VERs are modeled in a near-term ERA ~~is done~~ using the technical specifications of the existing fleet and a forecast of weather conditions translated into power (production) forecasts. Developing an ERA that is highly dependent on VERs requires consideration of the uncertainty of the energy available. ~~Even over a near-term horizon, the~~The forecast error of VER production can be high~~.~~ even over a near-term horizon. The energy available from VERs ~~are~~is based on the following factors:

- ~~1.~~ VER capacities~~,~~
- ~~2.~~ ~~g~~Geographical location of installed VERs~~,~~
- ~~3.~~ ~~t~~Typical forecast errors of wind, solar, and weather~~,~~
- ~~4.~~ ~~t~~The capacity, configuration, and transmission capacity of co-located energy storage~~,~~
- ~~5.~~ ~~o~~Outage rates of resources~~, and~~
- ~~6.~~ ~~a~~Amount of VERs connected to distribution or transmission~~.~~

For most BAs with high levels of VER installations, conducting a near-term ERA with deterministic production values beyond ~~seven to ten~~7–10 days may require the use of averaged production assumptions rather than forecasts due to accuracy concerns.

Near-term ERAs will generally use forecasts~~,~~ rather than assumptions and historical observations. These forecasts are available through a variety of weather vendors and national weather service providers~~,~~ that are derived from global models allowing for specific localized weather to be extracted. Model downscaling, blending and ~~model~~ improvement efforts generally produce higher accuracy and/or precision. ~~It is up to the~~The analyst ~~to~~can interpret the output of

[32] https://www.ice.com/index
[33] https://www.spglobal.com/en/

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weather models coordinated with VER production forecasts and apply the results to generator performance assumptions in an ERA.

The following ~~information~~table is useful for modeling VERs in a near-term ERA~~.~~:

Table 2.3: Information Useful for Modeling Variable Energy Resources in a Near-Term ERA		
Data	**Potential Sources**	**Notes/Additional Considerations**
Weather forecasts	Vendor supplied but could be developed using weather service models	There could be differences between one or multiple central forecast(s) and the aggregation of independent forecasts. Forecast error analysis of historical data would provide a measure of the performance of available options.
	In-house models or vendor-supplied data	Wind/solar profiles can be modified to capture uncertainty associated with rainy, windy, and/or cloudy days. ~~It's~~ It is important to maintain the correlation between wind, solar, and load in conducting these analyses.
VER production forecasts	Vendor supplied but could be developed using weather service models	Significant research and development ha~~s~~ve been done in the last decade to create and improve VER/DER forecasts for use in power system operations and analysis, including ERAs. Hourly or sub-hourly profiles of actual production from VERs can be scaled up or down to fit specific scenarios in an ERA.

~~Emissions Constraints on Generator Operation~~

Emissions Constraints on Generator Operation

Modeling constraints on generator operation in a near-term ERA can be done using the characteristics of the existing fleet, adjusting for any new resources that are expected to become available during the ~~time~~ period being studied.

The following ~~information~~table is useful for modeling emissions constraints on generator operation in a near-term ERA~~.~~:

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Table 2.4: Information Useful for Modeling Emissions Constraints on Generator Operation in a Near-Term ERA		
Data	**Potential Sources**	**Notes/Additional Considerations**
Output limitations by specific generators	Generator surveys	For short-term assessments, generator surveys would be the best source of emissions limitation information. Generator ~~owner/operators~~Owner/Operators should be ~~well~~ aware of what their limits would be and the plans to abide by those limits.
Output limitations for a set of generators	Generator surveys	Each ~~generator owner/operator~~Generator Owner/Operator may know their own operational information, but when determining when a collection of generators will reach a limit would require gathering information that each owner/operator has but not as a collective. The analys~~ist~~t performing the ERA would be the centralized collection point of the information required to accurately model the limit.

Outage Modeling

Near-term ERAs have the benefit of scheduled maintenance plans. These plans are usually set months in advance and give the analyst an indication of the ~~planned~~ work expected to occur, leaving only unplanned outages as a major source of uncertainty.

The following ~~information~~table is useful for modeling energy supply outages in a near-term ERA~~.~~:

Table 2.5: Information Useful for Modeling Energy Supply Outages in a Near-Term ERA		
Data	**Potential Sources**	**Notes/Additional Considerations**
Planned ~~O~~outages and ~~M~~maintenance	Maintenance schedules and outage coordination tools	ERAs can use planned maintenance as an input but can also be used to advise the shifting of planned maintenance to minimize energy-related risks.

Distributed Energy Resources

Most ~~regional~~area operators do not have real-time telemetry of DER within their footprint but may be able to work with their local energy commissions or local utility operators to get installed DER capacity at a suitably granular level, such as substation~~, zip~~ or ZIP code, ~~etc.,~~ as well as other useful information (e.g~~.~~., tilt, direction for solar panels). Creating time series data of DER production for near-term ERAs can be challenging. The results of a near-term ERA can show a high degree of uncertainty when DER installation exceeds a certain point (e.g., a few thousand MW~~,~~ for a small- to medium-demand ~~region~~area; more for larger ~~regions~~areas). The point where the amount of DER has significant impact on the power system is not clearly standardized and ~~must~~should be understood and defined by the analyst performing the ERA. A lack of visibility and ability to benchmark the DER forecast against actual production creates an additional level of complexity, and the analyst may need to rely on a variety of scenarios to determine the probability of deficiencies.

The following ~~information~~table is useful for modeling DERs in a near-term ERA~~.~~:

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Table 2.6: Information Useful for Modeling Distributed Energy Resources in a Near-Term ERA		
Data	**Potential Sources**	**Notes/Additional Considerations**
Installation data	Electric utility companies (i.e., Distribution Providers, or DPs), production incentive administrators	DERs are likely to be required to coordinate with the distribution ~~system operator~~System Operator before interconnecting. Additionally, any DER that is participating in a ~~sort of~~ renewable energy credit program will likely need to register with and provide production information to a program administrator.
Forecasted DER production	Vendor supplied but could be developed using weather service models	Significant research and development ha~~s~~ve been done in the last decade to create and improve DER/VER forecasts for use in power system operations and analysis, including ERAs.
Historical performance, observations of net load	Historical patterns of demand compared to a longer history	Comparing a similar-day demand curve from a more recent year to one from a year prior can give a sense of the difference in DER that was installed year-over-year.
Estimated performance of DERs	Based on limited samples of a subset of the DER type	Modern DERs may have advanced measurement devices that could be made available through vendor aggregation services. Smaller, evenly ~~-~~ distributed samples could be used to scale to the full amount. Testing should be done to validate whether the conceived process is accurate.

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Demand

In a near-term ERA, demand profiles should be well understood and can be forecasted accurately, reducing the need to make assumptions. The ever-changing demand profiles that are discussed in other chapters of this technical reference document ~~don't~~do not really change overnight, and the recent past should be very indicative of the near future, adjusted for weather.

The following ~~information~~table is useful for modeling demand in a near-term ERA~~.~~:

Table 2.7: Information Useful for Modeling Demand in a Near-Term ERA

Data	Potential Sources	Notes/Additional Considerations
Weather forecasts or projections	Numerical weather prediction (NWP) models, weather forecast vendors	Weather information is the primary variable input to demand forecasts. Near-term assessments can use weather forecasts.
Actual demand forecasts or projections	Load forecast models using weather information as an input	Historical weather and demand may be useful for projecting future conditions~~,~~; however, caution should be exercised to ensure that interrelated parameters remain interrelated. Decoupling weather and load could result in implausible outcomes.
Demand ~~R~~-response capabilities	Electric utilities or other organizations (e.g., demand-response aggregation service providers) that manage participation in demand-response programs	

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Electric Storage

Primary considerations for electric storage when performing a near-term ERA are that electric storage resources are less than 100% efficient, and modeling how the expected state of charge (i.e., how much energy is stored) of the resource may impact the operation of the storage facility. In the near-term ERA, electric storage may be used to provide ramping flexibility as solar generation drops off as the sun sets. Understanding of the state of charge facilitates this critical service. ~~Additionally, specific~~Specific storage inputs are needed to perform an ERA.

The following ~~information~~table is useful for modeling electric storage in a near-term ERA~~.~~:

Table 2.8: Information Useful for Modeling Electric Storage in a Near-Term ERA

Data	**Potential Sources**	**Notes/Additional Considerations**
State of ~~C~~charge	Resource owner	Additional considerations may be given to state of charge in a near-term ERA that reflect the recent operation of the electric storage facility.
Ramp Rate (~~Up/Down~~up/down) MW/minutes	Resource owner	Rate that the electric storage resource can discharge or absorb energy when electric demand or supply changes.
Cell ~~B~~balancing	Resource owner	This describes the change-out of cells within a storage device. Specifically, this would apply to faulty cells that could limit the capability of a battery plant. Balancing takes a few days to accomplish once cells are replaced.
Project-specific incentives (e.g., ~~Investment Tax Credits~~investment tax credits)	Resource owner	Investment tax credits, either ~~P~~production or ~~I~~investment, may indicate how the electric storage resource will run.
Cell temperature limits[34]	Resource owner	This is the ambient temperature at the storage facility. There are high- and low-temperature requirements for charging and discharging batteries at a normal rate. Outside that band, you may reduce the rate of charge, potentially to 0.

[34] Lithium-ion battery: Charge temperature at 32°F to 113°F; Discharge temperature at -4°F to 140°F
Lead acid battery: Charge temperature at -4°F to 122°F; Discharge temperature at -4°F to 122°F
Nickel-based battery: Charge temperature at 32°F to 113°F; Discharge temperature at -4°F to 149°F

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Chapter 3: Inputs to Consider When Performing a Seasonal ERA

A seasonal ERA ~~looks at~~considers an upcoming season, focusing on energy-related risks that are exposed in that season. The term *season* is used more as a generic term that means a time period ~~of time~~ longer than a few weeks~~,~~ but not a full year. Seasons, and their associated risks, are ~~regionally~~ unique across areas and ~~don't~~do not necessarily fit into the classic definitions. The analyst should have a good idea of what seasons are experienced by the ~~region~~area where they are performing a seasonal ERA and should apply that definition to the input assumptions. Partial seasons (e.g., three weeks of a winter period) may offer a vantage point that captures the representative risks of a full season without requiring the overhead of performing three-month-long assessments. Winter and summer peak periods are traditionally the focal point of seasonal capacity assessments, ~~however~~but there may be unexpected risks in ~~off-peak~~Off-Peak times (including ~~off-peak~~Off-Peak hours within days) that would be identified by an ERA and ~~shouldn't~~should not be overlooked. Considerations for inputs to a seasonal ERA are described below.

Supply

Modeling supply in a seasonal ERA relies on an analyst gathering information from an existing fleet of generators plus any generators that are expected to be added prior to the start of the season being assessed. This information is usually fairly static for a single season and can be included in registration data or gathered through generator surveys. VER production assumptions may be necessary for BAs with high levels of VERs. These BAs will use that information to make more informed decisions on required VERs that would be committed on any given day.

Stored Fuels

Stored fuel information in a seasonal ERA is likely ~~to be~~ similar to the current inventories plus adjustments for replenishment and usage plans between the time that the ERA is performed~~,~~ and the period being assessed. However, there may be season-specific constraints that affect these factors for the study period in a seasonal ERA.

The following ~~information~~table is useful for modeling stored fuels in a seasonal ERA:

Table 3.1: Information Useful for Modeling Stored Fuels in a Seasonal ERA		
Data	**Potential Sources**	**Notes/Additional Considerations**
Current inventory, inventory management strategies, and replenishment assumptions	Generator surveys, formal or informal generator outreach, assumptions based on historical performance, or annually variable conditions specific to the resource type	Replenishment is key to modeling inventory at any point during the study period. Replenishment restrictions are also an important aspect of an ERA. Performance expectations for hydroelectric resources may be informed by seasonal runoff conditions. Generator surveys can still be useful just prior to a specific season~~,~~; however, this information may still introduce some uncertainty at the time that the ERA is being performed. Communication with the entities deciding on replenishment strategies would result in more accurate assumptions for starting inventories.

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Table 3.1: Information Useful for Modeling Stored Fuels in a Seasonal ERA

Data	Potential Sources	Notes/Additional Considerations
~~Regional availability~~Availability of overall fuel storage	U.S. Energy Information Administration (EIA) reports	The U.S. EIA reports weekly inventories for five Petroleum Administration for Defense Districts (PADD). This can be an indicator of whether ~~or not~~ fuel may be available for generator fuel replenishment.
Shipping constraints	Industry news reports	Seasonal ERAs could be impacted by ~~current~~ weather patterns and world events that cause supply chain disruptions~~. This includes~~, including port congestion, international conflict, shipping embargoes, and confiscation.

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Just-in-Time Fuels

Modeling just-in-time fuels in a seasonal ERA relies on the existing fuel supply infrastructure and assumptions of the operation of those facilities as well as expected changes (e.g., expansion or planned outages) prior to the start of the upcoming season.

Natural Gas

Natural gas supply infrastructure is a fairly predictable input to ~~an~~a seasonal ERA. Pipeline expansion and demand growth are usually planned ~~out~~ far in advance and are implemented prior to peak-usage seasons. Planned outages of interstate natural gas pipelines are posted publicly.

The following ~~information~~table is useful for modeling natural gas supply in a seasonal ERA~~.~~:

Table 3.2: Information Useful for Modeling Natural Gas Supply in a Seasonal ERA

Data	Potential Sources	Notes/Additional Considerations
Pipeline, production, import, and export expansion projects	Pipeline websites, filings with state and federal agencies, advertising for open seasons	This includes new pipelines, compressor enhancements and expansions, and LNG import and export projects that will increase or reduce the amount of natural gas that is available.
Pipeline Planned Service Outages	EBB	Interstate natural gas pipelines are required[35] by FERC to post maintenance plans on their public-facing EBBs.
Natural gas commodity futures pricing	Several internet sources that monitor futures pricing	Futures pricing can give a sense of what pricing pressures the commodity is facing in the coming year(s). It may not be a fully accurate picture of what the pricing will be~~,~~ but gives an analyst some direction for a starting point for a seasonal ERA.

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[35] See U.S. Code of Federal Regulations Chapter I, Subchapter I, Part 284, Subpart A, § 284.13.(d).(1) - https://www.ecfr.gov/current/title-18/chapter-I/subchapter-I/part-284/subpart-A/section-284.13

Variable Energy Resources

~~Modeling VERs in a seasonal ERA can be done using the~~The existing fleet with minor adjustments for outages and expected expansions can be used to model VERs in a seasonal ERA. The variability presents an unknown risk that may require analysis from multiple perspectives. Multiple profiles should be considered because times of low production from VERs could also coincide with high demand or unplanned outages of other resources.

The following ~~information is~~table useful for modeling VERs in a seasonal ERA~~.~~:

Table 3.3: Information Useful for Modeling Variable Energy Resources in a Seasonal ERA

Data	Potential Sources	Notes/Additional Considerations
Weather outlook	NOAA (for the United States), Environment and Climate Change Canada, ~~H~~historical observations, ~~W~~weather models	Seasonal outlooks ~~from NOAA~~ can provide a direction on which historical observations to select when performing a seasonal ERA.
VER production assumptions	Historical observations adjusted for weather outlooks	Historical observations can set a starting point for what can be expected in upcoming seasons. Th~~at~~is would need to be adjusted for other known factors, such as drought conditions or temperature expectations.
New VER installations	Installation queues	New VERs installed between the time that an ERA is performed, and the start of the upcoming season can be large enough to impact the outcome and should be included as accurately as possible. ~~On the~~The seasonal horizon~~, there~~ should ~~be some~~have more certainty on what will be commissioned or not.

Emissions Constraints on Generator Operation

Modeling constraints on generator operation in a seasonal ERA can be done using the characteristics of the existing fleet, adjusting for any new resources that are expected to become available during the ~~time~~study period~~ being studied~~.

The following ~~information is useful~~table for modeling emissions constraints on generator operation in a seasonal ERA~~.~~:

Table 3.4: Information Useful for Modeling Emissions Constraints on Generator Operation in a Seasonal ERA

Data	Potential Sources	Notes/Additional Considerations
Output limitations by specific generators	Generator surveys	For short-term assessments, generator surveys would be the best source of emissions limitation information. Generator ~~owner/operators~~Owner/Operators should be ~~well~~ aware of what their limits would be and the plans to abide by those limits.

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Outage Modeling

~~Outage Modeling~~

When performing a seasonal ERA, the expectation for outages is somewhat clearer than a planning ERA, but there is more uncertainty than in the near ~~-~~term. Well-developed outage coordination processes have provisions to schedule and coordinate generation and transmission outages as far out in the future as possible, which would likely include the time period being addressed by seasonal ERAs.

The following ~~information~~table is useful for modeling energy supply outages in seasonal ERAs~~.~~:

Table 3.5: Information Useful for Modeling Energy Supply Outages in a Seasonal ERA

Data	Potential Sources	Notes/Additional Considerations
Weather-dependent outage rates	Surveys, registration information, assumptions based on historic performance	GADS will provide average outage rates. The information from GADS can be combined with weather information to derive correlations with weather conditions that could be modeled in an ERA.
Outage mechanisms	NERC GADS, operator logs	Outage mechanisms can be used to determine outage duration and impact.
Planned outage schedules	Outage coordination records	Planned outages are a good start for modeling the unavailability of resources, but considerations should be given to the accuracy of plans. Not every outage goes according to plan, and they may finish early or overrun.

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Distributed Energy Resources

Seasonal ERAs would depend more on historical performance from DERs while assuming that the resources are distributed similarly to how they are when the ERA is being developed and performed. ~~There may be some~~Some scaling ~~that is~~may be needed to account for some rapid new development.

The following ~~information~~table is useful for modeling DERs in a seasonal ERA~~.~~:

Table 3.6: Information Useful for Modeling Distributed Energy Resources in a Seasonal ERA

Data	Potential Source	Notes/Additional Considerations
Installation data coupled with expansion assumptions	Electric utility companies (i.e., ~~Distribution Providers, or~~ DPs), production incentive administrators	~~Similar to~~Like the information needed for a near-term ERA, DERs are likely to coordinate with distribution ~~system operators, giving~~System Operators, providing a path to make information available. Future information may also be available through those same channels~~,~~ but may also need to be inferred based on ~~regional~~ trends, growth forecasts, or legislative goals.
Historical DER production data	Operations data, assumptions based on past performance	The analyst may choose to model DER explicitly as a supply resource or as a demand reduction. Modeling the DER separately and incorporating it to the resource mix will allow the analyst to vary the assumptions without impacting other facets of the ERA.

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Demand

When considering demand on a long enough time horizon, forecasts are unavailable or unreliable. To supplement forecasts, assumptions ~~must~~should be made based on historical demand and projected load growth or contraction~~,~~ based on factors, such as climate change and economic factors.

The following ~~information~~table is useful for modeling demand in a seasonal ERA~~.~~:

Table 3.7: Information Useful for Modeling Demand in a Seasonal ERA		
Data	**Potential Sources**	**Notes/Additional Considerations**
Weather forecasts or projections	Historical data, seasonal weather projections (e.g., the National Weather Service, Climate Prediction Center outlooks~~[36]~~~~)~~)[37], Environment and Climate Change Canada,	Weather information is the primary variable input to demand forecasts. Near-term assessments can use weather forecasts. Longer-term assessments, including ~~S~~seasonal assessments, typically require assumptions or projections of weather due to forecast accuracy.
Actual demand forecasts or projections	Load forecast models using weather information as an input	Historical weather and demand may be useful for projecting future conditions~~,~~; however, caution should be exercised to ensure that interrelated parameters remain interrelated. Decoupling weather and load could result in implausible outcomes.
DER production forecasts or projections	Weather-based prediction models using the assumed weather as an input, which are available from a variety of vendors	This may or may not be considered in the demand side of the energy balance equation. Correlation with modeled weather conditions should be considered.
Demand-response capabilities and expectations	Electric utilities or other organizations (e.g., demand-response aggregation service providers) that manage participation in demand-response programs	Not all demand response operates at the command of the entity responsible for dispatching resources.

Electric Storage

Charging and discharging patterns for electric storage devices may change depending on the season being studied. During summer ~~seasons~~, electric storage may be used to store excess solar generation to be used during nighttime hours while ~~during winter seasons~~ storage may be used to inject energy into the grid during periods of high demand due to extreme cold~~.~~ during winter. Additionally, storage devices may also be providing ~~ancillary services~~Ancillary Services and, as such, would be charging and discharging when required by the ~~system operator~~System Operator.

The following ~~information~~table is useful for modeling electric storage in a seasonal ERA~~.~~:

~~[36] https://www.cpc.ncep.noaa.gov/products/predictions/long_range/~~
[37] https://www.cpc.ncep.noaa.gov/products/predictions/long_range/

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Table 3.8: Information Useful for Modeling Electric Storage in a Seasonal ERA		
Data	**Potential Sources**	**Notes/Additional Considerations**
Cell temperature limits[38]	Resource owner	This is the ambient temperature at the storage facility. There are high- and low-temperature requirements for charging and discharging batteries at a normal rate. Outside that band, you may reduce the rate of charge, potentially to 0.
Ramp Rate (~~Up/Down~~up/down) MW/minutes	Resource owner	Rate that the electric storage resource can discharge or absorb energy when electric demand or supply changes.
Project-specific incentives (e.g., ~~Investment Tax Credits~~investment tax credits)	Resource owner	Investment tax credits, either ~~P~~production or ~~I~~investment, may indicate how the electric storage resource will run.

Transmission

Transmission constraints in a seasonal ERA can be modeled using the existing system with any anticipated changes that would occur before the time being studied, including planned outages and new construction.

[38] Typically, today's battery technologies are constrained to the following temperature bands:
Lithium-ion battery: Charge temperature at 32°F to 113°F; Discharge temperature at -4°F to 140°F;
Lead acid battery: Charge temperature at -4°F to 122°F; Discharge temperature at -4°F to 122°F;
Nickel-based battery: Charge temperature at 32°F to 113°F; Discharge temperature at -4°F to 149°F

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Chapter 4: Inputs to Consider When Performing a Planning ERA

Planning ERAs are generally performed in the 1-to-10-year time horizon, beyond Operations Planning. The planning horizon offers more uncertainty~~,~~ but also more options to explore for correcting or minimizing shortfalls. The analyst performing a planning ERA will likely need to look at a wider array of possible inputs~~ which will result~~, resulting in an even wider array of outputs. The methods will be up to the analyst performing the ERA. Considerations for inputs to a planning ERA are described below and would generally apply to any type of analysis.

Supply

Modeling supply in a planning ERA leans heavily on assumptions due to the volatility of future resource mix possibilities. Variability in new construction, retirements, legislative goals, and possible emissions limitations drive a need to assess a variety of ~~different~~ outcomes.

Stored Fuels

Electrification of heating~~, in some regions,~~ is expected to replace oil, natural gas, and other unabated carbon-emitting combustible fuels over time with vast ~~disparity~~differences between state goals~~. That would shift~~, shifting competing demands for fuel into additional electric demand. ~~As a side note, electrification~~Electrification may not necessarily eliminate the need for combustible fuels~~, it may~~ but just move the combustion from inside each individual building (i.e., at the furnace or boiler) to centralized generating stations. Modeling long-term impacts of electrification of heating ~~on~~and fuel transportation networks will depend on the types of fuels being replaced~~,~~ and~~ will~~ be driven by policy, economics, and technical complications.

The following ~~information~~table is useful for modeling stored fuels in a planning ERA.

Table 4.1: Information Useful for Modeling Stored Fuels in a Planning ERA		
Data	**Potential Sources**	**Notes/Additional Considerations**
Inventory management and replenishment assumptions	Assumptions based on historical performance and/or commodity market evaluations.	Replenishment is key to modeling inventory at any point during the study period. Replenishment restrictions are also an important aspect of an ERA.
~~Regional availability~~Availability of overall fuel storage	EIA reports	The U.S. ~~Energy Information Administration~~EIA reports weekly inventories for five ~~Petroleum Administration for Defense Districts (PADD).~~PADDs. Trending PADD inventories over time may provide insight into how replenishment may occur over longer periods of time.
Intra-annual hydro availability	Historical drought or high-runoff conditions	~~Drought~~Since drought and high-runoff hydro forecasts may not cover an extensive enough period to depend on for a planning ERA, ~~so~~ assumptions would need to be made based on historical information.

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Just-in-Time Fuels

Natural Gas

Modeling natural gas availability in a planning ERA ~~potentially requires~~may require more extensive research of infrastructure projects and assumptions for competing demands for fuel. Natural gas pipeline and production expansion tend to require long lead times and have tended to become more uncertain in recent years.

The following ~~information~~table is useful for modeling natural gas supply in a planning ERA:

Table 4.2: Information Useful for Modeling Natural Gas Supply in a Planning ERA

Data	Potential Sources	Notes/Additional Considerations
Pipeline, production, import, and export expansion projects	Pipeline websites, filings with state and federal agencies, advertising for open seasons	This includes new pipelines, compressor enhancements and expansions, and LNG import and export projects that will increase or reduce the amount of natural gas that is available.

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Variable Energy Resources

Modeling VERs in a planning ERA requires a set of assumptions that depend on several factors. First, the expansion of installed facilities drives the magnitude of available energy. Profitability of VERs is the primary consideration, which is a function of the cost of materials, labor, shipping, and interconnecting to the transmission system. With that information, assumptions can be made on the scaling factors to be used.

The following ~~information~~table is useful for modeling VERs in a planning ERA~~.~~:

Table 4.3: Information Useful for Modeling Variable Energy Resources in a Planning ERA

Data	Potential Sources	Notes/Additional Considerations
Expected installed resources	Interconnection queue, ~~E~~economic analysis and forecasts	
Renewable energy goals	State legislature dockets	These goals drive the rate at which renewable (and likely variable energy) resources are built, including target years and amounts.
Production assumptions	Historical observations, weather models, climate trends	Profiling the expanded fleet across some historical dataset, adjusted for expected trends in climate, gives an ERA plausible inputs.

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Emissions Constraints on Generator Operation

~~**Emissions Constraints on Generator Operation**~~

Modeling constraints on generator operation in a planning ERA can be done partially by using the characteristics of the existing fleet but also requires an evaluation of planned new construction and retirements. Planning ERAs that go beyond the next few years may require the analyst to make assumptions on state or national policies, retirements, and new construction where final decisions have not yet been made.

The following ~~information~~table is useful for modeling emissions constraints on generator operations in a planning ERA~~.~~:

Table 4.4: Information Useful for Modeling Emissions Constraints on Generator Operation in a Planning ERA		
Data	**Potential Sources**	**Notes/Additional Considerations**
Output limitations by specific generators	Generator surveys	For short-term assessments, generator surveys would be the best source of emissions limitation information. Generator ~~owner/operators~~Owner/Operators should be ~~well~~ aware of what their limits would be and the plans to abide by those limits.
Trends in individual state carbon emissions goals	State government or public utiliti~~es~~y commission (PUC) websites	When assessing the probability of long-term retirements and new construction, emissions goals may provide insight to the analysts to decide whether ~~or not~~ a specific resource or a subset of the entire fleet may or may not be viable under the expected rules.

Outage Modeling

While past performance is not a perfect indicator for future performance, it can serve as a guide for the analyst to make assumptions about generation outages.

The following ~~information~~table is useful for modeling energy supply outages in a planning ERA~~.~~:

Table 4.4: Information Useful for Modeling Energy Supply Outages in a Planning ERA		
Data	**Potential Sources**	**Notes/Additional Considerations**
Forced~~ Outage Rates~~ outage rates	NERC GADS, assumptions based on historical performance	NERC requires outages and reductions to be reported with associated cause codes and makes that information available to registered entities. Alternatively, analysts can observe historical unplanned outage information to determine similar assumptions.
Weather-dependent outage rates	Surveys, registration information, assumptions based on historical performance	GADS will provide average outage rates. The information from GADS can be combined with weather information to derive correlations with weather conditions that could be modeled in an ERA.

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Table 4.4: Information Useful for Modeling Energy Supply Outages in a Planning ERA		
Data	**Potential Sources**	**Notes/Additional Considerations**
Assumed outage rates for newly constructed supply resources	Fleet averages using existing resources, when possible	New construction using existing plans means that there is likely a similar resource somewhere that has some performance data that can be used to estimate the performance of a new resource.
Outage mechanisms	NERC GADS, operator logs	Outage mechanisms can be used to determine outage duration and impact.

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Distributed Energy Resources

In a planning ERA, DERs are modeled similarly to a seasonal ERA~~,~~ but with more uncertainty in installed capacity. Past a certain point, the assumptions being made would overshadow the fact that the supply resources are connected in such a way that they would be less visible to the operator. There is also some uncertainty in whether each resource, once finally built, would even be distributed or not. That uncertainty supports a method of modeling DERs that can accommodate either outcome.

The following ~~information~~table is useful for modeling DERs in a planning ERA~~.~~:

Table 4.5: Information Useful for Modeling Distributed Energy Resources in a Planning ERA		
Data	**Potential Sources**	**Notes/Additional Considerations**
Growth estimates, renewable energy goals	State government and PUCs, directly or via their websites	

Demand

Demand is expected to become ~~even~~ more complicated than ever in the coming years~~ than it ever has been. Modern~~. Today's demand has components of actual demand~~,~~ (e.g., lighting, heating and air conditioning, appliances, industrial demand), varying types of demand response (including the impact of time-of-use rates~~,~~), and distributed generation that is considered load-reducing. Future demand will change throughout the evolution to decarbonize the power system.

~~The following information is useful for modeling demand in a planning ERA.~~
Further expected changes

~~Table 4.6: Information Useful for Modeling Demand in a Planning ERA~~		
~~**Data**~~	~~**Potential Sources**~~	~~**Notes/Additional Considerations**~~
~~Weather forecasts or projections~~	~~Historical data, adjusted using climate models~~	~~Weather information is one of the primary inputs to longer term demand forecasts. Longer term assessments typically require assumptions or projections of weather due to forecast accuracy concerns.~~

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~~Table 4.6: Information Useful for Modeling Demand in a Planning ERA~~		
~~**Data**~~	~~**Potential Sources**~~	~~**Notes/Additional Considerations**~~
~~Actual demand projections~~	~~Historical actual demand modified by the expected impact of demand changes,~~ ~~load forecast models using weather information as an input~~	~~Historical weather and demand may be useful for projecting future conditions, however caution should be exercised to ensure that interrelated parameters remain interrelated. Decoupling weather and load could result in implausible outcomes.~~ ~~Performing an energy assessment still requires a profiled demand curve over a period of time. Most legacy long-term forecasts produce a set of seasonal peak values.~~
~~Projected changes in actual demand magnitude and profile (e.g., load growth)~~	~~Analysis of economic factors, governmental policy, and technical considerations~~	~~This should include the impact on demand magnitude as well as changes in demand profiles. This includes energy efficiency and electrification. Electrification of heat is a function of local temperatures. Electrification of transportation will be more linked to commute distances and time-of-day.~~
~~DER production forecasts or projections~~	~~Historical production data, scaled to future capability~~	~~This may or may not be considered in the demand side of the energy balance equation.~~ ~~Correlation with modeled weather conditions should be considered.~~
~~Demand Response capabilities~~	~~Electric utilities or other organizations (e.g., demand response aggregation service providers) that manage participation in demand response programs.~~	

~~As we look forward there are further expected changes that~~ will continue to transform the actual demand profiles and the need for electric energy. Electrification of heating and transportation will likely shift demand curves away from traditional energy supplies of oil, natural gas, and gasoline to electricity. The shifts will result in net load profiles

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that, although not necessarily less predictable from a day-to-day point of view, are more difficult to predict through the transition when looking several years into the future and making assumptions. ERAs require modeling of multiple hours ~~for a period of time~~ and ~~must~~should consider the expected changes brought about by changes in demand.

The following table is useful for modeling demand in a planning ERA:

Table ~~4.~~6: Information Useful for Modeling Demand in a Planning ERA		
Data	**Potential Sources**	**Notes/Additional Considerations**
Weather forecasts or projections	Historical data, adjusted using climate models	Weather information is one of the primary inputs to longer-term demand forecasts. Longer-term assessments typically require assumptions or projections of weather due to forecast accuracy concerns.
Actual demand projections	Historical actual demand modified by the expected impact of demand changes, load forecast models using weather information as an input	Historical weather and demand may be useful for projecting future conditions; however, caution should be exercised to ensure that interrelated parameters remain interrelated. Decoupling weather and load could result in implausible outcomes. Performing an energy assessment still requires a profiled demand curve over a period of time. Most legacy long-term forecasts produce a set of seasonal peak values.
Projected changes in actual demand magnitude and profile (e.g., load growth)	Analysis of economic factors, governmental policy, and technical considerations	This should include the impact on demand magnitude as well as changes in demand profiles. This includes energy efficiency and electrification. Electrification of heat is a function of local temperatures. Electrification of transportation will be more linked to commute distances and time of day.
DER production forecasts or projections	Historical production data, scaled to future capability	This may or may not be considered in the demand side of the energy balance equation. Correlation with modeled weather conditions should be considered.
Demand-response capabilities	Electric utilities or other organizations (e.g., demand-response aggregation service providers) that manage participation in demand-response programs.	

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Electric Storage

As ~~was~~ noted in Chapter 1, when performing a planning ERA, it is important to know the source that will charge or fill the electric storage resource. It is expected that electric storage will become a critical resource for maintaining system balance as coal- and natural gas-fired generation retire and are replaced by VERs. Knowing how the electric storage resource is charged/filled, either a direct resource or off the grid, increases the value of the ERA. Information that would be useful for performing a planning ERA is similar to near-term and seasonal ERAs~~,~~ but with more uncertainty.

Transmission

In a planning ERA, transmission can be significantly more variable than the near-term or ~~S~~seasonal ERAs. ~~In this~~This time horizon~~, there is~~ presents an opportunity to ~~buildout~~build out or upgrade the transmission systems to relieve constraints or for other purposes.

Chapter 5: Methods

Introduction/Overview

The modeling ~~elements~~items described in the prior chapters are foundational for performing comprehensive ERAs. Many of these~~ elements~~ are also considered when performing capacity assessments with a key difference for ERAs being the finite amount of energy available from fuel and energy-limited resources. For example, a hydroelectric power plant with a capacity of 100 MW can only generate a total energy output~~,~~ over time~~,~~ equivalent to the amount of water in storage, and energy generated in one hour is not available to be used in a later period. Capacity assessments historically would count this hydro plant as having 100 MW available in every hour. Most modern capacity assessments instead attempt to account for energy limitations with various probabilistic methods that derate nominal capacity toward~~s~~ an expectation at the time of peak hour or greatest risk. An energy assessment constrains the total energy available, not the capacity. This is achieved through an explicit modeling and enforcing of all energy constraints on the system through the full study horizon.

An additional element of an energy assessment is identifying~~,~~ not only that ~~a sufficient amount of~~enough energy is available to meet expected demand for all hours of the study period~~,~~ but also that it is available to ensure that necessary essential reliability service requirements are met~~;~~, primarily ramping capability and reserves. As more variable generation is added to the system, the need for additional flexible or ramping resources ~~must~~should be evaluated. Ramping resources that can quickly raise or lower their output are essential to the ~~reliable operation~~Reliable Operation of the BPS. Certain demand also provides ramping capability, and an understanding of how these demand-side resources operate is essential for modeling and performing energy assessments.

Many methods can be used to perform an ERA and may require the use of both probabilistic and deterministic models to identify when the system may be at risk of energy shortages. Probabilistic ~~versus~~vs. deterministic methods are defined in Volume 1. ~~Put succinctly~~Succinctly, the probabilistic method considers at a high level many possible combinations of supply and demand~~,~~ to screen for potential reliability risks to the BPS. This method can be used to identify periods and conditions under which the system's energy supply and demand are stressed and could lead to unserved load.

A deterministic approach involves modeling one set of events for a given scenario. Running certain iterations of the supply and demand conditions identified in the probabilistic model through a deterministic model allows for a detailed analysis in which increased operational detail is modeled for the identified scenarios. Such a detailed analysis may not be computationally feasible in a probabilistic analysis. As such, deterministic and probabilistic approaches can be used in conjunction with one another to identify and explore high-risk scenarios in greater depth. ~~There are many~~Many different modeling tools ~~that~~ can be used to perform energy assessments, ~~however,~~but all fall into a handful of tool families with cross-family integration leading to more robust results.

Tool Families Overview

~~The following~~This section describes the families of tools that ~~are available to~~ an analyst ~~performing~~can use to perform an ~~energy reliability assessment.~~ERA. The subsections are not meant to be comprehensive~~,~~ but to provide the reader with a high-level understanding of the different tool families. By reading the materials presented, the reader can hope to learn at a high level~~: (1)~~ what each family of tools can do~~; (2)~~, what functionality each family has (i.e., the kinds of questions each family can answer~~); (3)~~), what each family does well~~; (4)~~, what each ~~doesn't~~ family does not do~~,~~ or does less than optimally~~; (5)~~, what level of system topology detail is captured~~; (6)~~, what time horizon each family can study and how time is represented~~;~~, and ~~(7)~~ where to find models of each family type. The ~~reader will~~section does not ~~find~~provide recommendations for or names of any specific tools within the described families~~, however, the~~., The reader should be cognizant of any regulatory requirements that require the provision of filings using a specified file format ~~which~~that may be vendor or program specific~~,~~ (e.g.~~. the Federal Energy Regulatory Commission~~., FERC requires Form 715 power flow cases to be filed in one of six specific formats~~.~~).[39]

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The tools described below can be used separately for some assessments but are recommended to be used in combination with each other (or with other tools that may not be described) to set up the assumptions and initial conditions needed to perform ERAs. The analyst will need to evaluate the value of each tool and employ sound judg~~e~~ment in selecting the proper tools. In the end, a reasonable set of initial conditions is subjective and requires the analyst to understand what each individual component means.

Resource Adequacy

Resource ~~a~~Adequacy (RA) tools are the core set of tools ~~that are utilized~~ used to perform an ERA.[40]~~.~~ They allow for resource capacity and energy ~~a~~Adequacy to be evaluated probabilistically~~,~~ for a range of possible scenarios. Risk metrics, such as loss of load expectation (LOLE) or expected unserved energy (EUE~~)~~), are calculated using an RA tool.

Historically, many ~~resource adequacy~~RA assessments used a convolution algorithm, ~~which is~~ an analytical method that calculates~~ a~~ total available capacity distribution by convolving together the distributions associated with available capacity for each unit in the system. In this method, each time interval is assessed independently of all others, meaning that the intertemporal nature of power systems operations is ignored.

Most ~~resource adequacy~~RA assessments and tools today instead use a Monte Carlo algorithm, which simulates hundreds or thousands of ~~different~~ scenarios using different outage ~~patterns~~ and/or weather patterns to understand the likelihood of load shedding. There are further nuances across Monte Carlo algorithms, with some algorithms considering chronological system operations and others considering every time interval independently. ~~Additionally, some~~Some methods use a heuristics-based method, while others use a dispatch-based method. A heuristics-based method is simpler and less computationally intensive than a dispatch-based method but may not fully capture all energy constraints on the system. A dispatch-based method provides the most accurate representation of power system operations within the ~~resource adequacy~~RA framework. Indeed, highly detailed dispatch-based Monte Carlo approaches closely resemble ~~PCM~~production cost modeling tools.

RA models can answer or provide guidance to ~~answer the following question:~~

- ~~Does~~determine if the system meets the required reliability level while considering outage probabilities, reserve margins, and load and weather uncertainty~~?~~. Some of items for consideration when applying an RA model to an ERA are described in the following table.

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[39] Part 2: Power Flow Base Cases https://www.ferc.gov/industries-data/electric/electric-industry-forms/form-no-715-annual-transmission-planning-and-evaluation-report-instructions

[40] Further information on RA tools can be found in the EPRI "Resource Adequacy Assessment Tool Guide: EPRI Resource Adequacy Assessment Framework" https://www.epri.com/research/products/000000003002027832

Table 5.1: Considerations for Applying Resource Adequacy Models to ERAs	
Consideration	**Description**
Availability of Stored Fuel	Certain RA models can be used to model the availability of stored fuel by considering inventory levels and replenishment rates. For example, for thermal power plants (coal, natural gas), the model should track fuel inventory levels and factor in delivery schedules to ensure that the plants have sufficient fuel to operate when needed to meet demand. The cost associated with fuel procurement and storage may also be included in the model''s calculations. ~~Note that this~~This may not be possible in all RA tools, and ~~that~~ such an analysis comes at a computational cost ~~which must~~that should be balanced against other modeling decisions within the probabilistic framework.
Just-in-Time Fuel Modeling	RA models may incorporate fuel consumption and delivery schedule forecasts. These forecasts, created externally to the RA model framework, may be based on historical data, demand projections, and market conditions. Just-in-time fuel modeling ensures that power plants receive fuel deliveries precisely when needed to optimize operational efficiency and minimize costs.
Variable Energy Resources	For VERs like wind and solar, RA models incorporate probabilistic forecasting methods to consider a range of possible generation outputs based on weather forecasts, historical data, and geographic characteristics.
Power-Specific Limits and Emission Modeling	Certain RA models can incorporate generator operating constraints and emissions constraints in the algorithms. The level of constraints that can be incorporated will be dependent on the type of RA tool used (for example, tools with convolution algorithms and certain heuristics-based algorithms may not allow for these constraints) and the computational tractability of the model.
Energy Supply Availability	RA models can assess energy supply availability by considering the availability of generation resources, transmission capacity, and fuel availability. They analyze generation unit availabilities, scheduled maintenance outages, and unplanned downtime to determine the overall energy supply ~~a~~Adequacy in meeting demand requirements. This is done over multiple weather years and/or outage draws and is used to assess ~~resource adequacy~~RA metrics, such as ~~loss of load expectation~~LOLE and ~~expected unserved energy~~EUE.
Electric Vehicles (EV~~s~~)	RA models should include representations of ~~electric vehicles~~EVs by incorporating EV charging demand profiles, vehicle-to-grid (V2G) interactions, and the impact of EV penetration on electricity demand patterns. The model should evaluate the effects of EV charging behavior on load profiles, including the potential for EVs to provide demand-response services to the grid.
Non-Transportation Electrification	Models should consider the uptake and usage patterns associated with electrification technologies in non-transportation sectors. They should assess the impact on system ~~a~~Adequacy of the shifts in timing and seasonality of load profiles and usage patterns.

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Table 5.1: Considerations for Applying Resource Adequacy Models to ERAs

Consideration	Description
Energy ~~s~~Storage	RA models vary substantially in the amount of detail included in energy storage modeling. At ~~its~~their most detailed, RA tools allow for consideration of parameters, such as cycling limitations, charging/discharging efficiencies, and transmission constraints. Storage may be dispatched to reduce overall system costs, maximize unit profit, reduce peak or net peak load, or reduce load shortfall events; careful consideration of the dispatch objectives is required to accurately represent storage operations.
T&D Export/Import and Deliverability	Many ~~resource adequacy~~RA models leverage a zonal consideration of their systems, with major interface limits between areas enforced. Some tools have the capability for nodal modeling, although this should be carefully balanced against the computational cost of implementation. A careful analysis of important transmission and ~~s~~Stability constraints to consider should be undertaken in other analyses (such as ~~PCM~~production cost modeling and power flow models~~)~~), and this information should be reflected in RA models as appropriate.
Essential Reliability Services and other ~~ancillary needs~~Ancillary Needs	Essential reliability services, such as ~~spinning reserves, non-spinning reserves~~Spinning Reserves, Non-Spinning Reserves, and ~~frequency regulation~~Frequency Regulation, can be modeled in RA assessments either as an increase to the effective demand, or explicitly modeled. ~~It's~~It is important to consider which ~~ancillary services~~Ancillary Services would be maintained in a load-shed situation, as this distinction will affect reliability assessment results.

Production Cost

Electricity production cost models (PCM~~s~~), sometimes referred to as rank-order security-constrained models, are a family of tools that provide insights into current and potential future market and system operating conditions. They are used to understand electricity market dynamics~~, understand~~ and future operational issues, identify potential reliability challenges, and perform economic and environmental benefit assessments. In~~ particular in~~ an ERA context, they can be used to evaluate deterministic scenarios that were identified as high interest in the RA model~~,~~ or to run extreme weather scenarios that ~~weren't~~were not represented in the probabilistic analysis.

At a high level, PCMs mimic the real-time operation (commitment and dispatch) of resources, considering factors, such as power generation, transmission, and demand. PCMs can answer or provide guidance to answer various questions, including the following:

- What is the total production cost of the resources meeting electricity demand while subject to system constraints?
- What is the optimal commitment and dispatch of energy resources considering factors, such as fuel costs and deliverability, environmental regulations, and technology constraints?
- What is the impact of policy changes (e.g., carbon pricing, renewable energy mandates) on the operation and economics of the power system?

~~PCMs'~~The underlying capabilities of PCMs include ~~but are not limited to~~the following features by model:

- **Unit Commitment (UC) Models:** ~~o~~Optimize the scheduling of power generation units over a specified time horizon, typically ranging from hours to days. The unit commitment problem considers detailed generation

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operational constraints, such as minimum unit run/down times, ramp rates, start-up/shut-down durations, and energy storage volume, along with load profiles to schedule the selection of generators that may be committed to operate based on cost, deliverability, and condition in the preceding time step.

- **Economic Dispatch Models:** ~~f~~Further resolves the schedule by determining the level of production from each scheduled resource and unscheduled resources on a rolling basis to satisfy the load in each hour~~,~~ or sub-hourly period~~,~~ at least-cost while satisfying imposed constraints, such as emissions limitations or ~~ancillary service~~Ancillary Service constraints. They ensure that the total generation output matches the system load while minimizing fuel and operating expenses.

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- **Security-Constrained Unit Commitment/Economic Dispatch Models:** ~~m~~Models extend unit commitment and ~~economic dispatch~~Economic Dispatch by allowing for transmission constraints to be enforced through a nodal representation of the system. They optimize the dispatch of generating units while representing the reliability and ~~s~~Stability constraints of the power system under normal and ~~c~~Contingency conditions.

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- **Ancillary Services Market Models:** ~~e~~Extend the unit commitment and ~~economic dispatch~~Economic Dispatch models to also simulate the procurement and provision of ~~ancillary services~~Ancillary Services, such as regulation, ~~spinning reserve~~Spinning Reserve, and ~~non-spinning reserve~~Non-Spinning Reserve, to maintain grid reliability and ~~s~~Stability. They co-optimize the allocation of resources across ~~ancillary services~~Ancillary Services and energy to ensure the availability of essential reliability services in real ~~-~~time.

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- **Price Forecasting Tools:** ~~u~~Using PCM tools (unit commitment~~ / economic dispatch~~/Economic Dispatch (UC/ED)) or other approaches to predict electricity prices in wholesale energy markets based on supply and demand fundamentals, market dynamics, weather forecasts, regulatory policies, and other relevant factors. They help market participants make informed decisions regarding generation scheduling, bidding strategies, and risk management.

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PCMs historically assumed perfect foresight and are solved using a two-step security-constrained algorithm that first resolves unit commitment for each simulation time step on a rolling ~~-~~basis before determining the unit dispatch in each simulation time step. PCMs are often used to assess issues, such as the integration of large amounts of variable renewable energy (like wind and solar) into the grid and determine the need for storage or other flexibility options to balance supply and demand. They can also be used to evaluate the potential for demand-side measures (like energy efficiency or load shifting) to reduce the cost of electricity production.

PCMs can be complex and require significant computational resources and expertise to develop, calibrate, and interpret. Results from PCMs can be sensitive to input parameters and assumptions, which may introduce uncertainties in the analysis. While PCMs can simulate various scenarios, they may not fully capture the complexities of extreme events or rare system failures.

PCMs operate at different time resolutions, ranging from hourly to sub-hourly time steps~~, depending~~ based on the level of detail required. The time horizon of analysis can span from short-term operational planning to long-term investment decisions.[41]~~.~~ Unlike capacity expansion models (CEM), which use aggregated representative time slices across each year, PCMs use sequential hourly or sub-hourly time slices to generate a least-cost solution across the simulated time horizon. PCMs incorporate extensive detail on electricity generating unit operating characteristics, transmission grid topology (typically represented as a dc representation of the ac network), operating characteristics~~,~~ and constraints, and market system operations to support economic system operation and detailed planning.

[41] Although CEMs are traditionally leveraged to make long-term investment decisions, PCMs can be used as a complement to this analysis to obtain a more accurate picture of a plant's operating costs.

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The results of PCMs provide valuable information on the system and market operations by determining the effects of transmission congestion, fuel costs, generator availability, bidding behavior, and load growth on market prices. PCMs provide forecasts of hourly/sub-hourly energy prices, unit generation, revenues and fuel consumption, external market ~~t~~Transactions, transmission flows and congestion, and loss prices. In non-market-based ~~regions~~areas, these models are still applicable as they can be used to understand future operations, provision of ~~ancillary services~~Ancillary Services and transmission congestion~~ as well as~~, and other factors impacting reliability and economics.

Electricity PCMs are built on robust data structures~~. This includes~~, including the ability to enter time-based data changes at the hourly and sub-hourly granular level and detailed generator data inputs. In addition to unit capacity changes, users can enter data describing future changes to generator and transmission operational data. While PCMs rely heavily upon detailed generator specification, the level of transmission detail is determined by the user and can be aggregated into zonal representations or highly detailed nodal representations. The level of transmission detail included in a PCM simulation significantly influences the rigor of the simulation results, ~~however,~~but this comes at the expense of non-trivial increases in simulation run times as more transmission detail is included. While very detailed transmission representations can be included, PCMs do not fulfill the role of the detailed power flow operational analysis tools as they typically use a dc representation of the ac power flow (i.e~~.~~., no voltage constraints or ~~s~~Stability issues represented~~),~~) and may produce infeasible power flow results. Many different PCM options are available to an analyst performing an ERA, including both open-source and commercial options. The selection of a PCM, as with all the tools described in this section, should consider the needs of the assessment, the veracity and availability of data within the model, licensing and maintenance costs, and ease of use.

The boundary between PCM and RA tools is blurring~~,~~ given the increased need for ~~resource adequacy~~RA analyses to represent a greater level of operational detail than ever before. As such, PCM tools are sometimes leveraged for probabilistic analysis by simulating hundreds or thousands of scenarios and calculating ~~resource adequacy~~RA risk metrics in post-processing.

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Table 5.2: Considerations for Applying Production Cost Models to ERAs

Consideration	Description
Availability of Stored Fuel	PCMs can be used to model the availability of stored fuel by considering inventory levels and replenishment rates. For example, for thermal power plants (coal, natural gas), the model should track fuel inventory levels and factor in delivery schedules to ensure that the plants have sufficient fuel to operate when needed to meet demand. The cost associated with fuel procurement and storage may also be modeled as an additional generator cost impacting unit commitment and dispatch decisions.
Just-in-Time Fuel Modeling	PCMs may incorporate fuel consumption and delivery schedule forecasts. These forecasts, created externally to the PCM framework, may be based on historical data, demand projections, and market conditions. Just-in-time fuel modeling ensures that power plants receive fuel deliveries precisely when needed to optimize operational efficiency and minimize costs.
Variable Energy Resources	PCMs can be used to study the impacts of uncertainty, where a plan (e.g~~.~~., day-ahead commitment) is based on one forecast~~,~~ and the system then needs to react as different wind, solar and demand show up in the dispatch.

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Table 5.2: Considerations for Applying Production Cost Models to ERAs

Consideration	Description
Power-Specific Limits and Emission Modeling	PCMs account for off-power specific limits, such as emission constraints and ~~c~~Contingency modeling, by incorporating regulatory requirements and operational constraints into the optimization algorithms. For example, emission limits for pollutants like sulfur dioxide, nitrogen oxides, and carbon dioxide are integrated into the model to ensure compliance with environmental regulations while optimizing generation dispatch and scheduling.
Energy Supply Availability	PCMs assess energy supply availability by considering the availability of generation resources, transmission capacity, and fuel availability in the market.
Electric Vehicles (EV~~s~~)	PCMs should include representations of ~~electric vehicles~~EVs by incorporating EV charging demand profiles, ~~vehicle-to-grid (~~V2G~~)~~ interactions, and the impact of EV penetration on electricity demand patterns. The model should evaluate the effects of EV charging behavior on load profiles, helping utilities plan for EV integration and infrastructure upgrades.
Non-Transportation Electrification	Models should consider the uptake and usage patterns associated with electrification technologies in non-transportation sectors. They should assess the shifts in timing and seasonality of load profiles and usage patterns.
Energy ~~s~~Storage	PCMs model energy storage systems by considering parameters, such as cycling limitations, charging/discharging efficiencies, and transmission constraints. They optimize the dispatch of energy storage resources to reduce overall system costs, manage ~~peak demand~~Peak Demand, and provide ~~ancillary services~~Ancillary Services, such as ~~frequency regulation~~Frequency Regulation; careful consideration of the optimization objectives is required to represent storage operations. Cycling effects, including degradation over time due to charge-discharge cycles, should also be considered in the model~~'~~'s analysis.
T&D Export/Import and Deliverability	~~Explained in the text above.~~PCM model allows for transmission constraints to be enforced through a nodal representation of the system. However, PCMs do not fulfill the role of the detailed power flow operational analysis tools as they typically use a dc representation of the ac power flow (i.e., no voltage constraints or Stability issues represented) and may produce infeasible power flow results. A careful analysis of important transmission and Stability constraints to consider should be undertaken in other analyses (such as power flow models), and this information should be reflected in PCM models as appropriate.
Essential Reliability Services and other ~~ancillary needs~~Ancillary Needs	PCMs can explicitly model procurement of essential reliability services, such as ~~spinning reserves, non-spinning reserves~~Spinning Reserves, Non-Spinning Reserves, and ~~frequency regulation~~Frequency Regulation, to maintain grid reliability. They optimize the allocation of reserve resources to respond to sudden changes in demand or generation outages, ensuring sufficient capacity to restore system balance and prevent ~~c~~Cascading failures during contingencies. They do not analyze the response after contingencies.

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Capacity Expansion Models

~~Capacity expansion models (~~CEMs~~)~~ are a family of tools used in long-term system planning to inform investment decisions and potential future system designs through least-cost optimization of system resources given assumptions about future electricity demand, fuel prices, technology cost and performance, policy and regulation, and reliability targets. The output of a CEM would provide an analyst performing an ERA with a resource buildout to which energy constraints would then be applied. ~~Note that the~~The CEM ~~wouldn't~~would not provide information on the nature of these energy constraints: ~~t~~This would need to be implemented by the analys~~is~~t using their knowledge of the system. Many ~~different~~ CEM options ~~are available to an analyst~~, including both open-source and commercial options, are available to an analyst. The selection of a CEM, as with all the tools described in this section, should consider the needs of the assessment, the veracity and availability of data within the model, licensing and maintenance costs, and ease of use. Capacity expansion tools excel in providing insights into long-term infrastructure investment decisions by considering multiple factors and scenarios. They help policymakers, regulators, and utilities identify cost-effective strategies to maintain energy reliability while meeting environmental and sustainability goals. These tools can assess the ~~trade-offs~~tradeoffs between different investment options and optimize the allocation of resources over time. CEMs can answer various questions related to long-term energy planning, such as the following:

- What is the optimal mix of generation technologies to meet future demand while minimizing costs?
- When and where should new power plants be built or retired?
- What transmission and distribution infrastructure upgrades are necessary to accommodate the future resource buildout? (~~Note that many~~Many CEM models ~~don't~~do not yet have this capability~~)~~.)

~~CEMs'~~The CEM family of tools typically includes at least a generation capacity expansion capability~~,~~ to help determine the type and quantity of power generation facilities that should be built in a specific time frame to meet future energy demand at the lowest cost. In some cases, ~~they~~CEMs may also represent transmission capacity expansion in a co-optimized or coordinated manner with generation expansion, focusing less on specific transmission lines but more on upgrades between the zones represented in the model. Additionally, several commercially available CEMs have recently started to include high-level representations of distribution upgrade needs to accommodate load growth and DERs. Integrated generation, transmission, and distribution planning assessments may require several levels of tools, including CEMs as well as more detailed transmission and/or distribution analysis, though efforts are underway to improve the existing CEMs to better represent transmission or distribution for a more fully integrated capability. All ~~of~~ these tools can be used to produce a starting point of generation and transmission that would be used to set initial conditions for ERAs.

CEMs rely on assumptions and input data that may not fully capture the complexities and uncertainties of the energy landscape. There is ~~a large amount of~~significant uncertainty regarding changes in technology characteristics and cost attributes, fuel prices, regulatory policies, operational flexibility needs, and consumer behavior. These uncertainties in input data translate to a resource buildout ~~which~~that is itself very uncertain. Additionally, these tools may have limitations ~~in~~for representing certain aspects of the power system, such as the dynamic interactions between generation, transmission, and distribution networks during extreme events or emergencies. Scenario analysis can support investigation of these issues.

Unlike the other model families described in this section, CEMs use high-level aggregate assumptions to reduce solve times given the length of time horizon considered. These tools typically operate over a long-term planning horizon, ranging from 10 to 30 years or more, depending on the specific needs and objectives of the analysis. They may use annual or sub-annual time steps to capture seasonal variations in demand, renewable energy availability, and other factors influencing system operations. CEMs typically use a structure built upon the use of time slices reflecting a handful of representative days each year consisting of blocks of hours with similar characteristics. A typical CEM includes ~~less~~fewer than 50 total time slices to represent each simulated year, which may or may not be simulated in time sequential order. Most CEMs include a planning reserve margin as an input or constraint to the simulation to ensure that solutions include sufficient resources to cover for variation from the 50/50 conditions of the representative days and operational experiences such as generator ~~forced outages~~Forced Outages.

Capacity expansion tools can be customized to specific ~~regions~~areas or jurisdictions to account for ~~regional~~ differences in energy resources, demand patterns, regulatory frameworks, and infrastructure constraints. They allow stakeholders to tailor the analysis to reflect the unique characteristics and priorities of their respective ~~regions~~areas. Since CEMs sometimes consider transmission solutions as an investment choice, it can be intimated that they are quasi-transmission constrained, ~~however,~~but these constraints are only as detailed as the system representation used by the CEM. Since most CEMs use a zonal approximation of the system, the level of transmission constraint reflected is at the zonal interface, meaning that copperplate deliverability is assumed within the zone. Because of the number of simplifying assumptions, level of aggregation, and assumption of perfect foresight reflected in a CEM, it is possible for it to produce a least-cost solution that is infeasible for dispatch and operations~~,~~ or ~~which isn't~~that is not adequate when evaluated probabilistically for a wider range of possible scenarios.

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CEM results are normally used in integrated resource plans and regulatory analyses. Advanced CEMs may consider the interdependencies between generation investments and the corresponding transmission upgrades necessary to deliver electricity from remote generation sites to load centers efficiently.

Although CEMs are not directly used to assess energy reliability, a robust analysis ~~which~~that incorporates energy constraints where computationally feasible will allow for a recommended resource buildout ~~which~~that is more likely to be energy adequate than if these constraints ~~weren't~~were not incorporated. CEMs should be run in combination with other types of models ("round-trip analysis") when direct inclusion of constraints is not computationally or technically feasible. ~~Additionally, other~~Other types of models can be used to guide a choice of simplified pseudo-constraints ~~which~~that allow for some representation of energy constraints within the CEM in a simplified manner.

Table 5.3: Considerations for Applying Capacity Expansion Models to ERAs

Consideration	Description
Availability of Stored Fuel	~~Capacity expansion models~~CEMs can incorporate assumptions about the availability and cost of stored fuel, such as coal, natural gas, or uranium, based on historical data and market projections. They can also consider storage capacities and inventory management strategies to ensure a reliable fuel supply for thermal power plants over the planning horizon. One possible approach to incorporating this into a CEM would be to impose operational limits on fuel-limited resources. These operational limits could be informed by a PCM.
Just-in-Time Fuel Modeling	Models should simulate the logistics and transportation infrastructure required for delivering fuel to power plants, including pipelines, railroads, and storage facilities. They can account for lead times, delivery schedules, and supply chain disruptions to assess the reliability of just-in-time fuel delivery systems. One possible approach to incorporating this into a CEM would be to impose forced derates or ~~forced outages~~Forced Outages for resources in time periods where their output is forecast to be limited.

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Table 5.3: Considerations for Applying Capacity Expansion Models to ERAs	
Consideration	**Description**
Variable Energy Resources	~~Capacity expansion models~~CEMs should account for the variability and intermittency of renewable energy sources, such as wind and solar, in their analysis. One approach to incorporating weather shape diversity would be to incorporate rolling weather years in the CEM analysis: This would allow for some of the variability of renewables to be reflected in the analysis while maintaining computational tractability. Additionally, CEMs should be run in coordination with RA models, which can allow the ~~a~~Adequacy of the proposed resource buildout to be evaluated across ~~a number of~~multiple weather years.
Power-Specific Limits and Emission Modeling	Models should incorporate technical constraints and environmental regulations governing power plant operations, including emission limits, generator operating constraints, heat rate curves, and outage schedules, as is computationally feasible. ~~They~~The models have the capability to assess the impact of compliance costs, emissions trading schemes, and regulatory changes on investment decisions. ~~Additionally, including~~Including important generator operating constraints allows for the flexibility needs of the system to be captured within the CEM framework. One possible approach to incorporating emissions constraints and other energy-based constraints into a CEM would be to impose operational limits on affected resources ~~which~~that are informed by a previous PCM analysis. ~~Note that emissions~~Emissions constraints in particular may sometimes be overridden during high-risk load-shed periods, so it is important to be aware of the specific aregiona's regulations when modeling this process.
Energy Supply Adequacy	~~Capacity expansion model~~CEM buildouts should be evaluated using ~~resource adequacy~~RA models to ensure a reliable energy supply for scenarios that minimize costs and environmental impacts. This may require pairing these CEM tools with related tools, as described in earlier parts of this section, or even tools specifically designed to perform ERAs.
Electric Vehicles (EV~~s~~)	Models should account for the growth of EVs and their impact on electricity demand patterns, grid congestion, and infrastructure requirements. They should analyze charging behaviors, load profiles, and grid integration challenges to ensure that the selected resource buildout is reflective of the needs of the electric transportation system.
Non-Transportation Electrification	Models should consider the uptake and usage patterns associated with electrification technologies in non-transportation sectors. They should assess the shifts in timing and seasonality of load profiles and usage patterns to optimize resource deployments.
Energy ~~s~~Storage	Capacity expansion models should consider the role of energy storage technologies, such as batteries, pumped hydro, and thermal storage, in enhancing grid flexibility and reliability. They should optimize the sizing, placement, and operation of energy storage systems to address intermittency, ramping requirements, and system balancing needs.

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Table 5.3: Considerations for Applying Capacity Expansion Models to ERAs	
Consideration	**Description**
T&D Export/Import and Deliverability	CEMs should model the interconnection capacity and transmission constraints between different ~~regions~~areas or neighboring systems, considering import/export capabilities and congestion management strategies, as is computationally feasible. In a traditional CEM model, including key interfaces through a zonal constraint model is recommended. Interface limits should be set to account for thermal limits~~,~~ as well as voltage ~~stability limits~~Stability Limits and line losses. In a more advanced CEM model, nodal analysis may be possible, or transmission expansion may be co-optimized with generation expansion. A full analysis of T&D systems is likely an external process but would be useful to gauge the validity of the results from a CEM.
Essential Reliability Services and ~~other ancillary needs~~Other Ancillary Needs	Capacity expansion models should incorporate the provision of essential reliability services, such as ~~frequency regulation~~Frequency Regulation, voltage support, reserves, and ~~black start~~blackstart capability, from diverse sources in the generation mix. Analysts should consider including provisions to evaluate the cost ~~-~~effectiveness and technical feasibility of providing these services through various generation, storage, and demand-response options.

Power System Operational Modeling Tools

At the opposite end of the spectrum from CEM and PCM are power system physical simulation tools. This family of tools is used to study very short-term transient periods, typically only a few cycles (or seconds) in duration, on the system. These tools simulate the physical behavior of power systems under various operating conditions, including ~~d~~Disturbances, contingencies, and dynamic responses. While it may not be readily apparent, these tools may play an important part in the successful execution of an ERA. While not necessarily incorporated directly into an ERA process, these tools would help an analyst gain an understanding of the fundamental engineering-driven equipment responses that are not captured in lower time resolution models ~~during a period of question~~(PCMs, CEMs, RAs). Operational modeling tools may provide insights into different concerns and solutions~~,~~ (e.g. fault ride through~~,~~) and allow them to create more precise models when needed to assess energy reliability.

Operational models can address a variety of questions crucial for ERAs, including the following:

- ~~Does~~Can the system ~~have the ability to~~ maintain synchronism and ~~s~~Stability following ~~d~~Disturbances, such as ~~f~~Faults or sudden changes in load or generation, and what assumptions would be applied in an ERA to such a ~~d~~Disturbance?
- How do the different components of the power system, including generators, transformers, and control systems, respond to changes in operating conditions, resulting in how they would be modeled in an ERA?
- ~~Does~~Can the system ~~have the ability to~~ maintain voltage and frequency within acceptable limits under varying conditions, or is a different set of resources needed to supplement the expected commitment and dispatch?
- How do equipment failures or other contingencies impact system reliability and performance?

Operational ~~M~~modeling tools excel ~~in~~at providing detailed insights into the dynamic behavior of power systems during transient events. They accurately capture the interactions between various system components and can simulate complex scenarios with high fidelity. These tools are valuable for identifying potential vulnerabilities and assessing system resilience under different operating conditions. This family of tools includes the most detailed representation of the transmission system~~,~~ but at the expense of a lesser representation of generator constraints.

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Operational models encompass various software packages and computational techniques designed to simulate the dynamic behavior of power systems during operational conditions. Some of the key tools ~~included~~ are listed as follows:

- **Transient Stability Analysis Tools:** ~~s~~Simulate the dynamic response of power systems following ~~d~~Disturbances such as ~~f~~Faults, sudden changes in load, or contingencies. They assess the system~~'~~'s ability to maintain synchronism and ~~s~~Stability over short ~~timeframes~~time frames, typically ranging from a few cycles to a few seconds.
- **Dynamic Simulation Software:** ~~m~~Model the behavior of power system components, including generators, transformers, transmission lines, and control systems, under varying operating conditions. They provide insights into voltage and frequency dynamics, system oscillations, and response to control actions.
- **Contingency Analysis Packages:** ~~e~~Evaluate the impact of equipment failures, line outages, or other contingencies on system reliability and performance. They identify critical contingencies and assess the effectiveness of mitigation strategies, such as ~~remedial action schemes~~Remedial Action Schemes and automatic load shedding.
- **Voltage and Frequency Regulation Tools:** ~~f~~Focus on analyzing the system~~'~~'s ability to maintain voltage and frequency within acceptable limits under normal and abnormal operating conditions. They assess the effectiveness of automatic voltage control devices, governor systems, and other control mechanisms.
- **Wide-Area Monitoring and Control Systems (WAMS):** ~~utilize~~Use real-time measurement data from synchronized phasor measurement units (PMU~~s~~) to monitor and control power system dynamics over large geographic areas. They provide situational awareness, early ~~f~~Fault detection, and system-wide ~~s~~Stability analysis capabilities that can be used to detect unexpected dependencies ~~which~~that can then be modeled in an ERA.

While these tools offer valuable insights, they have limitations, including computational intensity, complexity, data dependencies, and scalability. Simulating short-term dynamic events requires significant computational resources and time, therefore limiting the scope of analysis. The complexity of power system dynamics can make it challenging to model all interactions accurately. Simplifications and assumptions may be necessary, which can affect the accuracy of results. Operational models rely heavily on accurate data inputs, including system parameters, network topology, and equipment models. Inaccurate or incomplete data can compromise the reliability of simulation results. These tools may struggle to scale up to large, interconnected power systems or to incorporate detailed representations of DERs effectively. They may also ~~not~~ be unable to capture impacts of certain issues, such as control interactions between inverter-based resources, ~~whereby~~for which electromagnetic transient (EMT) tools would be necessary. These issues are well covered ~~in~~by other NERC activities related to modeling for IBRs, including the Inverter-~~b~~Based Resource Planning Subcommittee (IRPS). Additionally, these tools can only analyze one operational condition at a time~~,~~ and, as such ~~aren't~~, are not well suited to analyze a large number of uncertainty scenarios for a full study horizon. Since they can only model one system snapshot at a time, they also ~~aren't~~are not well adapted to analyzing energy sufficiency issues.

Operational models offer flexible resolution capabilities, allowing users to adjust time steps and time horizons based on the specific requirements of the analysis. Shorter time steps enable more detailed simulation of fast transients, while longer time horizons facilitate assessment of system behavior over extended periods.

Operational models typically represent ~~G~~generation and ~~T~~transmission (G&T) components in detail, including generators, transformers, transmission lines, and control systems. These components are modeled using mathematical equations and algorithms that capture their dynamic behavior accurately during transient events. However, the level of detail and complexity in G&T representations may vary based on the specific objectives and

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constraints of the reliability assessment. Demand is also represented in various ways, with more detailed models that can cover different types of loads, as well as DER, being increasingly represented in such models.

~~At present, this~~This is currently the only family of tools that is directly covered by established NERC standards~~—~~—the MOD family of standards. These tools are used directly in the study of power system reliability through the performance of power flow simulation to assess system dynamics, ~~s~~Stability, optimal power flow, and many other short-term transient conditions. Unlike the prior families of tools that produce solutions driven by economic least-cost optimization, power flow tools are not economically constrained. ~~Many different~~This family offers many tool options ~~are available from this family~~ to an analyst performing an ERA, including both open-source and commercial options~~,~~; however, industry has primarily settled around a small handful of mature commercial tools in this space driven by regulatory requirements. Application in an ERA would be limited to having a better understanding of dependencies, which would then be modeled in ERA-specific tools or other modeling tools that feed the ERA process.

Screening Tools

In addition to the detailed tools ~~that are~~ described above, ~~there is often a need to use~~ specialized simple tools covering one or more items are often needed to create a narrowed set of scenarios or considered variables. These may include ~~c~~Contingency screening tools, probabilistic screening tools to identify likely energy reliability risk scenarios for deeper exploration, and/or covariance of inputs (e.g., load dependence on weather ~~&~~, outage dependence on the same weather input ~~&~~, and higher ~~CT~~generator capability with cold air input). The choice to use these tools is often narrowed by the need to supplement experience-based judg~~e~~ments.

Interdependence ~~t~~Tools

The family of models in this ~~section~~category are those that simulate items that intersect or impinge on electric~~ity~~ system planning and operation ~~which~~that may be used to inform the performance of an ERA or mitigation plan development, including ~~but not limited to~~ commodity, supply chain, transportation, weather, and economic sector models. ~~These~~Since these models can vary in complexity, cost, and availability to the analyst or entity performing an ERA, ~~so it is advisable that~~ performers are advised to closely consider the needs and benefits for including these types of models in an ERA over the use of engineering judg~~e~~ment. Often, it is only feasible for the entities to include these types of models in a planning ERA because of the major differences in modeled time domains compared to the electric~~ity~~ sector~~,~~; however, this is not always the case as information from these models may be available through collaborations with partners and other industries. Examples of benefits from including non-electric~~ity~~ sector models in the performance of an ERA include establishing feedback loops to capture the dynamic interdependency concerns that may not otherwise be captured. For instance, inclusion of detailed natural gas models can significantly improve an entity's ability to mitigate against natural gas-electric interdependency concerns as these models can be used to develop price and congestion forecasts, which can be integrated with or used to inform electricity models, such as a PCM, to determine re-dispatch or fuel switching solutions. Similarly, rail and truck transport models can be used over a longer-term horizon, enabling an entity to assess whether mitigating actions are needed to accommodate fuel and consumables stockpile replenishment timelines.

Implementation

Any analyst performing an ERA would need to evaluate the benefits and shortcomings of each model~~,~~ and consider the needs and objectives of the ERA when determining what model, or models, should be employed in the performance of their assessment. Models can feed bi-directionally to inform each other, as binding constraints from one family may not be captured or identifiable in another~~,~~. ~~f~~For example, it may be desirable to move from a low ~~-~~level of detail to a higher ~~-~~level of detail to evaluate identified periods of concern~~,~~ or to pass constraints identified in higher-detail models to the lower-detail model (i.e., congestion constraints identified in a power flow that ~~aren't~~are not captured in a first-pass PCM or CEM). Implementation and performance of an ERA may be iterative within and between tools depending on the scenario design and desired outcomes. Figure 4 illustrates the interdependencies of tools involved in the ~~energy reliability assessment~~ERA process, including some of the tools detailed above.

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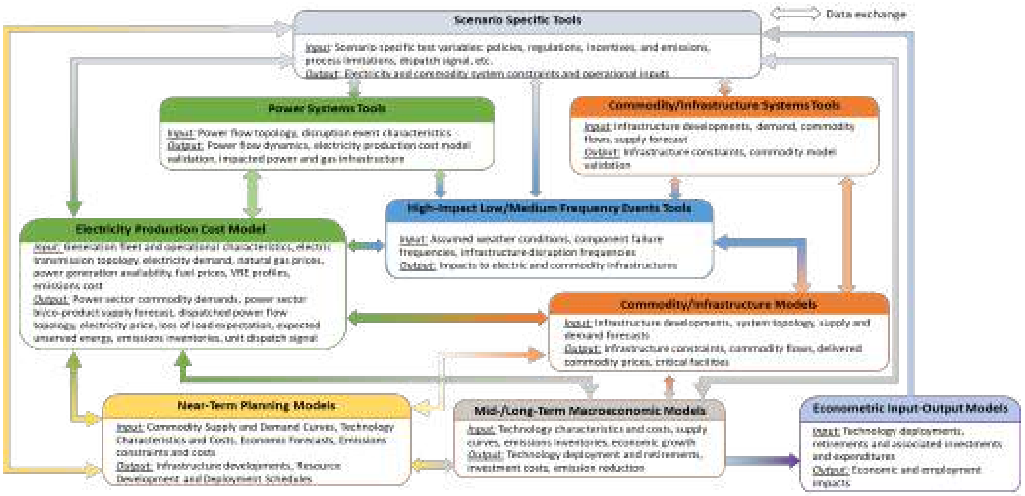

Figure 5.1: Illustrations of the ~~i~~Interdependence of ~~t~~Tools as ~~they relate~~They Relate to the ERA ~~p~~Process

Chapter 6: Base Case and Scenario Modeling

Base Case

The ~~Base Case~~base case for an ERA is a model of projected power system conditions for a specific point in time. From the ~~Base Case~~base case, additional scenarios and contingencies can be applied for further analysis of risks. Studying the ~~Base Case~~base case will give an analyst a view of a standard starting point. ~~An~~Since ERA is a look at a certain time period~~. Therefore~~, a ~~Base Case~~base case would include the most-likely-to-occur series of conditions over the defined period.

~~There are several~~Several input considerations ~~to include~~should be included in an ERA. Ultimately, the ~~Base Case~~base case represents the *expected* quantity for all ~~of~~ the input considerations in each interval (e.g., hour, day, week~~ etc.)~~) of the assessment. The contributing factors that the analyst will associate with are their contribution to energy, either from the supply or demand point of view. Starting with demand, and the input factors that contribute to demand. All ~~of~~ the contributing factors that drive demand (e.g., weather, behind-the-meter generation, industrial processes, seasonal considerations, electrification~~, etc.)~~) would be modeled as the *expected* value for each, resulting in an *expected* demand value. Likewise, for supply capabilities and availabilities, the analyst would use the *expected* values for production capabilities, fuel supply factors without ~~c~~Contingency, and any other factor that would contribute to the availability of supply resources.

The term "~~Base Case~~base case" in an ERA is used generically, meaning that it is a set of baseline assumptions that define a reference point by which scenarios and contingencies would be applied. The term ~~Base Case~~base case is **not** intended to draw any similarities to transmission ~~Base Cases which~~base cases that are used for transmission planning studies~~,~~; however, it is also not intended to disallow transmission studies to be coupled with ERAs. How a ~~Base Case~~base case is defined may depend on the time horizon of the ERA. Near-term, seasonal, and planning ~~Base Cases~~base cases have a variety of differences in how particular inputs are modeled or formulated.

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Near-term ~~Base Cases~~base cases will likely~~ will~~ start with a forecast set of conditions or verified known quantities. Near-term ~~Base Cases~~base cases start off with higher certainty in weather, demand, planned outages, fuel availability, transmission capability, etc~~…~~. In a deterministic analysis, a median forecast or known quantity would serve as the ~~Base Case~~base case for all parameters and then be varied using specific scenarios as needed. In a probabilistic analysis, a number of probabilistically weighted replications representing operational uncertainties (primarily due to ~~forced outages~~Forced Outages and weather uncertainty) would be used to create a ~~Base Case~~base case, with various specific scenarios relating to other system risks being subsequently analyzed as needed.

Seasonal ~~Base Cases~~base cases introduce some uncertainty over near-term ~~Base Cases~~base cases due to the longer time horizon~~,~~ but still require the outlining of an appropriate set of system conditions representative of the time horizon modeled. These system conditions need to be determined by the analyst using the tools and information available~~,~~ but are intended to be similar in nature to near-term ~~Base Cases~~base cases. Longer time horizons will likely depend more on scenarios than shorter-term ~~Base Cases~~base cases, but a ~~Base Case must~~base case should be established ~~in order~~ to introduce uncertainty. With enough scenarios, emphasis on the accuracy of a ~~Base Case~~base case gives way to ~~the~~a variety of possibilities. There will be seasonal considerations for both supply and demand. Seasonality will have a different impact depending on what system is being assessed. The intent of modeling the *expected* conditions does not change based on the season being studied~~,~~; it just changes what the literal assumptions are.

Planning ~~Base Cases~~base cases again ~~must~~should outline an appropriate set of system conditions, even given the increased uncertainty associated with a more distant study time horizon. As such, ~~P~~planning ERAs will depend much more heavily on a comprehensive scenario analysis to form a complete picture of future risk~~,~~ as compared to short-term ERAs, where a ~~Base Case~~base case analysis may be sufficient.

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While scenarios and contingencies gain importance as the horizon increases, ~~it's still~~it remains necessary to define a reasonable ~~Base Case~~base case. The results of the ERA on the ~~Base Case~~base case will be important in conveying risk. If ~~Base Case~~base-case assumptions result in energy shortfall or other unfavorable conditions, the ~~Base Case~~base case may not be defined properly, or the proposed system may not be prepared to reliably serve energy demands and require corrective actions sooner than anticipated. ~~It's~~It is also helpful when applying scenarios to have a ~~Base Case~~base case to compare results~~. This~~, which allows an analyst to point to specific parameters and convey trends.

All ~~Base Cases~~base cases should be defined as part of a repeatable process, especially if the ERA is intended to be performed routinely, ~~in order~~ to allow for comparison and metric tracking and trending. That process can be updated over time as knowledge and experience dictates. There is some likelihood that ~~Base Cases~~base cases will be developed in accordance with stakeholder-approved processes and may not have the flexibility to change frequently. Provisions for updating assumptions in the ~~Base Case~~base case and then again in subsequent sensitivities and scenarios should be included in the process for when large, unexpected changes happen that were not included in the original ~~Base Case~~base case or new methods become available that make for more robust modeling in a ~~Base Case~~base case. Examples would include large resource unplanned outages (e.g., nuclear power station trips) or major transmission system element failures.

One last consideration for ~~Base Case~~base-case assumptions is the verification of the reasonability of assumptions, after the time that was assessed has passed and actual observations are available. Items that were identified in prior scenario models may influence an evolution in ~~Base Case~~base case modeling. It is impossible to forecast energy assessment conditions with 100% accuracy. However, with a large enough sample size and a series of assessments, they can be benchmarked against actual conditions and the analyst can detect and minimize or eliminate biases.

Scenarios and Risk Assessment

Risk is a product of three primary components:

- ~~t~~The events or scenarios considered~~,~~
- ~~t~~Their likelihood of occurrence~~,~~
- ~~and their~~Their associated impact~~.~~

Choosing the scenarios (or method of generating scenarios) appropriately is critical to a robust risk assessment and tolerance definition because these choices determine the outcome of an ERA~~;~~, either implicitly or explicitly by their likelihood of occurrence. ~~As a result, these choices set a risk tolerance based on what types of scenarios are considered and their associated likelihood of occurring.~~ While ~~not~~defining an ~~easy to define and~~ objective standard is not easy, the analyst should consider the expected or likely, credible, and even worst credible scenarios with their associated risk metrics or criteria based on their inherent risk tolerance to fully assess risk through an ERA. Chapter 7 ~~will discuss~~discusses how to use metrics and criteria to evaluate risk and communicate that risk based on the method and scenarios used.

Sensitivity and Scenario Modeling

Sensitivities and scenarios are not ~~a~~ new concepts to industry planners~~. However, they~~ but are ~~being~~ looked at from a different angle in an ERA.

~~An~~The following is an excerpt from page 13 of the NERC Probabilistic Assessment Technical Guideline Document~~, page 13~~:[42]~~:~~

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[42] https://nerc.com/comm/pc/pawg%20dl/proba%20technical%20guideline%20document_08082014.pdf

Sensitivity Modeling: Sensitivity analyses are run to assess the impact of a change in an input (either load, transmission, or resource-related) on resource ~~a~~Adequacy metrics. The runs are performed by changing one input at ~~-~~a ~~-~~time~~ in order~~ to isolate the potential impact of each input. Ideally, the change in each input should be accompanied by an associated probability.

Scenario Modeling: In its most general form, a scenario analysis is performed to assess the impact of changes in multiples inputs (either load, transmission, or resource-related) on resource ~~a~~Adequacy metrics. The runs are performed by changing multiple inputs at the same time. Ideally, each scenario should have an associated probability calculated based on the changes in inputs included within the scenario. Scenarios are likely to be identified in the NERC *Long-Term Reliability Assessment* or by sensitivity analysis results. In some cases, scenario analysis may require additional inputs (not included in the Core Probabilistic Assessment) relevant to address a specific reliability concern.

While these descriptions are specific to the NERC Probabilistic Assessment (ProbA), application to an ERA is similar. Sensitivity modeling adjusts one input parameter and scenario modeling adjusts multiple input parameters.

In probabilistic ERAs, each uncertainty will have an associated probability of occurrence. ~~It is important for the~~The analyst ~~to~~should understand what ~~is~~ the appropriate probability is and what it means for ~~the~~an ERA's outcome~~ of performing ERA.~~. Some inputs may have equal chances of occurrence (e.g., weather assumptions for upcoming seasons~~)~~), while others may have a higher chance to a specific value (e.g., weather forecasts for the next seven days). Further, some inputs may have a lesser chance of occurrence but a larger impact on the outcome of an ERA. However, it is challenging to assign a probability of occurrence to certain uncertainty pathways. This is particularly true for the evaluation of macro ~~-~~risks, such as policy changes and shifts in ~~macro-economic~~macroeconomic conditions. A sensitivity or scenario analysis would be particularly useful ~~to analyze~~for analyzing the risk associated with these types of uncertainties.

Scenarios should be selected to analyze certain conditions, either simple or complex, with a reasonable risk of occurring that stress the system beyond the conditions modeled in the ~~Base Case~~base case to examine risks that the system may experience. This is especially important for conditions for which the entity wants to be prepared. Scenarios in an ERA would have varying levels of severity. Consideration should be given for how the results of a scenario will be compared to specified criteria. For example, low-impact scenarios ~~shouldn't~~should not result in outcomes with unacceptable consequences (e.g., a scenario similar to the ~~Base Case with~~base case probably should not result in a relatively large-magnitude energy shortfall). Conversely, it may be appropriate to ~~find~~get results with large-magnitude energy shortfall when the worst-case scenario for all inputs is selected. The analyst would need to determine the ~~level~~degree of variance that would be needed ~~in order~~ to create that stress~~,~~ and approach shortfall. ~~It's~~It is likely that multiple iterations would be required when initially setting up multiple scenarios (e.g., if the first attempt adds no stress, more variances may be required).

Credible risks are events that are plausible to occur and would have a severe impact. The choice of scenarios, paired with the selection of metrics and criteria (discussed in Chapter 7), helps set the level of risk or reliability ~~that~~around which an entity plans and designs a system~~ around~~ and expects reliability to be maintained. Scenarios should be chosen such that the entity can describe and document ~~that~~ the scenarios that have some risk of occurring, and their system should be designed to operate reliability through that occurrence.

~~The~~As the term "credible" is inherently subjective~~.~~, ~~F~~formulating conditions that would be considered credible may require research and effort to ensure that a scenario would be accepted as "credible~~"~~." Some examples that will lend credibility to scenarios include~~:~~ industry assessments, academic research papers, documented historical event reports, verified analyst experience, the judgement of subject matter experts, and statistical evaluations. ~~Taking into account conditions~~Conditions that have happened before, locally or in other similar locations, also lend credibility in terms of historical events. ~~Note that~~Nevertheless, just because an event has happened ~~in the past, doesn't~~before

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does not necessarily mean that it will happen again. Similarly, just because an event has not happened in the recorded past ~~doesn't~~does not mean that it can~~'~~not happen in the future.

Finally, scenarios will have inputs that ~~have dependence from one to the other or~~ are co-dependent on a similar driving factor~~. Weather is an example of co-dependence. Demand~~, such as demand, variable supply (e.g., solar and wind), outage assumptions, and fuel availability ~~are all examples of inputs to an ERA that are~~all being co-dependent on weather. These inputs should be coupled together when modeling input assumptions. Decoupling related co-dependent assumptions can result in impossible scenarios. Including these scenarios in a solution set and comparing the results of that solution set to a criteri~~a~~on can give biased results, potentially triggering actions to be taken for a scenario with a 0% probability of occurrence. Worse, these impossible scenarios dilute the pool of results and can potentially mask indications of real problems in ERAs~~, or~~. Additionally, certain severe events that are only present when weather outputs are properly correlated could fail to be captured within the analysis.
Near-term scenarios will likely have less variability than seasonal or planning scenarios. Higher certainty in data allows for the use of forecasted conditions rather than assumptions in the ~~Base Case~~base case and can limit the variability in scenarios. Demand, fuel supply availability, generation and transmission outages, stored fuel inventories, emissions limitations, ~~as well as~~and most other input assumptions~~,~~ present some level of clarity in the near ~~-~~term, and a high degree of variability may not be necessary. Resources that inherently operate with a high degree of variability (e.g., wind and solar) are exceptions~~. The~~, and the variability of some inputs may not change from near-term to planning ERAs.

Scenarios in seasonal ERAs may need to offer more variability than those in the near ~~-~~term. Some variability would remain similar, as mentioned before with wind and solar supplies. Some inputs (e.g., weather, demand, planned outages) would introduce some additional variability and ~~must~~should be understood by the analyst ~~in order~~ to define scenarios that would be considered credible. Further, some inputs would remain predictable with limited variability (e.g., which generators and transmission capabilities are built). Weather scenarios in ~~a~~ seasonal assessments can be limited by long-range forecasts (e.g., NOAA outlooks, El Ni~~n~~ño conditions and forecasts), which should be used with caution ~~so as~~ to avoid overlooking potential real conditions. Long-range forecasts provide a general direction over a long period of time (i.e., month or months~~),~~) but ~~won't~~may not capture the possibility of shorter-duration spell of more extreme weather embedded within the outlook period.

Scenarios in planning ERAs are completely based on assumptions~~,~~ rather than forecasts. Historical information coupled with assumptions for expected changes gives the analyst information that can be used to determine credible scenarios. For example, historical demand could be used to represent future demand, so long as it is adjusted for any known changes in climate ~~and~~, coupled with growth/contraction assumptions. For longer-term ERAs, this becomes even more critical given the anticipated greater reliance on weather-dependent resources on the BPS. Supply resources are more uncertain in long-term ERAs~~,~~ but are not completely uncertain. A variety of factors need to be considered when creating long-term scenarios. For example, the future resource mix will be influenced by economics, technological advances, environmental policy and regulations, and other incentives to build new resources. Many of those factors will impact all infrastructure expansion and would need to be researched ~~in order~~ to be plausibly varied in a longer-term ERA.

Chapter 7: Study Metrics and Criteria

Purpose of Metrics and Criteria

An ERA will show an analyst what the outcome of a range of events or operating conditions would look like. To determine what the risk is and whether that risk is acceptable, there must be some metrics and associated criteria (or minimum thresholds) for comparison and evaluation of risk. The evaluation of system ~~a~~Adequacy using these metrics and criteria will drive when and what corrective actions may be required to minimize the impact of the perceived risks. Metrics are measurements derived from deterministic or probabilistic ~~a~~Adequacy analysis to indicate the reliability or risk ~~of~~to the system~~, and~~ while criteria are a set standard to determine if the level of a metric is acceptable. In the case of ERAs, a criteri~~a~~on for a metric might be set such that if ~~the criteria~~it is not met, some mitigation activities need to be performed.

~~Using metrics~~Metrics and criteria are useful for four purposes: quantifying the risk, setting a risk tolerance or identifying what risk is acceptable, evaluating whether the risk of the system is acceptable, and comparing potential risk-reduction activities. Based on these purposes, the method and scenarios of the ERA should quantify the current risk, the analyst should have defined a risk tolerance specific to the scenarios based on evaluation criteria, and the analyst should use those criteria or metrics to evaluate whether and what interventions are needed.

Traditional ~~resource adequacy (~~RA~~)~~ processes, metrics, and tools may not be fully able to evaluate ~~a~~Adequacy requirements and properly articulate risks in the context of an evolving resource mix, changes to demand profiles, and extreme weather scenarios. The evaluation criteria and associated metrics should be based on the methods used in ERAs, the level of risk that entities can tolerate, and how entities want to quanti~~t~~fy and present the risk. Considerations for stakeholder involvement in the development of metrics will be a key input to the process. Expertise, responsibility, and authority to address deficiencies will all likely fall with~~in~~ different entities and should be coordinated for all stakeholders. A significant challenge is to identify appropriate ERA metrics that provide a comprehensive picture of system risk to planners, operators, regulators, and ~~policy makers~~policymakers and to set minimum ~~a~~Adequacy criteria that reflect both the costs and benefits of avoiding excessive unserved energy, the frequency and duration of loss-of-load events, and the risk of energy deficiency that ~~regions~~areas can accept. ~~However, the~~The names of some of the metrics are not different whether used in a capacity- or an energy-based assessment~~s~~ but ~~reflect~~represent the ~~on~~specific capacity or energy risk depending on the methods and quality of the analysis method used to calculat~~ing~~e the metrics.

Existing Metrics

Many reliability and ~~a~~Adequacy metrics used within the capacity assessment framework can be directly used in an energy assessment framework. To understand the risk of losing load, an analyst needs to consider the duration of events, the magnitude of the loss of load, and frequency of the loss of load.

Deterministic Metrics and Criteria

Deterministic metrics can be useful ~~to examine~~in examining a specific forecasted scenario or set of scenarios that the analyst expects to occur, including, in certain situations, tail-risk events (high impact/low frequency [HILF]) that can provide a system design basis for planning purposes. Using deterministic scenarios is especially helpful if the analyst wants to stress test ~~a~~an electrical system model to understand if the ~~electrical~~ system can reliab~~il~~~~it~~y meet certain minimum thresholds with respect to criteria including~~, but not limited to,~~ unserved energy, Energy Emergency ~~A~~alert (EEA) levels, or a higher reserve margin under extreme weather or system conditions.

Creating credible lower-probability but high-impact events and assigning a deterministic criterion to them allows the analyst to set a risk tolerance for those events and what their expectations ~~is~~are for handling severe events. The analysis of these high-impact events is useful to understand how the system may behave during these events and allow for planning that is more resilient even if the expectation is that the system may experience some adverse or abnormal conditions if those events occur.

Unserved Energy

Unserved ~~E~~energy is the amount of load that is not served in terms of energy for a given time period, generally expressed in MWh. Unserved ~~E~~energy can be determined for individual deterministic scenarios with a limit in the amount that you will accept during severe contingencies~~.~~ for a given time period, generally expressed in MWh.

Forecasted Energy Emergency Alert ~~(FEEA)~~

~~Energy Emergency Alerts (~~EEAs~~)~~ are defined in NERC Standard EOP-011-1,[43]~~,~~ Attachment 1 as follows:

- **EEA 1**~~–~~: All available generation resources in use
- **EEA 2**~~–~~: Load management procedures in effect
- **EEA 3**~~–~~: Firm ~~L~~load interruption is imminent or in progress

These thresholds are useful for connecting the forecasted or possible Energy Emergency that might be observed in an ERA to the actual Energy Emergency events that the analyst is trying to avoid. These thresholds indicate system conditions that would be considered ~~Energy Emergencies~~energy emergencies even if load loss is not expected to occur. Using the increasing level of impact of the EEAs as criteria may be useful ~~for set~~to setting criteria for increasingly less probable but impactful events.

For example, ISO New England uses Forecasted EEAs[44] (FEEA~~s~~) in near-term ERAs, leveraging the existing and well-understood EEA definitions. FEEAs can be used as an indication that available resources during any hour of an ERA are forecasted to be less than the quantity defined by ~~Energy Emergency Alerts (~~EEAs~~). These~~. The EEA metrics have been used consistently for ~~a number~~many years in ERAs.

Reserve Margins

Reserve margins requirements can be set as criteria to have a sufficient amount of excess energy or capacity available beyond generation levels needed to meet demand. This threshold provides an additional buffer before expected load loss and therefore a lower expectation of impact in any scenarios that are simulated. These reserve ~~margins~~ margin requirements could be based on a fixed value~~,~~ or a set percent of energy demand or be related to ~~ancillary service~~Ancillary Service requirements or uncertainty ~~on~~of supply or demand variables.

Probabilistic Metrics and Criteria

Probabilistic methods allow the analyst to assess risk based on a wider range of scenarios and better incorporate the likelihood of the events occurring than individual deterministic scenarios. The resulting probabilistic metrics are based on all the events simulated or statistical calculations and combined into statistical values of shortfall events. The metrics more explicitly reflect risk across a range of operating conditions instead of a design around a specific defined scenario's ~~results defined.~~result. However, individually the metrics ~~do~~may not reflect as clearly ~~reflect~~ the frequency, durations, and magnitude of expected events.[45]

All ~~of~~ the following metrics can potentially be calculated based on the same set of ERA simulations ~~so do~~and may not necessarily require separate probabilistic analyses to be performed.

Loss of Load Expectation ~~(LOLE)~~Error! Bookmark not defined.

LOLE is the expected number of days per periods (generally studied for a year) for ~~for~~ which the available generation is insufficient to serve demand. The calculation is based on whether ~~or not~~ shortfalls are observed during individual

[43] https://www.nerc.com/pa/Stand/Reliability%20Standards/EOP-011-1.pdf
[44] https://www.iso-ne.com/static-assets/documents/rules_proceds/operating/isone/op21/op21_rto_final.pdf
[45] See: Probabilistic Adequacy and Measures Report - 2018

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scenarios and the likelihood of those events occurring. As a result, the metric reflects the frequency of events or at least the number of days with loss-of-load events but does not give any information of the expected duration or magnitude of these events or even if multiple events occur on the same day.

In an ERA, LOLE would be tailored to the defined study period but would effectively mean the same as in capacity assessments, event-days per period. LOLE would not show depth of shortfall, only the likeli~~d~~hood of the occurrence of a shortfall. Used in combination with the ~~expected unserved energy~~EUE metric, this metric can have criteria defined to trigger corrective actions~~ to be taken~~. For example, a threshold for the number of shortfall days you are willing to risk loss of load for a given time period~~ might be useful~~, such as 0.1 days per year (similar to the 1 day-in-10 year reliability metric that is often cited across the industry~~).~~), might be useful.

Loss of Load Events~~ (LOLEv)~~

Loss of ~~Load Events~~load events (LOLEv) is the number of events per ~~year ~~period (generally on a per-year basis) when load is lost. This metric differs from the LOLE metric in that LOLEv takes into account~~s~~ days with multiple loss of load events and records one event for multi-day loss of load events. Using LOLE alone will obscure multiple events occurring during a single day. Multiple events in a single day may be different magnitudes and may occur at different times of day, reflecting inherent differing system conditions and associated risk.

Loss of Load Hours~~ (LOLH)~~

Loss of load hours (LOLH) is the expected number of hours per period (generally on a per-year basis) when a system's hourly demand is projected to exceed the available generating capacity. This metric is calculated using each hourly load in the given period instead of using only the daily peak in the classic LOLE calculation.

With LOLH reflecting the duration of energy shortfalls better than LOLE, LOLH can be used in an ERA in combination with EUE, and perhaps LOLE, to set a limit on the number of ~~hours~~LOLH. Limits could be conditional as well by including system conditions with the metric~~.~~, ~~F~~for example, limiting LOLH to 12 hours as long as no more than 2 of the hours are below 32°F.

One caution to this approach is that higher precision does not necessarily lead to higher accuracy. When working in a longer-duration energy space, actions are available to move some shortfall from one period of time to another. LOLH may not be an appropriate metric for this reason.

Expected Unserved Energy~~ (EUE)~~

EUE[46] is the measure of the resource availability to continuously serve all loads at all delivery points while satisfying all planning criteria. EUE is energy-centric and analyzes all hours over a period of time. Results are calculated in MWh or can be normalized to expected demand. EUE can be normalized (NEUE) as a percentage of total energy demand. In an ERA, EUE can be used to show the expected energy shortfall over the duration of a study period. The study period would be carefully defined to examine the impact of a specific risk (e.g., the duration of a long-duration cold spell or heat wave~~,~~ or duration of a drought). EUE would be cumulative~~,~~ over the selected duration~~,~~ but could also be combined with LOLE or LOLH. For example, a limit can be placed on the total MWh of EUE~~,~~ while also satisfying a limit on the number of days or hours where a shortfall may occur throughout the study period~~ being studied~~.

Limits on EUE could then be used to inform and/or trigger corrective actions to be taken ~~in order ~~to maintain reliability.

Loss of Load Probability~~ (LOLP)~~

Loss of load probability (LOLP) is the probability of system daily peak or hourly demand exceeding the available ~~electrical energy~~Electrical Energy during a given period.

46 https://nerc.com/comm/pc/pawg%20dl/proba%20technical%20guideline%20document_08082014.pdf

LOLP can be useful for probabilistic ERAs when defining risk associated with EUE or LOLE/LOLH.

Value at Risk ~~(VaR)~~ and Conditional Value at Risk ~~(CVaR)~~

Value at ~~R~~risk (VaR) and ~~Conditional Value~~conditional value at ~~R~~risk (CVaR) are risk metrics that evaluate the tail ~~a~~Adequacy risk instead of an average or expected risk. VaR and CVaR are ~~metrics~~ used in the finance industry to measure risk, especially related to tail risk or the magnitude of impact of lower-probability but higher-impact events. VaR is the maximum loss ~~that~~ at given probability or confidence interval and can be calculated as the loss for a given percentile of scenarios. CVaR is similar to VaR but is the average risk of losses above a given percentile of losses (e.g., average losses of the 95th percentile or higher losses). These metrics are not specific to any energy concept but can be applied to many energy metrics, such as ~~loss of load, loss of load hours, of Unserved Energy.~~LOLE, LOLH, or EUE. These metrics differ~~s~~ from the other probabilistic methods discussed in this document ~~because they~~ as the VaR results are based on a percentile or confidence level ~~of results in the case of VaR and~~, while CvaR is based on a conditional metric ~~in the case of CVaR.~~. These metrics are therefore good indicators of tail risk and the impact of lower-probability and higher-impact events. ~~Currently~~LOLE95 and LOLH95 are currently used examples of these metrics ~~are LOLE95 or LOLH95~~[47].

Figure 5 illustrates an example of VaR and CVaR of energy deficiencies based on a probabilistic ERA. The figure is a histogram of the energy deficiency results calculated from the assessment. The 95% VaR of energy deficiencies (shown by the black line) is 236.6 MWh, which means that the assessment expects that 95% of scenarios will have 236.6 MWh or less of load ~~will be lost~~loss.

The 99% CVaR of energy deficiency ~~is~~of 485.3 MWh loss ~~would mean~~means that the average load loss for the worst 1% of scenarios is 485.3 MWh.

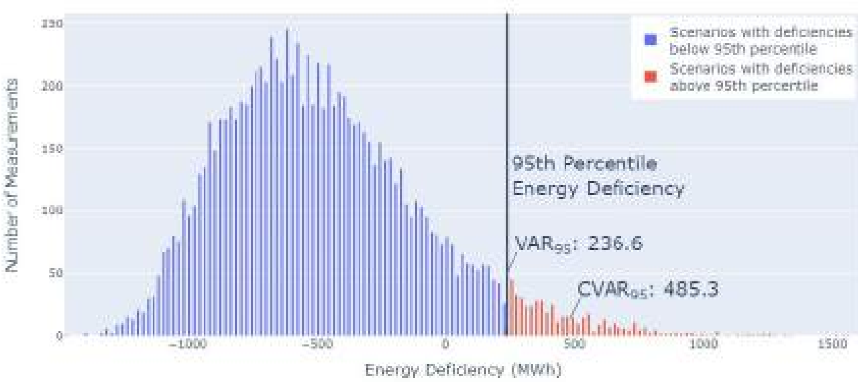

Figure 7.1: Example of V~~A~~aR and CV~~A~~aR for the 95th percentile of energy deficiency. VAR is 236.67 since it is the 95th percentile of the measurements and CVAR is the mean of the values greater ~~tha~~than the 95th percentile (shown in red).

[47] ~~"Adequacy Standards & Criteria" EPRI.~~

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Selecting the Right Metrics and Criteria

The methods used to perform an ERA ~~are a decision to~~should be ~~made~~decided on in the early stages of development~~,~~ ~~as these~~ and will drive subsequent decisions and/or potential corrective actions. Methods and metrics would likely be developed in tandem with one another and are inherently subject to the risk tolerance of stakeholders. Considerations for scenario-dependent, deterministic metrics would also be part of that development. Probabilistic ERAs will have different metrics and criteria than deterministic ERAs. Similarly, scenarios with varying levels of supply loss or additional demand will have different minimum criteria than "all-facilities-in" or "normal conditions" ERAs.

It is also necessary to decide what parameters are important for measuring while staying in alignment with existing standards or other requirements. For example, the decision point on either maintaining some amount of Operating Reserves[48] or avoiding energy shortfall (i.e., load shed) comes early in the process and may vary by scenario simulated. Considerations for operations procedures or actions should also be tak~~i~~en~~g~~ into account when establishing criteria. This decision will also guide the analysts on what information is needed to come out of the ERA.

Using Deterministic Metrics

Deterministic ERAs and associated scenarios imply that a small set of discrete possibilities are examined. These scenarios ~~are~~make it easier to inspect and determine what mitigation activities would lower the risk of specific scenarios. This ~~aspect makes~~facilitates communication of the choice of mitigation activities and ~~problems that were~~ identified ~~easier~~problems.

Using Probabilistic Metrics

Probabilistic metrics can be similar to those used in deterministic ERAs, with the addition of an associated probability, resulting in a metric that is defined as a criteria curve rather than a single point. The criteria curve would be on axes of the metric and probability, and ~~then~~ the results of the ERA could be plotted against the criteria curve. The ~~final~~ result of the defined criteria would then be a curve showing the results of the ERA versus a curve showing the pass/fail criteria.

Using Multiple Metrics and Criteria

Given that each metric represents an aspect of risk (frequency, duration, or magnitude), combining metrics is likely necessary to achieve the specified goals in performing the ERA. The use of multiple metrics will evolve and may even include using both probabilistic and deterministic methods to enable a better understanding of resource and energy ~~a~~Adequacy conditions.[49]~~.~~

The reliability or risk thresholds can be set by a number of entities, not always the one performing the ERA or implementing the corrective or preventive actions. Criteria should be set through some stakeholder process, formal or otherwise, to ensure that affected parties are able to contribute and convey their concerns.

Table 7.1: Representation of Metrics in ERAs

Metrics	**Type of Metric**	**Can Represent Duration**	**Can Represent Frequency of Event**	**Can ~~r~~Represent Magnitude or Impact of ~~e~~Events**	**Can Represent Tail Risk**
Forecasted EEA	Deterministic			X	X*

48 Note, for one example, that NERC Standard *BAL-002-3 – Disturbance Control Standard – Contingency Reserve for Recovery from a Balancing Contingency Event* may provide useful guidance on developing an ERA-based criteria for maintaining operating reserves throughout the duration of an ERA.

49 See "New Resource Adequacy Criteria for the Energy Transition" for more discussion on choosing and using multiple criteria. https://www.esig.energy/new-resource-adequacy-criteria/

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Table 7.1: Representation of Metrics in ERAs					
Metrics	**Type of Metric**	**Can Represent Duration**	**Can Represent Frequency of Event**	**Can ~~r~~Represent Magnitude or Impact of ~~e~~Events**	**Can Represent Tail Risk**
Energy Reserve Margin	Deterministic			X	X*
Unserved Energy	Deterministic			X	X*
Loss of Load Probability (LOLP)	Expected or Average	X	X		
Expected Unserved Energy	Expected or Average			X	
Loss of Load Events (LOLEv)	Expected or Average		X		
Loss of Load Expectation	Expected or Average		X		
Loss of Load Hours	Expected or Average	X			
Value at Risk	Conditional or Percentile	X**	X**	X**	X
Conditional Value at Risk	Conditional or Percentile	X**	X**	X**	X

* Deterministic metrics can represent tail risk if being applied to a stress test or "extreme" scenario

** VaR and CVaR metrics can represent duration, frequency, or magnitude depending on whether they are applied to LOLH, LOLE/LOLEv, or EUE

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Chapter 8: Considerations for Corrective Actions

After performing an ERA and comparing the results to a set of defined criteria, if it is determined an energy shortfall is forecasted, the following actions could delay, reduce, or eliminate ~~energy shortfalls~~a potential realization of the forecasted energy shortfall or forecasted conditions ~~exceeding~~that exceed the pass/fail criteria. Likely, the pass/fail criteria will be more conservative than a real-life situation that would cause an energy shortfall, ensuring that there is some level of ~~contingency reserve~~Contingency Reserve or energy reserve to manage the uncertainty associated with the conditions being studied~~,~~. However, there may be some allowable shortfall depending on the risk tolerance, reiterating the importance of understanding, and establishing the appropriate criteria when developing a response. A set of corrective actions can be formulated into an ~~Operating Plan~~operating plan, Operating Process, Operating Procedure, Corrective Action Plan (all of which are NERC-defined terms),[50]~~),~~ or any number of documented or undocumented actionable steps to minimize the impact of an energy shortfall.

Possible corrective actions can range from some fairly limited in scope (e.g., enhanced communication and/or more frequent assessments) to widely expansive (e.g., controlled power outages across a ~~wide area in order~~Wide Area to conserve fuel that can be used when system conditions are at their worst), ~~and depend~~depending on the time horizon of the ERA. Near-term ERAs provide fewer options for mitigation than planning ERAs. Actions should be commensurate with the forecasted risk. Care should be taken to maintain reliability and minimize the impact on the BPS and the general public~~,~~ whenever possible~~, then minimize the severity when it is necessary~~. For example, public appeals should be considered before firm load shedding, when the option is available. Low-probability events may not require extreme responses.~~ Measured response that takes probability and severity into consideration when coming up with action plans.~~ Awareness and outreach with regulators and other stakeholders will help define the acceptable and proper responses to energy shortfalls and may also help with the establishment of more defined criteria commensurate with the risk tolerance. For longer-term planning purposes, corrective actions would include actions targeted at addressing the specific deficiencies noted in the ERA, such as enhancements to market structures, delaying planned retirements, or increasing the projected new builds on the system.

~~Considerations~~Examples of and considerations for possible actions, along with the time horizon where the actions would be appropriate, are outlined in the ~~following~~ table below. This is not intended to be an all-inclusive list~~,~~ and ~~also~~ may not apply in every situation. The responsible party performing these steps ~~must~~should use caution to ensure that they are effective and practical. It is becoming increasingly apparent that there is no single authority that can take action to remediate all energy reliability issues. Responsibility and authority depend~~s~~ on the actions being taken and can be assigned to the federal government~~s~~ (i.e., legislatures and agencies/regulators), state and/or provincial governments (~~i.~~e.g., legislatures and regulators), and registered entities (~~i.~~e.g., resource owners, independent ~~system operators, etc.). Awareness~~System Operators). Sound judgment, awareness, and collaboration between all entities and organizations, coupled with a well-defined problem and a range of options for practical solutions, is the most appropriate path to finding a solution to the forecasted energy reliability problem.

~~The following table lists suggested potential actions that should be considered, along with the time horizon where the actions would be appropriate. This list is not all-inclusive, nor does it list required actions. Sound judgement should be used when deriving the appropriate plan of corrective action.(s)~~

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

Table 8.1: Considerations for Recommended Corrective Actions in Response to Energy Shortfalls		
Corrective Action	**Time Horizon(s)**[51]	**Considerations**
Enhanced Communication	NT S P	For many actions that can prevent or minimize an energy shortfall, the entity performing the assessment may not have the authority to take all ~~of~~ the necessary corrective actions. Communicating early with parties ~~who~~that do have that authority allows for time to implement actions in the most efficient and successful manner. Pre-deficient communications should be considered as well. Depending on the time horizon, this can be in the form of seasonal workshops and tabletop exercises~~,~~ or simply holding meetings to inform parties of what indications they may receive and what actions they could take.
Perform more frequent ERAs	NT S	In a situation where highly variable inputs are driving the studied system into an energy shortfall, more accurate forecasts may be the solution. An assessment for several months or years in the future with a low to moderate probability of an energy shortfall may require more frequent assessments that refine the inputs as they become more certain. This allows the analyst to formulate plans with more concrete impact.
Capacity deficiency actions	NT	There are several capacity deficiency actions that would occur at the time when load shed is being used, in accordance with capacity-deficiency procedures. For an energy shortfall, there ~~must~~should be an understanding of what impact those actions will have to reduce or remedy the reliability issue. One example is using demand-response programs that target thermostats, hot or cold. When the ~~set-point~~setpoint of a thermostat is changed in response to a capacity deficiency, the temperature of a building is allowed to drift further away from comfortable settings. Unless those ~~set-points~~setpoints are maintained indefinitely, the energy requirement would remain relatively unchanged. Lowering the temperature ~~set-point~~setpoint on a cold day will draw less power over time~~,~~ but restoring the ~~set-point~~setpoint within only a few hours of lowering it will cause ~~for~~ a temperature recovery ~~to occur~~, drawing the same amount of overall energy, just at different times.

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Time Horizon definitions:
- NT = Near Term Operations Planning
- S = Seasonal Operations Planning
- P = Planning

Table 8.1: Considerations for Recommended Corrective Actions in Response to Energy Shortfalls		
Corrective Action	**Time Horizon(s)** 51	**Considerations**
Replenishment of fuel supplies	NT S P	ERAs will show when generators are expected to run out of fuel. ~~Replenishment of fuel~~Fuel replenishment is ~~a~~ key to extending the operations of stored fuel resources. Replenishment actions are highly dependent on how the power system is operated in a given area. Vertically integrated utilities can procure and schedule fuel directly, where power market operators are limited in the actions that they can take, mostly to providing more information to those ~~who have the responsibility to operate generators. Longer-term assessments can be used to inform market design, mandated buildout or retention of resources, or other methods to ensure that resources are available when needed.~~ responsible for operating generators
Outage ~~C~~coordination	NT S	Outages can cause or worsen energy reliability issues. When detected, rescheduling planned outages of energy resources may be the solution to deficiencies.
Dispatch to ~~Preserve Limited Fuel Inventory~~preserve limited fuel inventory	NT	Models may dispatch resources based on cost order, but if a shortfall in energy results, one alternative ~~maybe~~may be to dispatch resources in the order of fuel inventory to maximize reliability (e.g.~~.~~, capacity, energy, ~~ancillary services~~Ancillary Services) in future periods.
Targeted appeals for conservation	NT	Appeals for conservation should be considered~~,~~ and focused on *when* conservation would make an impact. To target conservation at the right time ~~requires~~, the analyst ~~to~~should understand what is causing the shortfall. For example, if the shortfall is caused by a lack of just-in-time fuels (solar, wind, natural gas), the time to conserve is at the moment of shortfall. If the cause of the shortfall is diminishing quantities of stored fuels, conservation should be targeted to when those fuels are in use~~,~~ so that the depletion rate is slowed.
Targeted controlled power outages (i.e., rolling blackouts)	NT	Controlled power outages can be a last resort or a preemptive action. When energy is unavailable to serve load, then that load must be shed. When ~~in a situation of~~facing a loss of stored fuels ~~where~~with conservation actions ~~are not enough~~insufficient to prolong the availability of that fuel, controlled power outages may ~~serve to~~ conserve the fuel. This ~~doesn't~~does not seem different~~, however it~~ than controlled power outages during an Energy Emergency but does offer the option to shift when the power outages occur, such that fuel is available when ~~it's~~it is needed most. For instance, shedding load would be done on a moderately cold day to conserve fuel so that load shed is not required on the coldest day. This consideration is highly situational and would require significant analysis, documentation, and coordination between multiple parties, specifically state and local authorities, and regulatory agencies. This ~~action~~ should not be taken lightly.

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Table 8.1: Considerations for Recommended Corrective Actions in Response to Energy Shortfalls		
Corrective Action	**Time Horizon(s)** [51]	**Considerations**
Operational strategies for electric storage	NT S P	No storage is 100% efficient. Therefore, energy storage devices (e.g., batteries, pumped storage~~, etc.~~)) are a net draw on energy supplies. Once ~~reaching a point where~~ energy shortfalls are occurring, changes to how storage is operated should be considered. Accounting for the operational aspects of storage in planning ERAs would inform the analyst of what shortfalls can be mitigated by optimizing electric storage.
Infrastructure ~~E~~expansion	P	While likely not ~~p~~f~~e~~e~~rmi~~as~~s~~ible in most cases, additional infrastructure may be needed ~~in order~~ to minimize energy shortfalls that are detected far enough in advance. While the entity performing ERAs may not have the authority to build infrastructure for energy reliability, informing the entities that do have that authority may yield positive results.
Retention of ~~R~~resources	P	After a resource or infrastructure is built, there are more opportunities to retain that resource to maintain energy reliability compared to building new resources.
Market ~~Rule Enhancements~~rule enhancements	P	Enhancing market rules to account for future energy needs can be one option for market operators. Market rules with an emphasis on energy can incentivize the right type of products that would serve as solutions to energy problems.

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Chapter 9: Conclusion

~~Energy reliability assessments are becoming~~ERAs are a necessary component in the suite of tools used by power system planners and operators as more ~~variable energy resources~~VERs and stored fuel dependencies gain prevalence. Gaps in traditional capacity assessment methods, when applied to energy-related issues, present risks where potential shortfalls can go undetected before a reliability event occurs. Efforts are underway to bolster assessment requirements and provide some clarity to industry such that these gaps can be better understood and undergo assessments that will ~~then~~ allow ~~for~~ planners and operators to take actions to reduce the impact of energy shortfalls or eliminate them altogether.

~~In this~~This technical reference document~~,~~ provides the reader ~~has been provided~~ with a framework that can be used to perform ~~energy reliability assessments~~ERAs. From input assumptions and tools/methods to criteria and corrective action considerations, the audience ~~now~~ has a better understanding of how to perform an ~~energy reliability assessment~~ERA. With more experience, and as the resource mix continues to evolve away from resources with relatively assured fuels to those with a wider degree of variability, there will be opportunities to develop new methods to perform assessments with new tools, build models to enhance corrective actions, and more clearly define criteria and metrics such that ~~energy reliability assessments~~ERAs are meaningful to stakeholders. The assessments described here are not intended to replace existing study work~~,~~ but to supplement that work and address energy-related assessment gaps necessary for understanding power system reliability.

Appendix A: Summary of Available and Suggested Data

This appendix is a summary of all ~~of~~ the tables in ~~c~~Chapters 1 through 4 delineating what information may be useful in performing ERAs and where that information might be available to the analyst to retrieve.

Table A.1: Abbreviations for Summary of Potential Information Sources in All ERAs	
Category	**Abbreviation**
Stored Fuels	SF
Natural Gas	NG
Energy Supply Variability	ESV
Electric Storage	ES
Variable Energy Resources	VER
Emissions Constraints on Generator Operations	ECGO
Energy Supply Outages	ESO
Distributed Energy Resources	DER
Demand	D
Transmission	T

Table A.2: Summary of Potential Information Sources in All ERAs

Near Term	Seasonal	Planning	Topic	Data	Potential Sources	Notes / Additional Considerations
X	X	X	SF	Specific, usable[52] inventory of each generation station	~~Generation survey~~ Generator surveys Assumptions based on historical performance	Inventory is often shared for a group of generators located at a single station. Surveys should be performed as often as necessary to initialize an assessment with accurate information. It is recommended to start each iteration of an assessment with updated data. Hydroelectric resources may need to consider the availability of water as a fuel input – change over the course of the year or vary by year. Environmental limitations~~ –~~: water flows/rights priority, dissolved oxygen (DO) limitations, etc. Stored fuels may be used for unit start-up with a portion embargoed for ~~black start~~blackstart service provision.
X	X	X	SF	Minimum consumption requirements of fuels that have shelf-life limitations	Surveys of ~~generator owners~~Generator Owners or ~~o~~Operators Assumptions based on ~~H~~historical performance	May result in a fuel being consumed at a time when it is less ~~-~~than ~~-~~optimal.
X	X	X	SF	Replenishment assumptions	Generator surveys Assumptions based on historical performance	Replenishment is key to modeling inventory at any point during the study period. Replenishment restrictions are also an important aspect of an ERA.

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[52] Usable inventory is the amount of fuel that is held in inventory after subtracting minimum tank levels that are required for quality control and fuel transfer equipment limitations.

Table A.2: Summary of Potential Information Sources in All ERAs						
Near Term	**Seasonal**	**Planning**	**Topic**	**Data**	**Potential Sources**	**Notes / Additional Considerations**
X	X	X	SF	Shared resources	Generator surveys or registration data	Modeling the sharing of fuel between multiple resources allows for precise modeling of fuel availability.
X	X	X	SF	Global shipping constraints	Industry news reports	Stored ~~energy~~fuel supply is often impacted by world events that cause supply chain disruptions~~.~~ ~~This includes~~, including port congestion, international conflict, shipping embargoes, and confiscation.
X	X	X	SF	Localized shipping constraints	Weather forecasts or assumptions, direct communication with local transportation providers, emergency declarations[53]	Considerations for local trailer transportation of fuels over wet/snow-covered roads, rail route disruptions due to weather or debris, as well as seaport weather when docking ships or river transportation route restrictions for barge movements.
X	X	X	NG	Pipeline transportation capacity	Pipeline Electronic Bulletin Boards (EBB), open season postings, firm transportation contracts	Interstate pipeline information is readily available through public sources, usually directly from the pipeline company itself.
X	X	X	NG	Gas pipeline constraints	EBB postings of operationally available capacity and planned service outages, pipeline maps	Starting with pipeline maps or one-line diagrams, pinpointing the location of specific constraint points requires research. Communication with pipeline operators is helpful when specific locations are in question or difficult to find.
X	X	X	NG	Generator location on pipelines	Pipeline maps, generator surveys, registration data	Research is required to properly place generators on pipelines in the correct location.

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[53] https://www.fmcsa.dot.gov/emergency-declarations

Table A.2: Summary of Potential Information Sources in All ERAs

Near Term	Seasonal	Planning	Topic	Data	Potential Sources	Notes / Additional Considerations
X	X	X	NG	Non-generation demand estimates	Historical scheduled gas to city ~~-~~gates and end users, historic~~al~~ weather data, weather assumptions based on historic~~al~~ weather and climatology	Similar to load forecasting on the electric system, gas estimates play a crucial role in developing a holistic energy solution. Assuming that more gas is available than physically possible could lead to inaccurate study results.
X	X	X	NG	Heating and end-user demand assumptions	Filings with state regulators, historical demand data	Regulated utilities will file their expected needs for natural gas with their respective state regulators.
X	X	X	NG	Contractual arrangements	EBB index of customers, generator surveys, FERC Form 549B	Some information can be obtained via the EBB Index of Customers~~,~~; however~~ there are~~, nuanced data ~~that~~ would ~~be~~ ~~needed~~need to be queried directly from generators. Non-public information includes generator arrangements with gas marketers and participation in capacity release agreements.
X	X	X	NG	Generator heat rates	Registration data, generator surveys	Converting electric energy to fuel consumption and vice versa requires the heat rate of a generator, typically expressed in Btu/kWh or MMBtu/MWh.
X	X	X	ESV	VER assumptions	VER forecasts as described in the ~~variable energy resources~~VER sections of this document	VER production drives the need for flexible generation to be available or online. Additionally, the ability to curtail VER production should be considered as a mitigating option.
X	X	X	ESV	Generation ramping capability	Registration data, market offers	Balancing resources would be used to maintain system frequency from moment to moment.

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Table A.2: Summary of Potential Information Sources in All ERAs

Near Term	Seasonal	Planning	Topic	Data	Potential Sources	Notes / Additional Considerations
X	X	X	ESV	Fuel supply dynamic capabilities	Fuel supply network models, market-based models to determine volumes delivered to specific sectors or historic~~al~~ observations	The key to including ramping capability in an ERA is focusing on the capabilities of the fuel delivery network (e.g., gas pipelines, fuel oil or coal delivery systems at specific generators) and how that network responds to the ramping needs of the system.
X	X	X	ECGO	Output limitations for a set of generators	Generator surveys	Each ~~generator owner/operator~~Generator Owner/Operator may know their own operational information, but when determining when a collection of generators will reach a limit would require gathering information that each owner/operator has but not as a collective. The analys~~is~~t performing the ERA would be the centralized collection point of the information required to accurately model the limit.
X	X	X	ESO	Forced ~~Outage Rates~~ outage rates	NERC GADS, assumptions based on historical performance	NERC requires outages and reductions to be reported with associated cause codes and makes that information available to registered entities. Alternatively, analysts can observe historical unplanned outage information to determine similar assumptions.
X	X	X	ES	Maximum charge ~~/~~ /discharge rates (in MW or kW) and total storage capability (in MWh or kWh)	Registration data~~, operational data~~	These two parameters combined define~~d~~ the primary characteristics of a storage device.

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Table A.2: Summary of Potential Information Sources in All ERAs						
Near Term	**Seasonal**	**Planning**	**Topic**	**Data**	**Potential Sources**	**Notes / Additional Considerations**
X	X	X	ES	Usable Capacity	Registration data, operational data	Battery storage may not operate well above and below a specific charged percentage. For example, batteries charged above 80% or below 20% may ~~under perform.~~underperform. Therefore, the storage capacity may be less tha~~t~~n intended.
X	X	X	ES	Transition time between charge and discharge cycles	Registration data, operational data, market offers	
X	X	X	ES	Cycling efficiency	Operational data	Calculating the cycling efficiency of storage can be done using operational data, dividing the sum of output energy by the sum of input energy over some period. A longer duration will yield a more accurate efficiency value. All storage requires more input energy than the output that will be produced.
X	X	X	ES	Co-located~~,~~ ~~H~~/hybrid or ~~stand-alone~~standalone configuration. Charging source~~,~~ – primary and secondary	Registration data	Scenario studies may remove a generation type (~~i.~~e.g., solar~~)~~), which may eliminate the energy supply source.

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Table A.2: Summary of Potential Information Sources in All ERAs						
Near Term	Seasonal	Planning	Topic	Data	Potential Sources	Notes / Additional Considerations
X	X	X	ES	Ambient temperature limits	Registration data, operational data	This ~~is~~refers to the ambient temperature limitations at the storage facility, which are part of the formula for calculating cell temperature limitations. There are high- and low-temperature requirements for charging and discharging batteries at a normal rate. Outside that band, the rate of charge could be reduced, potentially to 0.
X	X	X	ES	No-~~L~~load losses	Registration data, operational data	Electric storage facilities may experience a loss of energy even when not delivering energy to the grid.
X	X	X	ES	Emergency ~~L~~limits	~~Registration data, operational data~~	Can the storage resource run below the P-Min or above the P-Max, and if so, for how long?
X	X	X	T	Planned ~~O~~outages and Maintenance	~~TOPs, TOs,~~Transmission Operators (TOP), Transmission Planners (TP), or other transmission planning entities	~~Should be included in the BA and/or TOP Data Specifications~~
X	X	X	T	Import/~~Export Transport Limits~~export transfer limits	~~Topology and ATC or similar calculations, engineering studies~~Engineering studies	
X	X	X	T	Import/~~Export Resource Limits~~export resource limits	Coordinated ERA with neighboring areas	Aligning input assumptions between areas would be necessary for ensuring that energy is not ignored or double counted in multiple ~~regions~~areas.
X	X	X	T	Transmission ~~T~~topology and ~~C~~characteristics	~~BAs~~Transmission and ~~TOPs~~distribution models	Potentially, ~~you may use~~using a simplified or ~~DC~~ dc-equivalent circuit for probabilistic or similar analysis. Considerations for including planned transmission expansion projects.

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Table A.2: Summary of Potential Information Sources in All ERAs						
Near Term	Seasonal	Planning	Topic	Data	Potential Sources	Notes / Additional Considerations
X	X	X	T	Transmission ~~Outage Rates~~outage rates	NERC ~~G~~TADS	Ideally, weather-dependent and ~~unit~~ facility-specific outage rates could be used to reflect energy scenarios.
X			SF	Current inventory, inventory management plans, and replenishment assumptions	Generator surveys, assumptions based on historic~~al~~ performance, or annually variable conditions specific to the resource type	Replenishment is key to modeling inventory at any point during the study period. Replenishment restrictions are also an important aspect of an ERA. Performance expectations for hydroelectric resources may be informed by seasonal runoff conditions.
X			NG	Natural gas scheduling timelines	Pipeline tariffs, NAESB	Timelines may differ between pipelines. The NAESB sets five standard cycles that are to be followed by Federal Energy Regulatory Commission (FERC) jurisdictional entities (which generally excludes intrastate pipelines and local distribution networks~~)~~).
X			NG	Natural gas commodity pricing and availability	Intercontinental Exchange (ICE~~)~~),[54]~~,~~ Platts[55]	Natural gas commodity pricing is an indicator of its availability. Continuously monitoring pricing will allow an analyst to estimate the availability of natural gas into a near-term ~~energy reliability assessment.~~ERA.

[54] https://www.ice.com/index
[55] https://www.spglobal.com/en/

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Table A.2: Summary of Potential Information Sources in All ERAs						
Near Term	Seasonal	Planning	Topic	Data	Potential Sources	Notes / Additional Considerations
X			VER	Vendor supplied but could be developed using weather service models In-house models or vendor~~Weather forecasts~~-supplied data	There could be differences between one or multiple central forecast(s) and the aggregation of independent forecasts. Forecast error analysis of historical data would provide a measure of the performance of available options. Wind/solar profiles can be modified to capture uncertainty associated with rainy, windy, and/or cloudy days. It is important to maintain the correlation between wind, solar, and load in conducting these analyses.~~Vendor supplied but could be developed using weather service models~~ ~~In-house models or vendor supplied data~~	Vendor supplied but could be developed using weather service models In-house models or vendor-supplied data~~There could be differences between one or multiple central forecast(s) and the aggregation of independent forecasts. Forecast error analysis of historical data would provide a measure of the performance of available options.~~ ~~Wind/solar profiles can be modified to capture uncertainty associated with rainy, windy and/or cloudy days.~~ ~~It's important to maintain the correlation between wind, solar and load in conducting these analysis.~~

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Table A.2: Summary of Potential Information Sources in All ERAs

Near Term	Seasonal	Planning	Topic	Data	Potential Sources	Notes / Additional Considerations
X			VER	Vendor supplied but could be developed using weather service models~~VER production forecasts~~	Significant research and development have been done in the last decade to create and improve VER/DER forecasts for use in power system operations and analysis, including ERAs. Hourly or sub-hourly profiles of actual production from VERs can be scaled up or down to fit specific scenarios in an ERA.~~Vendor supplied but could be developed using weather service models~~	Vendor supplied but could be developed using weather service models~~Significant research and development has been done in the last decade to create and improve VER/DER forecasts for use in power system operations and analysis, including ERAs. Hourly or sub-hourly profiles of actual production from VERs can be scaled up or down to fit specific scenarios in an ERA~~
X			ECGO	Output limitations by specific generators	Generator surveys	For short-term assessments, generator surveys would be the best source of emissions limitation information. Generator ~~owner/operators~~Owner/Operators should be ~~well~~ aware of what their limits would be and the plans to abide by those limits.
X			ECGO	Output limitations for a set of generators	Generator surveys	Each ~~generator owner/operator~~Generator Owner/Operator may know their own operational information, but when determining when a collection of generators will reach a limit would require gathering information that each owner/operator has but not as a collective. The analys~~is~~t performing the ERA would be the centralized collection point of the information required to accurately model the limit.

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Table A.2: Summary of Potential Information Sources in All ERAs						
Near Term	**Seasonal**	**Planning**	**Topic**	**Data**	**Potential Sources**	**Notes / Additional Considerations**
X			ESO	Planned ~~O~~outages and ~~M~~maintenance	Maintenance schedules and outage coordination tools	ERAs can use planned maintenance as an input but can also be used to advise the shifting of planned maintenance to minimize energy-related risks.
X			DER	Installation data	Electric utility companies (i.e., Distribution Providers, or DPs), production incentive administrators	DERs are likely to be required to coordinate with the distribution ~~system operator~~System Operator before interconnecting. Additionally, any DER that is participating in a ~~sort of~~ renewable energy credit program will likely need to register with and provide production information to a program administrator.
X			DER	Forecasted DER production	Vendor supplied but could be developed using weather service models	Significant research and development ha~~s~~ve been done in the last decade to create and improve DER/VER forecasts for use in power system operations and analysis, including ERAs.
X			DER	Historical performance, observations of net load	Historical patterns of demand compared to a longer history	Comparing a similar-day demand curve from a more recent year to one from a year prior can give a sense of the difference in DER that was installed year-over-year.
X			DER	Estimated performance of DERs	Based on limited samples of a subset of the DER type	Modern DERs may have advanced measurement devices that could be made available through vendor aggregation services. Smaller, evenly -distributed samples could be used to scale to the full amount. Testing should be done to validate whether the conceived process is accurate.
X			D	Weather forecasts or projections	Numerical weather prediction (NWP) models, weather forecast vendors	Weather information is the primary variable input to demand forecasts. Near-term assessments can use weather forecasts.

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Table A.2: Summary of Potential Information Sources in All ERAs

Near Term	Seasonal	Planning	Topic	Data	Potential Sources	Notes / Additional Considerations
X			D	Actual demand forecasts or projections	Load forecast models using weather information as an input ~~-~~	Historical weather and demand may be useful for projecting future conditions~~,~~; however, caution should be exercised to ensure that interrelated parameters remain interrelated. Decoupling weather and load could result in implausible outcomes.
X			D	Demand~~ R~~-response capabilities	Electric utilities or other organizations (e.g., demand-response aggregation service providers) that manage participation in demand-response programs	
X			ES	State of ~~C~~charge	Resource owner	Additional considerations may be given to state of charge in a near-term ERA that reflect the recent operation of the electric storage facility.
X			ES	Ramp Rate (~~Up/Down~~up/down) MW/minutes	Resource owner	Rate that the electric storage resource can discharge or absorb energy when electric demand or supply changes.
X			ES	Cell ~~B~~balancing	Resource owner	This describes the change-out of cells within a storage device. Specifically, this would apply to faulty cells that could limit the capability of a battery plant. Balancing takes a few days to accomplish once cells are replaced.
X			ES	Project-specific incentives (e.g., ~~Investment Tax Credits~~investment tax credits)	Resource owner	Investment tax credits, either ~~P~~production or ~~I~~investment, may indicate how the electric storage resource will run.

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Table A.2: Summary of Potential Information Sources in All ERAs						
Near Term	**Seasonal**	**Planning**	**Topic**	**Data**	**Potential Sources**	**Notes / Additional Considerations**
X			ES	Cell temperature limits[56]	Resource owner	This is the ambient temperature at the storage facility. There are high- and low-temperature requirements for charging and discharging batteries at a normal rate. Outside that band, you may reduce the rate of charge, potentially to 0.
	X		SF	Current inventory, inventory management strategies, and replenishment assumptions	Generator surveys, formal or informal generator outreach, assumptions based on historical performance, or annually variable conditions specific to the resource type	Replenishment is key to modeling inventory at any point during the study period. Replenishment restrictions are also an important aspect of an ERA. Performance expectations for hydroelectric resources may be informed by seasonal runoff conditions. Generator surveys can still be useful just prior to a specific season; however, this information may still introduce some uncertainty at the time that the ERA is being performed. Communication with the entities deciding on replenishment strategies would result in more accurate assumptions for starting inventories.

[56] Lithium-ion battery: Charge temperature at 32°F to 113°F; Discharge temperature at -4°F to 140°F
Lead acid battery: Charge temperature at -4°F to 122°F; Discharge temperature at -4°F to 122°F
Nickel-based battery: Charge temperature at 32°F to 113°F; Discharge temperature at -4°F to 149°F

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Table A.2: Summary of Potential Information Sources in All ERAs

Near Term	Seasonal	Planning	Topic	Data	Potential Sources	Notes / Additional Considerations
	X		SF	~~Regional availability~~Availability of overall fuel storage	U.S. Energy Information Administration (EIA) reports	The U.S. EIA reports weekly inventories for five Petroleum Administration for Defense Districts (PADD). This can be an indicator of whether ~~or not~~ fuel may be available for generator fuel replenishment.
	X		SF	Shipping constraints	Industry news reports	Seasonal ERAs could be impacted by ~~current~~ weather patterns and world events that cause supply chain disruptions~~. This includes~~, including port congestion, international conflict, shipping embargoes, and confiscation.
	X		NG	Pipeline, production, import, and export expansion projects	Pipeline websites, filings with state and federal agencies, advertising for open seasons	This includes new pipelines, compressor enhancements and expansions, and LNG import and export projects that will increase or reduce the amount of natural gas that is available.
	X		NG	Pipeline Planned Service Outages	~~Electronic Bulletin Boards (EBB)~~EBB	Interstate natural gas pipelines are required[57] by FERC to post maintenance plans on their public-facing EBBs.
	X		NG	Natural gas commodity futures pricing	Several internet sources that monitor futures pricing	Futures pricing can give a sense of what pricing pressures the commodity is facing in the coming year(s). It may not be a fully accurate picture of what the pricing will be~~,~~ but gives an analyst some direction for a starting point for a seasonal ERA.

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[57] See U.S. Code of Federal Regulations Chapter I, Subchapter I, Part 284, Subpart A, § 284.13.(d).(1) - https://www.ecfr.gov/current/title-18/chapter-I/subchapter-I/part-284/subpart-A/section-284.13

Table A.2: Summary of Potential Information Sources in All ERAs

Near Term	Seasonal	Planning	Topic	Data	Potential Sources	Notes / Additional Considerations
	X		VER	Weather outlook	NOAA (for the United States), ~~Historical~~Environment and Climate Change Canada, historical observations, ~~W~~ weather models	Seasonal outlooks ~~from NOAA~~ can provide a direction on which historical observations to select when performing a seasonal ERA.
	X		VER	VER production assumptions	Historical observations adjusted for weather outlooks	Historical observations can set a starting point for what can be expected in upcoming seasons. Th~~at~~is would need to be adjusted for other known factors, such as drought conditions or temperature expectations.
	X		VER	New VER installations	Installation queues	New VERs installed between the time that an ERA is performed, and the start of the upcoming season can be large enough to impact the outcome and should be included as accurately as possible. ~~On the~~The seasonal horizon~~, there~~ should ~~be some~~have more certainty on what will be commissioned or not.
	X		ECGO	Output limitations by specific generators	Generator surveys	For short-term assessments, generator surveys would be the best source of emissions limitation information. Generator ~~owner/operators~~Owner/Operators should be ~~well~~ aware of what their limits would be and the plans to abide by those limits.

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Table A.2: Summary of Potential Information Sources in All ERAs						
Near Term	Seasonal	Planning	Topic	Data	Potential Sources	Notes / Additional Considerations
	~~X~~		~~ECGO~~	~~Output limitations for a set of generators~~	~~Generator surveys~~	~~Each generator owner/operator may know their own operational information, but when determining when a collection of generators will reach a limit would require gathering information that each owner/operator has but not as a collective. The analysis performing the ERA would be the centralized collection point of the information required to accurately model the limit.~~
	X		ESO	Weather-dependent outage rates	Surveys, registration information, assumptions based on historic~~al~~ performance	GADS will provide average outage rates. The information from GADS can be combined with weather information to derive correlations with weather conditions that could be modeled in an ERA.
	X		ESO	Outage mechanisms	NERC GADS, operator logs	Outage mechanisms can be used to determine outage duration and impact.
	X		ESO	Planned outage schedules	Outage coordination records	Planned outages are a good start for modeling the unavailability of resources, but considerations should be given to the accuracy of plans. Not every outage goes according to plan, and they may finish early or overrun.
	X		DER	Installation data coupled with expansion assumptions	Electric utility companies (i.e., ~~Distribution Providers, or~~ DPs), production incentive administrators	~~Similar to~~Like the information needed for a near-term ERA, DERs are likely to coordinate with distribution ~~system operators, giving~~System Operators, providing a path to make information available. Future information may also be available through those same channels~~,~~ but may also need to be inferred based on ~~regional~~ trends, growth forecasts, or legislative goals.

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Table A.2: Summary of Potential Information Sources in All ERAs

Near Term	Seasonal	Planning	Topic	Data	Potential Sources	Notes / Additional Considerations
	X		DER	Historical DER production data	Operations data, assumptions based on past performance	The analyst may choose to model DER explicitly as a supply resource or as a demand reduction. Modeling the DER separately and incorporating it to the resource mix will allow the analyst to vary the assumptions without impacting other facets of the ERA.
	X		D	Weather forecasts or projections	Historical data, seasonal weather projections (e.g., the National Weather Service, Climate Prediction Center outlooks)[58], Environment and Climate Change Canada,	Weather information is the primary variable input to demand forecasts. Near-term assessments can use weather forecasts. Longer-term assessments, including ~~S~~seasonal assessments, typically require assumptions or projections of weather due to forecast accuracy.
	X		D	Actual demand forecasts or projections	Load forecast models using weather information as an input	Historical weather and demand may be useful for projecting future conditions~~,~~; however, caution should be exercised to ensure that interrelated parameters remain interrelated. Decoupling weather and load could result in implausible outcomes.
	X		D	DER production forecasts or projections	Weather-based prediction models using the assumed weather as an input, which are available from a variety of vendors	This may or may not be considered in the demand side of the energy balance equation. Correlation with modeled weather conditions should be considered.

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[58] https://www.cpc.ncep.noaa.gov/products/predictions/long_range/

Table A.2: Summary of Potential Information Sources in All ERAs

Near Term	Seasonal	Planning	Topic	Data	Potential Sources	Notes / Additional Considerations
	X		D	Demand-response capabilities and expectations	Electric utilities or other organizations (e.g., demand-response aggregation service providers) that manage participation in demand-response programs	Not all demand response operates at the command of the entity responsible for dispatching resources.
	X		ES	Cell temperature limits[59]	Resource owner	This is the ambient temperature at the storage facility. There are high- and low-temperature requirements for charging and discharging batteries at a normal rate. Outside that band, you may reduce the rate of charge, potentially to 0.
	X		ES	Ramp Rate (~~Up/Down~~up/down) MW/minutes	Resource owner	Rate that the electric storage resource can discharge or absorb energy when electric demand or supply changes.
	X		ES	Project-specific incentives (e.g., ~~Investment Tax Credits~~investment tax credits)	Resource owner	Investment tax credits, either ~~P~~production or ~~I~~investment, may indicate how the electric storage resource will run.
		X	SF	Inventory management and replenishment assumptions	Assumptions based on historical performance and/or commodity market evaluations.	Replenishment is key to modeling inventory at any point during the study period. Replenishment restrictions are also an important aspect of an ERA.

[59] Typically, today's battery technologies are constrained to the following temperature bands:
Lithium-ion battery: Charge temperature at 32°F to 113°F; Discharge temperature at -4°F to 140°F;
Lead acid battery: Charge temperature at -4°F to 122°F; Discharge temperature at -4°F to 122°F;
Nickel-based battery: Charge temperature at 32°F to 113°F; Discharge temperature at -4°F to 149°F

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Table A.2: Summary of Potential Information Sources in All ERAs

Near Term	Seasonal	Planning	Topic	Data	Potential Sources	Notes / Additional Considerations
		X	SF	~~Regional availability~~Availability of overall fuel storage	EIA reports	The U.S. ~~Energy Information Administration~~EIA reports weekly inventories for five ~~Petroleum Administration for Defense Districts (PADD).~~PADDs. Trending PADD inventories over time may provide insight into how replenishment may occur over longer periods of time.
		X	SF	Intra-annual hydro availability	Historical drought or high-runoff conditions	~~Drought~~Since drought and high-runoff hydro forecasts may not cover an extensive enough period to depend on for a planning ERA, ~~so~~ assumptions would need to be made based on historical information.
		X	NG	Pipeline, production, import, and export expansion projects	Pipeline websites, filings with state and federal agencies, advertising for open seasons	This includes new pipelines, compressor enhancements and expansions, and LNG import and export projects that will increase or reduce the amount of natural gas that is available.
		X	VER	Expected installed resources	Interconnection queue, ~~E~~ economic analysis~~,~~ and forecasts	
		X	VER	Renewable energy goals	State legislature dockets	These goals drive the rate at which renewable (and likely variable energy) resources are built, including target years and amounts.
		X	VER	Production assumptions	Historical observations, weather models, climate trends	Profiling the expanded fleet across some historical dataset, adjusted for expected trends in climate, gives an ERA plausible inputs.

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Table A.2: Summary of Potential Information Sources in All ERAs

Near Term	Seasonal	Planning	Topic	Data	Potential Sources	Notes / Additional Considerations
		X	ECGO	Output limitations by specific generators	Generator surveys	For short-term assessments, generator surveys would be the best source of emissions limitation information. Generator ~~owner/operators~~Owner/Operators should be ~~well~~ aware of what their limits would be and the plans to abide by those limits.
		X	ECGO	Trends in individual state carbon emissions goals	State government or public utilit~~ies~~y commission (PUC) websites	When assessing the probability of long-term retirements and new construction, emissions goals may provide insight to the analysts to decide whether ~~or not~~ a specific resource or a subset of the entire fleet may or may not be viable under the expected rules.
		X	ESO	~~Planned Outage Cycles~~Forced-outage rates	~~Historical planned outrages~~NERC GADS, assumptions based on historical performance	~~While it's unlikely to have a firm outage schedule years in advance, some information can be gleaned from historical outage trend evaluation. For example, a specific nuclear plant refuels every 18 months at a fairly dependable schedule, or generators with annual inspection requirements are consistent with the timing of those outages.~~NERC requires outages and reductions to be reported with associated cause codes and makes that information available to registered entities. Alternatively, analysts can observe historical unplanned outage information to determine similar assumptions.
		X	ESO	Weather-dependent outage rates	Surveys, registration information, assumptions based on historical performance	GADS will provide average outage rates. The information from GADS can be combined with weather information to derive correlations with weather conditions that could be modeled in an ERA.

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Table A.2: Summary of Potential Information Sources in All ERAs						
Near Term	Seasonal	Planning	Topic	Data	Potential Sources	Notes / Additional Considerations
		X	ESO	Assumed outage rates for newly constructed supply resources	Fleet averages using existing resources, when possible	New construction using existing plans means that there is likely a similar resource somewhere that has some performance data that can be used to estimate the performance of a new resource.
		X	ESO	Outage mechanisms	NERC GADS, operator logs	Outage mechanisms can be used to determine outage duration and impact.
		X	DER	Growth estimates, renewable energy goals	State government and PUCs, directly or via their websites	
		X	D	Weather forecasts or projections	Historical data, adjusted using climate models	Weather information is one of the primary inputs to longer-term demand forecasts. Longer-term assessments typically require assumptions or projections of weather due to forecast accuracy concerns.
		X	D	Actual demand projections	Historical actual demand modified by the expected impact of demand changes, load forecast models using weather information as an input	Historical weather and demand may be useful for projecting future conditions; however, caution should be exercised to ensure that interrelated parameters remain interrelated. Decoupling weather and load could result in implausible outcomes. Performing an energy assessment still requires a profiled demand curve over a period of time. Most legacy long-term forecasts produce a set of seasonal peak values.

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Table A.2: Summary of Potential Information Sources in All ERAs						
Near Term	Seasonal	Planning	Topic	Data	Potential Sources	Notes / Additional Considerations
		X	D	Projected changes in actual demand magnitude and profile (e.g., load growth)	Analysis of economic factors, governmental policy, and technical considerations	This should include the impact on demand magnitude as well as changes in demand profiles. This includes energy efficiency and electrification. Electrification of heat is a function of local temperatures. Electrification of transportation will be more linked to commute distances and time ~~-~~of ~~-~~day.
		X	D	DER production forecasts or projections	Historical production data, scaled to future capability	This may or may not be considered in the demand side of the energy balance equation. Correlation with modeled weather conditions should be considered.
		X	D	Demand ~~R~~-response capabilities	Electric utilities or other organizations (e.g., demand-response aggregation service providers) that manage participation in demand-response programs.	

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~~Appendix B: Lists of Examples and Figures~~

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~~Appendix C:~~Appendix B: Contributors

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