Agenda
Reliability and Security Technical Committee

June 11, 2024 | 8:00 a.m. – 4:00 p.m. Pacific
Hybrid

Amazon Headquarters
SEA51 Mayday
1220 Howell Street
Seattle, WA 98101

Join WebEx

Call to Order

NERC Antitrust Compliance Guidelines and Public Announcement

Safety Briefing by Amazon Security

Introduction and Chair's Remarks

Agenda

1. **Administrative items**
   a. Arrangements
   b. Announcement of Quorum
   c. Reliability and Security Technical Committee (RSTC) Membership 2023-2026
      i. RSTC Roster
      ii. RSTC Newsletter
      iii. RSTC Charter
      iv. Participant Conduct Policy
   d. RSTC Executive Committee (EC) Actions taken between meetings:
      i. RSTC Work Plan Changes:
         (1) Removal of "Special Reliability Assessments Scope and Prioritization" from RAS work plan
         (2) High Priority Work Plan items (Reviewed in March with RSTC) and the RSTC Work Plan
         (3) SPIDERWG Work Plan Change (Table SAR and Develop Technical Reference Document)
      ii. Sponsor Appointments
      iii. Standards Committee Request for RSTC Review of CIP-013 SAR by the SCWG

Consent Agenda

2. **Consent Items* – Approve**

a. March 11-12, 2024 RSTC Meeting Minutes

b. Electric Gas Working Group Scope Document

Regular Agenda

3. **Remarks and Reports**

   a. Subcommittee Reports*

   b. RSTC Work Plan

   c. Report of May 8, 2024 Member Representatives Committee (MRC) Meeting and May 9, 2024 Board of Trustees Meeting

4. **Large Loads Task Force Scope* and Electric Vehicle Task Force Scope* – Approve** – Marilyn Jayachandran, John Skeath, NERC Staff

5. **Reliability Guideline: Generating Unit Operations During Complete Loss of Communications* – Approve** – Greg Park, RS Chair | Rich Hydzik, Sponsor

6. **An Analysis of ERO Event Analysis Process Data with Respect to Human and Organizational Performance – Information** – Ed Ruck, NERC Staff

7. **Performance Analysis Program Update: State of Reliability Report – Information** – Donna Pratt, NERC Staff

8. **Reliability Guideline: Electromagnetic Transient Studies for Interconnection of Inverter-Based Resources (EMTTF Work Item #2)* – Accept to post for a 45-day Comment Period** – Aung Thant, NERC Staff | Jody Green, Sponsor

9. **Technical Reference Document: Considerations for Performing an Energy Reliability Assessment – Vol 2* – Accept to Post for a 45-day Public Comment Period** – Mike Knowland, ERAWG Chair | Srinivas Kappagantula, Sponsor

10. **Reliability Guideline: DER Forecasting and Relationship to BPS Studies* – Accept to Post for a 45-day Public Comment Period** – Shayan Rizvi, Chair SPIDERWG | Wayne Guttormson, Sponsor

11. **White Paper: Variability, Uncertainty, and Data Collection* – Request RSTC Comments** – Shayan Rizvi, Chair SPIDERWG | Wayne Guttormson, Sponsor

12. **White Paper: Sampling as Part of an Effective Facility Ratings Program* – Request RSTC Comments** – Jennifer Flandermeyer, Chair FRTF | Ian Grant, Sponsor

13. **Revised Implementation Guidance: Reliability Standard FAC-008-5* – Request RSTC Comments** – Robert Reinmuller, FRTF Team Lead | Ian Grant, Sponsor

14. **White Paper: New Technology Enablement and Field Testing * – Request RSTC Comments** – Brian Burnett, SITES Chair | Marc Child, Sponsor

15. **Proposed Charter Revisions* – Request RSTC Comments** – Candice Castaneda, NERC Staff

16. **Draft Special Assessment: NERC-NAERM Joint Project – Potential Bulk Power System (BPS) Impacts Due to Severe Disruptions on the Natural Gas System* – Request RSTC Comments** – Scott Barfield-McGinnis, NERC Staff

17. **Chair's Closing Remarks**

*Background materials included.

Special Reliability Assessments Scope and Prioritization

Action

RSTC Information and Discussion

Background

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

Summary

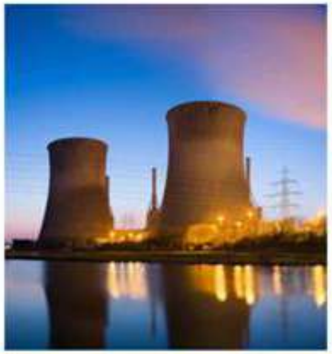
The RSTC EC approved removal of the work plan item from the RAS work plan. NERC Staff will continue to coordinate this effort.

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

RAS Special Reliability Assessments Scope and Prioritization

Andreas Klaube, RAS Chair
Amanda Sargent, RAS Vice Chair
March 12 - 13, 2024

RELIABILITY | RESILIENCE | SECURITY

RAS Work Plan Item #5

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

2021 RISC Recommendation 2.1

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

RAS Efforts

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

RAS developed a scope framework for the interdependency special assessment

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

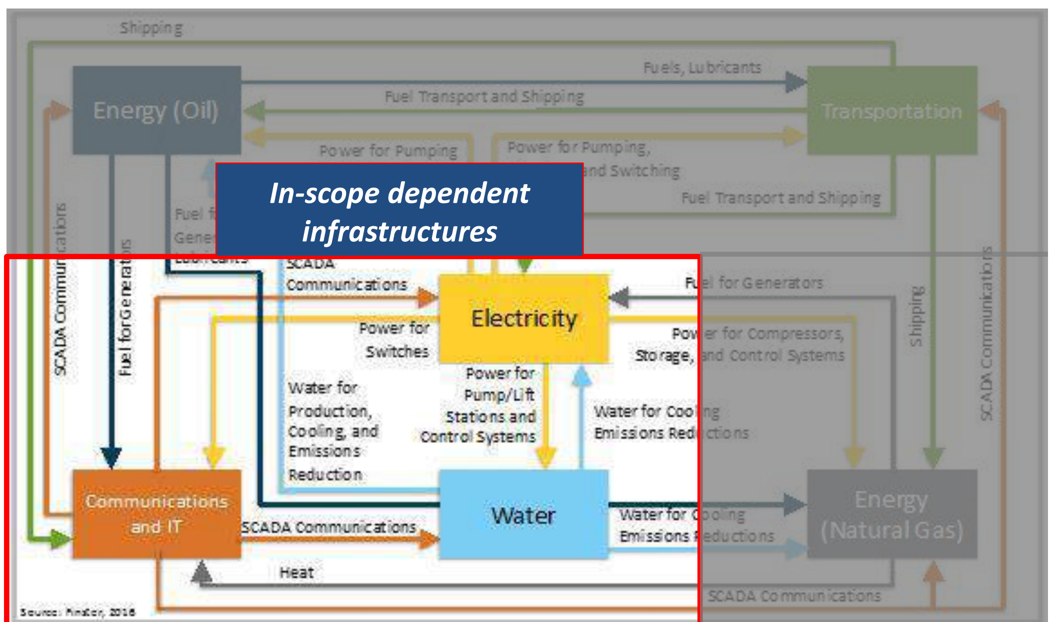
Using the model will require inputs from interdependent infrastructures (e.g., telecom and water industries), which is beyond the scope of the RAS

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

RAS Thoughts on Assessment Objective

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

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



NAERM is not fully matured for analyzing all infrastructures

Next Steps

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

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Questions and Answers

Agenda Item 1d.i.2
RSTC Meeting
June 11, 2024

High Priority Work Plan items and the RSTC Work Plan

Action

RSTC Information and Discussion

Background

The RSTC Was presented a list of high priority work plan items at eh March RSTC meeting. The RSTC EC approved the high priority wok plan items along with the RSTC Work Plan. The high priority work plan items are:

- White Paper: Energy Reliability Assessments Vol. 2
- Monitor Performance of Electric-Gas Interface during Extreme Events
- Generating Unit Winter Weather Readiness Webinar
- Monitor and Share Development of EV Charging Model
- SAR: Revisions to FAC-001 and FAC-002—IBR Performance
- Reliability Guideline: Recommended Approach to Interconnection Study of BPS-Connected IBRs
- Reliability Guideline: EMT Modeling and Simulations of IBR
- White Paper: Case Study on Adoption of EMT Modeling
- White Paper: Probabilistic Planning for the Tails
- Response to Cold Weather Recommendations:
    - Effects of Load-Shedding during Long-duration Events
    - Impacts of Transfer Limits
    - Improvements to Load Forecasting
        - Impacts of Forecasting Intermittent Generation
- Monitor and Support NERC Alerts for Supply Chain Issues

Summary

The RSTC EC approved the high priority work plan items along with the completed RSTC work plan.

Agenda Item 1d.i.3
RSTC Meeting
June 11, 2024

SPIDERWG Work Plan Changes

Action

Approval

Background

The SPIDERWG sought comments on a SAR that was presented to the RSTC in March 2024. The SAR identified inaccurate representation for aggregate DER levels with a reasonable allocation of their connection points to the BPS may affect the outcomes of the Transmission Operator's (TOP) Operational Planning Analysis (OPAs) and Real-Time Assessment (RTAs). The SAR sought to provide clarity of DER in the OPA and RTA Definitions. The SPIDERWG received comments that it might be more appropriate to create a Technical Reference Document to address the provisions of the SAR and table the development of the SAR to a more appropriate time.

Summary

The RSTC EC approved the changes to the SPIDERWG Work Plan.

RSTC Group Sponsor Appointments

Action
Approve

Background
The RSTC EC sought volunteers to be sponsors for groups within the RSTC organization. The following RSTC members were appointed as sponsors:

Group	Current Sponsor
Reliability Assessments Subcommittee (RAS)	Mark Spencer
Supply Chain Working Group (SCWG)	Nathan Brown
Security Integration and Technology Enablement Subcommittee (SITES)	Marc Child
Event Analysis Subcommittee (EAS)	Stephen George
Performance Analysis Subcommittee (PAS)	Darryl Lawrence
System Protection and Control Working Group (SPCWG)	David Mulcahy
Inverter-based Performance Subcommittee (IRPS)	Jodirah Green
Real Time Operating Subcommittee (RTOS)	Todd Lucas
Resources Subcommittee (RS)	Rich Hydzik
Security Working Group (SWG)	Monica Jain
Load Modeling Working Group (LMWG)	Ahmed Maria
Electric Gas Working Group (EGWG)	Venona Greaff
EMP Working Group (EMPWG)	John Stephens
System Planning Impacts from Distributed Energy Resources Working Group (SPIDERWG)	Wayne Guttormson
Energy Reliability Assessment Working Group (ERAWG)	Srinivas Kappagantula
Facility Ratings Task Force	Ian Grant
6 GHz Task Force	David Grubbs

Summary
The RSTC EC appointed the above list of sponsors.

Reliability and Security Technical Committee Sponsor Selection Process
April 2024

The Reliability and Security Technical Committee (RSTC) is a standing committee that strives to advance the reliability and security of the interconnected BPS of North America by:

- Creating a forum for aggregating ideas and interests, drawing from diverse industry stakeholder expertise, to support the ERO Enterprise's mission; and,
- Leveraging such expertise to identify solutions to study, mitigate, and/or eliminate emerging risks to the BPS for the benefit of industry stakeholders, the NERC Board of Trustees (Board) and ERO Enterprise staff and leadership.; and,
- Overseeing the implementation of subgroup work plans that drive risk-mitigating technical solutions.

Being a Sponsor in the RSTC

The RSTC succeeds through the successes of the various subcommittees, working groups and task forces that identify and mitigate risks to the reliable operation of the bulk power system. To enable their success, the Chair and Vice Chair of these subcommittees, working groups and task forces will be supported by Sponsors, which is a unique role created to enhance and support the quality of leadership in these groups. All sponsors are members of the RSTC.

Leadership is not the same as management. While the participants on these groups are likely skilled as managers, a higher level of success will be realized if all participants are engaged as leaders. Leadership is defined as the inspiration of others. These inspired actions produce actions from others which are extraordinary and geared to produce exceptional outcomes. This is intended to produce dynamic and effective leadership from every person on a subcommittee, working group and task force. The leadership provided by the Chair and Vice-Chair will therefore be essential in bringing out the leadership of others. The Sponsors will support the Chair and Vice-Chair in inspiring leadership of all participants, as well as represent the wishes of the RSTC for successful outcomes.

Sponsorship is a unique form of leadership. It is intended to inspire leadership from individuals as well as groups. This inspiration occurs through guidance, mentoring and support of participants, towards creating leaders from members of RSTC's subcommittees, working groups and task forces. The Sponsor's relationship with committee Chairs and Vice Chairs enables unique insights as well as effective listening. The Sponsor stands outside the dynamics of the group yet is passionate about the effectiveness and eventual success of that group. Sponsor(s) are actively interested, and not disinterested bystanders. Rather, Sponsors remain aware of both the dynamics and effectiveness of the group. The relationship is not one of passively waiting for a formal report from the team in predictable time, such as quarterly or twice a year. Instead Sponsor(s) remain in communication with the Chair/Vice Chair of the subcommittees, working groups and task forces, and are perceptive to the issues being faced by the group. Among the common issues which may be encountered are:

- Disconnection between what work results the RSTC desires and the work of the committees
- Loss of clarity of the group's purpose
- Confusion regarding expected deliverables

Group dynamics
In understanding the role of Sponsors, it is also useful to be clear what Sponsors are not. Sponsors are NOT:

- A Chair of the working groups, dictating or telling working groups what to do
- Subcommittees, working groups and task force members
- Attempting to push their own personal agendas
- Representing the organization from which they come

The unique leadership provided by Sponsors will promote excellence in each of the groups with which they interact.

Sponsor Nominations and Assignment
RSTC members can nominate themselves to be a sponsor and identify a group or groups they would like to be considered as a sponsor. The term for a sponsor is two years or the remainder of an individual's RSTC term.

The RSTC EC will assign sponsors based on requests and need, ensuring the highest priority groups are assigned a Sponsor.

Group	Current Sponsor
Reliability Assessments Subcommittee (RAS)	Mark Spencer
Supply Chain Working Group (SCWG)	Nathan Brown
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Group	Current Sponsor
Energy Reliability Assessment Working Group (ERAWG)	Srinivas Kappagantula
Facility Ratings Task Force	Ian Grant
6 GHz Task Force	David Grubbs

Standards Committee Request for RSTC Review of CIP-013 SAR

Action
RSTC Information and Discussion

Background
On January 30, 2024 the Standards Committee requested that the RSTC determine if there is another approach to addressing the issues laid out in the SAR. The RSTC Executive Committee (RSTC EC) tasked the Supply Chain Working Group (SCWG) to examine the SAR dated September 18, 2023 and provide their analysis s to the RSTC EC for review and approval.

The SCWG has identified three alternative options for addressing the reliability gaps in the CIP-013-2 SAR. Please note that these are not mutually exclusive:

1. Create or update CMEP processes and practice guides to map to guidelines developed by NATF, EEI, EPRI, APPA, and RSTC SCWG.
2. Industry and the ERO can adopt practices consistent with the DHS/OMB/NIST Secure Software Development Framework to provide more consistency and clarity to suppliers through a digital supplier attestation process/format.
3. Enforcement practices should encourage entities to adopt a comprehensive SCRM/3rd Party risk plan (note: this is listed as Option 4 in the presentation).

Lastly, should the Standards Committee elect to approve the SAR, the SCWG has offered the following recommendation (Option 3 in the presentation):

1. The standards drafting team should refer to guidelines developed by NATF, EEI, EPRI, APPA and RSTC SCWG as recommended language for standard's enhancements.

Summary
The RSTC EC approved the analysis and recommendations of the SCWG and will be notifying the SC of these recommendations upon completion of the June 11 RSTC meeting.

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RELIABILITY CORPORATION

January 30, 2024

Michaelson Buchanan

Dear Sir:

Thank you for submitting a Standard Authorization Request (SAR) dated September 18, 2023 titled CIP-013-2 Supply Chain Risk Management with the purpose to revise CIP-012-3 to have complete and accurate assessments of supply chain security risks that reflect actual threat(s) posed to the entity, provide triggers on when the supply chain risk assessment(s) should be performed and require a response to risks identified.

Pursuant to Section 4.1 of the NERC Standard Processes Manual (SPM), Appendix 3A to the NERC Rules of Procedure, I am writing to inform you that on September 20, the Standards Committee (SC) reviewed the submitted SAR and voted to delay action pending consultation with the Reliability and Security Technical Committee (RSTC) to determine if there is another approach to addressing the issues laid out in the SAR.

For additional information on this matter, please see the attached background document and the SAR. These documents were considered at the September 20, 2023 SC meeting.

Sincerely,

Todd Bennett
Chair, NERC Standards Committee

cc:
Michaelson Buchanan, NERC Compliance
Holly Peterson, NERC Compliance
Rich Hydzik, Chair, RSTC
John Stephens, Vice Chair, RSTC
Stephen Crutchfield, Secretary, RSTC

Enclosures:
Standards Committee Background Document
CIP-013-2 Supply Chain Risk Management SAR

CIP-013-2 Supply Chain Risk Management

Action

- Accept the CIP-013-2 – Supply Chain Risk Management[1] Standard Authorization Request (SAR) submitted by the NERC critical infrastructure protection technical and compliance staff;
- Authorize posting of the SAR for a 30-day formal comment period; and
- Authorize solicitation of the SAR drafting team (DT) members.

Background

This project would address the current implementation of CIP-013, which has been wide-ranging and variable, potentially leading to incomplete or inaccurate supply chain risk evaluations. This project would revise CIP-013 to have complete and accurate assessments of supply chain security risks that reflect actual threat(s) posed to the entity. Additionally, it would provide triggers on when the supply chain risk assessment(s) must be performed (i.e., planning for procurement, procurement, and installation) and require a response to risks identified.

Summary

NERC staff recommends that the Standards Committee accept the CIP-013-2 SAR, authorize its posting for a 30-day formal comment period, and authorize the solicitation of DT members.

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[1] https://www.nerc.com/pa/Stand/Reliability%20Standards/CIP-013-2.pdf

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:	CIP-013-2 Supply Chain Risk Management SAR		
Date Submitted:	September 18, 2023		
SAR Requester			
Name:	Michaelson Buchanan		
Organization:	NERC		
Telephone:	470.725.5268	Email:	michaelson.buchanan@nerc.net
SAR Type (Check as many as apply)			
☐ New Standard ☒ Revision to Existing Standard ☐ Add, Modify, or Retire a Glossary Term ☐ Withdraw/retire an Existing Standard		☐ Imminent Action/ Confidential Issue (SPM Section 10) ☐ Variance development or revision ☐ Other (Please specify)	
Justification for this proposed standard development project (Check all that apply to help NERC prioritize development)			
☒ Regulatory Initiation ☐ Emerging Risk (Reliability Issues Steering Committee) Identified ☐ Reliability Standard Development Plan		☐ NERC Standing Committee Identified ☐ Enhanced Periodic Review Initiated ☐ Industry Stakeholder Identified	
Industry Need (What Bulk Electric System (BES) reliability benefit does the proposed project provide?):			
The language in CIP-013-2 Requirement R1 lacks specificity to properly identify, assess, and respond to supply chain security risks. Specifically, Requirement R1 Part 1.1 does not indicate how to perform risk identification and assess vendor risks effectively. Additionally, CIP-013-2 does not contain sufficient triggers requiring activating an entity's supply chain risk management plan. Industry implementation is wide ranging and variable across the ERO Enterprise. The implemented Industry supply chain risk processes are ambiguous and generally lack rigor for validating the completeness and accuracy of the data, assessing the risks, considering the vendor's mitigation activities, and documenting and tracking residual risks. This also leads to inconsistent information collected from vendors. The lack of specificity for correctly identifying and assessing supply chain security risks may lead to incomplete or inaccurate risk evaluations. This may lead to supply chain risk likelihood and/or impact ratings that are not truly reflective of the actual risk posed to the entity.			

Requested information
There is a lack of activation triggers to perform an entity's supply chain risk management program. The ambiguous language of Requirement R2's "Note" and the potential for a sizeable time delay between the actual procurement of equipment and the installation of the procured equipment. This delay could render the risk assessment outdated and potentially inaccurate during installation. An updated or revised risk assessment would ensure that all current and relevant risks are identified, assessed, and addressed. A requirement to update or re-perform a risk assessment for equipment or software before installation is necessary, as well as a time limit between the assessment and installation. There is a lack of tracking or responding to the risks identified through an entity's supply chain risk assessment. Requirement R1 Part 1.1 requires entities to "identify and assess," but the Standard does not require an entity to take any actions (i.e., respond) to any identified risks through the risk assessment. This includes accepting risks if they fall within a certain threshold. If accepted risks increase over time to a level above the entity's threshold, the entity may not be aware of the change due to the lack of tracking said risks. The majority, if not all, risk management frameworks hold fast to three pillars: 1. Identify, 2. Assess, and 3. Respond. Industry has many options to respond to risks, including mitigation, acceptance, transfer, and/or avoidance. Regardless of the option chosen, a response includes documenting and tracking the risk(s).
Purpose or Goal (How does this proposed project provide the reliability-related benefit described above?):
This project would revise CIP-013-2 to have complete and accurate assessments of supply chain security risks that reflect actual threat(s) posed to the entity. Additionally, it would provide triggers on when the supply chain risk assessment(s) must be performed (i.e., planning for procurement, procurement, and installation) and require a response to risks identified.
Project Scope (Define the parameters of the proposed project):
This project will make revisions to CIP-013-2 to require complete and accurate assessments of supply chain risks. Provide triggers of when activation of the supply chain risk assessment(s) must be performed and tracking and responding to all risks identified.
Detailed Description (Describe the proposed deliverable(s) with sufficient detail for a drafting team to execute the project. If you propose a new or substantially revised Reliability Standard or definition, provide (1) a technical justification[1] that 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):
Revise CIP-013-2 to: • Require entities to create specific triggers to activate the supply chain risk assessment(s).

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

Requested information
• Include the performance of supply chain risk assessment(s) during the planning for procurement, procurement, installation of procured equipment/software/services, and post procurement assessment. • Include steps to validate the completeness and accuracy of the data, assess the risks, consider the vendor's mitigation activities, and document and track any residual risks. • Track and respond to all risks identified. • Re-assessment of standing contract risks on a set timeframe. • Re-assessment of time delay installation beyond a set timeframe.
Cost Impact Assessment, if known (Provide a paragraph describing the potential cost impacts associated with the proposed project):
The Cost impact of implementing the proposed Standard depends on the method(s) by which a Responsible Entity chooses to meet any additional Requirements. However, a question will be asked during the comment period to ensure cost aspects are considered.
Please describe any unique characteristics of the BES facilities that may be impacted by this proposed standard development project (*e.g.*, Dispersed Generation Resources):
No unique characteristics of BES facilities that may be impacted are known at this time.
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):
Balancing Authority, Distribution Provider, Generator Operator, Generator Owner, Reliability Coordinator, Transmission Operator, Transmission Owner
Do you know of any consensus building activities[2] in connection with this SAR? If so, please provide recommendations or findings from the consensus building activity.
SAR was developed in cooperation with and reviewed by voting members of the ERO CIP Compliance Task Force.
Are there any related standards or SARs that should be assessed for impact due to this proposed project? If so, which standard(s) or project number(s)?
None at this time.
Are there alternatives (e.g., guidelines, white paper, alerts, etc.) that have been considered or could meet the objectives? If so, please list the other options.

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

Requested information
None at this time.

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 operating of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
☐	4. Plans for an 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 from achieving compliance with that standard.	Yes
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards.	Yes

Identified Existing or Potential Regional or Interconnection Variances	
Region(s)/ Interconnection	Explanation
e.g., NPCC	None

For Use by NERC Only

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

Version History

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

To: Todd Bennett, Chair NERC Standards Committee

From: Rich Hydzik, Chair NERC Reliability and Security Technical Committee

Re: CIP-013-2 SAR

Date: May 7, 2024

In response to your request on January 30, 2024, the Reliability and Security Technical Committee (RSTC) tasked the Supply Chain Working Group (SCWG) to examine the standards authorization request (SAR) dated September 18, 2023, and as you indicated "...determine if there is another approach to addressing the issues laid out in the SAR."

The SCWG prioritized their deliberations and presented their findings to the RSTC executive committee on April 9, 2024. A copy of their presentation is attached.

In summary, the SCWG has identified three alternative options for addressing the reliability gaps in the CIP-013-2 SAR. Please note that these are not mutually exclusive:

1. Create or update CMEP processes and practice guides to map to guidelines developed by NATF, EEI, EPRI, APPA, and RSTC SCWG.
2. Industry and the ERO can adopt practices consistent with the DHS/OMB/NIST Secure Software Development Framework to provide more consistency and clarity to suppliers through a digital supplier attestation process/format.
3. Enforcement practices should encourage entities to adopt a comprehensive SCRM/3rd Party risk plan (note: this is listed as Option 4 in the presentation).

Lastly, should the Standards Committee elect to approve the SAR, the SCWG has offered the following recommendation (Option 3 in the presentation):

1. The standards drafting team should refer to guidelines developed by NATF, EEI, EPRI, APPA and RSTC SCWG as recommended language for standards enhancements.

cc: Latrice Harkness
Dominique Love
Alison Oswald
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NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Supply Chain Security Gap Assessment

Performing a Gap Analysis of the NERC CIP Supply Chain Standards

Tobias Whitney, Gap Assessment Project Lead

Reliability and Security Technical Committee Meeting
June 11-12, 2024

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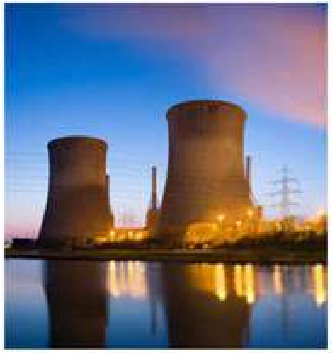

Key Updates: CIP-013-2 SAR

- Update from NERC Director of Standards & Development:
  - The Standards Committee (SC) is asking the Supply Chain Working Group (SCWG) to review the SAR and provide them feedback by the March SC meeting.
  - The Supply Chain SAR should be reviewed separately from other CIP Standards development activities.
  - FERC is aware and would like to see how the SC addresses the SAR

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January 30, 2024

Michaelson Buchanan

Dear Sir:

Thank you for submitting a Standard Authorization Request (SAR) dated September 18, 2023 titled CIP-013-2 Supply Chain Risk Management with the purpose to revise CIP-012-3 to have complete and accurate assessments of supply chain security risks that reflect actual threat(s) posed to the entity, provide triggers on when the supply chain risk assessment(s) should be performed and require a response to risks identified.

Pursuant to Section 4.1 of the NERC Standard Processes Manual (SPM), Appendix 3A to the NERC Rules of Procedure, I am writing to inform you that on September 20, the Standards Committee (SC) reviewed the submitted SAR and voted to delay action pending consultation with the Reliability and Security Technical Committee (RSTC) to determine if there is another approach to addressing the issues laid out in the SAR.

For additional information on this matter, please see the attached background document and the SAR. These documents were considered at the September 20, 2023 SC meeting.

Sincerely,

Todd Bennett
Chair, NERC Standards Committee

cc:
Michaelson Buchanan, NERC Compliance
Holly Peterson, NERC Compliance
Rich Hydzik, Chair, RSTC
John Stephens, Vice Chair, RSTC
Stephen Crutchfield, Secretary, RSTC

Enclosures:
Standards Committee Background Document
CIP-013-2 Supply Chain Risk Management SAR

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https://www.nerc.com/pa/Stand/Documents/CIP-013%20RSTC%20letter%20and%20SAR%2009182023.pdf

FERC Staff Feedback

- Audit staff observed that some entities lacked consistency and effectiveness when evaluating vendors and procuring vendor-supplied equipment and software.
- Audit staff observed that other audited entities' supply chain risk identification and assessment processes were unclear and generally lacked rigor.
- Staff also observed multiple instances where entities failed to properly implement their own supply chain risk management plans.

FERC Staff Feedback

- In some cases, staff found that entities' supply chain risk management plans did not include processes or procedures to respond to risks once identified, specifically for "grandfathered' contracts that existed prior to the effective date of the Reliability Standard.
- In some circumstances where these contracts were considered in the risk management plans, there was minimal consideration given to mitigation and response strategies.
- Audit staff recommends that entities include responses to every risk event identified in their supply chain risk management plans to ensure that appropriate mitigations are employed such that the entity has no "blind spots" in its operations

NERC Staff Feedback – SAR

- Commission staff observed on several occasions unmitigated risk that was present in a Bulk Electric System (BES) Cyber System due to assets that had been integrated during the contract term that would have otherwise been minimized if managed within the framework of the supply chain risk management plan parameters required by CIP-013-1, Requirement 1
- Require entities to create specific triggers to active the supply chain risk assessment(s).
- Include the performance of supply chain risk assessment(s) during the planning for procurement, procurement, installation of procured equipment/software/services, and post procurement assessment.

NERC Staff Feedback – SAR

- Include steps to validate the completeness and accuracy of the data, assess the risks, consider the vendor's mitigation activities, and document and track any residual risks.
- Track and respond to all risks identified.
- Re-assessment of standing contracts risks on a set timeframe.
- Re-assessment of time delay installation beyond a set timeframe.

NERC Staff Feedback – SAR

- Require entities to create specific triggers to active the supply chain risk assessment(s).
  - **Technical Justification:** Without specific triggers such as a merger, acquisition or a change in the control environment of the supplier, key operational or reliability risk would not be evaluated as part of CIP-013. Unevaluated risk could negatively impact the reliable operation of the BES.
  - **Reliability Benefit:** All material risk to the reliable operation of the BES should be evaluated prior to implementing the technology or asset via the procurement process. Without having specific triggers that will activate a supply chain risk assessment, unknown or undocumented risks may be present and could interfere with the reliable operations of the BES.

NERC Staff Feedback – SAR

- Include the performance of supply chain risk assessment(s) during the planning for procurement, procurement, installation of procured equipment/software/services, and post procurement assessment.
    - **Technical Justification:** 3rd party risks can emerge through various stages of the procurement process. Risk that are specific to a given implementation may not be identified via a high-level enterprise assessment. Therefore, certain technical risks could emerge during the procurement process which may not be identified which could lead to a risk to the BES.
    - **Reliability Benefit:** Risk assessments should be defined to address the risk that is most associated with the implementation of procured assets or services. If the project requires software that has relies on new or emerging technologies, a NATF questionnaire may not be appropriate to address the risk of the given implementation.

NERC Staff Feedback – SAR

- Include steps to validate the completeness and accuracy of the data, assess the risks, consider the vendor's mitigation activities, and document and track any residual risks.
  - Track and respond to all risks identified
    - **Technical Justification:** The asset owner's judgement of the data provided by the 3rd party or service provider, assessment or risk, or evaluation of the vendor's mitigation would provide meaningful insight into how the risk of a product or service is being identified and mitigated prior to implementation.
    - **Reliability Benefit:** Documentation and tracking of residual risk will provide the asset owner risk-based action to further monitor the health of their relationship with the 3rd party and adjust its contracts accordingly to activity mitigate reliability or operational risks.

NERC Staff Feedback – SAR

- Re-assessment of standing contracts risks on a set timeframe.
- Re-assessment of time delay installation beyond a set timeframe.
    - **Technical Justification:** "There is a lack of activation triggers to perform an entity's supply chain risk management program. The ambiguous language of Requirement R2's "Note" and the potential for a sizeable time delay between the actual procurement of equipment and the installation of the procured equipment. This delay could render the risk assessment outdated and potentially inaccurate during installation. An updated or revised risk assessment would ensure that all current and relevant risks are identified, assessed, and addressed. A requirement to update or re-perform a risk assessment for equipment or software before installation is necessary, as well as a time limit between the assessment and installation." – CIP-013-2 SAR
    - **Reliability Benefit:** The technical justification if implemented would improve operational or reliability risk management processes.

Supply Chain Working Group Actions

- Interviewed representatives from NERC CIP Compliance Staff to understand the challenges faced by industry and how the auditors accounted for them during CMEP Activities
- Performed a "guidance gap analysis" to determine if existing guidelines and documented practices from NATF, EEI, EPRI and the RSTC that could address the identified deficiencies in the Supply Chain Standards
- Identified key recommendations for the Standards Committee to consider when evaluating changes to Supply Chain Standards.
- Performed a technical justification and reliability benefit analysis of the CIP-013 SAR. (new)

Gap Assessment Team Recommendations

- Gap Assessment Team Recommendations
  - How to respond to the Standards Committee's request for input regarding the Supply Chain SAR:
    - **Option 1** – refer Standards Committee to mapped guidelines developed by NATF, EEI, EPRI, APPA and RSTC and direct compliance monitoring staff to consider them during the CMEP processes.
      - Direct CMEP staff give deference to Registered Entities implementing best practices
      - Encourage industry's use of the best practices, highlight and give due credit for activities
    - **Option 2** – recommend a process like the DHS/OMB/NIST Secure Software Development Framework to provide more consistency and clarity to suppliers through a digital supplier attestation process/format.
    - **Option 3** – suggest to SC that to refer to the guidelines developed by NATF, EEI, EPRI, APPA and RSTC as recommended language for Standard's enhancements.
    - **Option 4** - adopt a comprehensive supply chain risk management/3rd party risk plan to increase the level and rigor of the operational execution of supply chain risk management

Questions and Answers

Minutes
Reliability and Security Technical Committee

March 12-13, 2024 | 8:30 a.m. – 4:00 p.m. Pacific
In-Person

A regular meeting of the NERC Reliability and Security Technical Committee (RSTC) was held on March 12-13, 2024, in person in San Diego, CA. The agenda packages and presentations are available on the RSTC webpage.

Chair Hydzik called the meeting to order and thanked everyone for attending. Ms. Sandy Shiflett reviewed the procedures for the meeting, reviewed the Antitrust Compliance Guidelines, and confirmed quorum, as well as provided an overview of the polling actions to be used for Committee actions during the meeting.

Introduction and Chair's Remarks
Chair Hydzik provided an overview of the agenda noting that due to the number of action items before the Committee it may be necessary to defer some non-action topics to the next meeting.

Administrative Items
Chair Hydzik called on Ms. Candice Castaneda to review the meeting governance guidelines which were included in the advance materials package.

Consent Agenda
Chair Hydzik reviewed the Consent Agenda and asked RSTC members if they concurred with the items on it. Mr. Robert Reinmuller made the motion to approve the consent agenda. The motion passed without dissent.

Regular Agenda
Remarks and Reports
Chair Hydzik provided highlights from the Member Representative Committee meeting on February 14, 2024, and the Board of Trustees meeting on February 15, 2024. He also noted that the Board approved Ken DeFontes for another year as Chair, Suzanne Keenan as the Vice Chair and Chair-Elect, and approved the 2024 Board Committee appointments, as well as approved the NERC Officers: Jim Robb, President, and CEO, Manny Cancel, Senior Vice President, and Chief Executive Officer of the E-ISAC, Kelly Hanson, Senior Vice President and Chief Administrative Officer, Mark G. Lauby, Senior Vice President and Chief Engineer, Sonia Rocha, Senior Vice President, General Counsel, and Corporate Secretary, Andy Sharp, Vice President and Chief Financial Officer.

With regard to the subject of approving the Proposed Revisions to NERC Rules of Procedure – Registration, Chair DeFontes opened the floor to the attendees for additional discussion and feedback. The proposed revisions were subsequently approved on February 22 in a separate Board open call.

Two standards actions were also completed during the Board meeting: Project 2022-01 Reporting ACE Definition and Associated Terms and Reliability Standard – EOP-012-2 – Extreme Cold Weather Preparedness and Operations were adopted.

At the end of the meeting, the Board provided an update on the Year-End Review 2023 Achievements and Work Plan Priorities.

Nominating Subcommittee Election
Chair Hydzik reviewed the slides for the Nominating Subcommittee process. Mr. Todd Lucas made the motion to approve the Nominating Subcommittee as nominated by the RSTC Chair. The motion passed without dissent.

RSTC Work Plan Priorities
Vice Chair Stephens provided information on the updated Work Plan Priorities. There was a lengthy discussion around the priorities as it relates to the RISC report. As a result, the RSTC will focus on the technical input related to policy discussions and will be to be mindful of the amount of work that is issued to industry and focus on the high priority items making sure that items we are mapping the Work Plan Priorities against the RISC report.

RAS - Special Reliability Assessments Scope and Prioritization
Mr. Andreas Klaube provided the information on the request for moving the scope document to a more diverse group. There was a lengthy discussion on this topic and all comments and concern were emailed to Vice Chair Stephens.

SAR: Revisions to FAC-001 and FAC-002
Mr. Alex Shattuck presented the SAR revisions. David Grubbs made the motion to accept to post for a 30-day RSTC/public comment period beginning March 18. The motion passed without dissent.

White Paper: Transmission-Distribution Coordination Strategies
Mr. Shayan Rizvi presented the information on the White Paper: Transmission-Distribution Coordination Strategies. Wayne Guttormson made the motion to approve the White Paper. The motion passed without dissent.

FERC Order 901 Update
Ms. Jamie Calderon provided updated information on FERC Order 901. There was a lengthy discussion on this item. It was noted that Ms. Calderon would bring this item back to the RSTC during the June meeting.

Reliability Guideline: BPS Planning Under High DER Penetration
Mr. Shayan Rizvi provided information on the Reliability Guideline: BPS Planning Under High DER Penetration. Mr. Wayne Guttormson made the motion to accept to post for a 45-day RSTC/public comment period. The motion passed without dissent.

SAR: Clarifications to Operational Planning Analysis and Real-time Assessment
Mr. Shayan Rizvi provided information on the SAR: Clarifications to Operational Planning Analysis and Real-time Assessment. Mr. Wayne Guttormson made the motion to accept to post for a 30-day RSTC/public comment period. The motion passed without dissent.

Review of Reliability Risk Framework
Mr. John Moura provided an update on the Review of Reliability Risk Framework.

Emerging Loads and Electric Vehicles Panel Session
Ms. Marilyn Jayachandran and Mr. John Skeath provided information on the panel pertaining to Emerging Loads and Electric Vehicles. The panel lead a very good discussion on Emerging Loads and Electric Vehicles. More information on this topic will be presented during the June RSTC meeting.

White Paper: Probabilistic Planning for Tail Risks
Mr. Bryon Domgaard gave information on the White Paper: Probabilistic Planning for Tail Risks. Saul Rojas made the motion to approve the White Paper. The motion passed without dissent.

PRC-023-5 R1 Determination of Practical Transmission Relaying Loadability Settings Paper
Mr. Matt Lewis presented the PRC-023-5 R1 Determination of Practical Transmission Relaying Loadability Settings Paper. Mr. David Mulcahy made the motion to approve the Paper. The motion passed without dissent.

Review and update Transmission System Phase Backup Protections
Mr. Matt Lewis provided information on the Transmission System Phase Backup Protections. Mr. Saul Rojas made a motion to approve posting for a 30-day comment period. The motion passed without dissent. The SPCWG will post the document for a 30-day public comment period in lieu of RSTC comments beginning March 25.

White Paper: Steady-state approach for PRC-024-3 Evaluation for Inverter-Based Resources
Mr. Matt Lewis presented on the White Paper: Steady-state approach for PRC-024-3 Evaluation for Inverter-Based Resources. Following the presentation, Mr. David Grubbs made a motion to approve posting the paper for a 30-day comment period. The motion received one objection. Consequently, the SPCWG will post the document for a 30-day public comment period starting from March 2, instead of seeking RSTC comments.

Chair's Closing Remarks and Adjournment
Chair Hydzik expressed gratitude to all attendees and sponsors for introducing the agenda items and making the motions for approval/endorsement items. He also looked forward to the presentations at the Informational Session scheduled for the next morning. Chair. Hydzik then invited Trustee Kelly, Vice Chair Stephens, Mr. David Ortiz, and Mr. Lauby to share any closing comments. As there was no further business before the RSTC, Chair Hydzik adjourned the meeting.

March 13, 2024
8:30 a.m. – 12:30 p.m. Pacific

Introductions and Chair's Remarks
Chair Hydzik thanked everyone for attending and provided an overview of the day's agenda. He then called on Ms. Sandy Shiflett to review the procedures for the meeting. Chair Hydzik emphasized that the Informational Session is intended to provide updates on important topics and that there are no action items on the agenda. Additionally, he clarified that no formal actions can be taken during the Informational Session.

Problems and Solutions with BESS Siting
Mr. Anthony Natale provided a presentation on Problems and Solutions with BESS Siting.

Security Working Group Security Guidelines (3 guidelines for retirement)
Ms. Monica Jain provided information about the proposed retirement guidelines. Chair Hydzik noted that these guidelines were listed as informational because they were part of the Triennial Review process and were accepted for posting a couple of years ago. No further discussion was held.

Event Analysis Program Update
Mr. Matt Lewis provided an update on the Event Analysis Program. No further discussion was held.

Electromagnetic Transient Modeling Task Force (EMTTF) Update
Mr. Aung Thant and Mr. Alex Shattuck presented crucial insights from the EMTTF Survey, focusing on the effectiveness of EMT Modeling Guidelines. They also discussed the Whitepaper on EMT Modeling Adoption and the Industry Engagement Framework, which aims to establish a common understanding of the risks associated with changing resource mix and increased IBR penetration. Following their presentation, no further discussion took place.

E-ISAC Security Update
Ms. Haley Floyd provided the E-ISAC update. No further discussion was held.

Performance Analysis Program Update
Ms. Donna Pratt provided the update on the Performance Analysis Program. No further discussion was held.

NERC Bulk Power System Awareness Update
Due to a conflict, Mr. Bill Graham was unable to attend the meeting but provided an update that was in the agenda package. Chair Hydzik directed members and observers to view the package for the updates.

Interregional Transfer Capability Study (ITCS)
Mr. John Moura provided a comprehensive update on the Interregional Transfer Capability Study (ITCS) project. The team engaged in a detailed discussion following the update.

Cyber Informed Engineering and National Lab Update
Mr. Sam Chanoski provided the update on Cyber Informed Engineering and National Lab. No further discussion was held.

Forum and Group Reports
Due to conflicts Mr. Roman Carter and Mr. Wayne Sipperly were unable to attend the meeting, but provided updates that were added to the agenda package. Chair Hydzik directed members and observers to view the package for the forum updates.

RSTC 2024 Calendar Review
Mr. Crutchfield reviewed the 2024 meeting dates and requested members to please advise him if there are any concerns or industry conflicts to the dates.

Chair's Closing Remarks and Adjournment
Chair Hydzik expressed gratitude to all the attendees, committee members, and presenters for their valuable time and impressive presentations during the past two days. Trustee Kelly thanked all the presenters, the committee, and Chair Hydzik for doing a great job leading the meeting and shared her experience from attending her first RSTC meeting as the Board Representative.

Next Meeting
The RSTC will host a hybrid meeting in Seattle, June 11-12, 2024.

Stephen Crutchfield
Stephen Crutchfield
RSTC Secretary

Electric Gas Working Group Scope

Purpose

The Electric Gas Working Group (EGWG) serves as an informational stakeholder forum open to all types of organizations, particularly to include representatives from a cross-section of the natural gas fuel supply/delivery chains and the electric grid, to support projects where the expertise of the diverse group is deemed valuable. The EGWG drives the development of resources to better educate and inform the electric industry on issues concerning the coordination and interdependence of the electric and natural gas systems.

Functions

The EGWG will work with the Reliability and Security Technical Committee (RSTC) and its subcommittees, working groups, and task forces as necessary to provide and complete any projects as requested and deemed appropriate. Ongoing functions of the EGWG include, but are not limited to, the following:

- Author guidelines, white papers, compliance guidance, etc.
- Develop educational materials that may be used for a range of audiences that describe any potential emerging risks and possible solutions to address these risks.
- Provide technical assistance in support for assessing fuel-related concerns in other NERC program areas.
- Provide assistance to NERC Event Analysis evaluations of bulk power system (BPS) disturbances when fuel disruptions are involved in the disturbance, as necessary.
- Support the development of any data collection requirements by the NERC Reliability Assessment Subcommittee (RAS), as necessary, for inclusion in the NERC Long-Term Reliability Assessment (LTRA) and other assessments.
- Provide support in the development of measurements or metrics related to fuel-related risk in the BPS and reported in independent NERC reports and assessments such as the State of Reliability report.
- Suggest areas which require attention such as issue identification on potential emerging risks, information or data needs related to those risks, and possible scope for solutions to be developed.
- Take on other assignments from the RSTC where the expertise of the group may be leveraged.

Deliverables

- Maintaining the 3-year review cycle for the Reliability Guideline: *Fuel Assurance and Fuel-Related Reliability Risk Analysis*

- Share information as requested that may be used for a range of audiences via workshops, webinars, joint meetings with other NERC stakeholder groups, or other beneficial platforms.
- Reporting of working group activity at RSTC meetings, as requested.
- Contribute to annual updates of the NERC State of Reliability report, as requested.

Membership

The EGWG may include members who have technical or policy level expertise in the following areas:

- Fuel supply and delivery chains
- Fuel procurement for electric generation
- Transmission Planning studies and system analysis
- Electric and fuel infrastructure operations

The EGWG will consist of a chair and vice chair appointed by the RSTC leadership. NERC staff will be assigned as coordinator(s). Decisions will be consensus-based of the membership, led by the chairs and staff coordinator(s). Any minority views may be included in an addendum.

Based on the needs of the EGWG to include expertise from the natural gas and related industries, members do not need to be registered NERC members but instead will be formal members of the EGWG roster. Based on this membership composition, the EGWG does not have decisional authority related to its activities.

Reporting

The EGWG will report to the NERC RSTC. EGWG work products will be approved by the NERC RSTC. The group will submit a work plan to the RSTC annually.

Meetings

Meetings occur as needed but will be scheduled at a minimum of once per quarter. Scheduled meetings may be cancelled if no emergent work exists, but meetings may be added depending on activity in the industry or the requests of the RSTC. The meetings are open and encourage participation by observers.

Scope Review

The EGWG Scope shall be reviewed on a biennial basis.

Approved by the NERC Reliability and Security Technical Committee on XX/XX/XXXX.

Electric-Gas Working Group

Scope Document
May 2024

~~Background~~Purpose

~~In November 2017, NERC published the Special Reliability Assessment: Potential Bulk Power System Impacts Due to Severe Disruptions on the Natural Gas System ("Report")[1]. In the Report, NERC made numerous recommendations for assessing disruptions to natural gas infrastructure and related impacts to the reliable operation of the Bulk Electric System (BES) in Planning studies, several of which were assigned to the NERC Planning Committee ("PC"). Through subsequent meetings and workshops, it became clear that in order to effectively assess the wide range of BES and natural gas interoperability concerns, a coalition of subject matter experts spanning the various industries would be needed. Thus, the EGWG was created to facilitates~~facilitate ~~this gathering~~ a forum ~~of experts and~~ to ~~drive the development of tools and other resources to better educate and inform the electric industry in light of these electric-gas concerns.~~ The EGWG ~~will~~ serves as an informational stakeholder forum open to all types of organizations, particularly to include ~~those that~~ representatives from a cross-section of the natural gas fuel supply/delivery chains and the ~~interrelated electric sectors~~electric grid, ~~. addressingsupporting~~ to support ~~any number of concerns~~ projects where the expertise of the diverse group ~~which includes fuel~~ is deemed valuable. The EGWG drives the development of ~~of tools and other~~ resources to better educate and inform the electric industry on issues concerning the coordination and interdependence of the electric and natural gas systems. ~~in light of electric-gas concerns.concerns.~~

~~Activities~~Functions

~~The NERC EGWG will serve as a stakeholder forum open to all types of organizations, particularly those that represent a cross-section of fuel supply/delivery chains and the interrelated electric sectors. The primary attention of the EGWG will initially be the development of educational guidance and/or guidelines regarding considerations of fuel-related risks in Bulk Power System (BPS) and BES Planning studies and system analysis. On a secondary level, EGWG will be a stakeholder forum, addressing any number of concerns where expertise of the diverse group is deemed valuable.~~ The EGWG will work with the ~~PC~~ RSTC and its~~other PC RSTCRSTCPC~~ subcommittees, working groups, and task forces as necessary to provide and complete any ~~analysis that is~~projects as requested and deemed appropriate. ~~Key~~ Ongoing ~~activities~~ functions of the EGWG include, but are not limited to, the following:

Commented [A1]: Per the comments below, knowing if there are completed tasks or clear ongoing tasks in this section or in Deliverables is helpful to know how much revision this needs.

Commented [A2]: Should we include "suggest areas which require attention and complete any projects as requested and deemed appropriate."

- ~~1.~~ Author guidelines, white papers, compliance guidance, etc. ~~in support of natural gas disruption considerations and risks that are applicable to all regions and could extend to be inclusive of all fuel sources.~~

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- ~~2.~~ Develop educational materials that ~~can~~ may be used for a range of audiences that

[1] ~~https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SPOD_11142017_Final.pdf~~

describe any potential emerging risks and possible solutions to address these risks.

~~3.~~ • Provide technical assistance in support for assessing fuel-related concerns in other NERC program areas.

~~4.~~ • Provide assistance to NERC Event Analysis evaluations of BPS disturbances when fuel disruptions are involved in the disturbance, as necessary.

~~5.~~ • Support the development of any data collection requirements by the NERC Reliability Assessment Subcommittee ("RAS"), as necessary, for inclusion in the NERC Long Term Reliability Assessment ("LTRA") and other assessments.

• Provide support in the development of measurements or metrics related to fuel-related risk in the Bulk Power System and reported in independent NERC reports and assessments such as the State of Reliability.

• Suggest areas which require attention such as issue identification on potential emerging risks, information or data needs related to those risks, and possible scope for solutions to be developed.

~~6.~~ • Take on other assignments from the RSTC where the expertise of the group may be leveraged.

Deliverables

~~The EGWG will develop technical reference documents, guidelines, and other educational materials to support industry efforts in planning with the following objectives:~~

Maintaining the 3-year review cycle for the ~~following~~ Reliability Guideline~~(s)~~:

~~1)~~ *Fuel Assurance and Fuel-Related Reliability Risk Analysis~~on effectively assessing fuel disruption risks in planning studies that provide a specific but broad set of recommendations.~~*

~~2)~~

~~a. Guidance should help entities determine the types of analysis needed to assess fuel disruption risks, as well as suggested contacts for gathering appropriate data.~~

~~b. Guidance should help entities understand regional factors that affect fuel assurance (e.g., geography, fuel supply chain, firm/non-firm fuel delivery, fuel access, market constructs, fuel infrastructure, etc.)~~

~~c.~~ • ~~Guidance should be malleable over time as technologies and operational landscapes evolve.~~

~~2. Recommendations for the development of tools/guides to enhance operational awareness of fuel- related information.~~

• Share ~~I~~information as requested that ~~can~~ may be used for a range of audiences ~~that describe potential emerging risks and possible solutions to address these risks. This information may include educational materials,~~ via workshops, webinars, joint meetings with other NERC

Commented [A3]: Are these completed? They should be completed and posted. Maybe this can be deleted.

Commented [A4]: Maybe this is on-going, but it seems like perhaps the tasks for this WG are completed. Do we still need an EGWG - particularly given the NAESB work group and the PJM senior task force looking at the electric-gas coordination issues?

Commented [A5]: This should also be complete by now. Are these posted yet?

Commented [A6]: Can we get a status report from the Chair and/or Vice Chair on these deliverables?

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- Reporting of working group activity at RSTC meetings, as requested.
- Contribute to annual updates of the NERC State of Reliability report, as requested.

~~3.~~

~~4. Other tasks as deemed appropriate.~~

Membership

The EGWG ~~will~~ may include members who have technical or policy level expertise in the following areas:

- Fuel supply and delivery chains
- Fuel procurement for electric generation
- Transmission Planning studies and system analysis
- Electric and fuel infrastructure operations

The EGWG will consist of a chair and vice chair appointed by the ~~PC~~ RSTC leadership. NERC staff will be assigned as Coordinator(s). Decisions will be consensus-based of the membership, led by the chairs and staff Coordinator(s). Any minority views may be included in an addendum.

Based on the needs of the EGWG to include expertise from the natural gas and related industries, members do not need to be registered NERC members but instead will be formal members of the EGWG roster. Based on this membership composition, the EGWG does not have decisional authority related to its activities.~~is~~

Reporting ~~& Duration~~

The EGWG will report to the NERC ~~PC~~RSTC. EGWG work products will be approved by the NERC ~~PC~~RSTC. The group will submit a work plan to the ~~PC~~ RSTC ~~following its inception~~annually~~, and will develop the deliverables outlined~~.

Meetings

~~Four to six open meetings per year, or as needed. The group is expected to have two to three in-person meetings, supplemented with conference calls to continue the workload throughout the year.~~ Meetings occur as needed~~,~~ but will be scheduled at a minimum of once per quarter. Scheduled meetings may be cancelled if no emergent work exists, but meetings may be added depending on activity in the industry or the requests of the RSTC. The meetings are open and encourage participation by observers.

Scope Review

The EGWG Scope shall be reviewed on a biennial basis.

Commented [A8]: This is very broad. Perhaps something like, "Issue identification on potential emerging risks, information or data needs related to those risks, and possible scope for solutions to be developed."

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Commented [A9]: Has this been met? Has the EGWG had sufficient membership participation? There seems to have been good participation at the meetings over the years, but if the deliverables are not there after all this time, then that would be a problem to look into.

Commented [A10]: From LMWG: A NERC staff member will be assigned as the Working Group Coordinator. The Working Group chair is selected by the Working Group for a two-year term or the conclusion of the Working Group, whichever comes first. The LMWG vice chair should be available to succeed the chair.

Commented [A11R10]: We have also had existing chairs for over two years, so that may need more flexibility

Commented [A12]: From RAS

Commented [A13]: Or from PAS: Meetings occur as needed. The meetings are open and encourage participation by observers. Observers may include participants from the Federal Energy Regulatory Commission, the United States Department of Energy and the National Energy Board, Canada.

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Approved by the NERC ~~Planning~~ Reliability and Security Technical Committee on ~~June 5~~XXX, ~~2019~~2024.

RSTC Status Report 6 GHZ Task Force (6GHZTF)

Chair: Jennifer Flandermeyer
Vice Chair: Larry Butts
June 11, 2024

On Track
Schedule at risk
Milestone delayed

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

Items for RSTC Approval/Discussion:

- **None**

Recent Activity

- Communication Interference Whitepaper approved and posted.
- Conducted Industry and Alert Awareness Webinar (480 attendees)

Upcoming Activities

- Support the development of a public-facing summary report of the responses to the Level 2 Alert

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

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

NERC NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

EAS Status Report

RSTC Status Report – Event Analysis Subcommittee (EAS)

Chair: Chris Moran
Vice-Chair: James Hanson
June 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 – 1 published; 2 in development
- Development of FMM Diagrams – 1 approved; 1 in development
- FMMWG Scope Document Revised & Approved
- Conducted EAP v5 Industry Webinar w/ >100 Participants
- RSTC Work Plan Summit

Ongoing & Upcoming Activities

- Development of Lessons Learned
- Development of Lessons Learned Webinar in 2024
- FMMWG Development of Failure Mode & Mechanism Diagrams
- Conduct 2nd EAP v5 Industry Webinar
- Develop Winter Weather Preparation Industry Webinar

Workplan Status *(6 month look-ahead)*

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

RSTC Status Report – Electric Gas Working Group

Chair: Mike Knowland
Vice-Chair: Daniel Farmer
June 11 - 12, 2024

On Track
Schedule at risk
Milestone delayed

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

Items for RSTC Approval/Discussion:

- NA

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

Milestone	Status	Comments
ERAWG/EGWG/RAS team coordination	On Track (green)	On track

Recent Activity

- Collaborated with NERC and created a summary of the "Inquiry into Bulk-Power System Operations During December 2022 Winter Storm Elliott" and summitted it to NERC's 2024 edition of the *State of Reliability Report*

Upcoming Activity

- Develop Coordination Plan for potential electric related risks/objectives in natural gas related standards.
- The next EGWG team call is scheduled for July 25, 2024.

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

Co-Chairs: Adam Sparacino, Miguel Acosta
June 11-12, 2024

On Track
Schedule at risk
Milestone delayed

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

Items for RSTC Approval/Discussion:

- For acceptance to post for industry comment: Draft Reliability Guideline: Recommended Practices for Performing EMT System Studies for Inverter-Based Resources

Workplan Status *(6 month look-ahead)*

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

Recent Activity

- Technical Presentation on EMT Modeling of the New York State Power Grid: Challenges and Solutions– Thanh Nguyen
- Technical Presentation on Dynamic Behavior of Grid-forming Inverters in Large-scale Low-strength Power Grids – Jaime Alberto Peralta Rodríguez, Coordinador Eléctrico Nacional, Chile

Upcoming Activity

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

Chair: Mike Knowland
Vice: Chair David Mulcahy
June 11 - 12, 2024

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

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

Recent Activity:

- The Tiger Team completed volume 2, a technical reference document with detailed scenarios on conducting energy reliability assessments in the operations time horizon and the planning time horizon.

Items for RSTC Approval/Discussion:

- *Approve for a 45-day comment period: Technical Reference Document - Considerations for Performing an Energy Reliability Assessment: Volume 2*

Upcoming Activity:

- The Tiger team will work on refining the tools and metrics to assist with energy reliability assessments.
- Provide technical assistance for the SDT, as needed.
- The next ERAWG team call is scheduled for July 10, 2024.

Workplan Status *(6 month look-ahead)*

Milestone	Status	Comments
Supporting SDT for Project 2022-03.	Green (On Track)	On track
The Tiger team will address comments from the 45-day comment period on the Volume 2 document on conducting an energy reliability assessment.	Green (On Track)	On track

RSTC Status Report: Facility Ratings Task Force (FRTF)

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

- 🟢 On Track
- 🟡 Schedule at risk
- 🔴 Milestone delayed

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

Items for RSTC Discussion:
- Whitepaper “Sampling as Part of an Effective Facility Ratings Program”
- Implementation Guidance for FAC-008-5

Recent Activity
- Held a leadership meeting to discuss progress and strategy on deliverables.
- Sub-teams holding regular meetings and working on deliverables.

Upcoming Activity
- Sub-teams 1 and 3 working on deliverables.
- Sub-team 2 Support for Project 2021-08 Modifications to FAC-008 SDT continues but the project priority has been set as ‘low’ by the NERC Standards Committee. Low priority projects will have completion dates of 2025 and beyond.

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

Milestone	Status	Comments
Item 1 – Implementation Guidance on sustaining accurate facility Ratings Estimated completion: September 2024	🟢	In Progress
Item 2 – Support Project 2021-08 Modifications to FAC-008 SDT Estimated completion date in 2025	🟢	In Progress
Item 3 – Whitepaper on sampling for Facility Rating Programs Estimated completion: September 2024	🟢	In Progress

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

Chair: Julia Matevosyan
Vice-Chair:Rajat Majumder

On Track
Schedule at risk
Milestone delayed

Purpose: To 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:

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

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

Recent Activity

- Approval of Item 22: Grid Forming White Paper

Upcoming Activity

- Work Plan Item #16: FAC SAR; RSTC Approval
- 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

RSTC Status Report – Load Modeling Working Group (LMWG)

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

On Track
Schedule at risk
Milestone delayed

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

Items for RSTC Approval/Discussion:

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

Recent Activity

- *Develop EV Charger Models*
- *Conduct Reliability Studies with EV Charger Models*
- *Reviewed responses to Data Center Questionnaire*
- *RSTC Approval of EV Reference Report and Electric Vehicle Charger Model parameterization*

Upcoming Activity

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

Workplan Status *(6 month look-ahead)*

Milestone	Status	Comments
Refinements to EV Charger Models and usage of EV Load Shapes	On Track	In progress
Refinements to 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	In progress

RSTC Status Report – Probabilistic Assessment Working Group (PAWG)

Chair: Bryon Domgaard
Vice-Chair: Anaisha Jaykumar
June 11-12, 2024

On Track
Schedule at risk
Milestone delayed

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

Items for RSTC Approval/Discussion:

- None

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

Milestone	Status	Comments
Incorporate 2024 ProbA results in 2024 LTRA	On Track	Plan to complete by Q3 2024

Recent Activity

- Met in April 2024 in joint PAWG/RAS meeting to finalize the data form and narrative questions for 2024 ProbA .
- Sent the 2024 ProbA data request April 15
- Ongoing engagement with RAS with probabilistic components of their assessments.

Upcoming Activity

- Perform peer review for the 2024 ProbA results when received .
- Work with assessment areas to address any issues with 2024 ProbA to have the .results ready by Q3 2024 to incorporate them on the 2024 LTRA
- Setup sub-team of PAWG members to go through PAWG documents and refresh them to align with enhanced ProbA/added Energy assessment component

RSTC Status Report – Reliability Assessments Subcommittee (RAS)

Chair: Amanda Sargent (04/2024)
Vice-Chair: Vacant (Pending Nomination)
June 11-12, 2024

On Track
Schedule at risk
Milestone delayed

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:
- Special Reliability Assessments Scope and Prioritization

Recent Activity:
- 2024 SRA published on May 15
- April 11-13, 2024 Joint RAS-PAWG meeting: Topics - RAS work plan review, 2024 LTRA planning, 2024 SRA, ProbA request materials

Upcoming (RSTC) Activity:

Workplan Status *(6-month look ahead)*

Milestone	Status	Comments
2024 Long-Term Reliability Assessment (LTRA)	On Track	Preliminary Assessment Area submissions are due June 14, 2024
2024-2025 Winter Reliability Assessment (WRA)	On Track	Assessment Area informational request material planned for August 2024
Winter Storm Elliott Rec. 10	On Track	Coordinating with RTOS. Info will be collected in 24-25 WRA data request
ERO Energy Assessments	On Track	Collaborating with PAWG to develop new approaches in ERO reliability assessments.

RSTC Status Report – Resources Subcommittee (RS)

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

On Track
Schedule at risk
Milestone delayed

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

Items for RSTC Approval/Discussion:

- Generating Unit Operations during Complete Loss of Communications Guideline

Recent Activity

- Quarterly review of interconnection performance
- Reporting ACE and Associated Terms Standard Drafting Team – SDT finished work. All ballot items completed.
- Balancing Authority "High Speed Measurements" survey was sent out. Allowing additional time for responses.
- Review Hz Bias Settings developed by NERC ERO for a delayed June 26th , 2024 implementation by BAs.

Upcoming Activity

- In Person/Hybrid Meetings Scheduled
    - July 24th and 25th
    - Location: Nashville TN
- Dan Baker will assume the Vice – Chair of the NERC RS effective after the July RS meetings. Vice – Chair Henson will be stepping off the Resources Subcommittee.
- Eastern Interconnection is performing a survey of Balancing Authority's Primary Inadvertent accumulation to determine trends for persistent high frequency.

Workplan Status *(6 month look-ahead)*

Milestone	Status	Comments
Support ERSWG Measures 1,2,4, and 6	On Track (green)	Periodic review and consultation with NERC staff ongoing
Reliability Guideline: Loss of Communications	Milestone delayed (red)	Sent for approval at June RSTC meeting.

RSTC Status Report – Real Time Operating Subcommittee (RTOS)

Chair: Christopher Wakefield
Vice-Chair: Derek Hawkins
June 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

- Met with the SPIDERWG on EOP_005 SAR, feedback was given regarding overall direction of effort and the current draft text in the SAR.
- Review and endorsement of updated Reliability Plans for SPP and MISO.
- Leadership Effective 2024-2025
  - Chair: Christopher Wakefield (SeRC)
  - Vice-Chair: Derek Hawkins (SPP)

Items for RSTC Approval/Discussion:

N/A

Upcoming Activity

Continued work related to the Cold Weather Report.
RTOS sub-group will participate in a Load Forecasting panel discussion.

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

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

RSTC Status Report – Supply Chain Working Group (SCWG)

Chair: Roy Adams
Vice-Chair: Dr. Tom Duffey
June 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:

- SCWG is seeking RSTC feedback on its proposals in response to NERC CIP-013-2 SAR.

Recent Activity

- Two revised guidelines (Vendor Incident Response and Procurement Language) were updated to include metrics; the teams responsible are finalizing their responses to public comments, and updated guidelines are expected to be ready for publication Q2 2024.
- SCWG has formed single project team for both gap assessment and NERC CIP 013-2 SAR response. Detailed update was provided to RSTC under separate cover.

Upcoming Activity

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

Workplan Status *(6 month look-ahead)*

Milestone	Status	Comments
Revising two guidelines (Vendor Incident Response and Procurement Language)	● (On Track)	In Progress
Gap Assessment for Supply Chain Security Standards encompassing: • NERC CIP-013-2 Standard • NERC CIP-013-2 SAR • Trades/Stakeholder Coordination • Supplier Coordination • Regulator Feedback • Industry Perspective Further evaluation of multiple proposed risk mitigation options and viability of individual or combined choices	● (On Track)	In Progress

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

Chair: Brian Burnett
Vice Chair: Thomas Peterson
June 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:
- Confirm/Appoint SITES Chair & Vice Chair roles due to expiring terms
- Seeking comments on final draft of Whitepaper: New Technology Enablement & Field Testing

Recent Work Plan Activity
- Completed SITES 2024 Work Plan Survey
- Whitepaper: New Technology Enablement & Field Testing completed, seeking RSTC comments
- Call for Volunteers launched for Security Guideline for Inverter-Based Resources
- Call for Volunteers launched for Security Guideline for Distributed Energy Resource Aggregators

Upcoming Activity
- Launch of two new SITES sub-teams to tackle the new security guidelines
- Join SWG's effort on Physical Security Guideline

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

Milestone	Status	Comments
Whitepaper: New Tech Enablement	Green	Submitting for RSTC comments
Security Guideline for Inverter-Based Resources	Green	Launching Soon
Security Guideline for Distributed Energy Resource Aggregators	Green	Launching Soon
Physical Security Guideline (with SWG)	Green	Launching Soon

RSTC Status Report – Synchronized Measurement Working Group (SMWG)

Chair: Qiang "Frankie" Zhang
Vice-Chair: Clifton Black
June 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 April SMWG Hybrid Meeting (4/18).

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	Initiated
Role-based Training Courses	On Track	Scheduled
Synchrophasor Data Accuracy Maintenance Manual (with EMSWG)	On Track	Initiated
Roadmap for Operationalizing Synchrophasor Technology	On Track	Initiated
CIP Implementation Guidance for Synchrophasors	On Track	Initiated

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

Chair: Lynn Schroeder
Vice-Chair: Manish Patel
June 11, 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:

None

Recent Activity
- Review TRD: Transmission System Phase Backup Protections
- Develop Technical Reference document for Ethernet based P&C.
- Steady-state approach for PRC-024-3 Evaluation for Inverter-Based Resources" white paper
- 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
- Review and respond to comments for two documents that were posted for review
- Joint meeting with NPCC TFSP in July
- Working to develop implementation guidance on on TPL-001-5.1 Footnote 13
- If work plan item was approved by the RSTC EC, begin work on a report analyzing misoperations

Workplan Status *(6 month look-ahead)*

Milestone	Status	Comments
Ethernet P&C TRD	On Track (green)	The outline is complete, and the writing portion has begun
Review and update Transmission System Phase Backup Protections	On Track (green)	Reviewing comments from public posting and will submit at the September meeting. (3 month delay due to timing of public posting)
TPL-001-5.1 footnote 13	On Track (green)	Team developing Implementation guidance
Steady-state approach for PRC-024-3 Evaluation for Inverter-Based Resources" white paper	On Track (green)	Reviewing comments from public posting and will submit at the September meeting. (3 month delay due to timing of public posting)
Misoperations Analysis Report	On Track (green)	Anticipate a January 2025 publication date.

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

Chair: Shayan Rizvi (Jan 2024-2026)
Vice-Chair: John Schmall (Jan 2024-2026)
June 11, 2024

On Track
Schedule at risk
Milestone delayed

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:

- **RSTC Review**: *White Paper: Reducing Impacts on Bulk Power System Variability and Uncertainty – DER Data Collection, Storage, and Sharing with DER Aggregators*
- **Authorize:** *Reliability Guideline: DER Forecasting Practices and Relationship to DER Modeling for BPS Planning Studies*

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 April 2024 to update work products.
- Engaged RS related to EOP remanded SARs.
- Developed the DER Forecasting reliability guideline and seeking review
- Drafted content for the additional reliability guidelines.

Upcoming Activity

- *Continue drafting of Reliability Guidelines from Standards Review White Paper*
- *Continue collaboration among the RSTC groups for SARs*
- *Continue drafting of White Paper on DER Aggregator Modeling*
- *Drafting of new Technical Reference Document*

Work Look Ahead – non-SAR

On Track
Schedule at risk
Milestone delayed

Workplan Status (6 month look-ahead)

Milestone	Status	Comments
S1 – Reliability Guideline: Bulk Power system Planning under Increasing Penetration of Distributed Energy Resources	On Track	Out for 45 day comment. Anticipated turnaround in Q3 2024.
C11 – White Paper: Variability, Uncertainty, and Data Collection for the BPS with DER Aggregators	On Track	Seeking RSTC review in Q2 2024
A3 – White Paper: Modeling of DER Aggregator and DERMS Functional Impacts	On Track	Seeking RSTC review in Q4 2024
Reliability Guideline: Detection of Aggregate DER Response during Grid Disturbances	On Track	In scoping and draft. Seeking post for public comment period near Q3 or Q4 2024
Reliability Guideline: DER Forecasting	On Track	Seeking RSTC authorization to post for 45 day comment
Reliability Guideline: Aggregate DER in Emergency Operations	On Track	In draft. Seeking post for public comment period Q3 2024 or Q4 2024
Technical Reference Document: DERs and OPA-RTAs	On Track	Seeking RSTC EC authorization to work and return Q3 2024.

Work Look Ahead - SAR

- On Track
- Schedule at risk
- Milestone delayed

Workplan Status (6 month look-ahead)

Milestone	Status	Comments
C15 – SAR EOP-004	Milestone delayed	In draft. Seeking RS prior to re-engaging RSTC. Engaged with RTOS already. Delayed to build consensus activities
C16 – SAR EOP-005	Milestone delayed	In draft. Delayed return to build consensus activities
C18 – SAR PRC-006	Schedule at risk	Responding to industry comments and need to seek SPCWG collaboration before returning to RSTC
C19 – SAR on OPAs and RTAs	Milestone delayed	Seeking return of Technical Reference Document and tabling this SAR till more appropriate time.

RSTC Status Report – Security Working Group (SWG)

Co-Chair: Brent Sessions
Co-Chair: John Tracy
June 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 Guidance
    - ERO Compliance Endorsed / Approved
- On-going
    - *CIP Evidence Request Tool (ERT)*
    - *CIP to NIST mapping*
- New Activity
    - *Physical Security SME Sub-team lead identified*

Items for RSTC Approval/Discussion:

- N / A

Upcoming Activity

- Establishing Physical Security Protections for BES Elements sub-team
  - Re-write of 2019 Physical Security Guideline
  - Call for volunteers released May 8, 2024
- CIP Implementation Guidance for Synchrophasors
  - Entity presentations at sub-team meetings for Synchrophaser Use-Cases
  - Both CIP and non-CIP approaches
- Communication Protection System Guideline
  - Identifying SMEs / volunteers
- OLIR Mapping NIST800-53 to NERC CIP
  - Working through control families
  - Quality assurance of data

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

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

Scope Document: Electric Vehicles Task Force

Action

Approval

Summary

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 or 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.

This scope document has been reviewed by RSTC Executive Committee members for initial feedback and their review has been incorporated in this version. An accompanying initial work plan is set to help guide the task force for the information found in the Activities section of the scope document.

Electric Vehicle Task Force (EVTF) Scope

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 or 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.

Activities

The NERC EVTF will serve as an open stakeholder forum for EV and charging station original equipment manufacturers (OEM) as well as utilities to improve on utility knowledge of modern EV charging technology, improvement to the modelling of such technology, and build a common nomenclature to exchange impact and risk information between the electric utilities and automotive industry. To do this, the EVTF will focus on the following activities:

1. Identify, prioritize, and develop a suite of risks that the EVTF deems critical to the reliable electrification of the transportation sector.
2. Increase the technological understanding of modern EV charging behavior by BPS utilities and develop educational materials that can be used for a wide range of audiences to describe the potential emerging risks and possible solutions to address those risks.
3. Reach and establish a common nomenclature to describe the electrical impact of EV charging for cross sector collaboration.
4. Provide technical recommendations on the impact of higher penetration of EV charging behavior on the BPS, and the potential solutions to mitigate any identified issues.
5. Provide technical recommendations on the impact for EV discharging behaviors and recommend appropriate modelling decisions to represent dynamic interchange between charging and discharging modes.
6. Develop recommendations for assessing EV charging impacts in other NERC program areas, including Resource Adequacy.
7. Any other task assigned to it by the NERC Reliability and Security Technical Committee (RSTC).

Deliverables

The EVTF will develop the following items within its anticipated one-to-two-year period:

1. A white paper on risks to identify potential BPS-level reliability risks. This paper plans to leverage the NERC *Framework to Address Known and Emerging Reliability and Security Risks*[1] to identify, validate, and prioritize the potential reliability risks related to transportation electrification. Where applicable, the EVTF will identify areas where potential security risks require additional follow-up assessment by security professionals.
2. A technical report on the EV charging states and type tests to validate the charging states. This document will identify the information available that transmission planners can use to integrate into their studies and leverage appropriate testing mechanisms for an attestation of known performance.
3. A white paper on load model updates to represent modern EV charging systems, their disconnection modes, and other standard protective functions that impact the electrical draw (or discharge) of energy. This paper will document and recommend various improvements to the aggregate representation of EV charging as well as through a stand-alone representation for large load interconnections. This paper will attempt to differentiate between the various charging levels and recommend the expected load representation.
4. A white paper detailing BPS studies that analyze the electrical impact of modern EV charging systems using the learnings from the other deliverables. These studies are to identify and recommend generalized grid interconnection procedure requirements to capture the reliable integration of EVs to the BPS.

EVTF will maintain its work plan and submit updates to the RSTC on the milestones for the above deliverables.

Membership

The EVTF will include members and observers who have technical expertise in the following areas:

- Design of EV charging stations, charging points, or charging algorithms
- Electrical interface design of EVs or EV service equipment
- Utility programs and interconnection studies for EV equipment
- Entities affected by adoption at-scale of EVs or EV service equipment.

The EVTF will contain open membership to complete the items on its work plan and include interested parties affected by the adoption of EVs or EV service equipment at-scale. Members will select if they are representing the electrical industry, the automotive industry, or observing the open task force. These distinctions will be used in reaching consensus of the attending membership for decisions by the EVTF. The EVTF will consist of a chair and vice chair appointed by the RSTC leadership. Where feasible, officers shall

[1] *Framework to Address Known and Emerging Reliability and Security Risks.*

be selected from individuals employed at entities within NERC membership sectors 1 through 12. NERC staff will be assigned as coordinator(s). Decisions will be based on the consensus of the attending membership, led by the chair and staff coordinator(s). Any minority views can be documented as appropriate. The EVTF chair, vice chair, and the assigned NERC staff coordinator can develop groupings of the membership to easier facilitate work plan product development of its various deliverables.

Reporting & Duration

The EVTF will report to the NERC RSTC. The NERC Reliability and Security Technical Committee will approve EVTF work products. The EVTF will develop the deliverables in its work plan on its proposed one-to-two-year timeline, with updates managed and approved by the NERC RSTC.

Meetings

The group is expected to have four meetings per year, supplemented with conference calls, to facilitate the completion of work products.

Approved by the Reliability and Security Technical Committee on XX/XX/XXXX

Electric Vehicle Task Force (EVTF)

2024-2025 Work Plan

Website: UPDATE	**Chair**: TBD	**NERC Lead**: JP Skeath
Hierarchy: Reports to RSTC	**Vice-Chair**: TBD	**Scope Approved**: TBD

#	Task Description	Target Completion	Status
1	**White Paper: Risk Profiles and Prioritization on Transportation Electrification** *A white paper on the list of risks the task force identifies, validates, and prioritizes related to the electrification of the transportation sector. The white paper will be at a high level and the remaining work products reinforce the outcomes of the NERC study on potential BPS impacts from EV Charging*	Q1 – 2025	In draft.
2	**Technical Report: EV Charging States and Type Tests** *A technical repository of known EV charger type tests, modern EV charging characteristics, and generic responses to EV electrical response to transient stability.*	Q3 – 2025	In draft.
3	**White Paper: Load Model Updates for EV Charging** *A set of recommended model improvements to represent the charging and discharging electrical behavior of EV charging stations.*	Q4 – 2025	In draft.
4	**White Paper: Study Results of EV Charging Modes** *Generalized study results from BPS planners to describe the impacts that occur when running a sample study using the most up to date model information and recommended utility requirements when running EV load interconnection studies.*	Q4 - 2025	In draft.

Scope Document: Large Loads Task Force

Action

Approve

Summary

The rapid expansion of large loads, such as data centers, crytpomining loads, in the transmission network presents challenges to the reliability and security of the bulk power system (BPS). The primary purpose of the Large Load Task Force (LLTF) is to expediate understanding of emerging large loads and their impact on BPS performance. Specifically, the LLTF aims to develop technical documents to provide guidance and support BPS planning and operations with the increased penetration of large loads. These technical materials will assist transmission entities in understanding risks, performance aspects, required modeling enhancements, and system studies necessary to mitigate reliability risks.

This scope document has been reviewed by the RSTC Executive Committee members for initial feedback and their review has been incorporated in this version. A work plan will be developed based on the activities outlined in the scope document upon the formation of the taskforce, guiding its activities.

Large Loads Task Force Draft Scope

Purpose

The purpose of the Large Loads Task Force (LLTF) is to expediate the understanding of emerging large loads and their impact on the performance of the bulk power system (BPS). The LLTF will focus on developing guidance in the form of technical documents to support BPS planning and operations under increasing penetrations of large loads. The technical materials are intended to help transmission entities understand the risks, performance aspects, required modeling enhancements, and perform system studies of emerging large loads.

Activities

The LLTF will focus on the following activities-

1. Help document performance of large loads and their impact on the BPS. Provide guidance to the industry on issues associated with the integration of large loads and recommended practices, as identified in simulations, real time performance, event analysis.
2. Coordinate and support any data collection activities and analyses related to large load performance and modeling.
3. Establish expectations for system analysis, in both Planning and Operations time horizons, as needed, and provide technical basis demonstrating the potential impacts of emerging reliability issues.
4. Develop guidelines and whitepapers in support of BPS reliability addressing transmission planning and operations issues associated with interconnecting large loads.
5. Conduct industry technical workshops and webinars to share key findings, lessons learned, and best practices, and gather feedback from Industry.
6. Proactively analyze and study any emerging reliability issues that may be identified and that may have an impact on the North American BPS.
7. Other activities as directed by the NERC Reliability and Security Technical Committee (RSTC).
8. Assess technical capabilities of large loads and recommend changes to system planning and operations to utilize those capabilities to enhance system reliability and resilience.

Deliverables

The LLTF will develop the following deliverables:

1. Issue guidance in the form of reliability guidelines, technical reference documents, or white papers related to emerging large load risks, performance, studies, forecasting, technology, and security.
2. Recommendations to any gaps in the assessments of the modeling, modeling practices, and analyses being performed across North America involving large loads.

Membership

The LLTF will include members and observers who have technical or policy level expertise in the following areas:

1. Assessing the reliability impacts of emerging large loads on the BPS.
2. Entities involved in implementing emerging large loads in BPS planning studies and real time operations.
3. Load forecasting and load modeling of emerging large loads.
4. Entities affected by influx of data centers, cryptomining loads, and other large loads.
5. Other interested parties include research organizations and entities involved in design and operation of large loads.

The LLTF will contain open membership to complete the items on its work plan and include interested parties affected by the influx of large loads. The LLTF will consist of a chair and vice chair nominated by the group and approved by the RSTC Chair. Where feasible, officers shall be selected from individuals employed at entities within NERC membership sectors 1 through 12 to support sufficient expertise and diversity in execution of the subordinate group's responsibilities. The task force will also be assigned an RSTC Sponsor to support its activities. NERC staff will be assigned as coordinator(s). Decisions will be consensus-based, led by the Chair and Vice Chair and staff coordinator(s). Any minority views will be included in an addendum. The LLTF chair, vice chair, and the assigned NERC staff coordinator can develop groupings of membership to facilitate the development of various deliverables identified in the work plan.

Reporting and Duration

The LLTF will report to the NERC RSTC. The NERC RSTC will approve LLTF work products. The group will develop the deliverables in its work plan on a timeline approved by the RSTC and will continue completion of the LLTF work plan.

Meetings

The LLTF is expected to have at least four meetings per year (monthly meetings can be expected, where appropriate), supplemented with conference calls, to facilitate the completion of work products.

Reliability Guideline Review: Generating Unit Operations During Complete Loss of Communications

Action
Approve

Summary
The Guideline "Generating Unit Operations during Complete Loss of Communications" has had its triennial review by the NERC Resources Subcommittee. The Reliability Guideline applies primarily to Balancing Authorities, Transmission Operators, Generator Operators and on-site generating unit(s) operators. The intent of this document is that Balancing Authorities and Transmission Operators, in accordance with their Reliability Coordinator, provide guidance for the coordination and training of the on-site generating unit(s) operators should **all communications be interrupted**, particularly during a severe impact event.

The applicable Balancing Authority, Transmission Operator or Reliability Coordinator may require a generator or group of generators to deviate from the guidance provided in this Reliability Guideline due to their electrical interconnection point to the Bulk Electric System. Therefore, it is important that Generator Operators coordinate the development of procedures and training with input and concurrence from their applicable Balancing Authority, Transmission Operator and Reliability Coordinator.

Background
The basic assumptions made is all data and voice communication, both primary and back up are lost between the on-site generating units(s) operator and the System Operator for the Balancing Area, Transmission Operator and Reliability Coordinator. The Reliability Guideline provides guidance to generator operators to include actions to take to maintain the interconnection frequency within limits using generator turbine speed as the measurement.

The Reference Document:
The NERC Resources Sub-Committee reviewed the Operating Reserve Management to ensure continued relevance. Changes to the guideline include:

- Changes were made to several hyperlinks,
- Wording change accepted regarding maintenance timing,
- Errata changes to correct grammar and typographical errors.

This guideline has been posted for 45 day industry comment and includes the response to those comments.

D

Reliability Guideline

Generating Unit Operations during Complete Loss of Communications

Date: December 2023

RELIABILITY | RESILIENCE | SECURITY




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Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Table of Contents

Preface

Electricity is a key component of the fabric of modern society and the Electric Reliability Organization (ERO) Enterprise serves to strengthen that fabric. The vision for the ERO Enterprise, which is comprised of the North American Electric Reliability Corporation (NERC) and the six Regional Entities, 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 Entity boundaries as shown in the map and 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

This Reliability Guideline provides a strategy for power plant operations in the case of complete loss of communications (both data and voice) between the on-site generating unit(s) operator and the System Operator for the Balancing Area, Transmission Operator and Reliability Coordinator.

This Reliability Guideline was developed as requested by the NERC OC in 2014 as part of the industry's response to the Severe Impact Resilience Task Force (SIRTF) Recommendations.

The Reliability Guideline applies primarily to Balancing Authorities, Transmission Operators, Generator Operators and on-site generating unit(s) operators. The intent of this document is that Balancing Authorities and Transmission Operators, in accordance with their Reliability Coordinator, provide guidance for the coordination and training of the on-site generating unit(s) operators should all communications be interrupted, particularly during a severe impact event.

The Reliability Guideline outlines a coordinated operations strategy for the on-site generating unit(s) operator to stabilize system frequency when centralized guidance is not possible. The strategy is designed to keep frequency within allowable limits and continue safe operation of generators while maintaining acceptable frequency control. The Reliability Guideline is not applicable to generation connected to asynchronous loads or systems not normally part of one of the Interconnections. This guideline was written originally for staffed synchronous generation, however, the guidance may be applied to non-synchronous generation that has manual control capabilities and is capable of responding.

Introduction

Purpose

The Reliability Guideline applies primarily to Balancing Authorities, Transmission Operators, Generator Operators and on-site generating unit(s) operators. The intent of this document is that Balancing Authorities and Transmission Operators, in accordance with their Reliability Coordinator, provide guidance for the coordination and training of the on-site generating unit(s) operators should all communications be interrupted, particularly during a severe impact event.

The applicable Balancing Authority, Transmission Operator or Reliability Coordinator may require a generator or group of generators to deviate from the guidance provided in this Reliability Guideline due to their electrical interconnection point to the Bulk Electric System. Therefore, it is important that Generator Operators coordinate the development of procedures and training with input and concurrence from their applicable Balancing Authority, Transmission Operator and Reliability Coordinator (see Error! Reference source not found.).

The Reliability Guideline is not meant to have the on-site generating unit(s) operator operate outside of the generator(s) limits or prevent the on-site generating unit(s) operator from taking actions necessary to protect the equipment under their supervision from damage including, if necessary, taking a unit off line in a safe manner. Protective equipment should not be bypassed or rendered inoperable in order to follow this guideline. Safety of personnel and prevention of damage to system equipment are the first responsibilities of electric system operators at all levels. Short-term instabilities and power grid outages can only be made worse if damage is allowed to occur to system equipment.

This Guideline does not create binding norms, establish mandatory Reliability Standards or create parameters by which compliance with Reliability Standards are monitored or enforced. In addition, the Reliability Guideline is not intended to take precedence over any Regional procedure.

Assumptions

The basic assumptions made in the development of this guideline are as follows:

1. **Loss of Communications** – all data and voice communications, both primary and backup, are lost between the on-site generating unit(s) operator and the System Operator for the Balancing Area, Transmission Operator and Reliability Coordinator.
2. **Generating Unit Status** – some generating capacity remains in service or can be brought into service locally at the on-site generating unit(s) operator's discretion, to serve the load over the period of lost communications. (This does not imply that steam units not already in service should be brought into service.)
3. **Instrumentation** – Generating unit(s) are equipped with turbine speed sensors capable of one RPM increments and sometimes frequency metering devices capable of displaying (and optionally recording) system frequency on both narrow (roughly 59.95 Hz to 60.05 Hz) and wide (roughly 58.0 Hz to 62.0 Hz) ranges. Nomograms or other job aids that convert generator speed to frequency can be used.
4. **Situation Awareness** – The on-site generating unit(s) operator recognizes that turbine speed, therefore frequency is abnormal and a unique situation is occurring.

Guideline Details

If all communications between the on-site generating unit(s) operator and the System Operator are lost, one data point that is generally available to the on-site generating unit(s) operator is turbine speed that is proportional to frequency as measured locally by plant instrumentation. It may not be possible for the on-site generating unit(s) operator to determine if the grid remains intact or if the plant is operating as part of a local island. There may be clues that a disturbance has occurred. However, any constant frequency operations strategy must function equally well with an intact grid or under island conditions.

In order to maintain stable system operations either with an intact grid or as part of an island, it is necessary to maneuver generation output to match changes in system demand. Without communications from the System Operator, the on-site generating unit(s) operator can only do this by controlling to frequency. Generator Operators should coordinate with their applicable Balancing Authority, Transmission Operator and Reliability Coordinator the development of procedures and training specific to each on-site generating unit(s) operator for complete loss of communication to incorporate any local actions that may deviate from the guidance provided in this document. Such procedures should include steps requiring periodic checks of communication status following the initial loss and steps requiring attempts to reestablish communication and potential alternate communication methods. This guideline proposes a structured approach to achieve frequency control for each of the following Interconnections:

- Eastern Interconnection
- ERCOT Interconnection
- Western Interconnection
- Quebec Interconnection

Chapter 1: Eastern Interconnection

Deadband (Green Zone) – as long as the frequency trend stays reasonably close to 60.00 Hz, no manual control actions should be taken by generating unit(s). This Deadband should be +/- 100 milliHertz (59.90 Hz to 60.10 Hz - See Chart 1 below). This Deadband is the "Secondary Control" deadband and should not be confused with governor deadband of the turbine governor.

Selective Response (Yellow Zone) – as the frequency trend moves outside the Deadband boundaries but remains within reasonable operational limits, frequency should be corrected by maneuvering generating unit(s) in a gradual manner. For the Eastern Interconnection, the Selective Response band should be beyond +/- 100 milliHertz but less than +/- 200 milliHertz (59.80 Hz to 60.20 Hz). The generation ramp rate recommended for Selective Response is roughly one percent of the unit rating per minute. The on-site generating unit(s) operator should carefully observe frequency during Selective Response and cease maneuvering their units when frequency is returned to within the Deadband. It should be noted that a sustained frequency less than 59.90 Hz or greater than 60.10 Hz in the Eastern Interconnection is an indication that a disturbance has occurred.

Full Response (Red Zone) – when the frequency trend exceeds reasonable operational limits, all units capable of responding should rapidly maneuver within their maximum capability to balance load with generation. Full Response should be triggered when frequency is less than 59.80 Hz or greater than 60.20 Hz. If frequency continues to exceed the Full Response limits, all available generation at the plant should be maneuvered to the appropriate unit operating limits (i.e. fully loaded in the case of low frequency or at minimum load in the case of high frequency). In particular, all available generating capacity at the plant should be deployed to halt frequency decline when the frequency drops below the Full Response limit. The on-site generating unit(s) operator(s) should carefully observe frequency during Full Response operation and reduce the ramp rate of their units when frequency reaches the Selective Response region.

Emergency Response

If the frequency trend continues to deteriorate, emergency measures may be required in accordance with actions developed in consultation with applicable Balancing Authority, Transmission Operator and Reliability Coordinator.

- **High Frequency –** high frequency Emergency Response will consist of maneuvering all available generation to its lowest stable operating point, followed by tripping of selected units.
  - **Low Minimums –** all generation should be maneuvered to its lowest stable minimum load operating point (with auxiliary fuel firing, if required) when frequency increases to 60.30 Hz.
  - **Unit Tripping –** when frequency increases to 60.50 Hz, plants with multiple units should trip generation off line. Generally, smaller units with minimal impacts to operations should be taken off line first, so that as much capacity as possible remains on line. Use operational judgment to minimize any adverse impacts. Subsequent generation should be taken off line as needed.
- **Low Frequency –** Emergency Response may consist of loading all available hydro generation, followed by commitment of quick-start generating unit(s) (primarily combustion turbines).
  - **Hydro –** all hydro generation should be loaded when frequency declines to 59.70 Hz
  - **Quick-Start –** all quick-start generation resources should be committed when frequency drops below 59.60 Hz

On-site generating unit(s) operators should be aware that underfrequency load shed relays start to operate automatically to disconnect customer load when frequency declines to 59.50 Hz. Roughly 10 percent of system load is typically shed at this point (note that specific frequencies and load percentages vary depending upon specific Regional requirements). Additional load is typically shed as frequency continues to decline. The amount of load actually shed in any particular island will vary.

Blackout Conditions

If conditions continue to deteriorate, it will be necessary for the on-site generating unit(s) operator to separate from the synchronized grid in order to protect generating unit equipment. This separation takes place on a sliding time scale, typically at roughly 58.00 Hz. (Note that this is based on turbine manufacturer's recommendations that operation below this frequency can result in significant fatigue failure of the turbine blades and may vary with specific turbine design).

While it is desirable to maintain service continuity, it is unacceptable to allow generating unit equipment to suffer major damage that would impede the restoration of service after a major disturbance. However, it is important that units not be prematurely tripped when frequency is declining, since such action will cause system frequency to decline further and adversely affect other generators in the island. It is recommended that unless frequency is declining rapidly, units should remain connected to the system until the operation of automatic underfrequency load shedding relays is completed at roughly 58.00 Hz.

If a unit is removed from the Transmission system by the on-site generating unit(s) operator and cannot continue operation on a self-supporting basis, the on-site generating unit(s) operator should shut down the plant in an organized manner in preparation for restart. Such operation should be continued until a request to re-synchronize the generating unit to the Transmission system can be communicated to and approved by the System Operator. The on-site generating unit(s) operator should maintain generating unit(s) in a state whereby the unit can be restarted quickly to reduce the time required to restore the electrical system to normal operation.

The on-site generating unit(s) operator should make regular attempts to restore communications with the System Operator to convey the status of their generating unit(s) and always follow their Transmission Operator's restoration plans. This should include attempts to contact the applicable Balancing Authority, Transmission Operator and/or Reliability Coordinator.

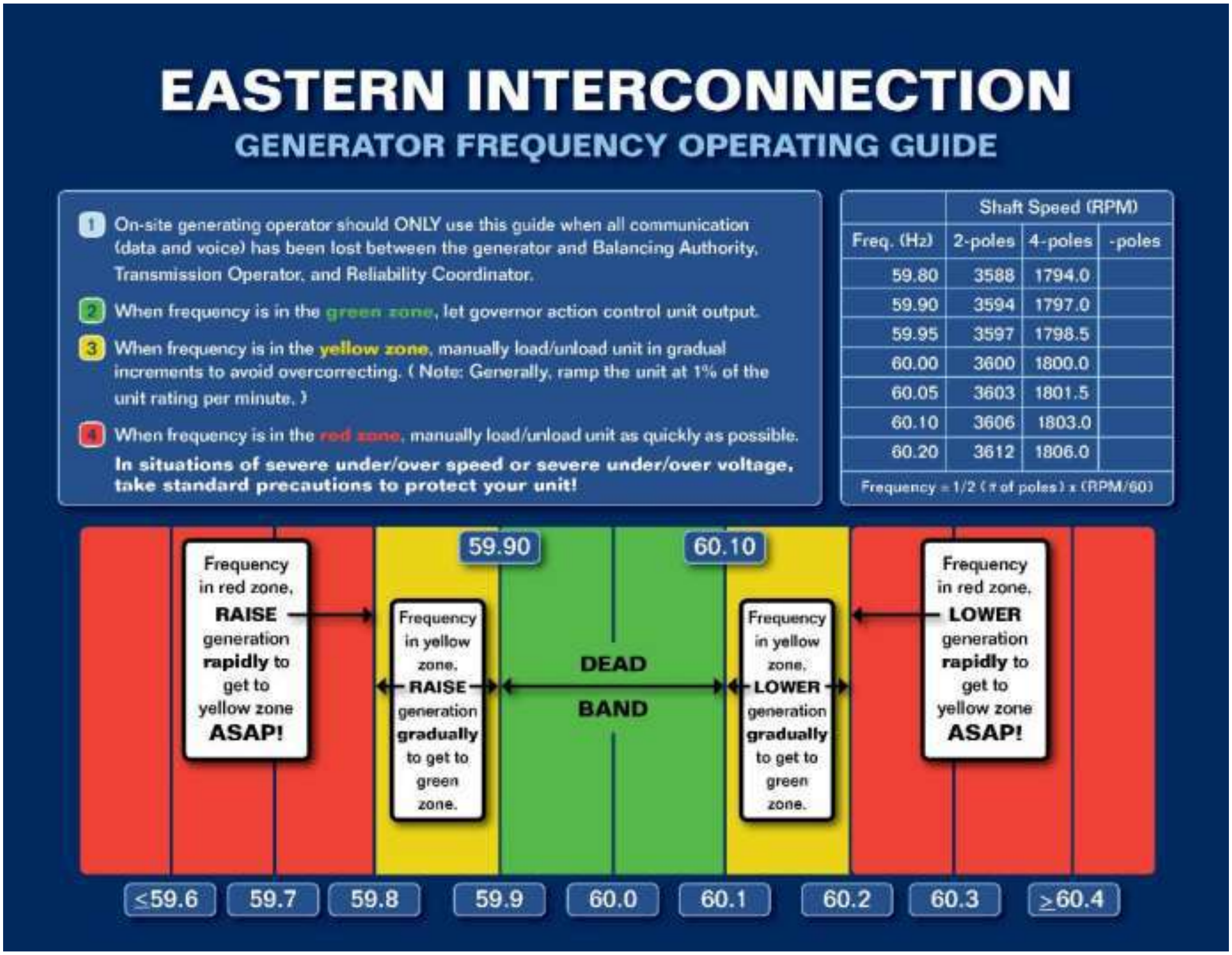


Figure 1.1: Eastern Interconnection Generator Frequency Operating Guideline

<u>Notes:</u>

- Nuclear generating plants are expected to stay on line at a sustainable, stable output level as long as possible. Under no circumstances should this Reliability Guideline be interpreted as requiring nuclear generating plants to operate in a manner that will violate their regulatory requirements, endanger public safety or adversely impact the integrity of plant equipment.
- Calibration of turbine speed and frequency measuring equipment should be included as part of the each generator's scheduled maintenance plan.

Chapter 2: ERCOT Interconnection

Deadband (Green Zone) – as long as the frequency trend stays reasonably close to 60.00 Hz, no manual control actions should be taken by generating unit(s). This Deadband should be +/- 100 milliHertz (59.90 Hz to 60.10 Hz - See Chart 2 below). This Deadband is the "Secondary Control" deadband and should not be confused with governor dead-band of the turbine governor. Turbine governor deadbands are established by ERCOT.

Selective Response (Yellow Zone) – as the frequency trend moves outside the Deadband boundaries but remains within reasonable operational limits, frequency should be corrected by maneuvering generating unit(s) in a gradual manner. For the ERCOT Interconnection, the Selective Response band should be +/- 200 milliHertz (59.80 Hz to 60.20 Hz). The generation ramp rate recommended for Selective Response is roughly one percent of the unit rating per minute. The on-site generating unit(s) operator should carefully observe frequency during Selective Response and cease maneuvering their units when frequency is returned to within the Deadband.

Full Response (Red Zone) – when the frequency trend exceeds reasonable operational limits, all units capable of responding should rapidly maneuver within their maximum capability to balance load with generation. Full Response should be triggered when frequency is less than 59.80 Hz or greater than 60.20 Hz. If frequency continues to exceed the Full Response limits, all available generation at the plant should be maneuvered to the appropriate unit operating limits (i.e. fully loaded in the case of low frequency or at minimum load in the case of high frequency). In particular, all available generating capacity at the plant should be deployed to halt frequency decline when the frequency drops below the Full Response limit. The on-site generating unit(s) operator should carefully observe frequency during Full Response operation and reduce the ramp rate of their units when frequency reaches the Selective Response region.

Emergency Response

If the frequency trend continues to deteriorate, then emergency measures may be required in accordance with actions developed in consultation with applicable Balancing Authority, Transmission Operator and Reliability Coordinator.

- **High Frequency –** high frequency Emergency Response will consist of maneuvering all available generation to its lowest stable operating point, followed by tripping of selected units.
  - **Low Minimums –** all generation should be maneuvered to its lowest stable minimum load operating point (with auxiliary fuel firing, if required) when frequency increases to 60.50 Hz.
  - **Unit Tripping –** when frequency increases to 62.50 Hz, plants with multiple units should trip generation off line. Generally, smaller units with minimal impacts to operations should be taken off line first, so that as much capacity as possible remains on line. Use operational judgment to minimize any adverse impacts. Subsequent generation should be taken off line as needed. Note that turbine overspeed trips typically engage at 63.00 Hz with auxiliary governor action beginning at 61.80 Hz.
- **Low Frequency –** Emergency Response may consist of loading all available hydro generation, followed by commitment of quick-start generating unit(s) (primarily combustion turbines)
  - **Hydro –** all hydro generation should be loaded when frequency decreases to 59.50 Hz
  - **Quick-Start –** all quick-start generation resources should be committed when frequency drops below 59.50 Hz.

On-site generating unit(s) operators should be aware that underfrequency load shed relays start to operate automatically to disconnect customer load when frequency declines to 59.30 Hz. Roughly five percent of system load is typically shed at this point. An additional 10% of system load is shed if frequency continues to decline and reaches

58.90 Hz. The final step of load shedding is 10% when frequency declines to 58.50 Hz. The amount of load actually shed in any particular island will vary.

Blackout Conditions

If conditions continue to deteriorate, it will be necessary for the on-site generating unit(s) operator to separate from the synchronized grid in order to protect generating unit equipment. This separation takes place on a sliding time scale, typically at roughly 58.00 Hz. (Note that this is based on turbine manufacturer's recommendations that operation below this frequency can result in significant fatigue failure of the turbine blades and may vary with specific turbine design).

While it is desirable to maintain service continuity, it is unacceptable to allow generating unit equipment to suffer major damage that would impede the restoration of service after a major disturbance. However, it is important that units not be prematurely tripped when frequency is declining, since such action will cause system frequency to decline further. It is recommended that unless frequency is declining rapidly, units should remain connected to the system until the operation of automatic underfrequency load shedding relays is completed at roughly 58.40 Hz. Off-frequency operations of steam turbines should be limited to nine minutes below 59.40 Hz, 30 seconds below 58.40 Hz and two seconds below 58.00 Hz. Please note that these time limitations are cumulative during the entire service-life of a generator.

If a unit is removed from the Transmission system by the on-site generating unit(s) operator and cannot continue operation on a self-supporting basis, the on-site generating unit(s) operator should shut down the plant in an organized manner in preparation for restart. Such operation should be continued until a request to re-synchronize the generating unit to the transmission system can be communicated to and approved by the System Operator. The on-site generating unit(s) operator should maintain generating unit(s) in a state whereby the unit can be restarted quickly to reduce the time required to restore the electrical system to normal operation.

The on-site generating unit(s) operator should make regular attempts to restore communications with the System Operator to convey the status of their generating unit(s) and always follow their Transmission Operator's restoration plans. This should include attempts to contact the applicable Balancing Authority, Transmission Operator and/or Reliability Coordinator.

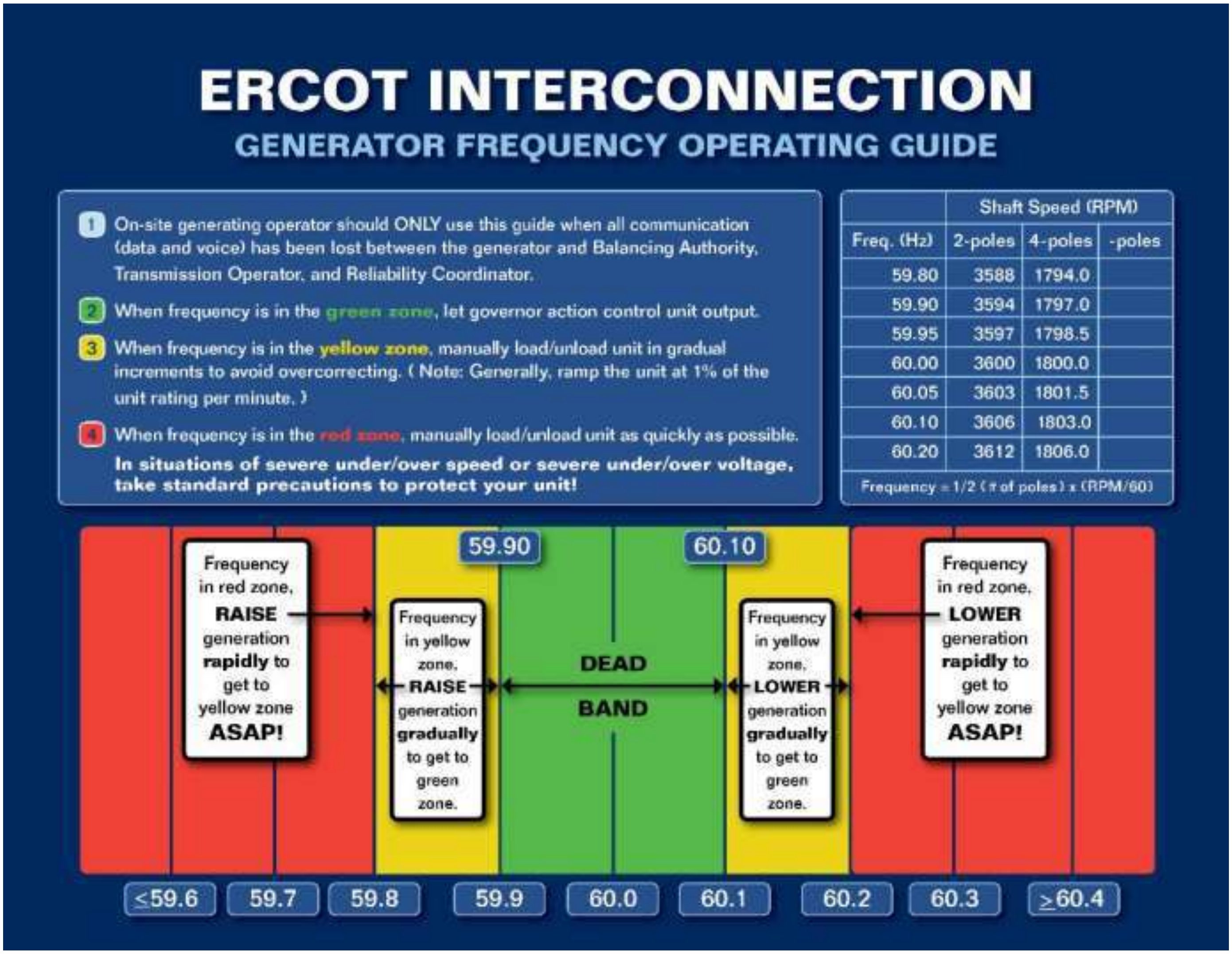


Figure 2.1: ERCOT Interconnection Generator Frequency Operating Guideline

<u>Notes:</u>

- Nuclear generating plants are expected to stay on line at a sustainable, stable output level as long as possible. Under no circumstances should this Reliability Guideline be interpreted as requiring nuclear generating plants to operate in a manner that will violate their regulatory requirements, endanger public safety or adversely impact the integrity of plant equipment.
- Calibration of turbine speed and frequency measuring equipment should be included as part of each generator's annual maintenance plan.
- For wind and solar resources that were curtailed prior to loss of communications with ERCOT should continue to hold their output at the level prior to the communication loss.
- In the event of a conflict between this guideline and the ERCOT governing documents, then the ERCOT governing documents will control.

Chapter 3: Western Interconnection

Deadband (Green Zone) – as long as the frequency trend stays reasonably close to 60.00 Hz, no manual control actions should be taken by generating unit(s). This Deadband should be +/- 100 milliHertz (59.90 Hz to 60.10 Hz- See Chart 3 below). This Deadband is the "Secondary Control" deadband and should not be confused with governor deadband of the turbine governor.

Selective Response (Yellow Zone) – as the frequency trend moves outside the deadband boundaries but remains within reasonable operational limits, frequency should be corrected by maneuvering generating unit(s) in a gradual manner. For the Western Interconnection, the Selective Response band should be +/- 200 milliHertz (59.80 Hz to 60.20 Hz). The generation ramp rate recommended for Selective Response is roughly one percent of the unit rating per minute. The on-site generating unit(s) operator should carefully observe frequency during Selective Response and cease maneuvering their units when frequency is returned to within the Deadband.

Full Response (Red Zone) – when the frequency trend exceeds reasonable operational limits, all units capable of responding should rapidly maneuver within their maximum capability to balance load with generation. Full Response should be triggered when frequency is less than 59.80 Hz or greater than 60.20 Hz. If frequency continues to exceed the Full Response limits, all available generation at the plant should be maneuvered to the appropriate unit operating limits (i.e. fully loaded in the case of low frequency or at minimum load in the case of high frequency). In particular, all available generating capacity at the plant should be deployed to halt frequency decline when the frequency drops below the Full Response limit. The on-site generating unit(s) operator should carefully observe frequency during Full Response operation and reduce the ramp rate of their units when frequency reaches the Selective Response region.

Emergency Response

If the frequency trend continues to deteriorate, then emergency measures may be required in accordance with actions developed in consultation with applicable Balancing Authority, Transmission Operator and Reliability Coordinator.

- **High Frequency –** high frequency Emergency Response will consist of maneuvering all available generation to its lowest stable operating point, followed by tripping of selected units.
  - **Low Minimums –** all generation should be maneuvered to its lowest stable minimum load operating point (with auxiliary fuel firing, if required) when frequency increases to 60.50 Hz.
  - **Unit Tripping –** when frequency increases to 60.60 Hz, plants with multiple units should trip generation off line. Generally, smaller units with minimal impacts to operations should be taken off line first, so that as much capacity as possible remains on line. Use operational judgment to minimize any adverse impacts. Subsequent generation should be taken off line as needed. Note that turbine overspeed trips typically engage at 61.20 Hz.
- **Low Frequency –** Emergency Response may consist of loading all available hydro and pumped storage hydro generation, followed by commitment of quick-start generating unit(s) (primarily combustion turbines).
  - **Hydro –** all hydro and pumped storage hydro generation should be loaded when frequency declines to 59.70 Hz.
  - **Quick-Start –** all quick-start generation resource(s) should be committed when frequency drops below 59.60 Hz.

On-site generating unit(s) operators should be aware that underfrequency load shed relays start to operate automatically to disconnect customer load when frequency reaches 59.50 Hz. Roughly, 4,200 MW of system load is shed at this point (note that specific frequencies and load percentages vary depending upon specific Regional requirements). Additional load is shed as frequency continues to decline. The amount of load actually shed in any particular island is per the WECC Off-Nominal Frequency Load Shedding Plan.

Blackout Conditions

If conditions continue to deteriorate, it will be necessary for the on-site generating unit(s) operator to separate from the synchronized grid in order to protect generating unit equipment. This separation takes place on a sliding time scale, typically at roughly 58.00 Hz. (Note that this is based on turbine manufacturer's recommendations that operation below this frequency can result in significant fatigue failure of the turbine blades and may vary with specific turbine design).

While it is desirable to maintain service continuity, it is unacceptable to allow generating unit equipment to suffer major damage that would impede the restoration of service after a major disturbance. However, it is important that units not be prematurely tripped when frequency is declining, since such action will cause system frequency to decline further. It is recommended that unless frequency is declining rapidly, units should remain connected to the system until the operation of automatic underfrequency load shedding relays is completed at roughly 58.30 Hz.

If a unit is removed from the transmission system by the on-site generating unit(s) operator and cannot continue operation on a self-supporting basis, the on-site generating unit(s) operator should shut down the plant in an organized manner in preparation for restart. Such operation should be continued until a request to re-synchronize the generating unit to the transmission system can be communicated to and approved by the System Operator. The on-site generating unit(s) operator should maintain generating unit(s) in a state whereby the unit can be restarted quickly to reduce the time required to restore the electrical system to normal operation.

The on-site generating unit(s) operator should make regular attempts to restore communications with the System Operator to convey the status of their generating unit(s) and always follow their Transmission Operator's restoration plans. This should include attempts to contact the applicable Balancing Authority, Transmission Operator and/or Reliability Coordinator.

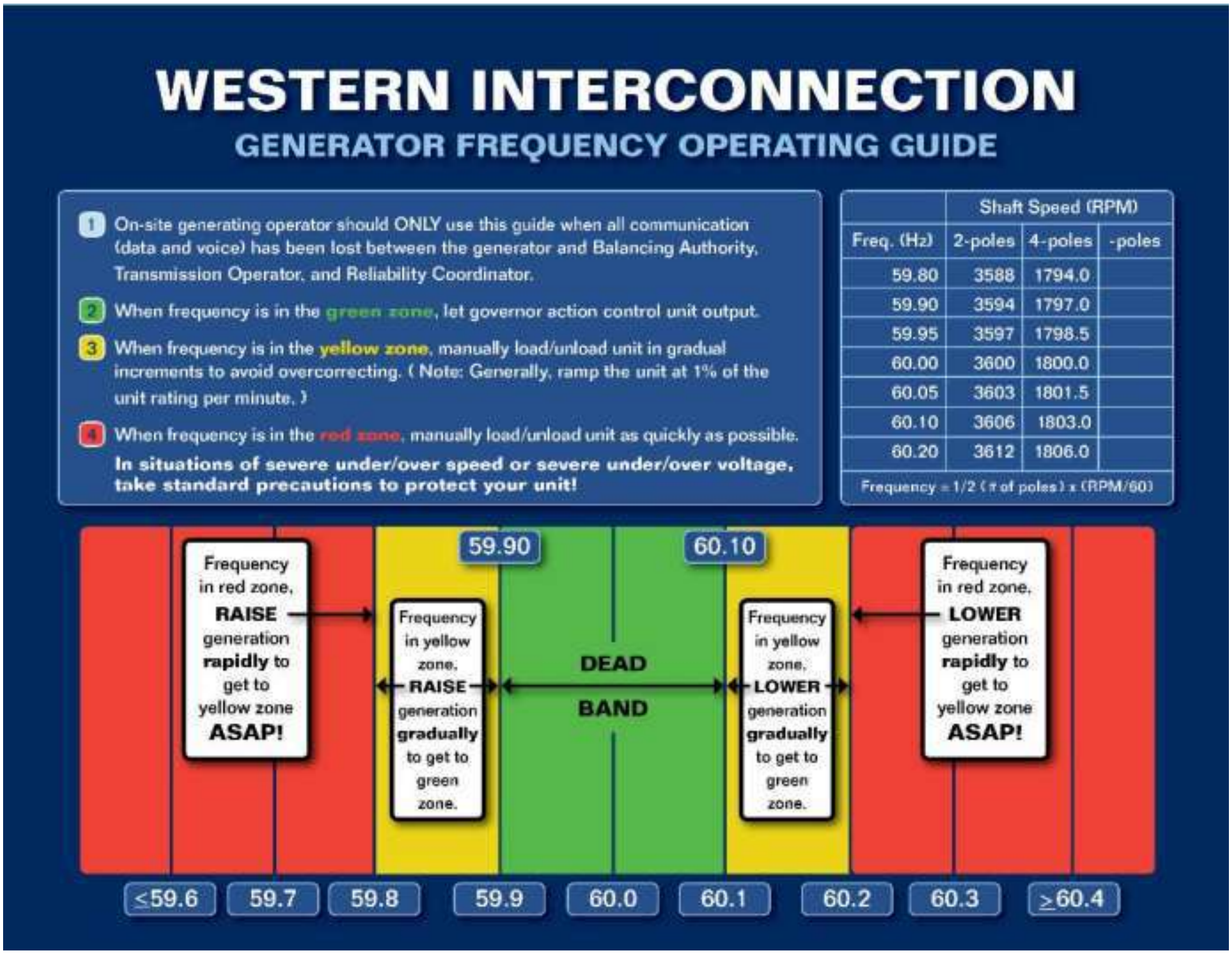


Figure 3.1: Western Interconnection Generator Frequency Operating Guideline

Notes:

- Nuclear generating plants are expected to stay on line at a sustainable, stable output level as long as possible. Under no circumstances should this Reliability Guideline be interpreted as requiring nuclear generating plants to operate in a manner that will violate their regulatory requirements, endanger public safety or adversely impact the integrity of plant equipment.
- Calibration of turbine speed and frequency measuring equipment should be included as part of each generator's annual maintenance plan.

Chapter 4: Quebec Interconnection

Deadband (Green Zone) – as long as the frequency trend stays reasonably close to 60.00 Hz, no manual control actions should be taken by generating unit(s). This Deadband should be +/- 100 milliHertz (59.90 Hz to 60.10 Hz- See Chart 3 below). This Deadband is the "Secondary Control" deadband and should not be confused with governor deadband of the turbine governor.

Selective Response (Yellow Zone) – as the frequency trend moves outside the deadband boundaries but remains within reasonable operational limits, frequency should be corrected by maneuvering generating unit(s) in a gradual manner. For the Western Interconnection, the Selective Response band should be +/- 200 milliHertz (59.80 Hz to 60.20 Hz). The generation ramp rate recommended for Selective Response is roughly one percent of the unit rating per minute. The on-site generating unit(s) operator should carefully observe frequency during Selective Response and cease maneuvering their units when frequency is returned to within the Deadband.

Full Response (Red Zone) – when the frequency trend exceeds reasonable operational limits, all units capable of responding should rapidly maneuver within their maximum capability to balance load with generation. Full Response should be triggered when frequency is less than 59.80 Hz or greater than 60.20 Hz. If frequency continues to exceed the Full Response limits, all available generation at the plant should be maneuvered to the appropriate unit operating limits (i.e. fully loaded in the case of low frequency or at minimum load in the case of high frequency). In particular, all available generating capacity at the plant should be deployed to halt frequency decline when the frequency drops below the Full Response limit. The on-site generating unit(s) operator should carefully observe frequency during Full Response operation and reduce the ramp rate of their units when frequency reaches the Selective Response region.

Emergency Response

If frequency continues to deteriorate, then emergency measures may be required in accordance with actions developed in consultation with applicable Balancing Authority, Transmission Operator and Reliability Coordinator.

- **High Frequency –** high frequency Emergency Response will consist of maneuvering all available generation to its lowest stable operating point, followed by tripping of selected units.
  - **Low Minimums –** all variable hydro generation should be maneuvered to its lowest stable minimum load operating point when frequency increases to 60.30 Hz.
  - **Unit Tripping –** when frequency increases to 60.50 Hz, plants with multiple units should trip generation off line. Variable hydro generation should be taken off line first and run-of-the-river units second. Use operational judgment to minimize any adverse impacts and to adequately manage hydraulic resource. Subsequent generation should be taken off line as needed. Note that over frequency generation tripping engages roughly at 60.9 Hz.
- **Low Frequency –**Emergency Response may consist of loading all available hydro and pumped storage hydro generation, followed by commitment of quick-start generating unit(s) (primarily combustion turbines).
  - **Variable Hydro –** all variable hydro generation should be loaded when frequency declines to 59.70 Hz.
  - **Quick-start –** all quick-start generation resources should be committed when frequency drops below 59.70 Hz.
  - **Run-of-the-river Hydro –** all run-of-the-river hydro generation should be loaded at maximum when frequency drops below 59.60 Hz.

On-site generating unit(s) operators should be aware that underfrequency load shed relays start to operate automatically to disconnect customer load when frequency reaches 59.00 Hz. Roughly, 500 MW of load is typically shed at this point (based on peak load conditions). An additional 800 MW of load is typically shed as frequency continues to decline by 500 milliHertz thresholds until it reaches the last step at 57.00 Hz.

Blackout Conditions

If conditions continue to deteriorate, it will be necessary for the on-site generating unit(s) operator to separate from the synchronized grid in order to protect generating unit equipment.

While it is desirable to maintain service continuity, it is unacceptable to allow generating unit equipment to suffer major damage that would impede the restoration of service after a major disturbance. However, it is important that units not be prematurely tripped when frequency is declining, since such action will cause system frequency to decline further. It is recommended that unless frequency is declining rapidly, units should remain connected to the system until the operation of automatic underfrequency load shedding relays is completed at roughly 57.00 Hz.

If a unit is removed from the transmission system by the on-site generating unit(s) operator and cannot continue operation on a self-supporting basis, the on-site generating unit(s) operator should shut down the plant in an organized manner in preparation for restart. Such operation should be continued until a request to re-synchronize the generating unit to the transmission system can be communicated to and approved by the System Operator.

The on-site generating unit(s) operator should make regular attempts to restore communications with the System Operator to convey the status of their generating unit(s) and always follow their Transmission Operator’s restoration plans. This should include attempts to contact the Balancing Authority, Transmission Operator and/or Reliability Coordinator.

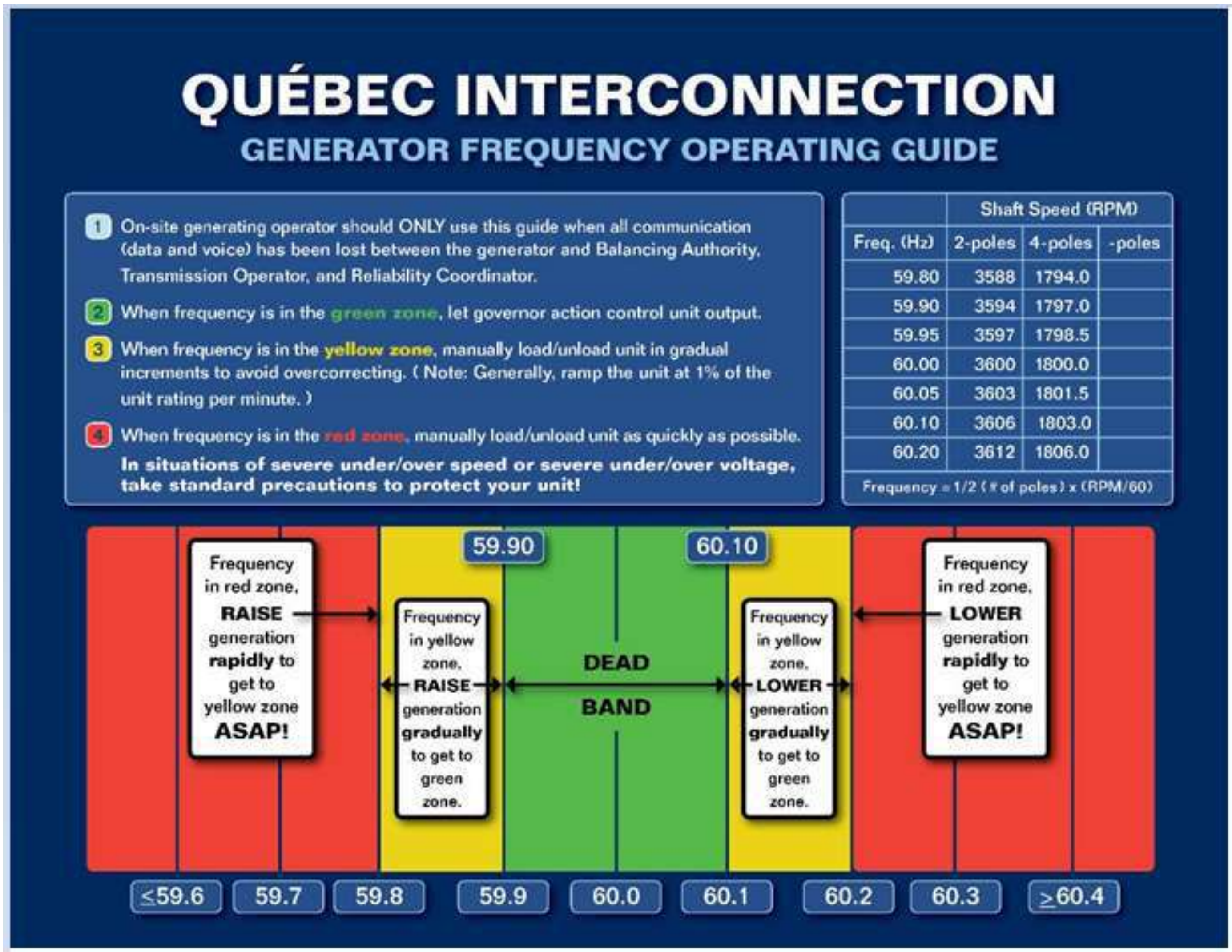


Figure 4.1: Quebec Interconnection Generator Frequency Operating Guideline

Notes:

- Calibration of turbine speed and frequency measuring equipment should be included as part of each generator's annual maintenance plan.

Related Documents and Links:

EPRI Power System Dynamics Tutorial

Appendix A: Training

Introduction

This appendix outlines suggested additional reading as well as provides a set of tasks the on-site generating unit(s) operator could consider as part of ongoing training and for participation in area restoration drills and seminars. Generator Operators may have a fleet of generators that crossover a number of Balancing Authorities and Transmission Operators footprints. Generator Operators should coordinate with each applicable Balancing Authority, Transmission Operator and Reliability Coordinator to develop guidelines and training specific to each generating unit operator for complete loss of communications.

Send comments and suggestions to balancing@nerc.com.

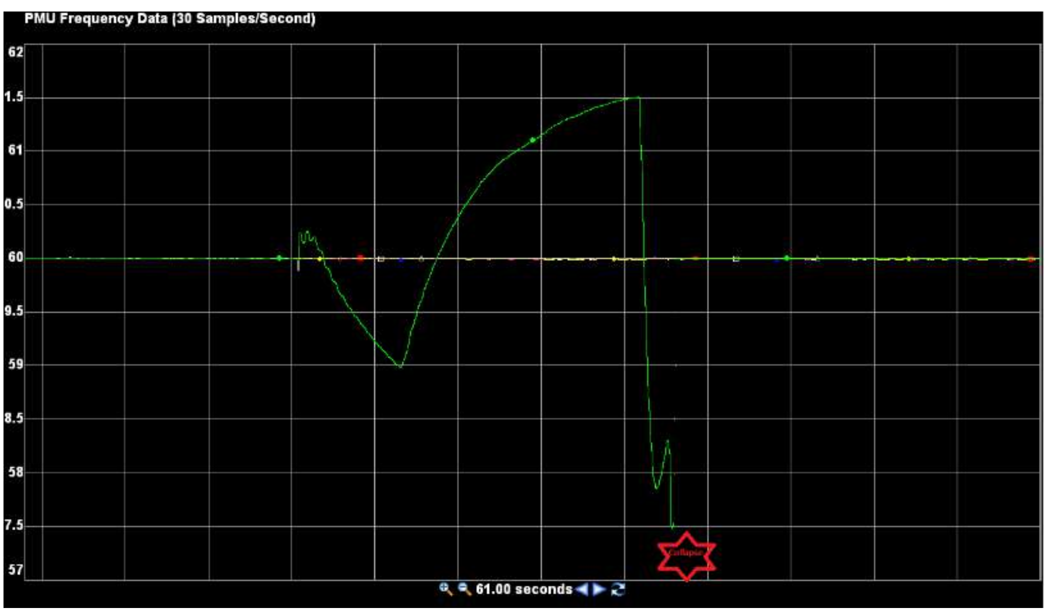
Additional Reading

A valuable resource available for training is the *EPRI Power System Dynamics Tutorial*. The tutorial can be downloaded for free at the link above. The parts of the tutorial that deal most directly to frequency control are:

- Section 4
- Section 8
- Section 11.3

Scenario

The tasks that follow are suggested as part of initial "emergency" training for the on-site generating unit(s) operator as well as refresher training during restoration drills. The tasks were developed after reviewing a few actual scenarios where generators found themselves in an island following a disturbance. While communications were still available to the Balancing Authority, the scenario still demonstrates the dynamics that can be observed following a disturbance. Since the most likely situation where an on-site generating unit(s) operator would need to take action and not have communications is following a disturbance or coordinated attack, the situation below is valid for comparison.



The frequency graph from a storm-created island in 2010 shows what took place within about 30 seconds. The storm left approximately 55 MWs of load in the area connected to 45 MWs of generation. This caused frequency to decline to 59 Hz, which was the first step of underfrequency load shedding (UFLS) in this area. The UFLS caused frequency to overshoot to approximately 61.5 Hz. Unfortunately, 18 MW of hydro generation tripped automatically at 61.5 Hz. This left an insufficient amount of generation in the area that caused a more rapid decline in frequency, which the next step of UFLS was unable to arrest.

The reality is that in some cases as outlined above, there is little for the on-site generating unit(s) operator to do. Knowing and coordinating the UFLS and generator trip setpoints in the area can help generators ride through local disturbances. For islands caused by major events, the islands may be larger and changes in frequency slower. The tasks below are intended to help the on-site generating unit(s) operator prepare for such events. It is suggested the tasks should be reviewed annually.

Tasks

- Discuss training activities and the guideline with your Balancing Authority.
- Identify your local load serving entity's under-frequency load shedding trip points.
- Identify your generator(s) overfrequency trip settings.
- Identify and test the generator(s) governor frequency control modes.
- Identify the ratings of the Transmission lines emanating from your station and the plant limitations if one or more lines are out of service.
- Discuss what steps the on-site generating unit(s) operator should take if controlling to voltage.
- List and discuss the symptoms of possible islanding.
- Identify and test possible alternate communication paths with your Balancing Authority, Transmission Operator and Reliability Coordinator (to include communications through other entities).
- If at a multi-unit station, discuss the frequency control strategy to be followed during islanding, restoration or complete loss of communications.
- Walk through the steps needed to isolate a generator from the grid while supplying its own auxiliaries.

Contributors

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

Name	Entity
NERC Resource Subcommittee 2014 Members	
NERC Resource Subcommittee 2022 Members	

Guideline Information and Revision History

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

Revision History		
Version	**Comments**	**Approval Date**
1.0	Initial Version – *"Generating Unit Operations During Complete Loss of Communications"*	06/11/2014
2.0	Revision to address unintended consequences on the transmission system that could result from uncoordinated voluntary generator movements driven by frequency alone.	06/9/2015
Draft 3.0	Revision for usability improvements identified in periodic review.	07/13/2018
3.0	Incorporation of comments on Draft 3.0	09/21/2018

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:

- Adaptation of Training between BA's and GOPs.

Effectiveness Survey

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

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

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

Guideline Effectiveness Survey [insert hyperlink to survey]

Analysis of Human Performance vs. Organizational Performance in the ERO Event Analysis Process

Action
Information

Summary
This topic will address an analysis of Human Performance vs. Organizational Performance in the ERO Event Analysis Process. This will include references to the make-up of Human Performance vs. Organizational Performance.

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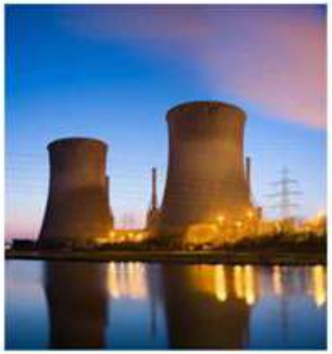
Human and Organizational Performance

An Event Causal Assignment Analysis

Ed Ruck, Senior Engineer of Event Analysis, NERC
NERC RSTC
June 11-12, 2024

RELIABILITY | RESILIENCE | SECURITY

Data Source

- Electric Reliability Organization Event Analysis Program
  - A program that includes reviewing off-normal events occurring on the bulk power system.
  - Requires industry participation and support to be effective.
  - Used to identify and publish lessons learned (NERC website) and support system reliability.
  - Event reporting supports identifying trends, identifying themes of occurrence, studying impact-risk relationships, and improving operating culture.

Data Source

- Trends are identified by cause codes that include the following:

Engineering and Design	Equipment and Material
Human Performance	Management and Organization
Communication	Training
Other	Overall Configuration
No cause found	Information to determine cause LTA

Event Numbers

NUMBER OF UNIQUE QUALIFIED EVENTS

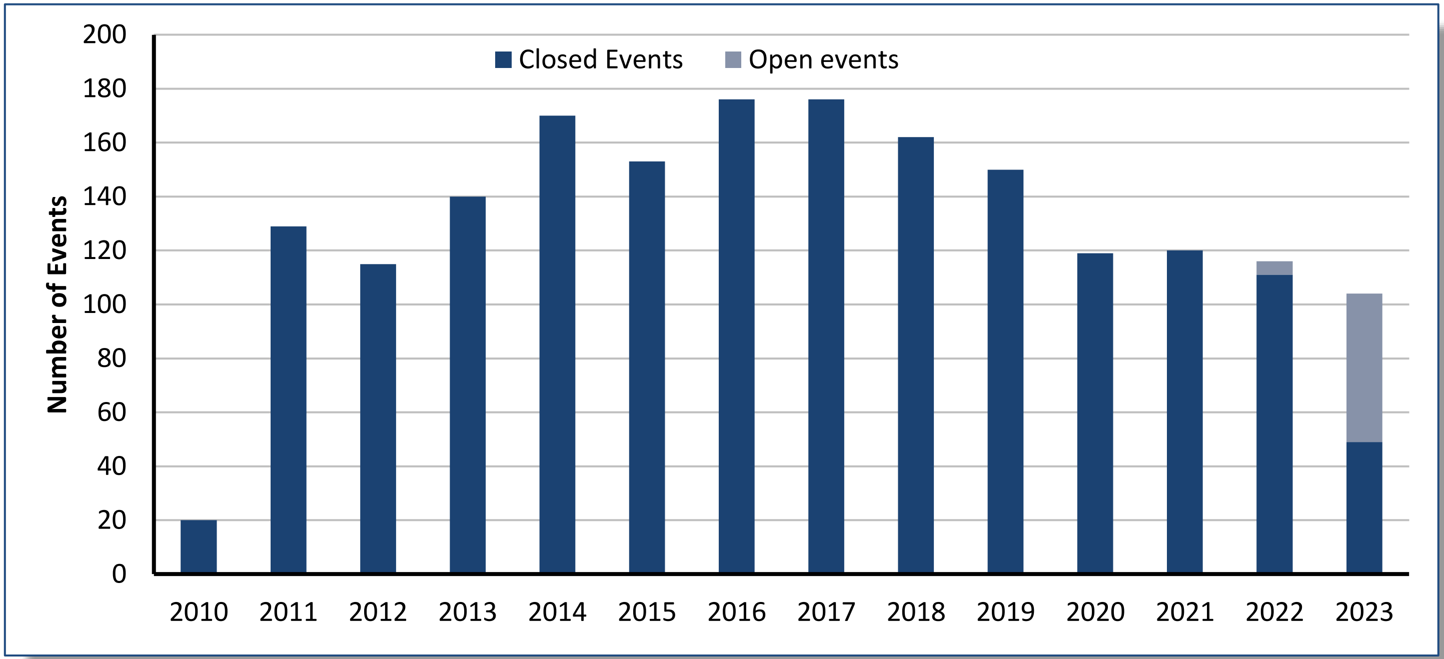
1,855

NUMBER OF EVENTS CAUSE CODED

1,790

NUMBER OF EVENTS IDENTIFIED ROOT CAUSE

1,007

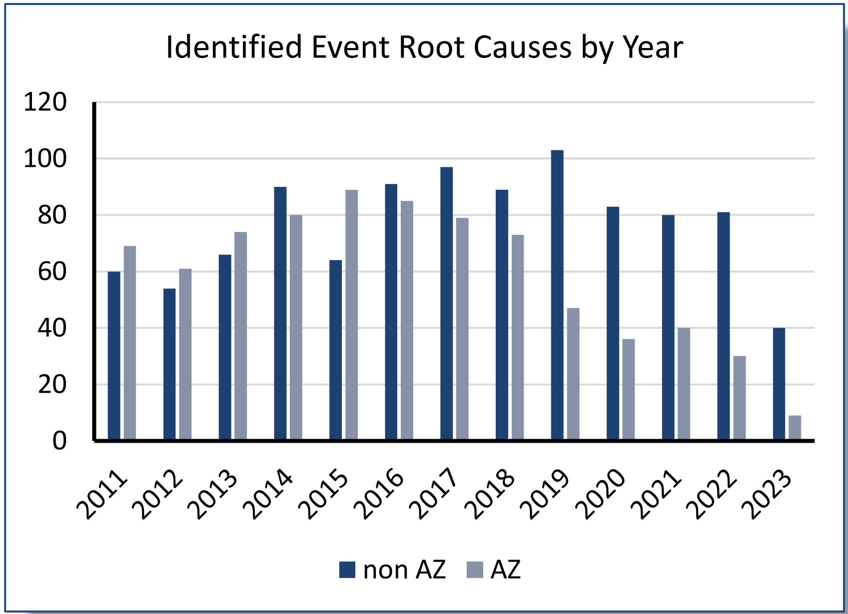


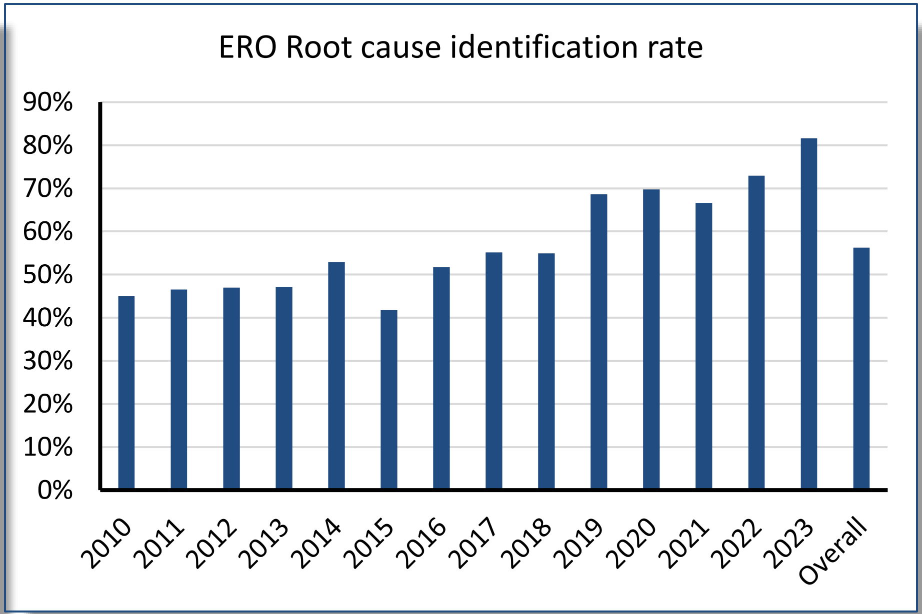
2.1

Per Week

Root Cause Identification Rate

- Root cause identification continues to improve
- Overall average is 55.4%
- 2018–2022 (rolling average of last 5 completed years) is 65.9%





**AZ Codes represent when a specific correctable/actionable root cause cannot be determined for an event*

Human Performance & Organizational Performance

- Human Performance refers to individual human performance
  - Refers to when a person makes a decision as an individual, not as part of a team
  - A substitution test would show different results, excluding the operating environment from influencing individual action
- Organizational Performance refers to practices, policies, procedures, management decisions, etc.
  - This would include work that is done as part of a team effort
  - Substitution test would show similar result indicting the operating environment leading the individual to action

Types of Human Error*

- Skill-Based Mode
- Rule-Based Mode
- Knowledge-Based mode
- Work Practices Error** (This is when a person can’t perform the task or deliberately causes an error.)

* Based on Rasmussen’s model

** Not Based on Rasmussen’s model

Skill Based Mode

- Skill-Based Mode–associated with highly practiced actions in a familiar situation

- Main error driver–Distraction
- Error Rate 1:10,000

- Rule Based Mode – based on the selection of stored rules derived from one's recognition of the situation

- Main error driver – Incorrectly identified the problem
- Error Rate 1:1,000

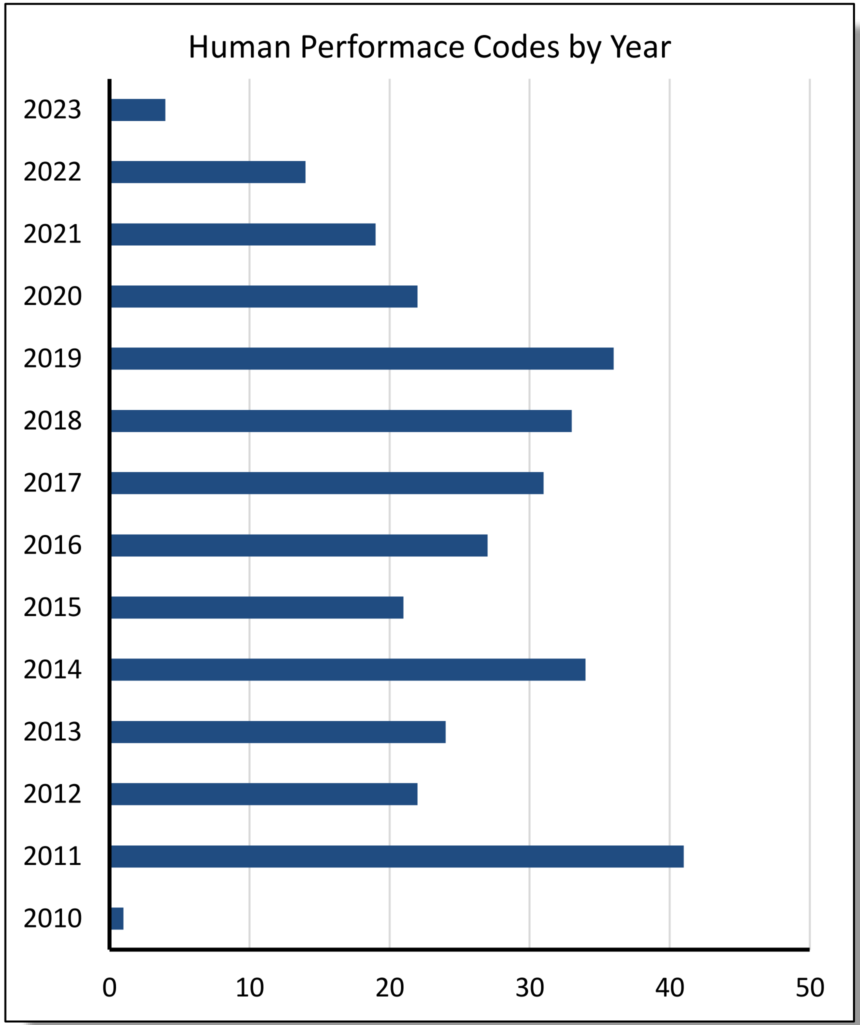
Knowledge Based Mode

- Knowledge-Based Mode–Behavior based on unfamiliarity, so individuals must rely on experience, perceptions, and perspectives

- Main Error Driver–Lack of a good mental model
- Error Rate 1:2

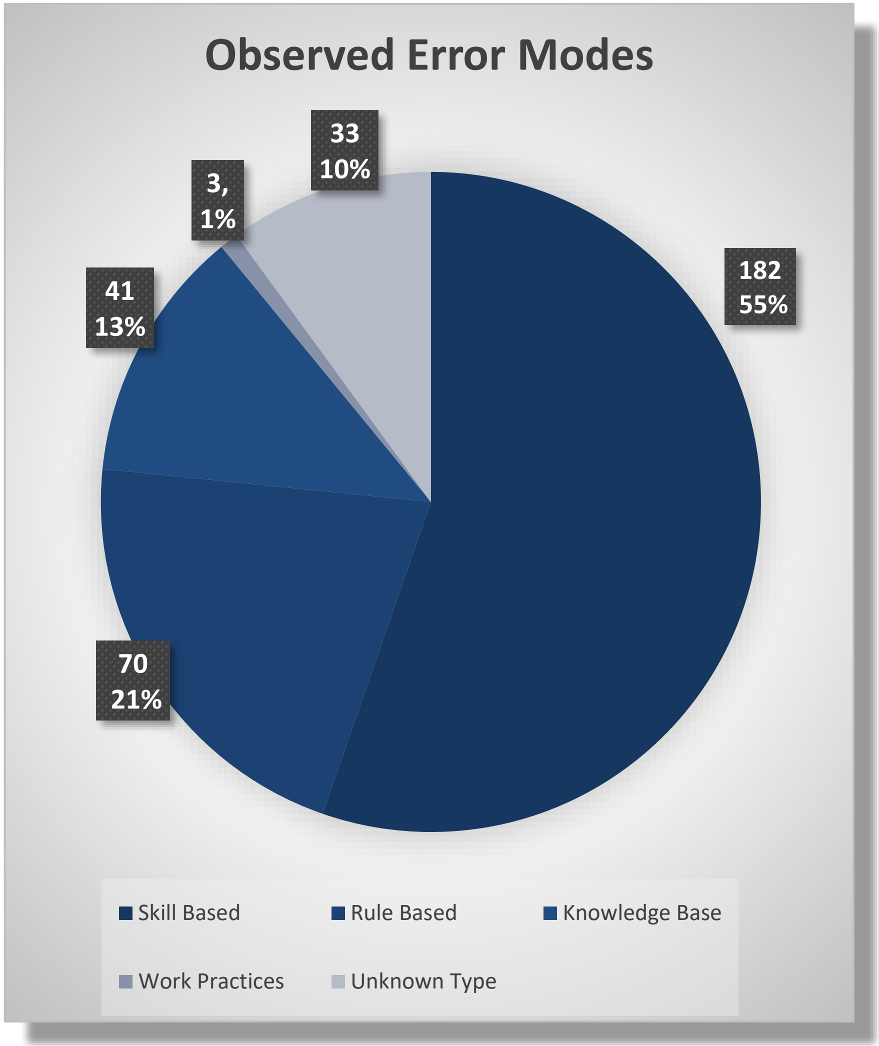
Human Performance Issues

- Human Performance has been identified as either a root cause or a contributing factor 329 times since 2010
- Average of ~26.2 events per year
- So more than once every other week, someone is making a mistake with consequences for the grid



Where are the problems

- Skill-Based Error (182 times)
- Rule-Based Error (70 times)
- Knowledge-Based Error (41 times)
- Unknown mode (33 times)
- Work Practices Error (3 times)



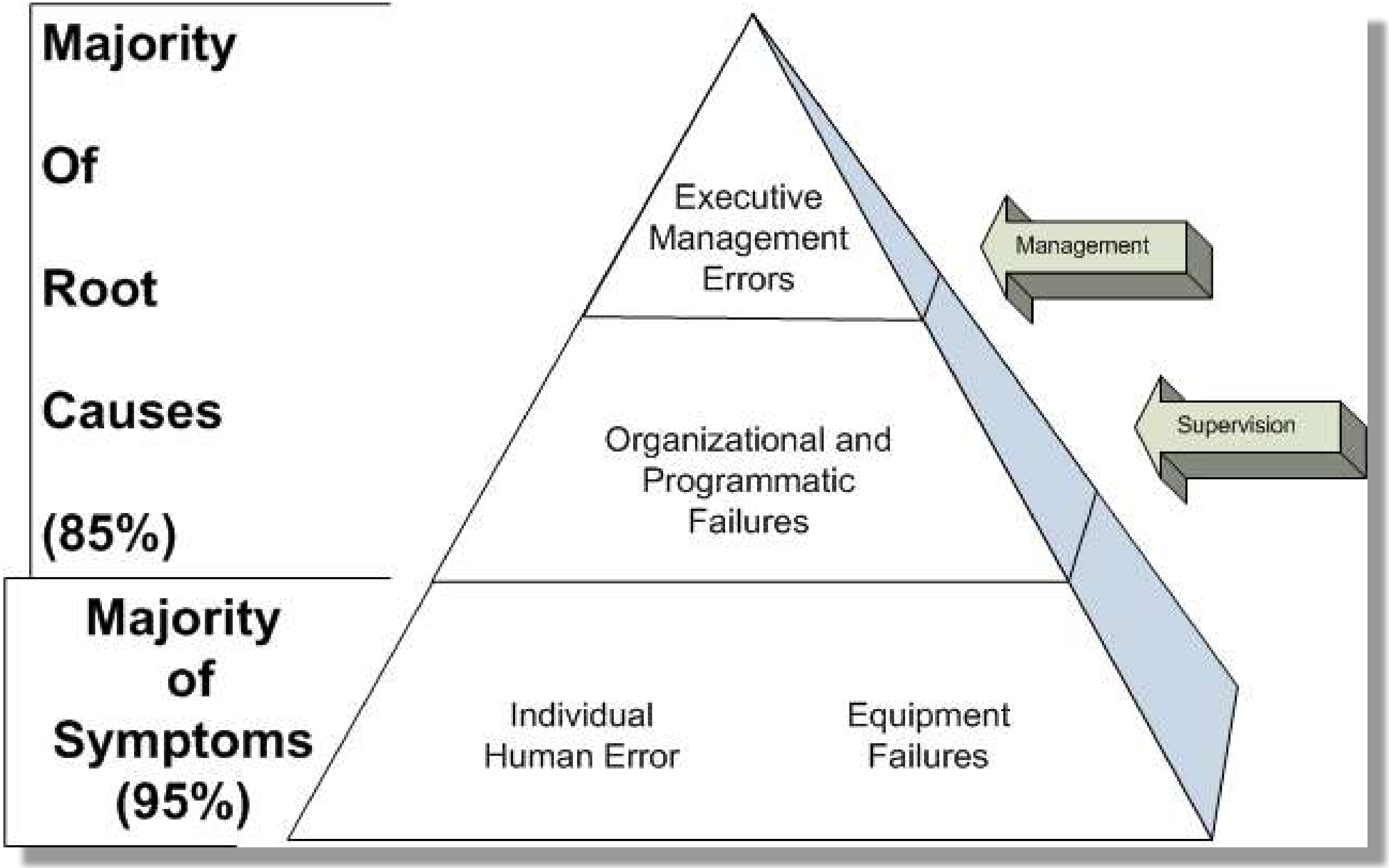
HP codes – Top 5

Out of 329 times a human performance code was identified, the top five codes were:

- Check of work Less than Adequate (LTA) (71 times, skill based)
- Individual Human Performance (33 times, unknown mode)
- Incorrect performance due to mental lapse (27 times, skill based)
- Situation incorrectly identified or represented resulting in wrong rule used (27 times, Rule based)
- General Skill Based Error (25 times)

So is it just the Human?

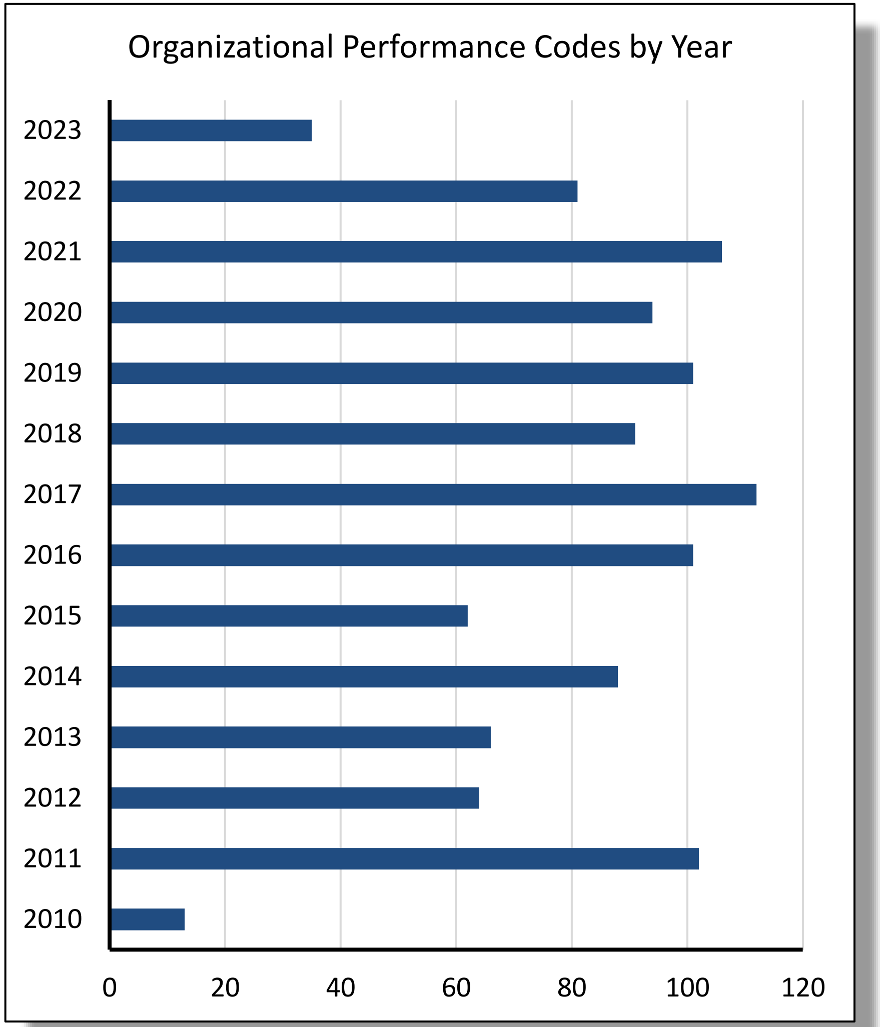
What do others see?



The PII Performance Pyramid TM

Organizational Performance Issues

- Organizational Performance has been identified as a root or contributing factor 1,116 times
- Average of ~89 events per year
- This is over 3x the rate of Individual Human Performance issues



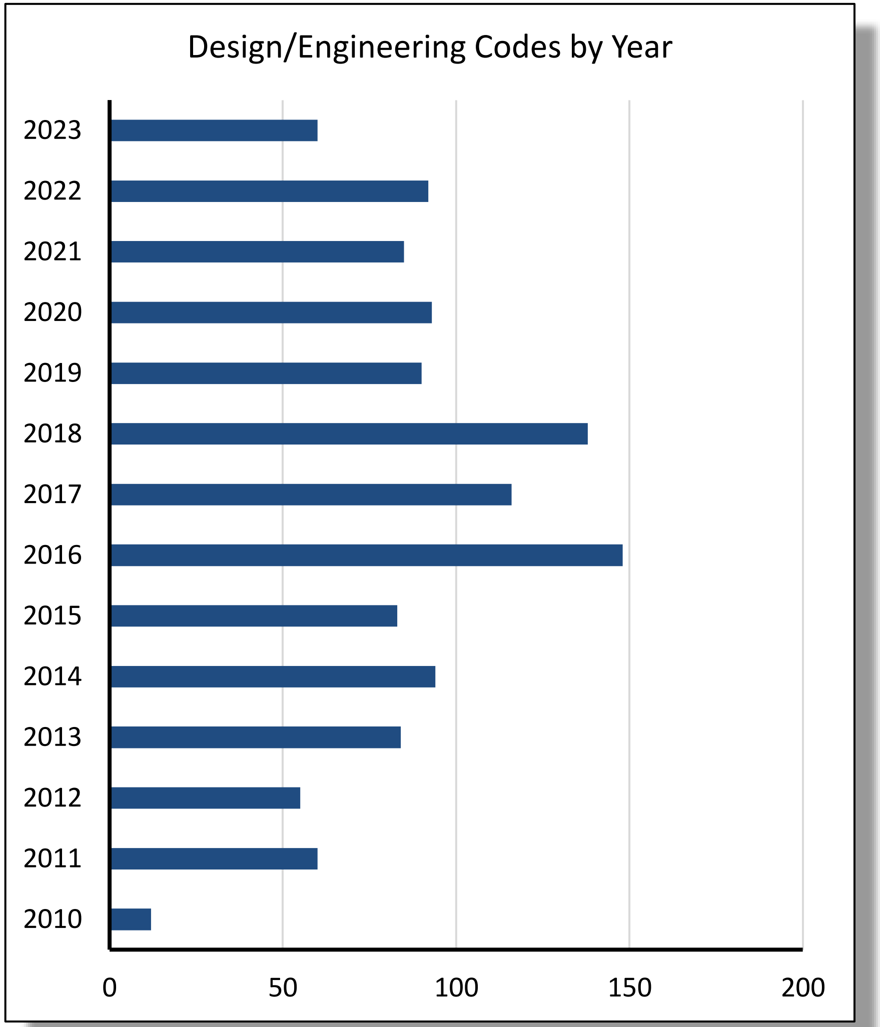
Organizational Performance Issues – Top 5

Out of the 1,116 times organization performance has been indicated as factor, the top five are the following:

- Job scoping did not identify special circumstances and/or conditions (135 times)
- Corrective action responses to a known or repetitive problem was untimely (99 times)
- System interactions not considered or identified (97 times)
- Risks/consequences associated with change not adequately reviewed/assessed (74 times)
- Previous industry or in-house experience was not effectively used to prevent recurrence (62 times)

Design/Engineering Issues

- Design/Engineering has been identified as a root or contributing factor 1,210 times
- Average of ~95 events per year
- This is over 3x the rate of Individual Human Performance issues

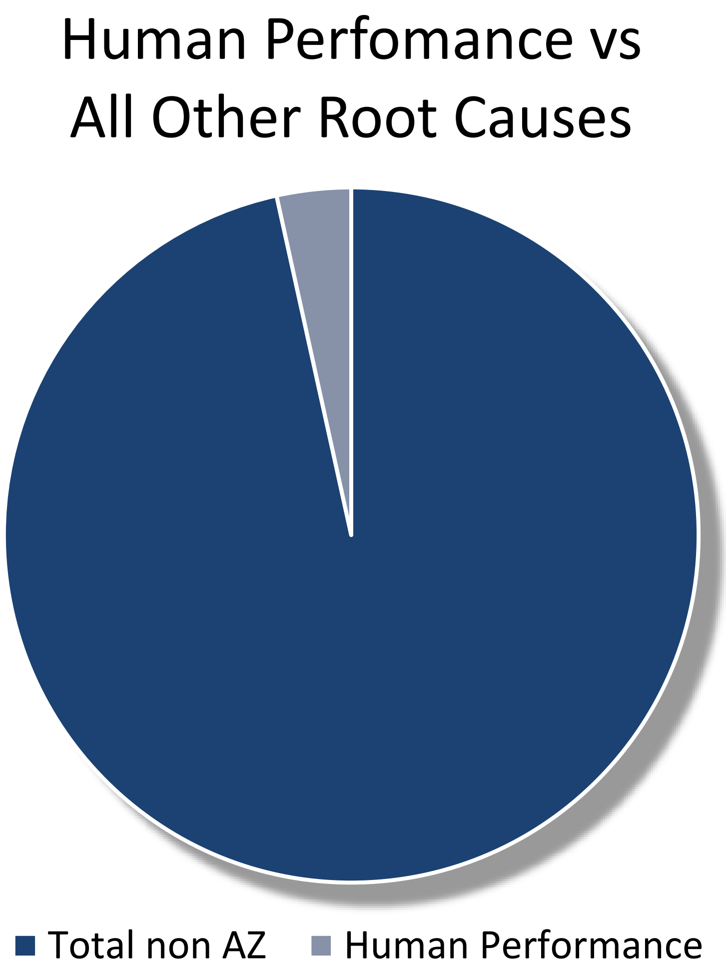


Design/Engineering Issues – Top 5

Out of the 1,210 times Design and Engineering has been indicated as factor, the top five are the following:

- Design output scope LTA (528 times)
- Errors not detectable (134 times)
- Independent review of design/documentation LTA aka, peer checking (126 times)
- Design output not correct (111 times)
- Testing of design/installation LTA (70 times)

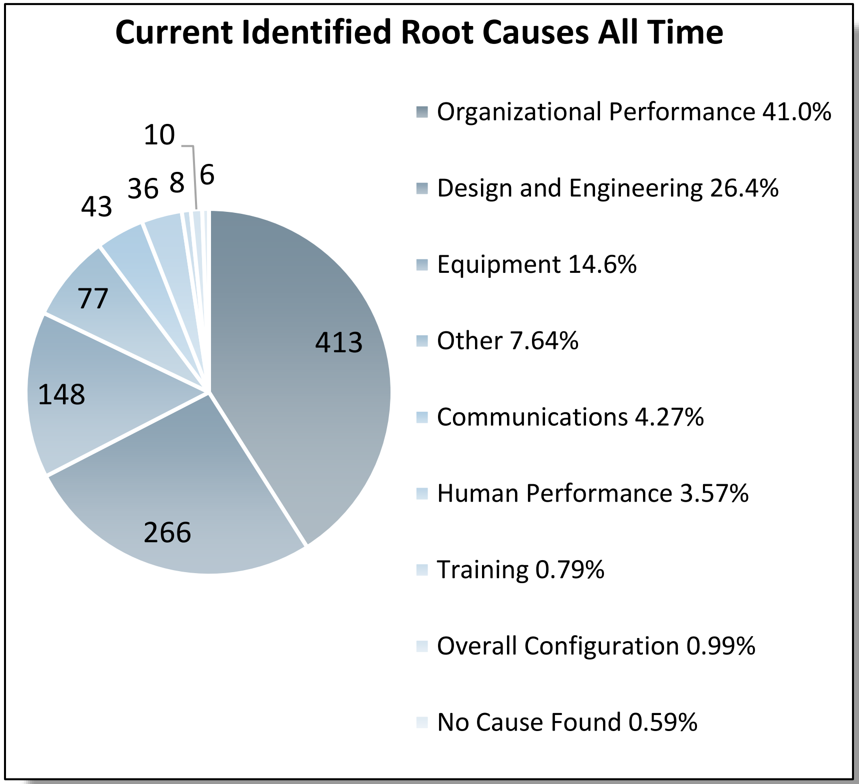
So is it the Human?

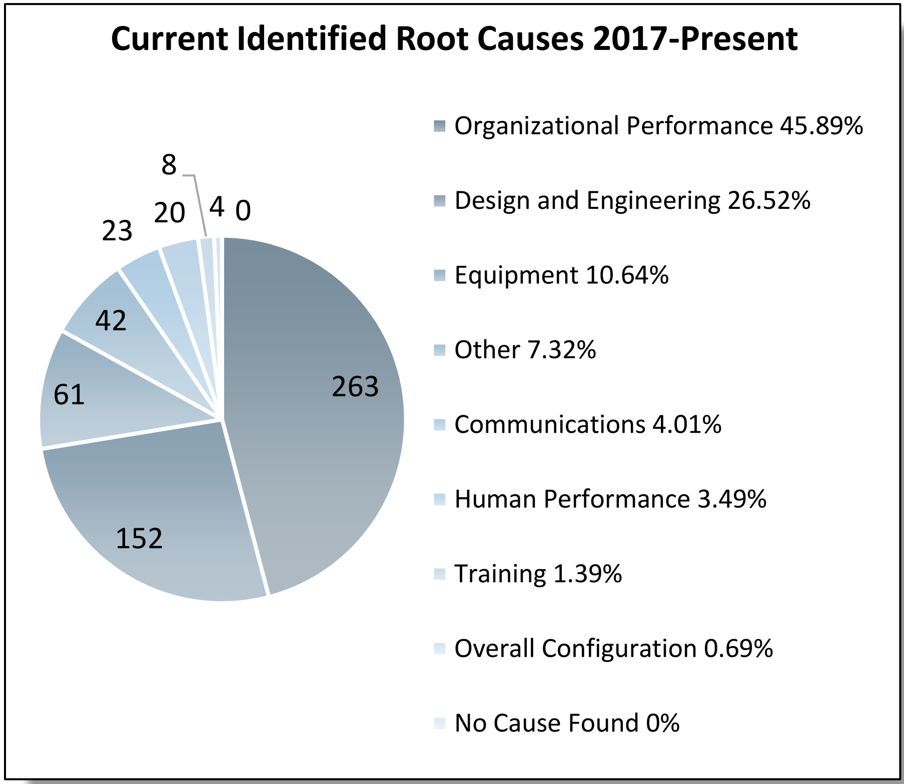


- Only 3.6% of identified event root causes indicate that the event is due to an Individual Human Performance issue

Where are our issues?

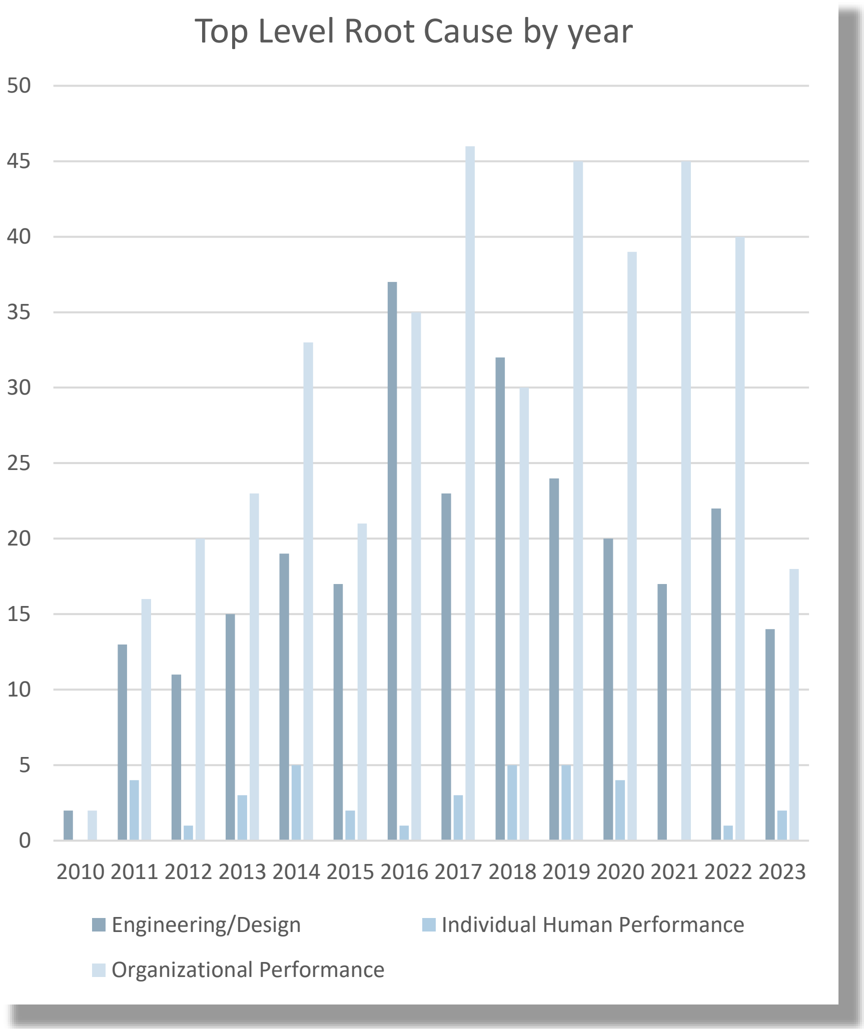
- 41.0% Organizational Performance (45.9% past 5 years)
- 26.4% Design and Engineering (26.5% past 5 years)
- 3.6% Human Performance (3.5% past 5 years)





Human Performance vs. Organization Performance

- Human performance remains fairly constant at a very low level
- Engineering has decreased over the past few years
- Organizational Performance issues remain a major driver of Categorized events



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Top HP/OP Event Root Causes

Eng. Design Output Scope LTA (184 times)

Org. Performance – Job scoping did not identify special circumstances and/or conditions (67 times)

Org. Performance – System interactions not considered or identified (40 times)

Org. Performance – Risks / consequences associated with change not adequately reviewed / assessed (31 times)

Org. Performance – Management policy guidance or expectations not well-defined, understood, or enforced (29 times)

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Conclusions

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Conclusions (Cont'd)

- "Human Performance issues" are usually a symptom of larger challenges within a company.
- Best ways to reduce events are by performing the following:
  - Working to improve engineering, especially improving the understanding of all the ways a design could fail and ensure you have a robust peer review process
  - Working with supervisors and crews to improve job scoping and understanding of how systems interact with each other
  - Ensuring that all potential impacts or dependencies are identified, reviewed, and (if needed) modified to accommodate changes when they are made
  - Ensure that policies and expectations are well defined and understood by your employees and contractors

Conclusions (cont'd)

- Doing what is easy vs doing what is hard
  - It is easy to blame the individual human, a failed component, or weather
  - It is harder to admit our processes, procedures, and policies need improvement
- Yet, It is by identifying and doing what is hard that results in significant improvement for a more Reliable, Resilient, and Secure industry.

"We choose to go to the Moon in this decade and do the other things, not because they are easy, but because they are hard." – President John F. Kennedy

Image Credit: NASA

References

- ERO Event Analysis Program Website
- ERO Event Analysis Process Document
- ERO Cause Code Assignment Process
- Lessons Learned Website

Questions and Answers

Contact:
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Senior Engineer of Event Analysis
ed.ruck@nerc.net

State of Reliability Report (SOR) Update

Action
Information

Summary
This agenda topic will provide the RSTC with an update of the annual State of Reliability Report (SOR) report. The objectives of the SOR are to:

- Provide objective, credible, and concise information to policy makers, industry leaders, and the NERC Board of Trustees on issues affecting the reliability and resilience of the North American bulk power system (BPS)
    - Identify system performance trends and emerging reliability risks
    - Determine the relative health of the interconnected system
    - Measure the success of mitigation activities deployed
- Evaluate the 2023 Operating Year and Historical Trends

The preliminary key findings of the SOR are:

- Severe, yet Routine, Weather Events Confirm Overall Resilience of BPS
- Performance of Inverter-Based Resources (IBRs) Continues to Impact the BPS
- Generation Forced Outage Rates Continue to Increase
- Texas Interconnection Reliability Performance Improves while Facing New Challenges

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2024 State of Reliability

Key Items

Jack Norris, Engineer II
RSTC June 2024 Meeting

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The State of Reliability: Objective

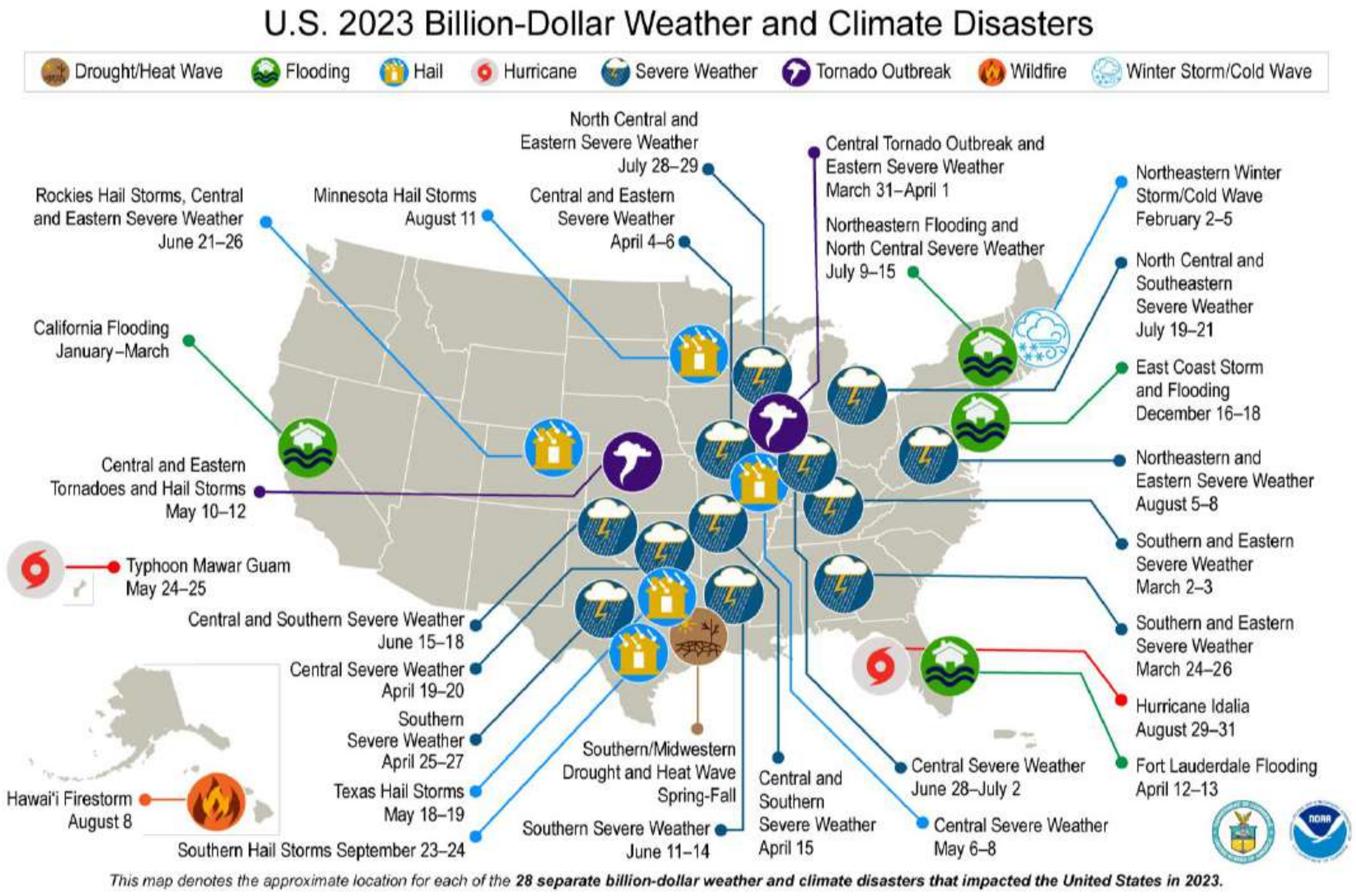
- Provide objective, credible, and concise information to policy makers, industry leaders, and the NERC Board of Trustees on issues affecting the reliability and resilience of the North American bulk power system (BPS)
  - Identify system performance trends and emerging reliability risks
  - Determine the relative health of the interconnected system
  - Measure the success of mitigation activities deployed
- Evaluate the 2023 Operating Year and Historical Trends

Preliminary Key Findings

- Severe, yet Routine, Weather Events Confirm Overall Resilience of BPS
- Performance of Inverter-Based Resources (IBRs) Continues to Impact the BPS
- Generation Forced Outage Rates Continue to Increase
- Texas Interconnection Reliability Performance Improves while Facing New Challenges

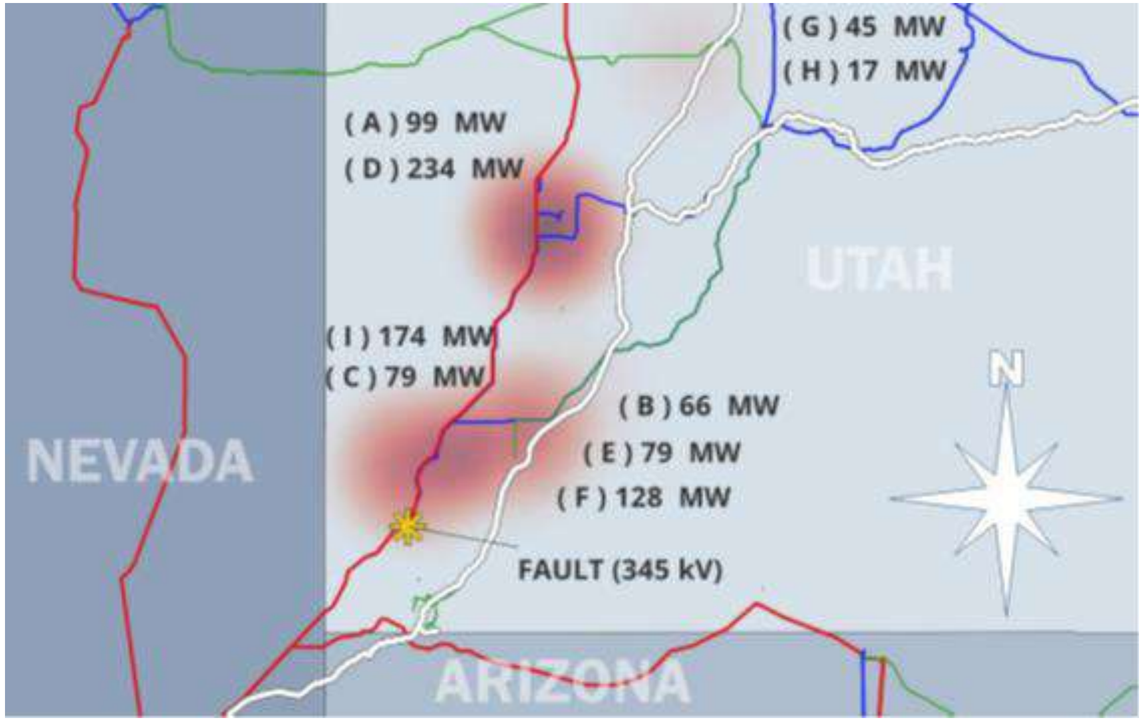
Severe, yet Routine, Weather Events Confirm Overall Resilience of BPS

- 28 Billion+ Dollar Weather Events in U.S.
- Canadian Wildfires
- No Events Analysis Disturbance Events at Category 3 or higher
- No load unserved due to Level 3 Energy Emergency Alerts

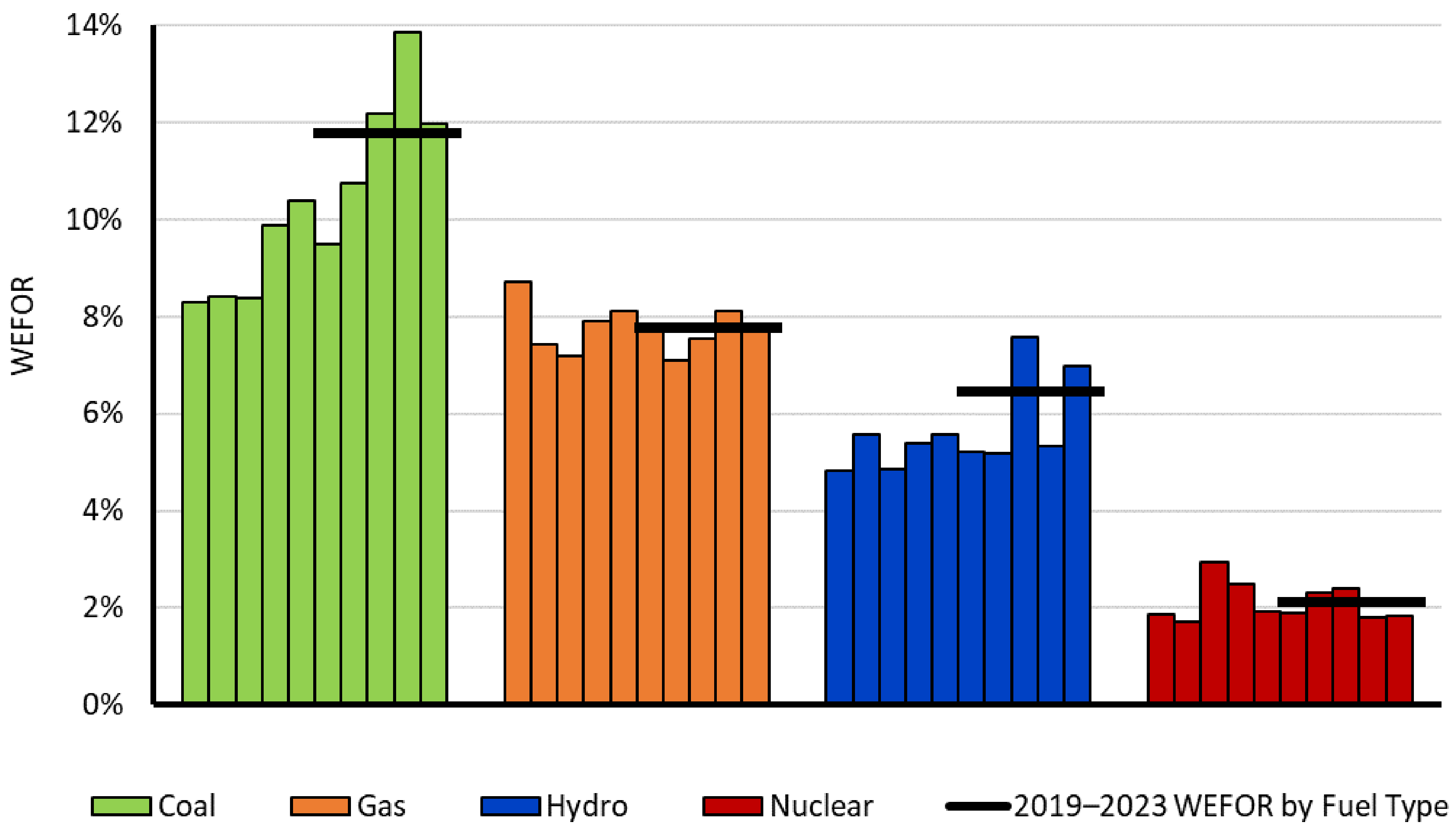


Inverter-Based Resources (IBRs) Performance Impact the BPS

- Utah Solar PV Performance Improvement (2023)
- CAISO Battery Storage System Disturbance (2022)
- Texas Interconnection Battery Storage Supporting Frequency Response
- Texas Interconnection IBR Ride-Through Performance Issues

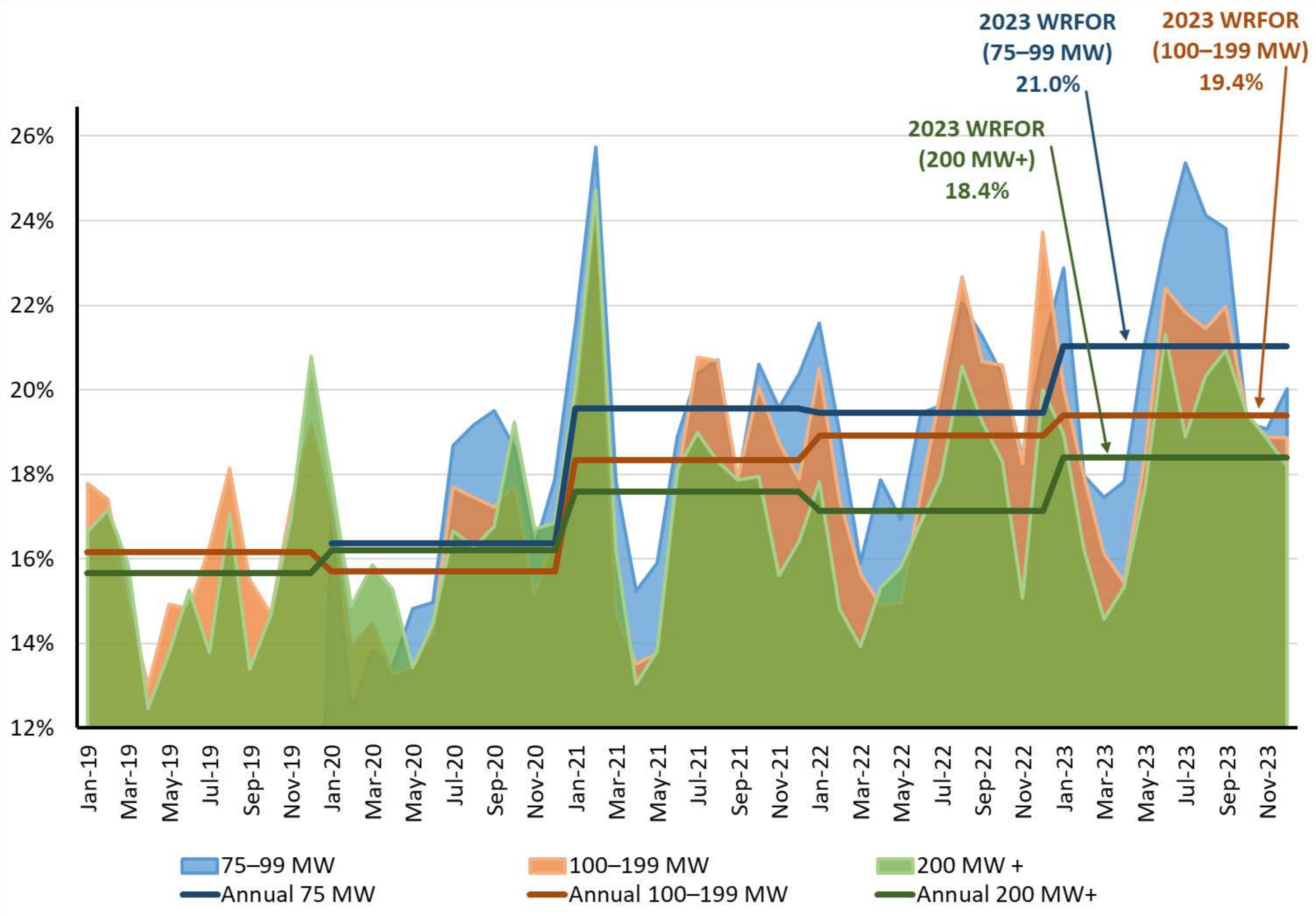


Generation Forced Outage Rates Continue to Increase



- 7.8% weighted equivalent forced outage rate (WEFOR)
- Third worst on record
- No major generation stressing events

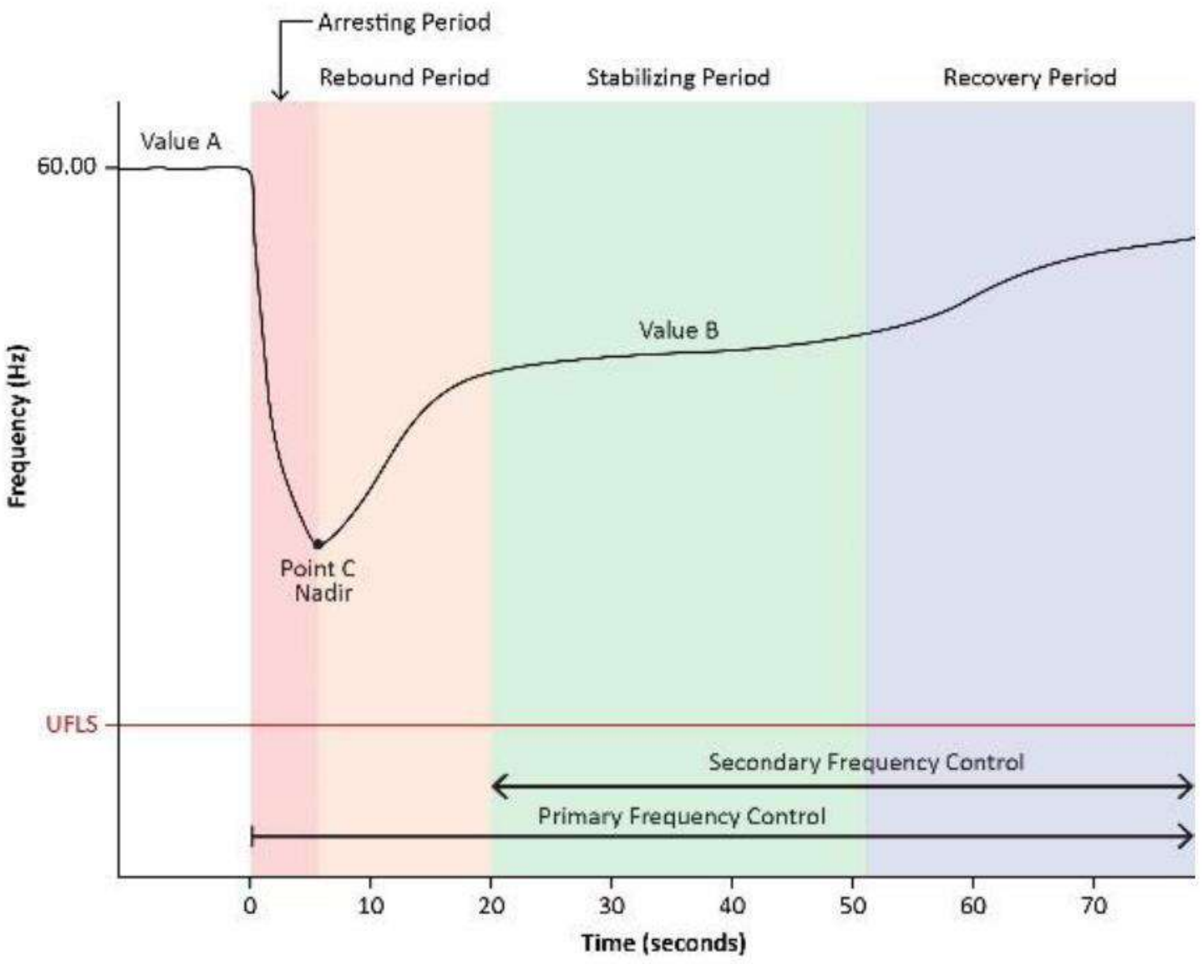
Generation Forced Outage Rates Continue to Increase



- Wind weighted resource forced outage rate (WRFOR) up to 18.9%, highest since data collection began in 2018
- More comprehensive wind & solar data collection begins in 2024

Texas Interconnection Frequency Response Improvements

- Very high IBR penetration
- Battery Energy Storage Systems
  - Rapid response
  - Ride-through performance failures
- Improved frequency response



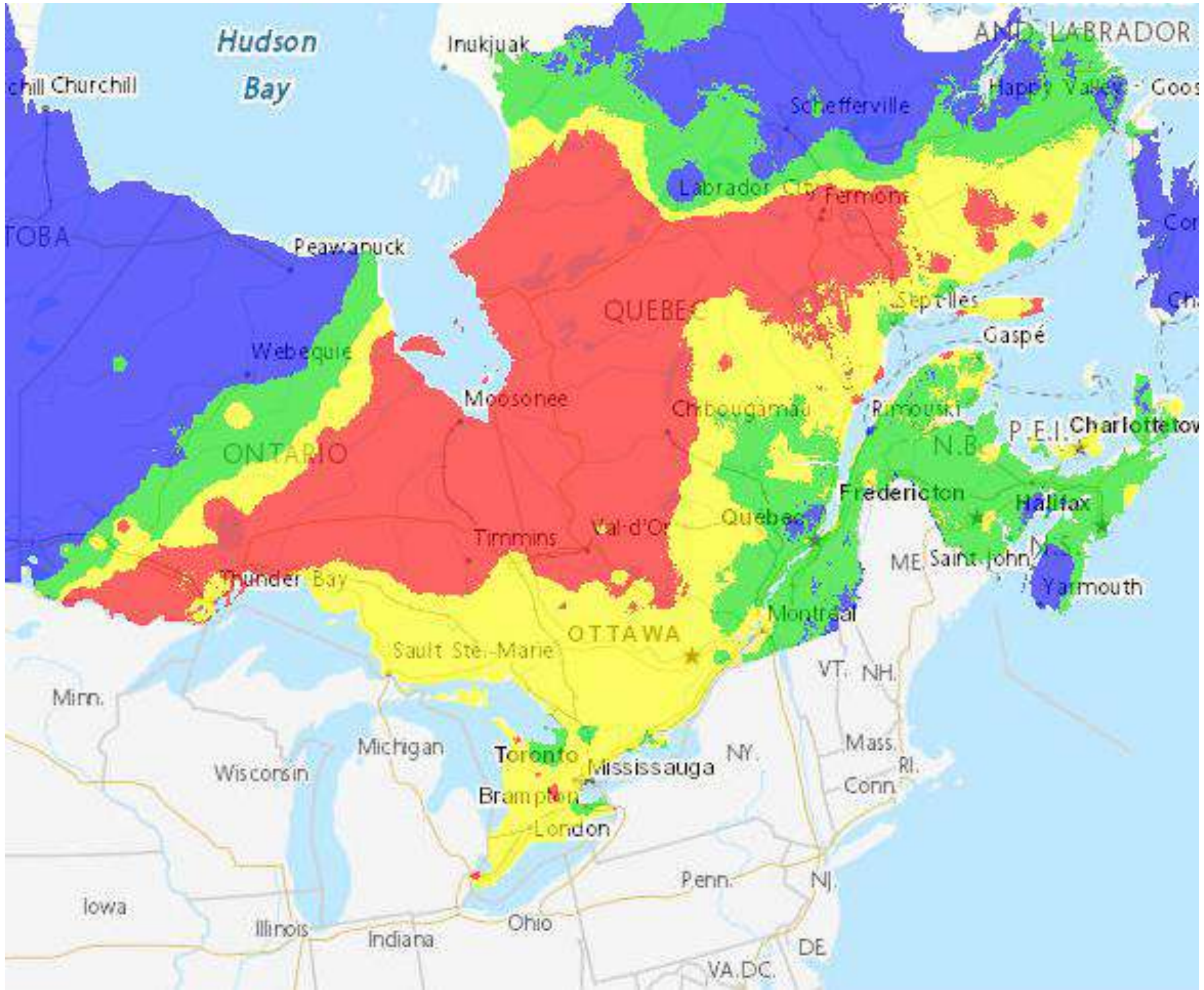
Key Occurrences

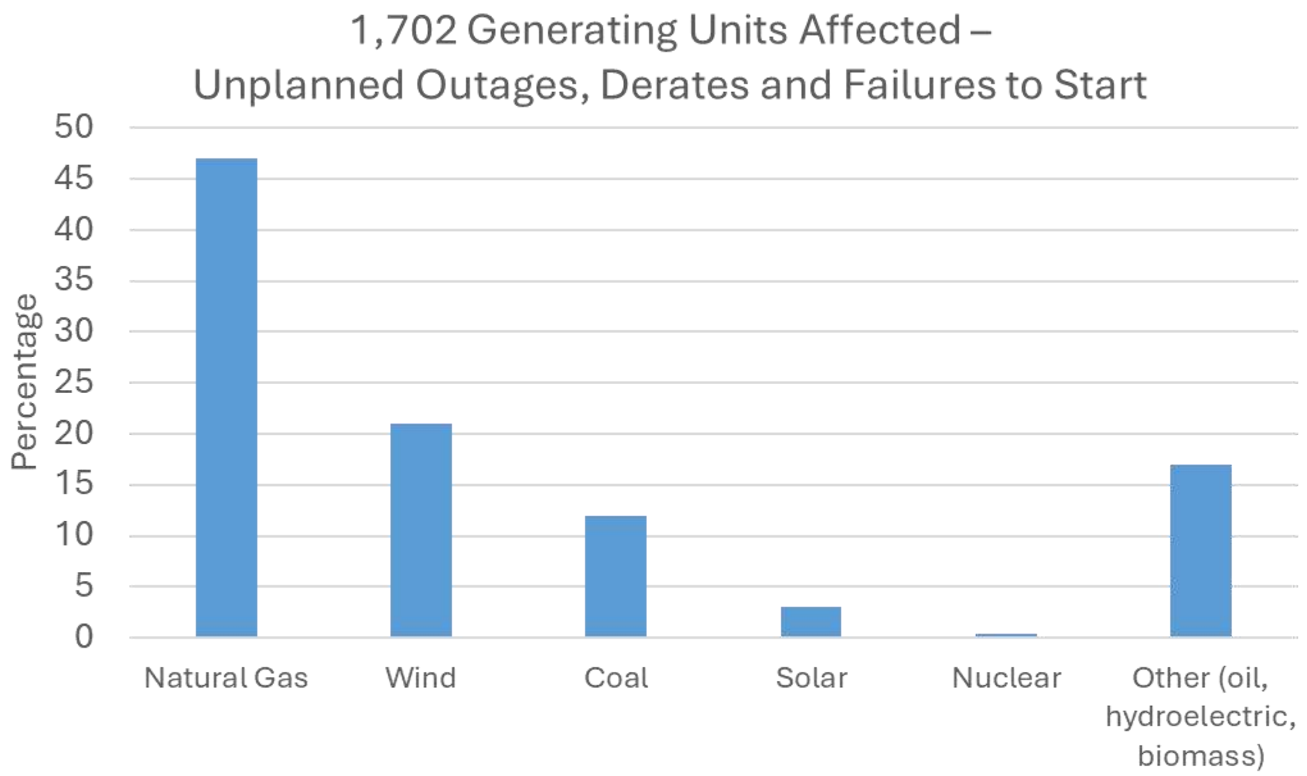
Québec Wildfires

- 16,674 square miles burned in Québec
- Multiple high voltage outages
- Remedial action scheme (RAS) 1800 MW shed
- Average customer outage <1 hour

Utah Solar PV Performance Improvement

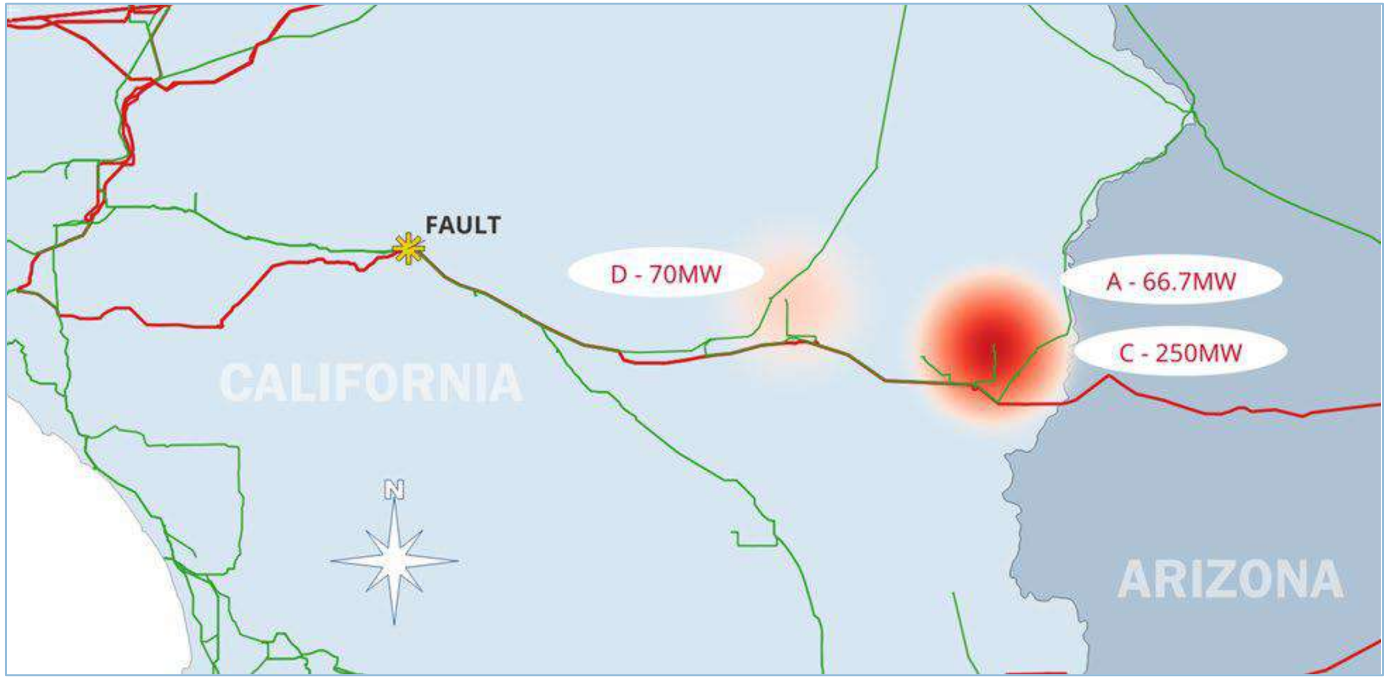
- April 10; 929 MW of solar loss
- September 29; 537 MW of solar loss




1,702 Generating Units Affected –
Unplanned Outages, Derates and Failures to Start
Percentage
50
45
40
35
30
25
20
15
10
5
0
Natural Gas
Wind
Coal
Solar
Nuclear
Other (oil, hydroelectric, biomass)


ISO-NE
NYISO
MISO
PJM
SPP
LGE-KU
TVA
DEC
DEP
DESC
SC PSA
Southern

- CAISO Battery Energy Storage System (BESS) Disturbance
  - Two events involving BESS
    - March 9, 2022
    - April 6, 2022
  - Main BESS causes
    - Inverter AC overcurrent tripping
    - Unbalanced AC current tripping



Questions and Answers

Reliability Guideline: Recommended Practices for Performing EMT System Studies for Inverter-Based Resources

Action

Accept the draft Reliability Guideline: Recommended Practices for Performing EMT System Studies for Inverter-Based Resources to post for public comment.

Background

The Electromagnetic Transient Modeling Task Force (EMTTF), under Inverter-Based Resource Performance Subcommittee (IRPS), has developed the draft Reliability Guideline: Recommended Practices for Performing EMT System Studies for Inverter-Based Resources. This draft 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 with detailed equipment specific EMT models within the EMT simulation domain.

This draft guideline was created by a diverse team of EMTTF members with input from the IRPS throughout the process – initial scoping stage, first draft and second draft.

Summary

The guideline was presented to IRPS in May meeting and achieved consensus to post for industry comment. EMTTF requests the RSTC accepts this draft guideline to post for public comment.

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Reliability Guideline

Recommended Practices for Performing EMT System Studies for Inverter-Based Resources

May 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 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

Accelerating changes in the bulk power system's (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 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 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 effective system impact assessments of IBRs using highly accurate EMT models. This Reliability Guideline expands on the previous document and will provide 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 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 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 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; NERC strongly encourages these entities to adopt all of the recommendations contained throughout this guideline and 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 inverter-based resources in the near future. As the penetration of inverter-based resources grows, the need for conducting EMT studies to adequately ensure reliable operation of the BPS increases more rapidly. 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 important pre-requisites to conducting EMT analysis.	TPs and PCs
Modeling Data Consistency: TPs and PCs should enhance their modeling data management processes for improved consistency which helps streamline the development of corresponding EMT 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 be a trigger for conducting an EMT study.	TPs and PCs
EMT Study Area Selection: TPs and PCs should 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.	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.	TPs and PCs
Consideration for Study Scenarios: TPs and PCs should consider the most critical contingencies and the worst-case operating conditions in which less grid stabilizing characteristics are available, such as system strength, inertia, and damping.	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 modeling and simulation platform limitations.	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 quantitative post-processing methods to narrow down the results to identify issues quickly.	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 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.	TPs, PCs and GOs

Introduction

The purpose of this guideline is to provide guidance on when and how to conduct select EMT studies, including how to scope and model study area, system external to 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 developed for and assumptions. All models, both EMT and positive sequence, inherently have 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 should be followed.

Chapter 1: provides recommended considerations for when EMT studies should be conducted. **Chapter 2**: covers how to scope an EMT study by selecting 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 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 are covered in **Appendix A**. Additional examples and exploratory discussion on EMT analysis in Operations are provided in **Appendix B and C**.

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 interest to be evaluated in those studies are aspects related to controller stability, interactions between IBRs and other dynamic devices and transmission protection system settings and schemes such as remedial action schemes. 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 increasing penetration of IBRs and retirement of synchronous generators, specific areas of BPS may experience reduced system strength or voltage stiffness. To approximate the strength of an area, there are various steady state system strength metrics available. Most are documented in the Technical Brochure of CIGRE WG B4.62 Connection of wind farms to weak AC networks[1]. These metrics are, however, based on the steady state network topology and power flow across the network. They 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 use those metrics to screen for weak areas[2].

Transmission Providers (TPs) and Planning Coordinators (PCs) are encouraged to get an understanding of the strength of their footprint and develop system strength metrics and criteria to determine weak areas for which EMT studies may be required. Important to note here is that 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 is important to note that these system strength metrics should not be applied without appropriate justification for the specific footprint 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 violation or close to violation of stability criteria set forth by TPs and PCs, EMT studies can be considered to double-check those results. 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 EMT study. If the numerical instability persists after verifying the robustness and quality of the model, it is recommended that the scenarios should be further studied in EMT tools. It is important to ensure all credible scenarios and contingencies were considered in positive sequence, phase domain studies (e.g. minimum synchronous generation dispatch).

Small signal stability can be assessed using analytical methods such as either impedance scanning methods or Eigen value analysis and can provide an insight with respect to possibility of control interactions, resonance, and/or

[1] https://www.e-cigre.org/publications/detail/671-connection-of-wind-farms-to-weak-ac-networks.html
[2] Example: EPRI's system strength assessment tool

instability in the small signal realm. The use of 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]

Keep in mind 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 in positive sequence stability studies. For example, a Hawaiian island system performed stably in positive sequence transient stability studies but showed instability in small signal stability study[3] and EMT study. 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 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 can consume significant amount of engineer time.

System Topology or Conditions Conducive to Instability

TPs or PCs should be aware 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[4]:
  - Series-compensated lines
  - FACTS devices
  - HVDC lines
  - Other IBRs
- High IBR penetration level
- Presence of any specialized protection schemes such as Remedial Action Schemes
- Presence of transmission lines protected by distance relays and declining fault current levels
- Areas where there is 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.
- Areas where there is a trend of increasing 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.

EMT Studies Following System Events

In addition to the system planning horizon, conducting an EMT study is also deemed necessary during the operational timeframe, 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

[3] Small signal stability study was based on more detailed EMT models

[4] See **Chapter 3**: Study Area

significantly deviates from the behavior and performance resulted from the past EMT simulations, it necessitates a new EMT study.

This study is essential for correcting any potential errors in existing EMT models and verifying the quality of the simulation base case. This 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 the introduction of unintentional or unacceptable reliability risks to the Bulk Electric System (BES).

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. Typically, 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 the steady-state and/or dynamic contributions of the external power system represented as an equivalent (discussed in **Chapter 3**:). Some techniques such as hybrid simulations 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 to determine how much of the system needs modeled in the EMT domain. For studies which are intended to quantify 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 system behavior and potential interactions between various dynamic devices can be captured. This Chapter will discuss the impacts of the time scale of power system dynamic phenomena on study area selection as well as methods for determining which dynamic devices should be included within the study area.

Study Area Selection

For 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 should be selected according to the phenomena under evaluation, as illustrated in **Figure 2.1**.

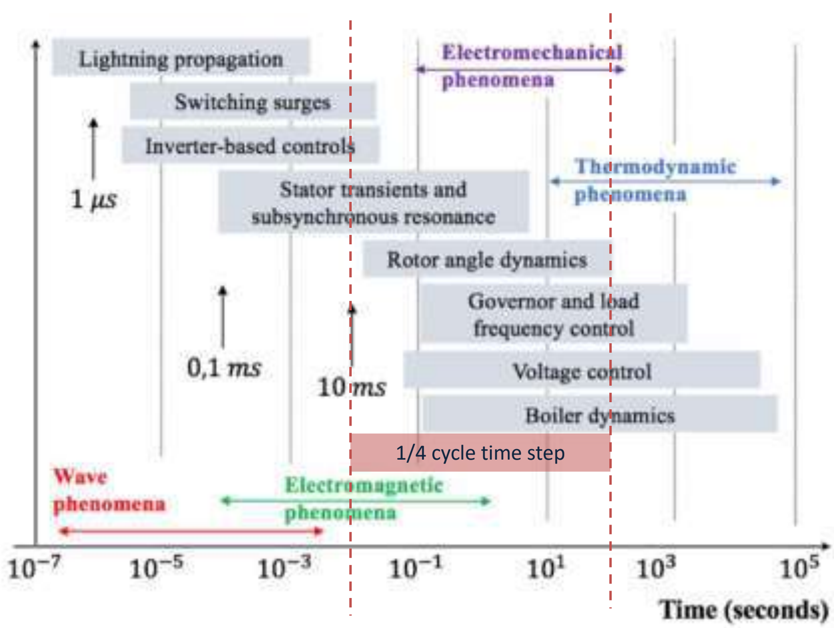

Figure 2.1: Timescales of Power System Phenomena ["Definition and Classification of Power System Stability – Revisited & Extended"; IEEE Transactions on Power Systems, July 2021]

The power system phenomena of primary interest for typical EMT simulations are as follows [IEEE Std. C62.82.2-2022 and IEC 60071-2 ED5]:

- EMT System Impact Assessment Studies: A Few Hz – 2 kHz.
  - This is the primary focus of this guideline. Phenomena of interests include evaluation of controls interactions, fault ride through performance issues, 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 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 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 EMT system impact assessment study, it acceptable to neglect the impedance 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 becomes important. Figure 2.2 provides an illustration of 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.

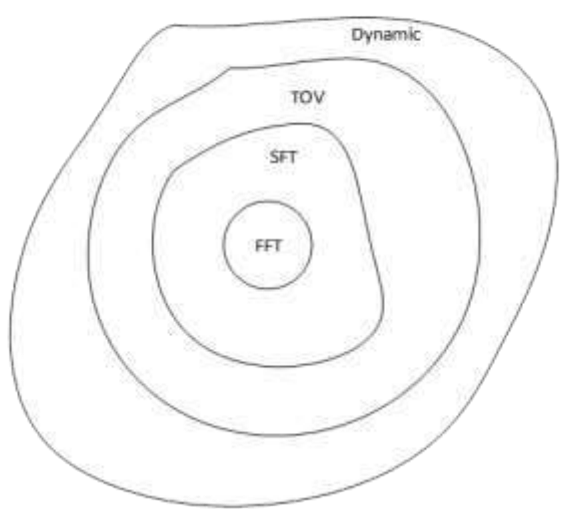

Figure 2.2: Study Area Size for Different Types of EMT Studies.

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 to become a more local phenomenon. When performing EMT studies for IBR's it is necessary to ensure adequate Electromagnetic system representation for the phenomena of interest at a given bus or between buses. There are different methods to accomplish this which will be discussed within this Chapter. However, conceptually, the process of Electromagnetic sizing would involve quantifying the frequency dependent impedance at a given bus within the power system considering progressively larger EMT 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 the study area until further increases in the size of the modeled system have negligible impact on the system frequency response.

Figure 2.3 provides an illustration of electromagnetic sizing for EMT system models. 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 out from the study bus. There is a significant difference between the 6-bus out and 9-bus out models, especially around 800-1100 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 take into account the following critical items:

- Throughout this discussion, the word "busses" has been used as a proxy to represent "electrical impedance". Practically, when performing study area selection, the goal is to ensure sufficient electrical impedance exists between the study bus or busses and the boundary equivalents representing the system outside of the study area. Improper study area selection can result in incorrect study results 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 induce false behaviors within the frequency range of interest. The process could be iterative in nature.

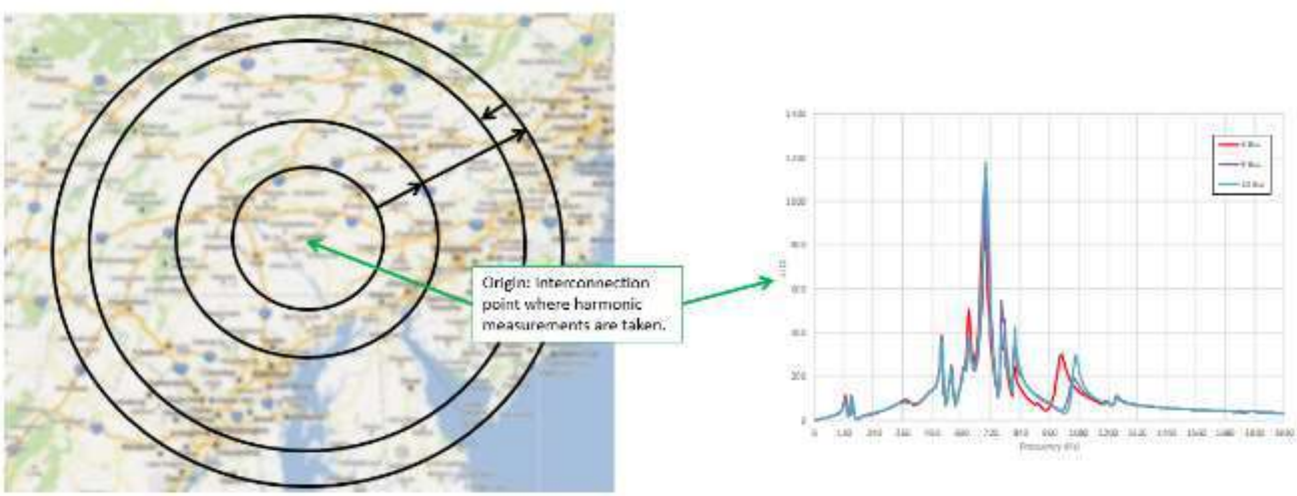

Figure 2.3: Concept of Iterative Approach to Electromagnetic Model Sizing

For studies analyzing IBRs the impacts on Electromechanical phenomena typically need to be considered. For example, interactions with existing turbine-generators and their excitation or governor control systems. 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-simulation electromechanical or dynamic network equivalents which will be discussed in **Chapter 3**: of this guide. For an illustration of benchmarking for a developed EMT model please refer to **Figure 2.4**. 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.

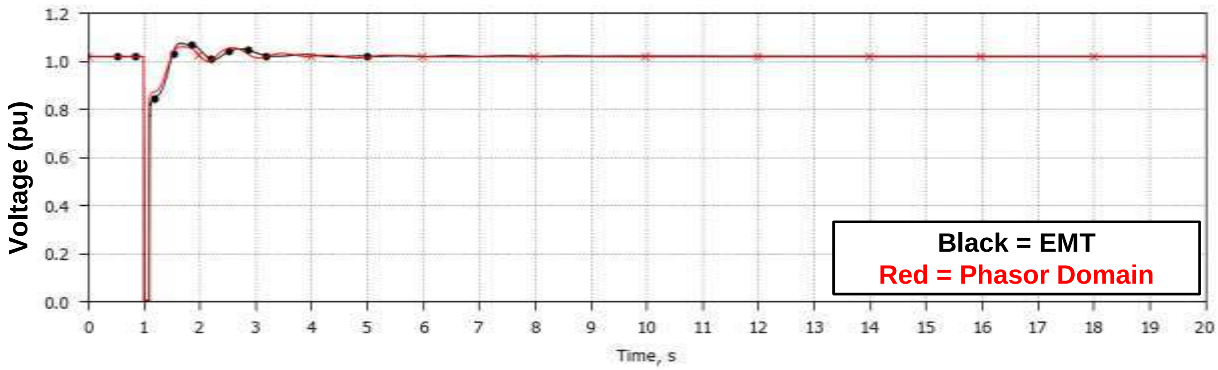

Figure 2.4: Comparison of RMS Voltage Response for a Given Fault Event Between Electromagnetic and Phasor Domain Simulation Tools.

Determining Which Dynamic Devices to Include in the Study Area

Beyond the electromagnetic and electromechanical sizing techniques 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 study area. If a dynamic device such as an IBR plant or Flexible AC Transmission System (FACTS) is omitted from the study area, then its dynamic behavior will be omitted from the study and could result in errors in the overall dynamic response of the system or prevents capturing potential interactions between devices. The following are examples of methods for determining which equipment should be included in the study area when performing EMT studies for IBRs:

- Engineers Experience
  - For study engineers performing EMT studies in a system where they have already performed EMT studies or performed detailed screening assessments, it is possible to determine which dynamic devices need to be included within the study area primarily using their experience with the system.
  - This experience can also be coupled with system measurements and event analysis to build confidence. For example, 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 SCADA data is available, 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)[5], improved/weighted MIIF[6], Multi-Infeed Voltage Interaction Factor (MVIF)[7] 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 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 require further, more detailed, analysis. Some examples of short circuit current based methods include, Available fault level, Weighted Short Circuit Ratio (WSCR), or Composite Short Circuit Ratio (CSCR)[8].
  - If a short circuit based assessment was used to determine if a single facility or cluster of facilities require detailed EMT studies, then the 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 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.

[5] CIGRE Technical Brochure 364: Systems with Multiple DC Infeed

[6] 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

[7] 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)

[8] 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, it is a common practice for study engineers to 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?

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-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. However, because of limitations of 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:

- 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.

For the dynamic devices within the study area, especially power electronic devices and IBR plants, it is recommended that they are represented using EMT models, provided by a manufacturer, of the device/plant for the phenomena under study. A recreation of a WECC Generic Renewable models in an EMT tool can provide correct dynamic response for events which 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. However, it is not always possible to get 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. The equivalent impedance 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 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 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 system. However, the disadvantage of this approach is that it entirely cancels out the contribution provided by the boundary system during the disturbance, which is not the case if the boundary buses were not placed too far away from the study area.
To avoid this drawback, some ISOs (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 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 can provide more accurate results as depicted below.

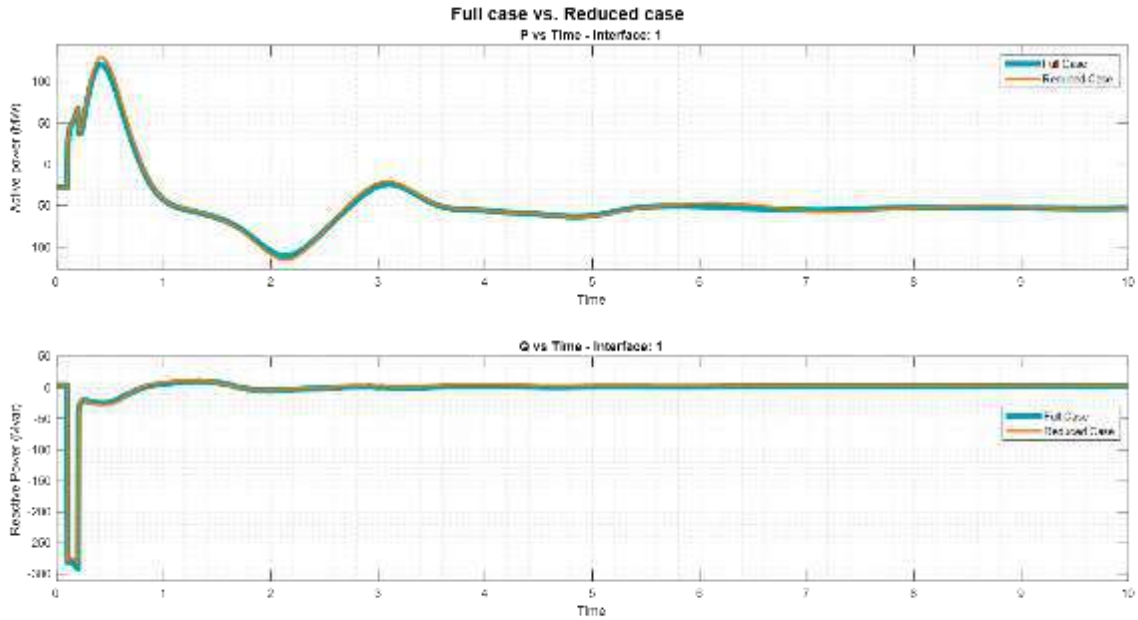

Figure 3.1: Full system vs. reduced system response with equivalent machines

Another approach to develop 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[9][10][11][12]. 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, equivalent branch connecting two buses of different voltage levels through a line instead of transformer.

Hybrid Simulation (positive sequence phasor domain + EMT)

The requirements for dynamic analysis in power systems are undergoing significant changes 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 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 representation of PE and single-phase devices. However, the portion of the system required to model in detailed in an EMT tool ("study area") has incresed siginificantly due to high penetration of IBRs. This has rasied a concern in terms of computational burden of EMT simulations. To address these challenges, various simulation methods have been proposed, including parallel processing by breaking up a

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[9] 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.

[10] 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

[11] 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

[12] 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

large network into smaller, decoupled networks, EMT-TS hybrid/co-simualtion, frequency-dependent network equivalents, and dynamic phasor-based approaches. Among them, 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:

- **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 of PE components and the local regions are developed with the wider power grid being represented in TS model (phasor-domain)[13]. Example use cases are grid fault response from PV plants and the corresponding impact on power grid as well as HVDC system fast control in low SCR 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 reactive power injection to understand the area in which voltage gets affected[14]. Another technique used in literature is based on sensitivity of the size of the "study area" in EMT such that smallest sized study area, which matches 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 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.

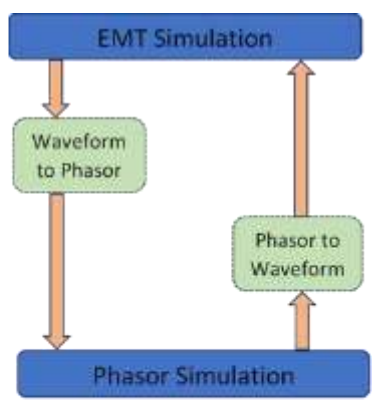


Figure 3.2: Communication between EMT and phasor simulations.

[13] ORNL, SCE, FPL/NextEra, Pennsylvania State University, CAISO, "Library of Advanced Models of large-scale PV (LAMP)" project.
[14] 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

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 EMT models ensure consistency with the phasor domain models across power flow, dynamic studies, and short circuit, care needs to be taken when extending such an approach especially when there is a lot of planned IBR integration into the system and even more so when dealing with weak system conditions. Such scenarios could present cases where the results of phasor domain models deviate from actual system behaviors, and it could be misleading to try and validate EMT models against phasor models. The following sections provide an explanation of the validation process and the possible reasons for any discrepancies that may arise.

System Model Validation

The primary means of validation 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 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.

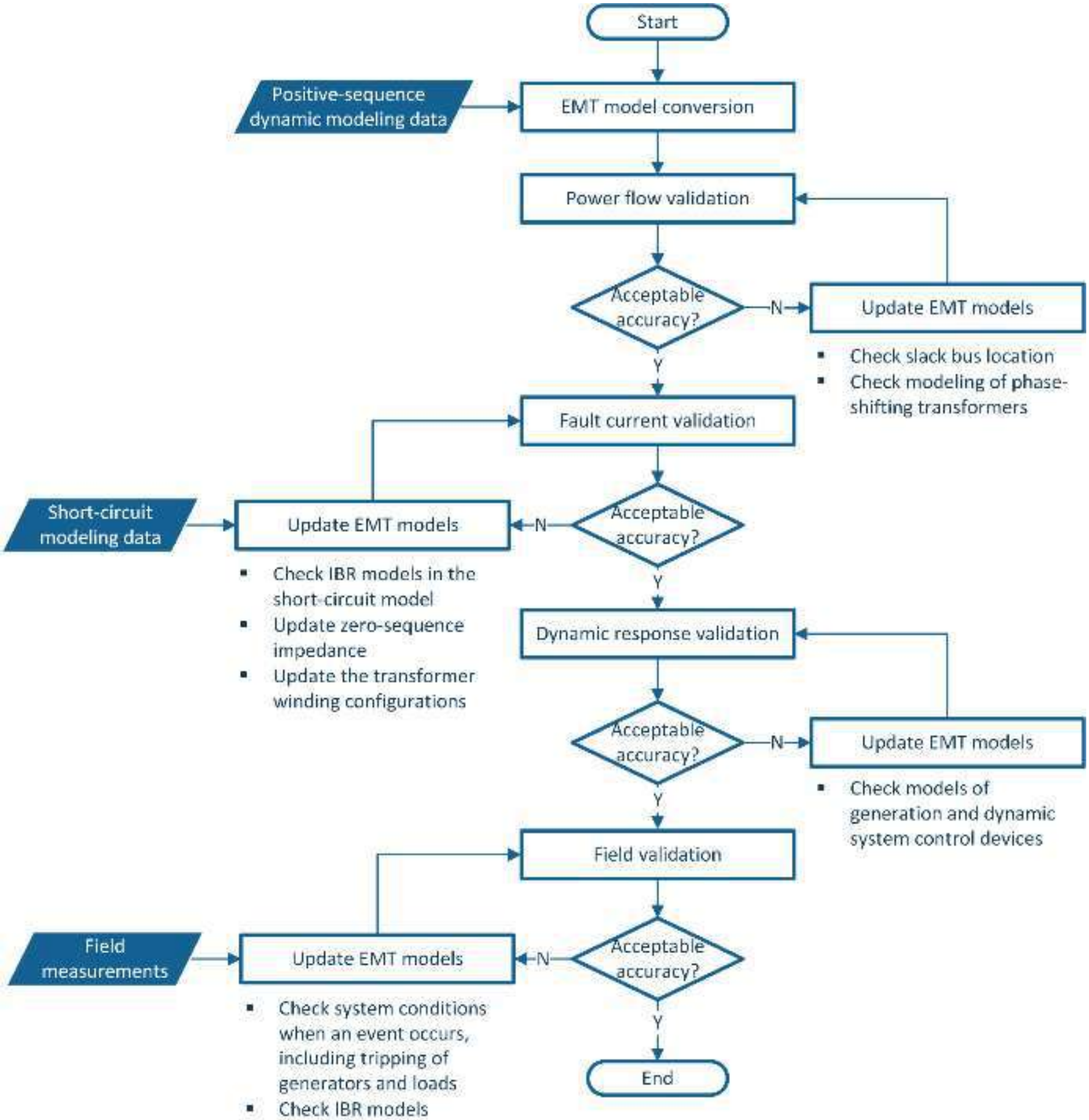


Figure 4.1: Example of System Model Validation Process

The following validations should be considered:

1. Power flow validation by benchmarking the EMT model against the positive-sequence dynamic model.
2. Fault current validation by benchmarking the EMT model against the short-circuit model for balanced and unbalanced faults.
3. Dynamic response validation by benchmarking the EMT models against the positive-sequence dynamic model.

4. Field validation by benchmarking the EMT models against recorded data from actual system events.

Power flow validation

The EMT model should be validated against the positive-sequence dynamic model for power flow results by comparing each branch's real and reactive power flow.

Typically, the 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 not the same, leading to the discrepancy in the power flow. The modeling of phase-shifting transformers in the EMT model also impacts the discrepancy in power flow.

Fault current validation

The EMT model should be validated 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 numerical format, the RMS value of steady-state currents in the EMT simulation should be recorded for comparisons. The fault duration in EMT simulation should be set to a long enough period to get 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 steady-state fault currents. **Figure 4.2** shows an example of recorded fault current in the EMT simulation and the data for RMS value.

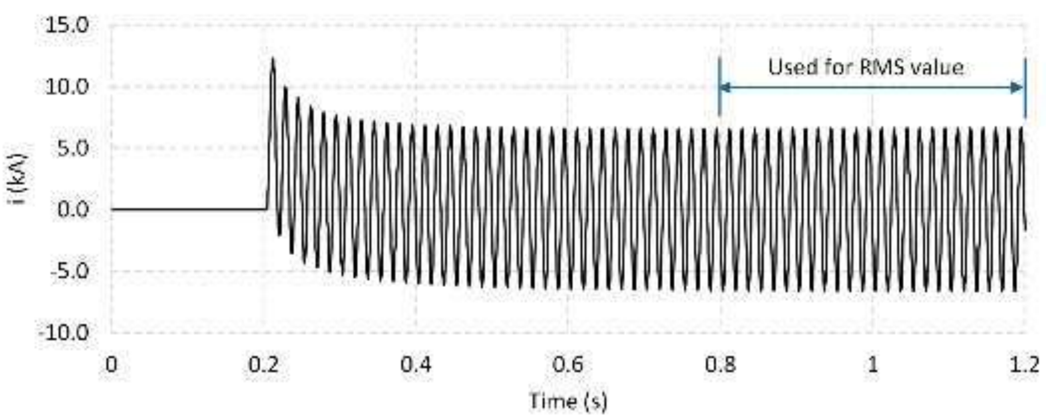


Figure 4.2: Example of Steady-State Fault Current

The discrepancy in fault current comparison can be caused by several factors, such as:

1. The IBR models in the EMT model and the short-circuit model are different if the IBR models were collected before requiring EMT model requirements. There is a possibility that the collected IBR models were not accurately modelled 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.

Dynamic response validation

The EMT model should be validated against the positive-sequence dynamic model for dynamic response under disturbances. 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 for a 350-bus power system by comparing the real and reactive power output, the generator speed, and terminal voltage in the EMT model and the positive-sequence dynamic model. The discrepancy in 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.

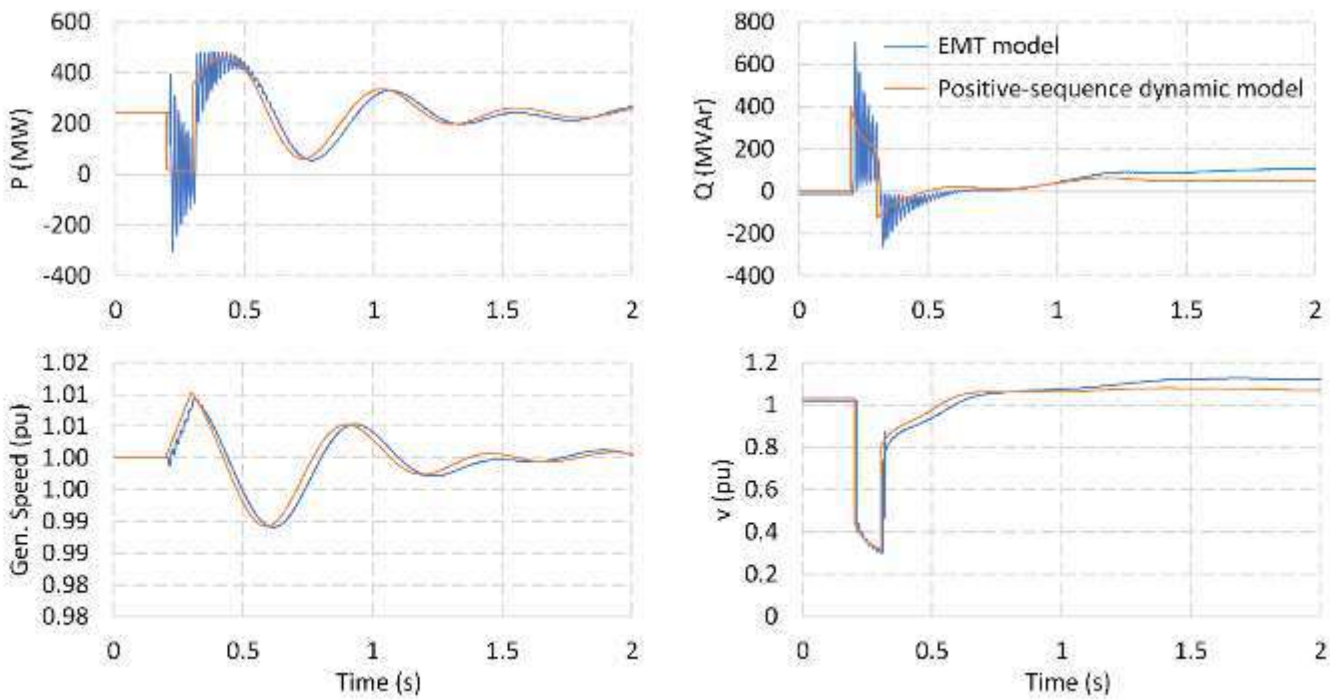


Figure 4.3: Example of Dynamic Response Validation for a 350-bus System Model

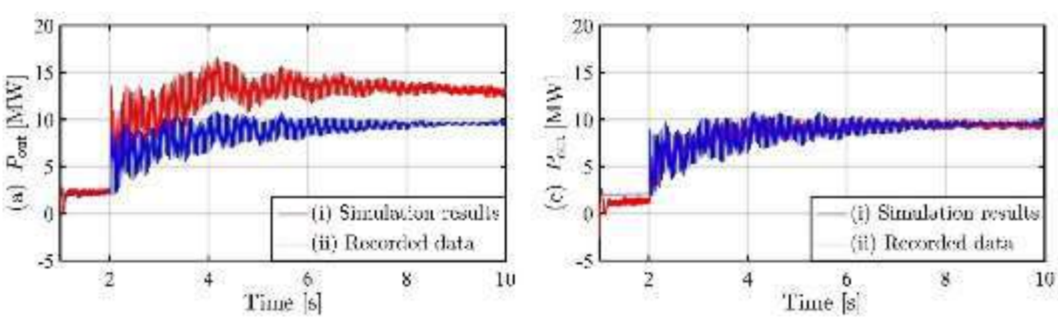
Field Validation

The developed EMT model can be further fine-tuned by validating against the field measurement data. Previous processes of validating 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 planned IBR integration into the system and even more so when dealing with weak system conditions. Such scenarios could present cases where the results of phasor domain models deviate from actual system behaviors, and it could be misleading to try and validate EMT models against 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 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.

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 specific IBR plant models are thoroughly validated with various types of test case scenarios before commissioning as a part of integration studies. These validated, vendor and plant-specific IBR plant models are integrated into existing system-level EMT models, which are then validated 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. Therefore, it is essential to include efforts that collect field test data periodically from available system resources to validate system level EMT models against real-world behaviors.

Figure 4.4 shows a case study from Hawaii comparing the results from a system level EMT model with vendor-provided IBR model against recorded, field data[15]. Initially, there were visible differences. After the model was tuned carefully, the system level EMT model was able to match the recorded field test data uncovering potential issues with settings and parameters in the model, thereby exemplifying the importance of validating system level EMT models with either hardware in the loop or field test data periodically.



(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

Figure 4.5 shows the validation of Maui EMT model against the utility PSSE model and field data for an event that consisted of a single-phase fault followed by a generation trip[16]. 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.

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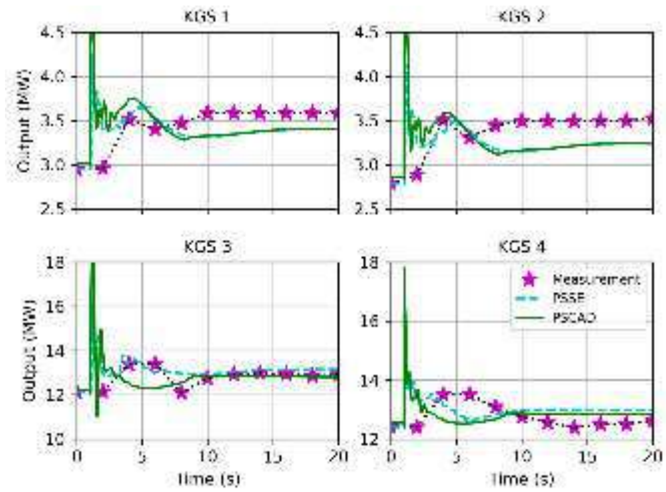
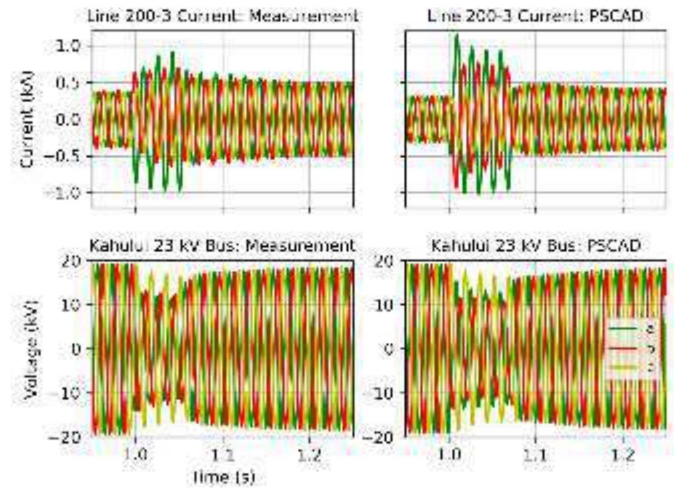
[15] Tan, Jin, Dong, Shuan, and Hoke, Andy. Island Power Systems With High Levels of Inverter-Based Resources: Stability and Reliability Challenges. United States: N. p., 2023. Web.

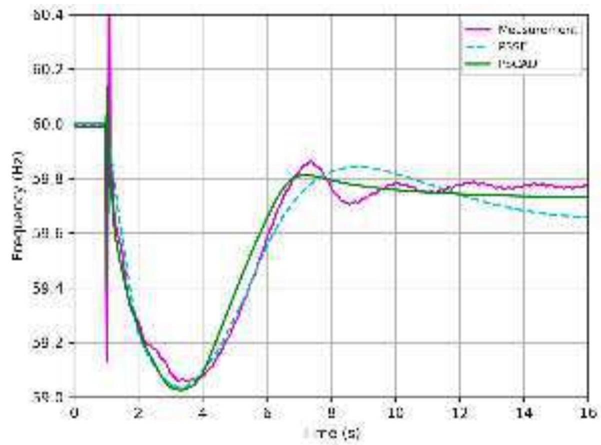
[16] R. W. Kenyon, B. Wang, A. Hoke, J. Tan, C. Antonio and B. -M. Hodge, "Validation of Maui PSCAD Model: Motivation, Methodology, and Lessons Learned," 2020 52nd North American Power Symposium (NAPS), Tempe, AZ, USA, 2021, pp. 1-6, doi: 10.1109/NAPS50074.2021.9449773.



(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

Recommendations

- TPs 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. By maintaining this consistency, the short-circuit modeling data can be easily utilized in updating the EMT model.
- TPs 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.

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 the study area depends on the type of study performed. For example, the study area for a SSO or dynamic system impact assessment study differs from insulation coordination studies. However, the study area is generally selected to include the major transmission corridor, major loads, nearby generation (synchronous machine or other IBRs). More details on the selection of the study area can be found in **Chapter 3**:.

Once the study area was selected in RMS domain, it can be converted to EMT domain and validated as described in **Chapter 4**:. Base cases representing different network power flow conditions, prior outages, etc. can be created in the RMS domain first and then converted into EMT domain. This step makes sure that the converted EMT case has correct initial conditions. In addition, to capture the worst-case scenarios the IBR dispatch can be selected to include operation under Pmax/Qmin, Pmax/Qmax, Pmin/Qmin and Pmin/Qmax conditions. Furthermore, the initial active power condition can be considered for Battery Energy Storage Systems.

Contingencies to be Considered

The most critical contingencies must be considered to capture the worst stress on the IBRs performance. This can be tripping any transmission corridor, large load, or generation plant as well as different fault scenarios. The information from system operators is useful in the process (e.g., a known oscillation in a specific network topology).

The following list provides an example of different contingencies that can be considered:

- Large signal disturbances: Fault at POC (bolted) and X-buses away from POC (different retained/residual voltage seen at POC)
    - Different types of faults: LLLG, LG, LL, LLG
    - Fault on the line side of the breaker so that it clears.
    - Breaker arrangement from utility, also considering Remedial Action Scheme (RAS)
    - Clearing times from ISOs (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).
- Small signal disturbances:
    - Switching with no faults: transmission lines, transformers, large loads, large generators, etc.

Note that the most common faults that occur in transmission power systems are unsymmetrical faults. A line-to-ground fault (L-G) is the most common and the least severe compared to other types of faults and 65-80 percent of all faults in transmission lines are of this type. Lightning and vegetation under the line among others, can cause these types of faults. They cause the conductor to contact the earth or ground.

Double line-to-ground faults in transmission lines cause two conductors to contact the earth or ground. They constitute 15 to 20 percent of all faults. 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 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 fault cases, voltage and current deviate from their nominal values. Storms resulting in collapsing of transmission towers or human errors are the major cause of these faults.

Performing studies for all possible options can result in an exhaustive list of scenarios and requires a lot of engineering hours to perform the simulation, 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 an example of the total number of simulation scenarios that can be considered to capture the worst-case conditions.

Table 5.1: An example of exhaustive list of study scenarios for all possible options	
Number of network power flow scenarios	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[17]
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														

[17] 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: 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 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.

Depending on the EMT software being used, and the capabilities of the models within the software, initialization may not be possible. 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 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 in EMT simulation could result in mismatches.

Another aspect to bear in the mind is the behavior of loads. If motor load models are used in a study, then the reactive power consumed by the motor loads can be different in EMT domain when compared to the power flow solution in RMS domain. This is because the method of initialization of motor loads in RMS domain has nuances associated with it.

Chapter 6: Three Types of EMT Studies

The study methodology for the following three common types of EMT studies is presented below:

- Dynamic system impact assessment study,
- Subsynchronous oscillation (SSO) study, and
- Transmission protection system validation study.

The first two are commonly conducted during interconnection process as part of system impact studies. Traditional EMT studies such as those for substation/line design (TrOV, Surge arrester and BIL rating (insulation coordination), CLR rating, TRV (breaker rating), induced OV due to mutual coupling from improper transposed or un-transposed lines, secondary arc current (double-circuit line - induced current in opened line) are not in the scope of this guideline.

Dynamic System Impact Assessment Study

EMT dynamic performance studies are system-level studies (not SMIB tests) which seek to evaluate performance of an IBR plant or group of IBR plants against applicable performance criteria using aggregate[18] 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 possible. Steady-state and phasor-domain transient stability (PDTS) analysis should be performed before the EMT analysis if possible, and the system model used in EMT analysis should include all upgrades / mitigations which were deemed necessary in those studies. However, EMT dynamic performance studies typically have much longer study schedules than steady-state and PDTS, and due to overall schedule constraints, it may be necessary to perform preliminary modelling and analysis in parallel with steady state and transient stability analysis.

EMT Analysis

Analysis of EMT study results is typically more challenging than analysis of phasor-domain study results due to the increased complexity of the device models (real code, black boxed) as well as the inherent simulation differences (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 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, voltage recovery, etc. The following sections highlight additional performance aspects which should be considered in EMT dynamic performance studies. Note that 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 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.[19]

[18] 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.

[19] There are some exceptions to this, such as when the model for a legacy plant which 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" includes a thorough description of IBR stability concerns, including screening methods, examples, and mitigation. Stability in EMT dynamic performance typically concerns:

- 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 which may involve natural system resonance and control-driven device characteristics [CIGRE brochure reference or ESIG oscillations guide].
- Control Mode Cycling / Chattering: EMT analysis of IBRs may result in interactions among IBRs or between IBRs and the system which 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 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 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 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 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.

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 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 [NER S5.2.5.5, 5.2.5.13, ATC criteria], however these should be applied in conjunction with engineering judgement which considers the equipment and wider-grid implications of the response.

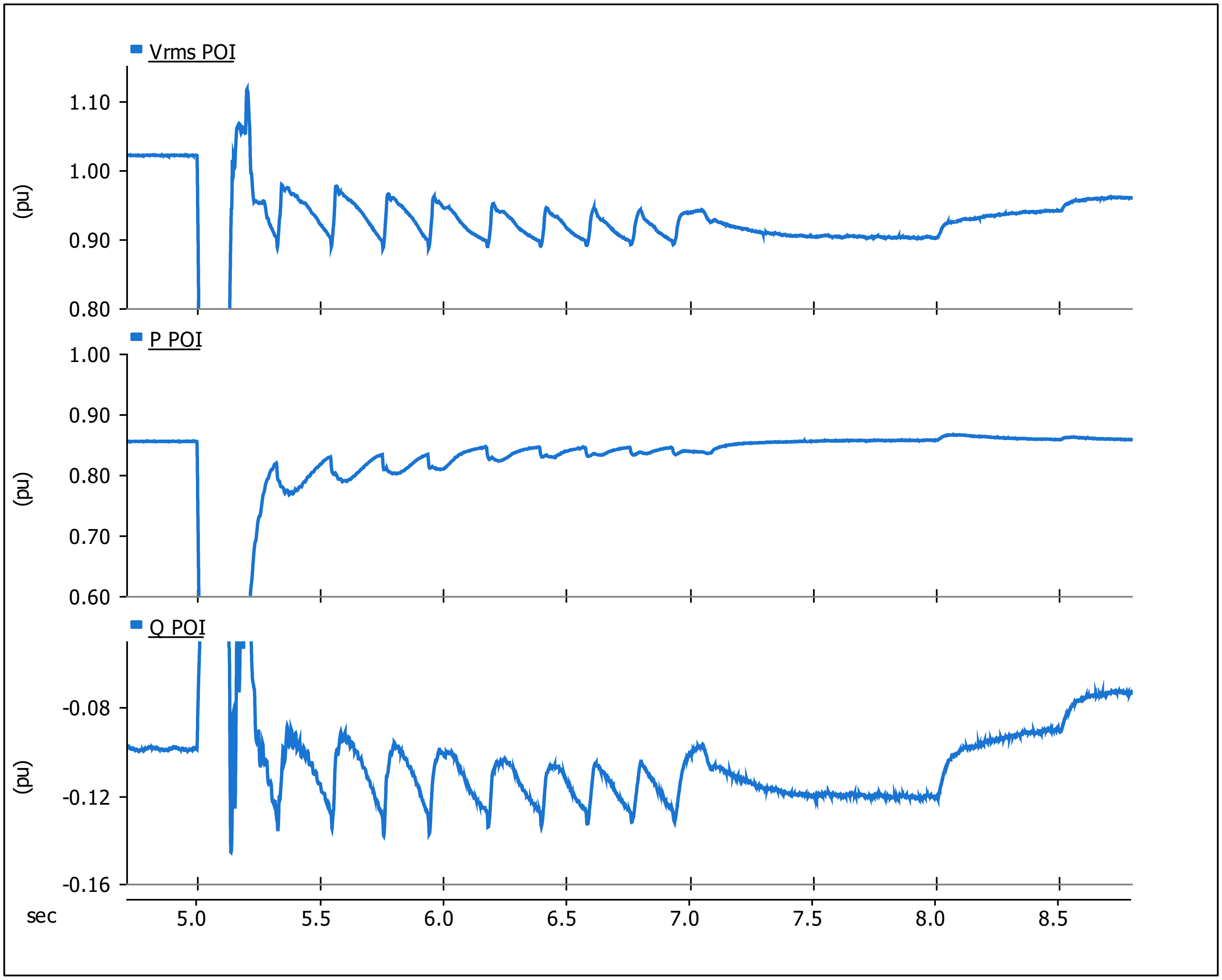


Figure 6.1: Reactive power mode cycling example (courtesy of American Transmission Company)

Ride-Through and Post-Disturbance Performance

EMT dynamic performance studies typically 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[20]: 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 within the applicable ride-through envelops (PRC-024-02, IEEE 2800-2022 Chapter 7.2.2.1, IEEE 2800-2022 Chapter 7.3.2.1)?

[20] 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. Return to 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: 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 the device 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 reduced the POI voltage from 1.01 to 0.95 pu at 5s. 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 15s 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.

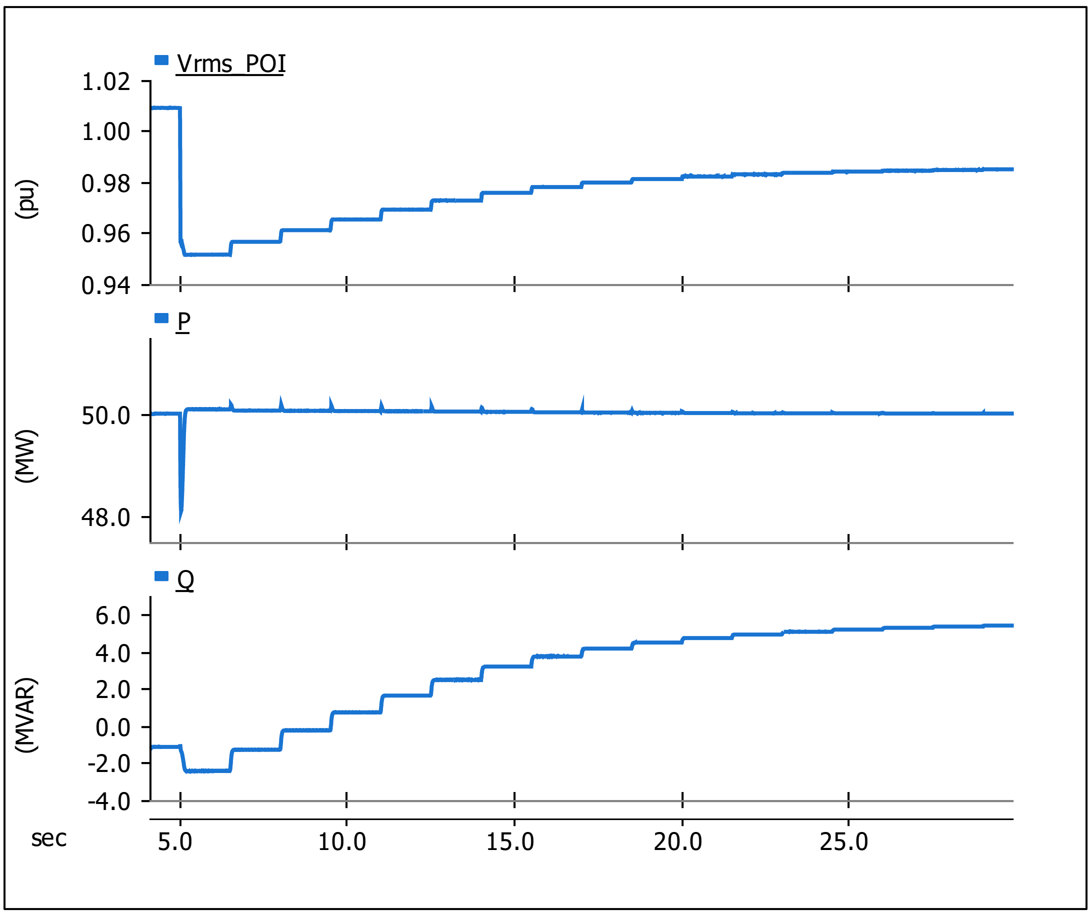


Figure 6.2: Plant Post-Event Voltage Support Example (courtesy of American Transmission Company)

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 Chapter 8:. Additionally, large voltage distortions at IBR 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 the simulation model has sufficient detail to be reasonably accurate at the distortion frequencies before taking further action.

Transient overvoltage and overcurrent

Transient over voltages 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 terminals or may originate at the terminals and propagate into the system. Investigating IBR tripping due to a transient overvoltage requires observation of the instantaneous terminal voltages as the overvoltage is often too brief in duration to be fully visible in RMS measurements. Observation of overvoltage at levels 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 does not cause the IBR to trip may require confirming that the EMT model has correctly modelled 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 rated continuous current limit for more than a few cycles, but does not result in a trip, is an indicator 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 unrealistic due to the thermal constraints of switching devices in modern inverter equipment, and therefore requires further investigation into the model quality.

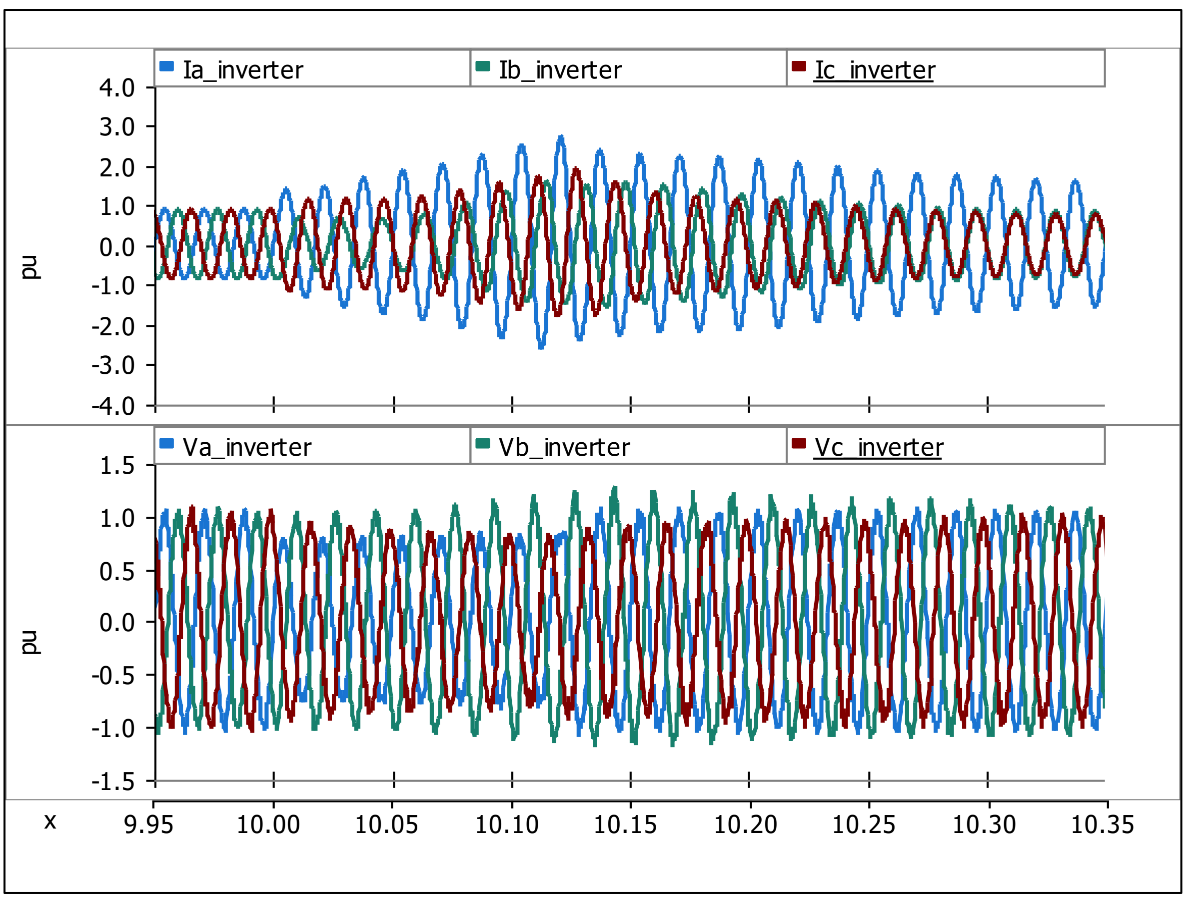


Figure 6.3: Example of unrealistic overcurrent output at inverter terminals

Simulation quantities to monitor

Simulation quantities which are typically monitored to assess the dynamic performance of specific devices and the system include:

- At the device terminals as well as at the reference point of applicability (RPA) (e.g. point of interconnection): terminal instantaneous voltage and current, RMS voltage and P/Q output. System frequency[21] at the RPA may also be of interested. Additional quantities such as 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 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 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, the LVRT and 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 PLL frequency / tracking error, measured RMS voltage, 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 concerns.
- System instantaneous voltage, RMS voltage, and P/Q flows for buses and branches of interest, as needed to assess applicable system performance criteria.

Error! Reference source not found. 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.

[21] Some frequency measurement methods (possibly even those which are embedded in EMT simulation tools) are prone to producing erroneous frequency measurements such as spikes during transients or errors in steady state measurement.

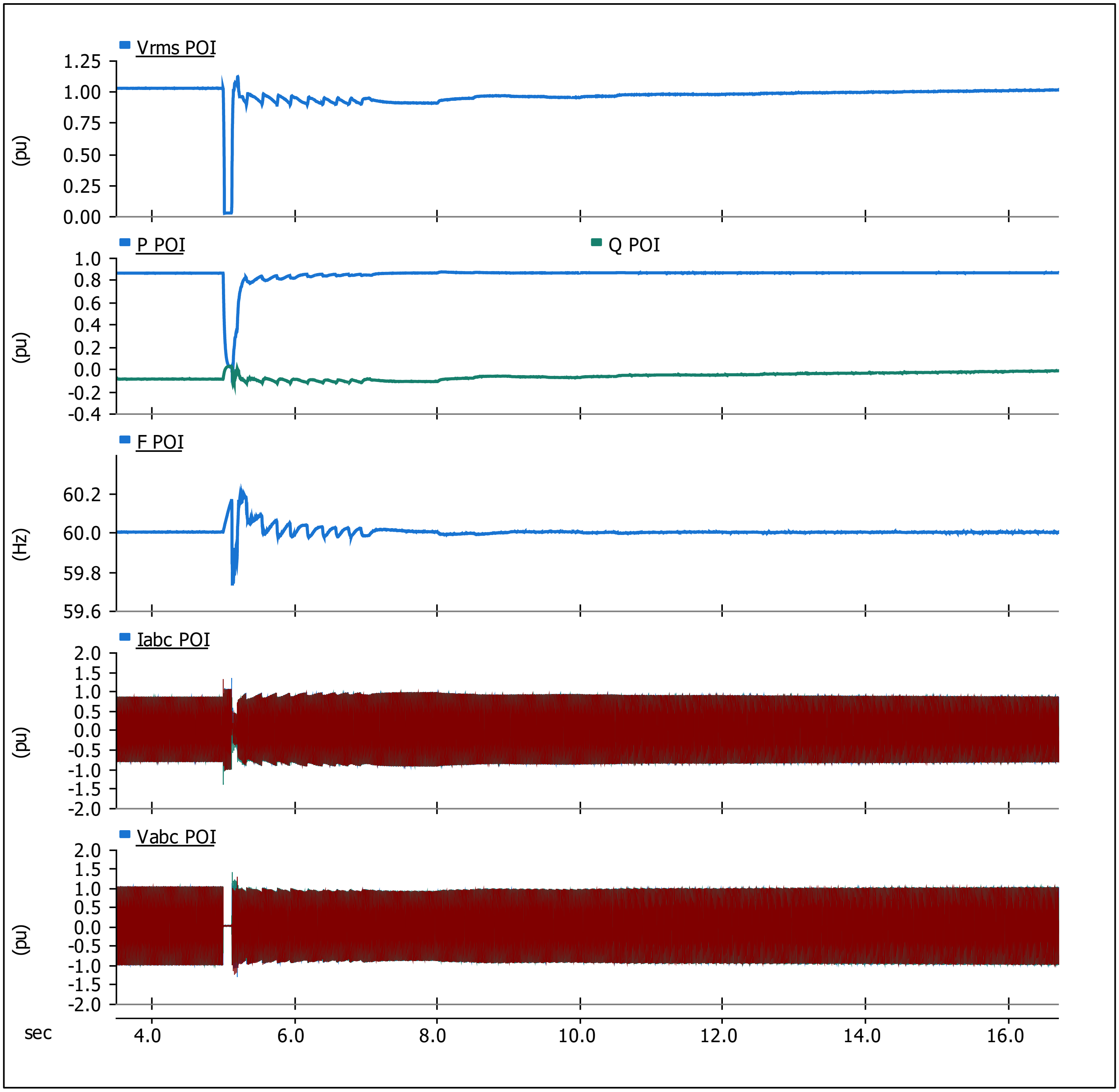


Figure 6.4: Example plot of typical IBR plant POI quantities (courtesy of American Transmission Company)

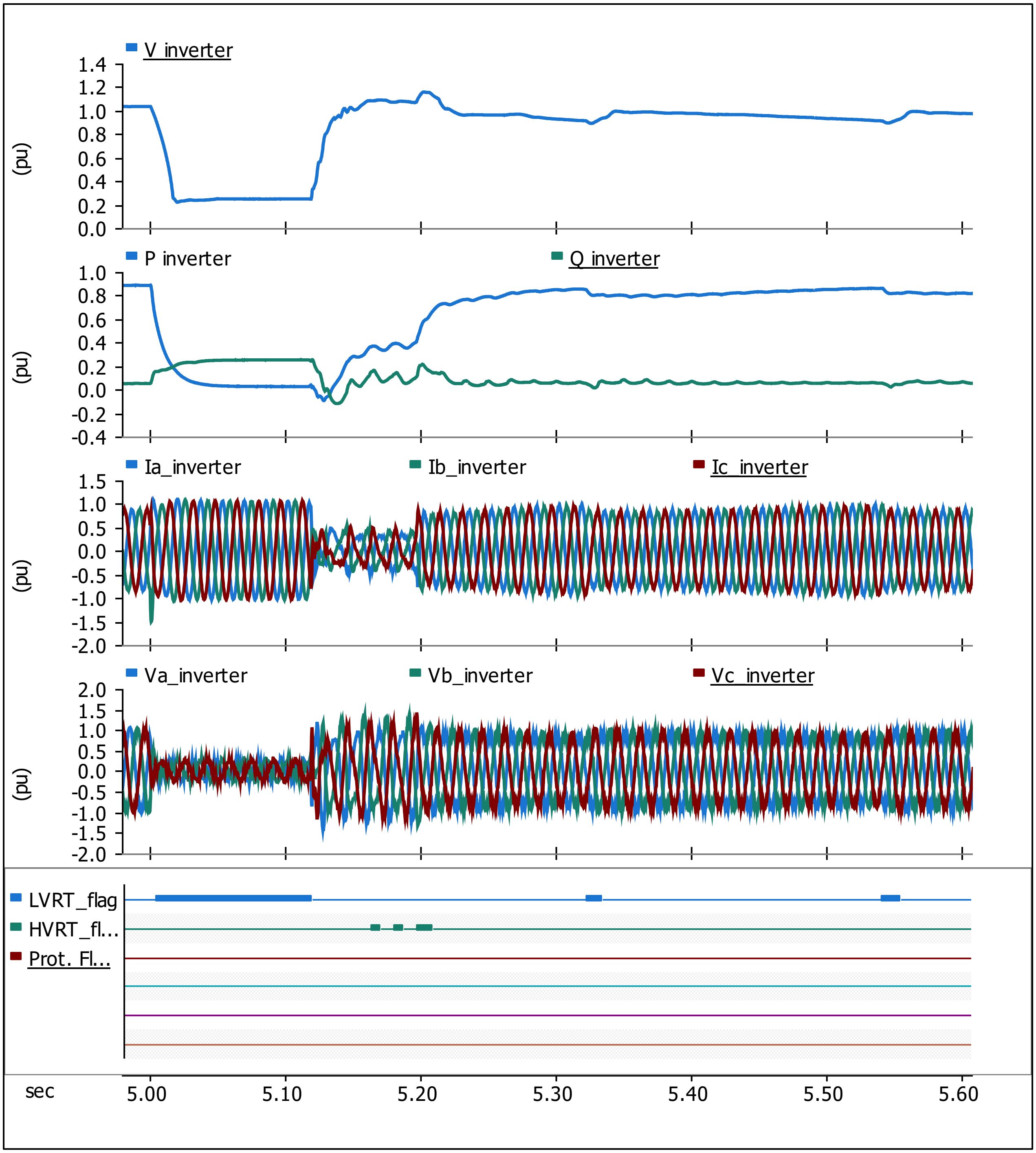


Figure 6.5: Example plot of typical IBR inverter quantities (courtesy of American Transmission Company)

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 which 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 traces should still be reviewed with good engineering judgement.

Comparison to Phasor-Domain Transient Stability

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 mistakes or inadequate kept system selection) or to identify 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 have not been benchmarked thoroughly against corresponding EMT models, and because the EMT system model is typically a subset of the PDTS system model.

Subsynchronous Oscillation Studies

Subsynchronous oscillation (SSO) is an electric power system condition where the electric network exchanges significant energy with generator at frequencies below the rated system frequency following a disturbance from the equilibrium[22]. Depending on the involved power system components, SSO is further classified into subsynchronous resonance (SSR), subsynchronous torsional interaction (SSTI), and subsynchronous control interaction (SSCI). Among them, SSCI is caused by the interaction between IBRs and series-compensated or weak grid conditions. Thus, with the increasing penetration of IBRs on the BPS, there is an increased likelihood of encountering Subsynchronous Oscillations (SSOs). These SSOs are detrimental for power systems, since they may exacerbate the power quality, cause power outage, or destroy power system components.

Another phenomena that might be encountered and categorized under the Subsynchronous oscillations are the subsynchronous ferroresonances (SSFR). The phenomenon of ferro resonance largely arises from the interaction between a capacitance and a non-linear inductance, 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.

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.

[22] 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

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 them from their usual sinusoidal shape. Consequently, it's 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.

Subsynchronous Control Interaction

Subsynchronous resonances are frequently observed between Type 3 Wind Turbine Generators (WTG) and weak, series-compensated grid lines. Figure 6.6 (top) and (bottom) illustrate 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 frequencies, potentially leading to grid instability, introducing the risk of a phenomenon called SSCI.

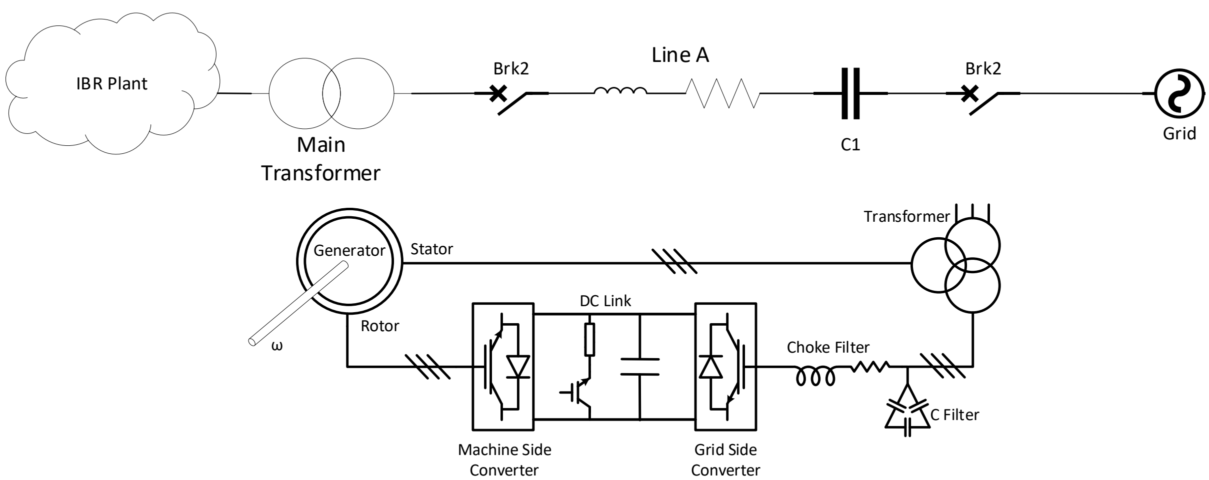


Figure 6.6: General diagram of a wind farm-connected series compensated network (Top), a DFIG-based WTG configuration (Bottom)

The interaction between the grid impedance and the WTG impedance may give rise to an unstable operation condition and may also influence the control performance of the turbine. To determine the equivalent impedance of the IBR plant, 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 subsynchronous frequencies as shown in Figure 6.2. The currents at these frequencies entering the wind plant are monitored. Using a Discrete Fourier Transform (DFT) algorithm, the magnitudes and phases of all relevant subsynchronous voltages and currents are extracted. From these measurements, using the initial harmonic perturbations, the resistance and reactance at each subsynchronous frequency are computed at the wind plant’s terminals. This resistance is then used to estimate the damping effects attributable to the plant.

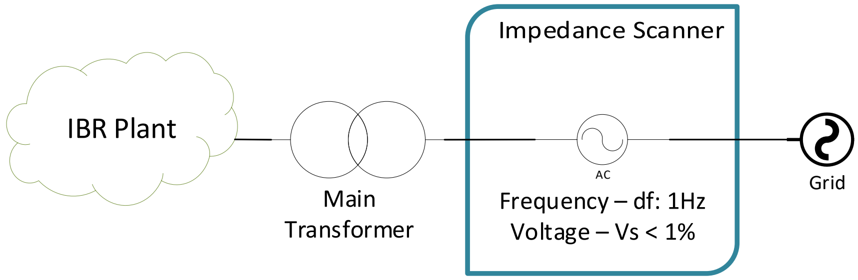


Figure 6.7: Single Line Diagram of Impedance Scanner

Figure 6.7 should be simulated using 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 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 FFT analysis must be conducted to obtain the equivalent impedance.

As observed in **Figure 6.8**, the real part of the impedance of various Inverter-Based Resource (IBR) plants is analyzed to evaluate their susceptibility to Subsynchronous Resonance (SSR). Type 3 wind turbines without SSR 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 to Subsynchronous Control Interaction (SSCI) compared to their Type 3 counterparts.

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 risks and enhancing the stability of the power system.

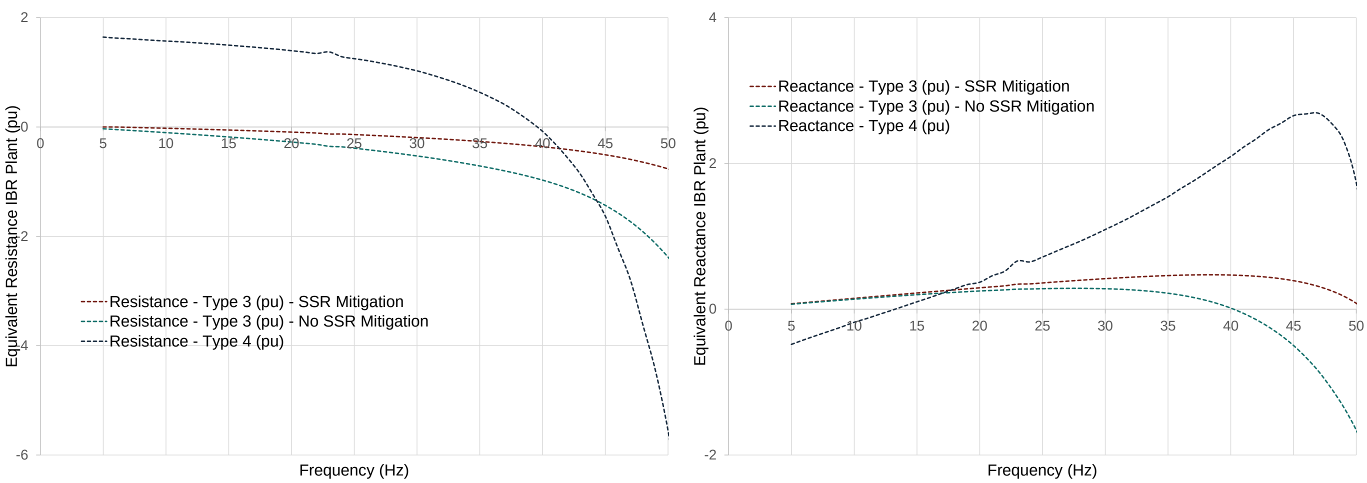


Figure 6.8: Impedance Scan Comparison

The issue of Subsynchronous Resonance (SSR) arises when the combined resistance of the grid and the Wind Turbine Generator (WTG) becomes 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 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 it is shown in **Figure 6.4**. Accordingly, the current IWTG flowing from the WTG to the grid is:

$$I_{WTG}(s) = \frac{V_{WTG}(s) - V_g(s)}{Z_{WTG}(s) + Z_g(s)}$$

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 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.

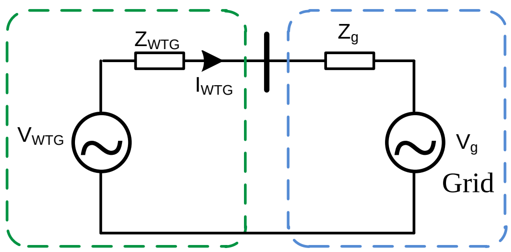


Figure 6.9: Small-signal model of a WTG connected to the grid.

Subsynchronous Ferroresonance

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 a transformer-terminated double circuit line, where 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 Subsynchronous 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 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) 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, 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.

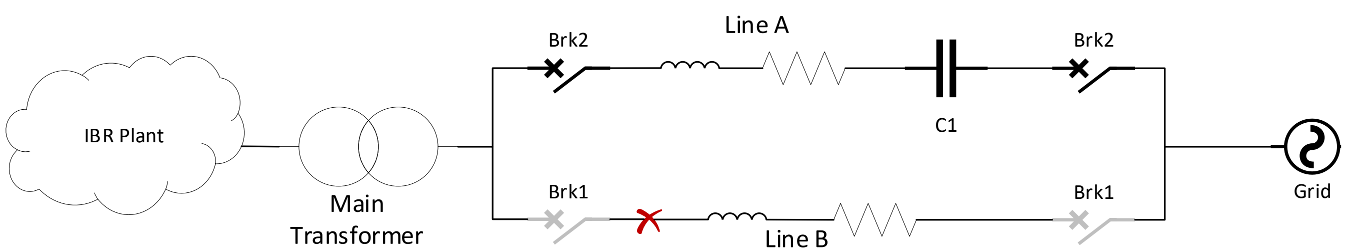


Figure 6.10: Single Line Diagram of a Series Compensated Plant

In the simulations depicted in **Figure 6.10**, 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**. Without core saturation, 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 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.

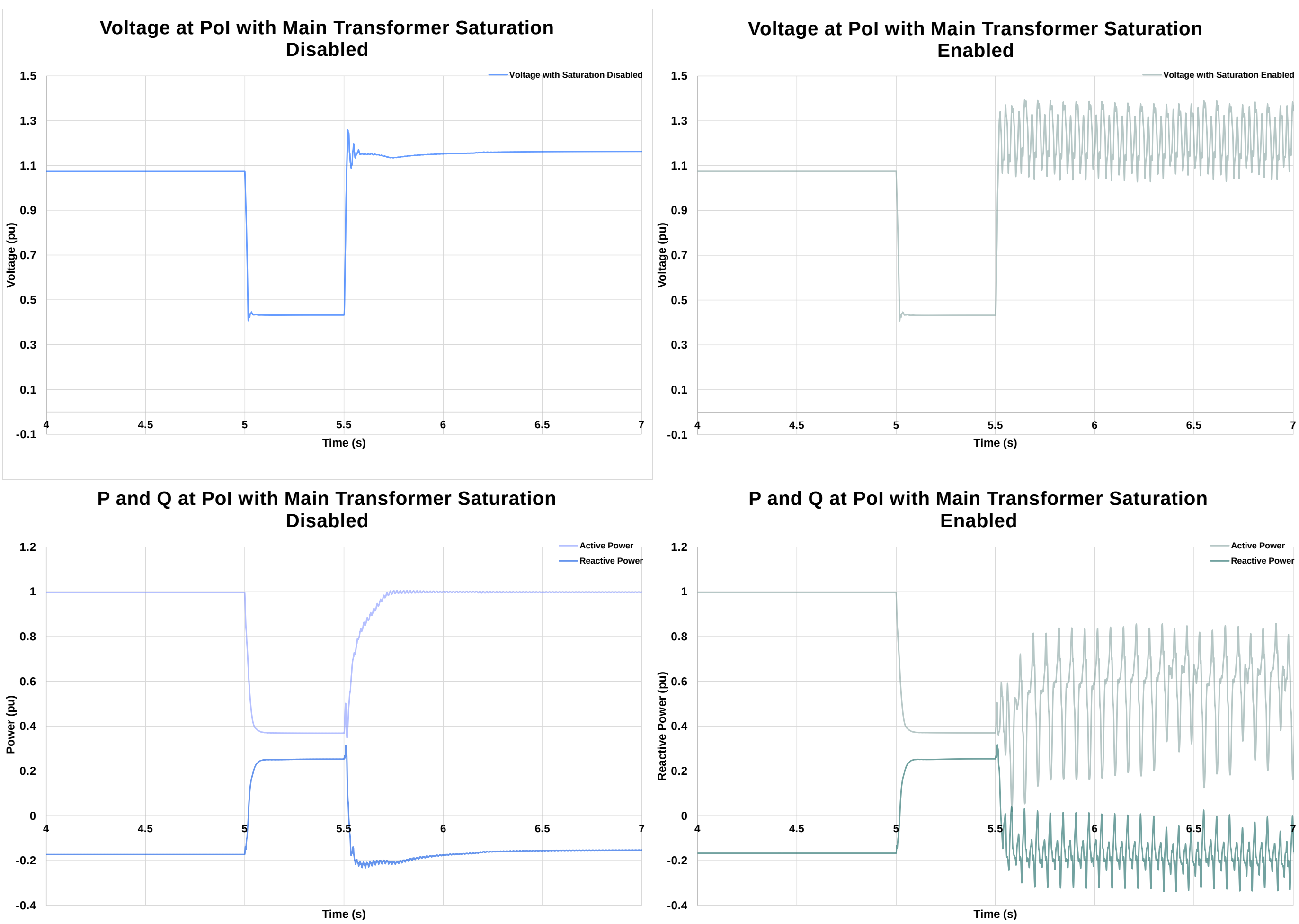


Figure 6.11: Comparison of Simulation Results of IBR in a Series Compensated line with and without transformer saturation

Real-World SSO Event Study Framework[23][24]

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. Yet, it is still difficult to completely prevent oscillation events due to the complicated SSO mechanisms. Thus, sometimes, post-SSO-event studies are needed to root cause and mitigate potential SSO issues. Therefore, in this guideline, the focus is given instead to post-event analysis for root causing SSO.

NREL developed a real-world SSO event analysis framework with six steps as displayed in **Figure 6.12** below. 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.

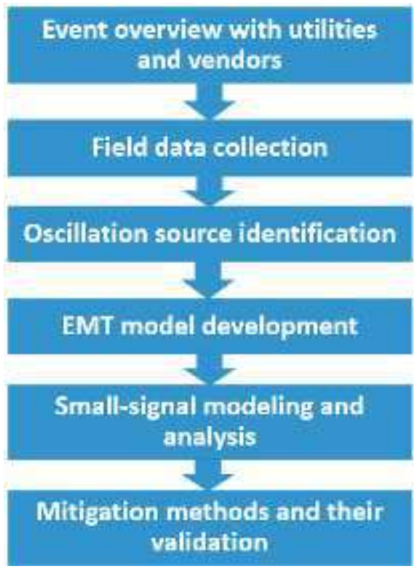


Figure 6.12: A real-world SSO event analysis framework proposed by NREL

- **Step 1:** Overview 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 (DEF)[25] and sub/super-synchronous power flow method[26].
- **Step 4:** Develop EMT model to replay the SSO event. In this step, we can leverage parallel simulation 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 scanning studies while analyzing the event.

[23] 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

[24] 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

[25] 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

[26] 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

- **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 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 largest island and has a meshed and isolated power system that is operated by Kaua`i Island Utility Cooperative (KIUC). Kaua`i power system features high penetration renewables during its operation. For example, 69.5% of Kaua`i Island's annual generation comes from renewables like solar, hydro, and biomass based on KIUC's 2021 annual report[27].

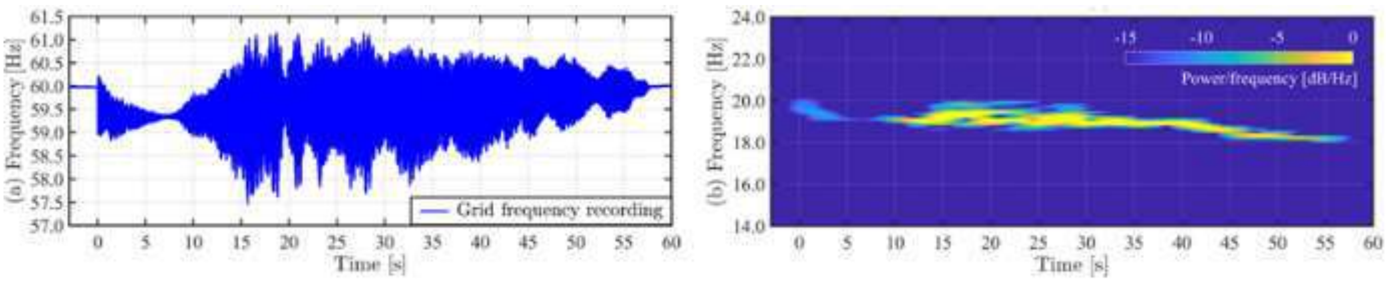


Figure 6.13: Kaua`i island frequency recording with 18-20 Hz oscillations

Following the N-1 contingency, one 18-20 Hz oscillation event occurred in Kaua`i Island at 5:30 am HST on November 21, 2021 (see **Figure 6.12** ). Note that the tripped synchronous generator supplied 60% of the total load before the event, and this generator trip indeed represented the most severe N-1 contingency in Kaua`i power system. Although the system was secured by four IBRs' fast frequency response, these 18-20 Hz oscillations are systemwide and still pose serious challenge to the stable operation of 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, this SSO event was studied with the analysis framework shown in **Figure 6.12**: A real-world SSO event analysis framework proposed by NREL, as detailed below.

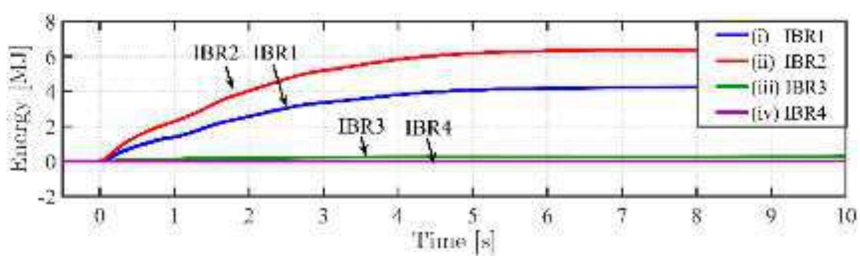


Figure 6.14: Identification of oscillation sources with the DEF method. This method shows that IBR1 and IBR2 are oscillation sources because they inject oscillation-frequency energy into the grid after t = 0 s

- **Steps 1-3:** After overviewing the event (step 1), KIUC's field data were collected for this event (step 2), which was recorded by digital fault recorder (DFR). Then, Step 3 was completed, and the oscillation source(s) were identified with two measurement-based algorithms—DEF **Error! Reference source not found.** and sub/super-s ynchronous power flow method. The DEF method only requires low-speed phasor data, and as shown in **Figure 6.12** two IBRs with grid-following (GFL) controller, 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 the oscillation sources in this event. To crosscheck the DEF analysis results, the high-speed point-on-wave

[27] Kaua'i Island Utility Cooperative, "Hitting the target – KIUC 2021 annual report," Lihue, HI, Dec. 2021

DFR data were leveraged to compute the sub/super-synchronous power flow corresponding to the oscillation frequency 18-20 Hz. The sub/super-synchronous power flow also suggests that IBR1 and IBR2 are the source 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 the root cause of the 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 studies is to recreate the oscillation event in our simulation. To achieve this goal, the detailed EMT model for Kaua`i island power system was built by converting KIUC PSS/E model and integrating available vendor-provided IBR models. Note that there was no challenge of defining the modeling boundary, since Kaua`i power system is a small and isolated island power system. Also, it should 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 have available vendor-provided models; they were represented with 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 6.12**.

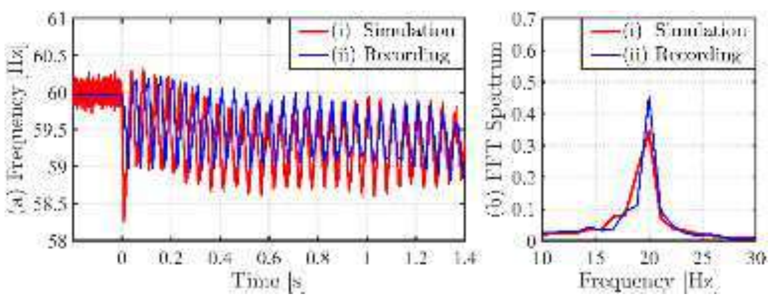


Figure 6.15: Simulated and recorded grid frequencies have similar time-domain responses and FFT spectra, which can validate the EMT model accuracy. (a) Simulated and recorded grid frequency waveforms. (b) FFT analysis results

- **Step 5:** After recreating the event with EMT simulation in step 4, model-based parameter sensitivity analysis, small-signal stability analysis, or frequency-scanning studies (step 5) should be performed. Taking 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 P/f droop constant and phase-locked loop (PLL) gain in IBR1 and IBR2 have larger impact on the simulated oscillations. Also, IBR1 and IBR2 were connected to medium weak grid following the N-1 contingency. Thus, this event is caused by a combination of different non-optimal settings. These findings were further confirmed by detailed small-signal analysis.

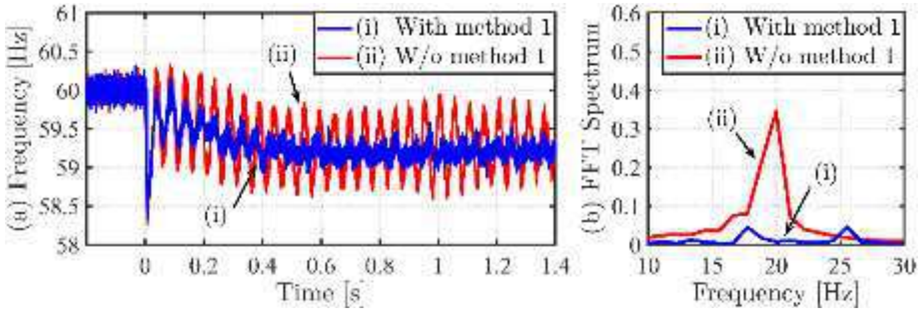


Figure 6. 16: Validation of our Method 1, which aims to mitigate the 18–20 Hz oscillations. (a) Simulated grid frequencies measured at IBR1 with and without Method 1. (b) FFT analysis results of simulated grid frequencies.

- **Step 6:** Based on our findings in 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 6.12**, the simulated frequency does not have obvious 18-20 Hz components any more after adopting method 1, proving the effectiveness of our proposed method.

Transmission System Protection Validation

As the number of IBRs connecting to the North American bulk power system 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 when IBR presence was minimal, if not nonexistent, and fault currents were predominantly influenced by the behavior of rotating machinery, particularly synchronous generators. The response of a synchronous generator during a fault event is well understood by protection engineers, who utilize linear circuit analysis techniques incorporating relevant machine impedances and time constants from that era.

In contrast, the fault response of an IBR depends on how its inverter control system is programmed to react to 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 controls to changing terminal conditions, remains less understood by protection engineers. Furthermore, there is inconsistency in response between IBRs from different manufacturers.[28]

In essence, the current protection practices, designed for systems with minimal IBR presence, may prove insufficient as IBR penetration grows, highlighting 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 of IBR penetration and to make necessary adjustments for protection settings or implement new schemes that works well with high level of IBRs. Objectives also include:

- Identification of IBR-based power plant interconnection scenarios where transmission system reliability could potentially be compromised by a lack of and/or poorly characterized response 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.

[28] https://www.osti.gov/biblio/1595917

- Guidance 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 “Dynamic System Impact Assessment Study” in Chapter 6.1, 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. The relays which are typically affected due to high penetration of IBRs are impedance-based relays (i.e. distance protection, out-of-step protection, negative sequence directional elements, etc.)[29].

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, a direct indication of the relay operation can be observed (i.e. expected, mal/mis operation). But typically, 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 device, approximate or generic protection models may not be suitable to perform the protection system studies. This is due to the fact that the relay outputs are highly dependent on the OEM algorithm, filtering, 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.

Simulation quantities to monitor

Simulation quantities which are typically monitored to assess the reliability and security of protection system include:

- Operating quantity of the relay (e.g. calculated impedance for a distance relay, output of a direction element)
- Settings of the relay (i.e. the characteristic where 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, 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 post-processing method which 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 traces should still be reviewed with good engineering judgement.

[29]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

Mitigation

In case of relay mal/mis operation occur, it is important to utilize mitigations techniques to resolve the issues observed. Some of the commonly seen mitigation options are:

- Apply modifications of relay settings
- Make changes to relay protection algorithm
- Introduce/modify RAS schemes to avoid conditions where relay mal operations are observed
- Complete change of the protection relay or scheme (e.g. replacing a distance relay with current differential relay)

Once the mitigation option is selected, it is recommended to re-study the affected scenarios to make sure there are no additional concerns due to changes made.

Examples

There are documented cases of relay mis-operations that have been attributed to lack of, or incorrect, fault current injection from IBR.

- A relay mis operation 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). 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)[30].
- Another relay mis operation 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 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' and prevent false tripping.
- Protection relay mis operations during ERCOT Odessa Disturbance[31]

Summary

In scenarios with high 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 modifications to existing protection systems without further investigation. Additionally, inverter manufacturers are seeking direction on how to appropriately respond to grid disturbances to better support the power system during such events.

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.

[30] 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.

[31] Odessa Disturbance, Texas Events: May 9, 2021 and June 26, 2021 Joint NERC and Texas RE Staff Report, September 2021.

Chapter 7: Additional Guidance on Modeling of IBR Plants

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 some may have not even existed just a few years ago. In addition, some of the inverter manufacturer companies are no longer in business. This has posed great challenges for Generator Owners (GOs) to obtain detailed models for such inverters. The term “legacy” has been used to name such resources. Expanding on the previous guideline on EMT modeling, additional guidance on modeling of legacy IBR plants is provided in this chapter.

While 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, generic model components built into simulation software may be used to represent such plants. It should be noted that these generic models have limitations and only provide an unrefined approximation of the actual plant’s behavior. The generic model response should be validated against field measurement. Also, if generic models are being used, they should comply with applicable technical specification requirements by TPs and PCs.

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 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 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.

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 Power Plant

"Generic" EMT models have also been developed over the years to produce standardized Wind Turbine Generators and WTG plant models. In the US and Europe, these efforts have been led by the Western Electricity Coordinating Council (WECC) and the IEC, respectively[32]. The focus has been put on developing WTG models that can conduct typical transient stability 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:

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 of the control features and behavior of legacy plants can be verified 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 plant location, system strength, size of the plant, and the type of studies that Transmission Planner 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, for similar inverters from the same OEM.

Some examples of legacy IBR plant modeling are provided in **Appendix A**:.

Hardware in the Loop (HIL) Validation of Existing IBR Plant Models with Field Measurements

It is well-known that generic models are insufficient in being able to represent all the nuanced behaviors of controls and protection elements. 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 generic models could be used with these parameters to model the plant based on available documentation. Also, models of similar plants with similar rating and control functions could 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

[32] https://www.esig.energy/wiki-main-page/generic-models-individual-turbines/

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[33]. This way, a large amount of field results can be acquired to compare with the model response in the same test scenarios. A generic EMT-based wind turbine model is validated against the field tests of a real wind turbine through a short-circuit container, which allows for applying different faults with different voltage dips at the turbine terminals[34][35]. 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[36]. 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.

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[37]. Similarly, wide-area monitoring data can be leveraged to identify the dominant control parameters to represent a DFIG wind farm with improved genetic algorithms[38]. 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 would be very important 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 different disturbances such as load dips/rejection, step responses.

HIL Validation of 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 FAT tests results when field tests are not available [Cite IEEE P2004]. 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 1. A hardware control unit would be connected to the simulator as if it was connected to the actual plant. Measurement signals such as active, reactive powers and RMS voltages, as well as binary signals such as breaker status, would be measured 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

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33 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.

34 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.

35 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.

36 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.

37 NREC, Reliability Guideline Model Verification of Aggregate DER Models used in Planning Studies, March 2021

38 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.

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.

The power plant controller for a Battery Energy Storage System (BESS) plant was validated against a commercially available PPC running on a General Electric PLC through HIL tests[39]. Different real power and reactive power control loops as well as capacitor bank control were validated.

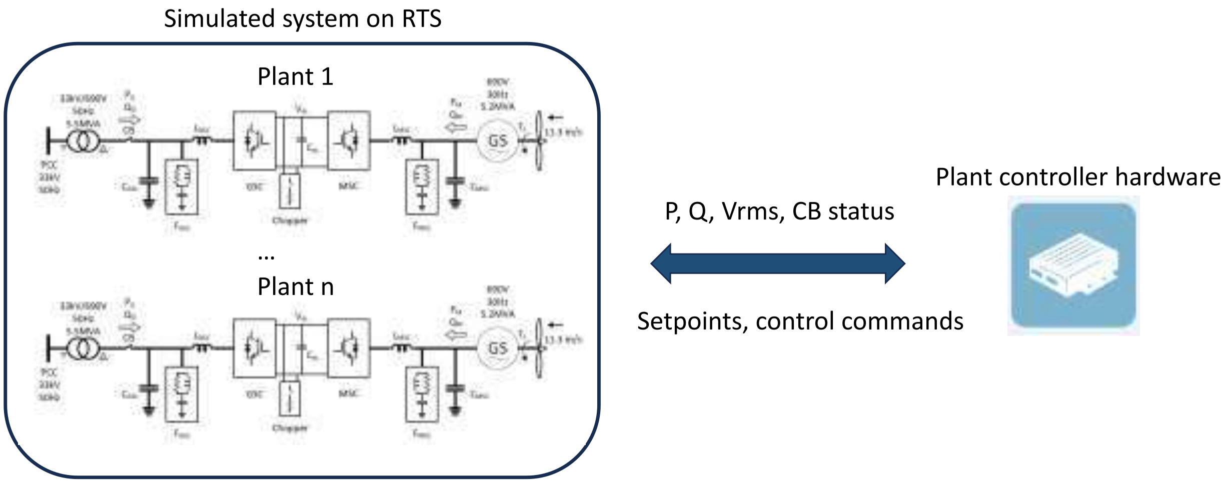

Figure 7.1: CHIL set up for power plant controller validation

To go one step further, Power-Hardware-In-the-Loop (PHIL) tests would allow for utilizing 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, drives and so on as shown in Figure 2. For example, if we considered 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 is that at this point, PHIL amplifiers that exist on the market are only available in a limited range of powers and voltages. Further, 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 Hydro Quebec Research Institute[40] aims to design a 7.5MW 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. Similarly, some research labs within the US 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.

[39] 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.

[40] 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

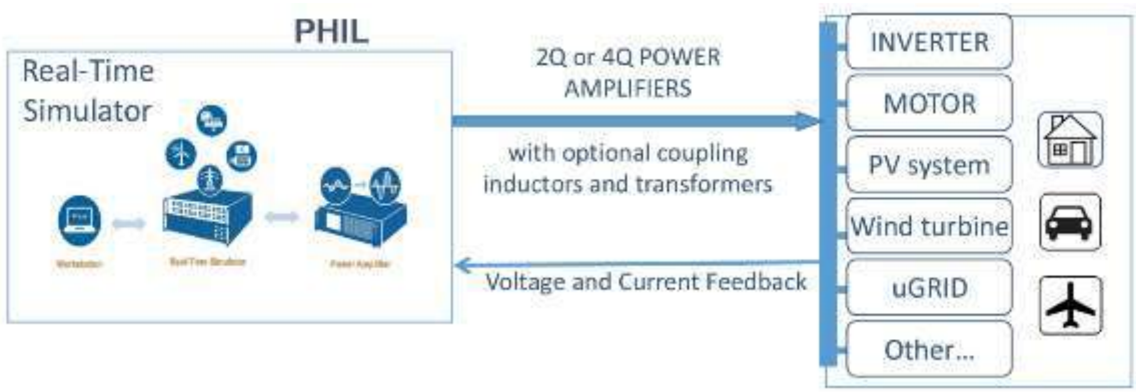

Figure 7.2: PHIL setup to interface electric components

Another example is where an EMT model of a GE DFIG wind turbine unit is validated against the actual hardware test data in the lab[41]. 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.

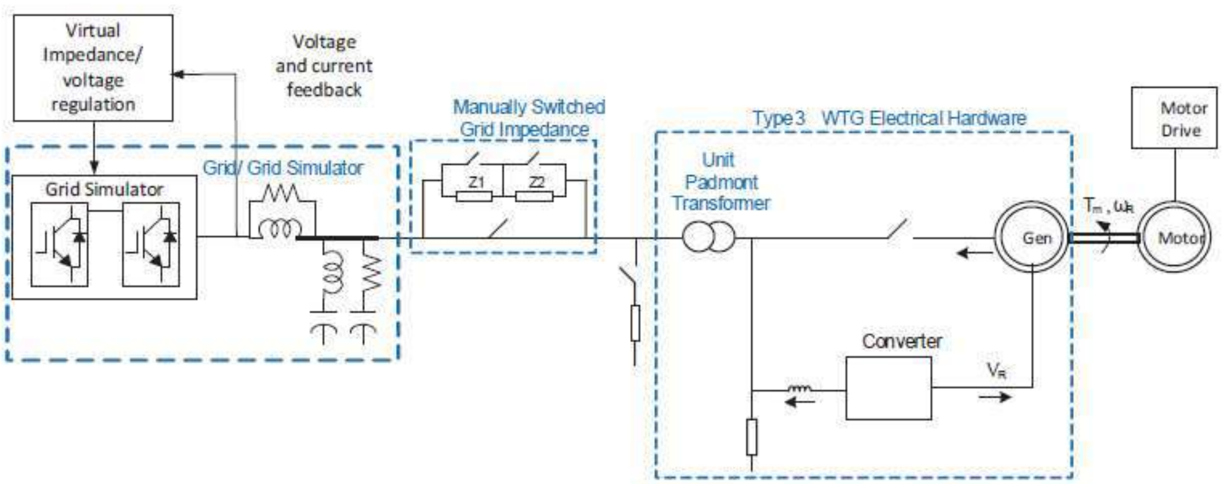

Figure 7.3: Schematic diagram of the GE lab test facilities

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 models and the overall plant models.

Inverter Control Models

Depending on the desired level of details at different regions 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.

[41] 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

- Real Code model (Most precise model):
  - Exact replica with all protections included (including all IBGT blocking protections)
  - It may be validated with all validations proposed for EMT models in IEEE2800.
  - It is intended to be used as a reference or inside the study area, close to perturbation.
  - It usually has time-step constraints and may be a large computation burden.
- Simplified model:
  - Model with simplifications allowing to simulate with larger time-steps, 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 be modeled 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 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 250Hz.
  - 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 it is being simulated outside of its range of validation.
  - It may be simulated with a time-step slightly larger than the True Replica.

Similar modeling philosophy can be applied to power plant controllers.

Inverter Electrical Models

Refer to the previous EMT guideline on switching model vs average converter model.

Overall Plant Models

There are generally three approaches to modeling an IBR plant. This section presents more details on these modeling approaches and their recommended uses.

- **Non-aggregated Models (Inverter-Level Models or Detailed Plant Models[42])**: 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. As mentioned earlier, detailed models are recommended for conducting ride-through verifications and assessing differential-mode circulating oscillations.
- **Semi-aggregated Models**: In cases where the number of inverters becomes impractical for simulation[43], and when they are geographically close, such as in solar or Battery Energy Storage Systems (BESS) plants, semi-

[42] 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.

[43] See Chapter 9 for leveraging parallel computing to accelerate simulation of a detailed wind farm model

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.

- **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 in Power System Protection has been increased in recent years. EMT simulation results can assist protection engineers to have better insight regarding steady-state fundamental frequency loads or harmonics which can cause issues for protection systems for any applications. In addition, the RMS power flow and short-circuit simulation tools assume the system is balanced. There are various unbalanced conditions in power system studies. Furthermore, the EMT tools provide insights on frequencies other than fundamental. This information is valuable for harmonic rejections in the relays.

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 IBRs are subject to the NERC Reliability Standards, such as PRC-024-3, PRC-025-2, and PRC-027-1. In addition, the inverter controls and protection need to be coordinated with other forms of protection within the overall plant. The IBRs have several protection elements in their protection system. Few of these elements are listed below:

- Inverter protection functions:
  - ac and dc overcurrent protection.
  - dc undervoltage protection.
  - Under/Over frequency protection.
  - Under/Over voltage protection.
  - ac ground fault protection.
  - dc undervoltage protection for BESS
- Inverter transformer protection.
- Collector system protection.
- Substation and Main Power Transformer Protection.
- Main line and breaker protection

The protection functions for these resources can often use phase-based quantities 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 the ride-through capability of the inverters. Therefore, EMT simulation tools might be needed to fully capture the dynamic behavior of the inverters.

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 model of an IBR. The inverter model and associated protection elements should come from Original Equipment Manufacturer (OEM). After the site-specific model is built in EMT tool, then various grid conditions can be simulated to determine if the plant ride through performance compliance with NERC PRC-024-3.

Another critical aspect is the consideration of model simplifications and assumptions made in Electromagnetic Transient (EMT) models. It is important to acknowledge that EMT models are not inherently accurate. 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 protection systems 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. 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 detailed thermal model 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) studies, also recently included in IEEE 2800. Most modern converters can handle much higher ROCOF levels than those specified in the standard. Especially in Type 4 machines, converters typically do not have ROCOF protection per se; rather, the converters monitor the frequency through the Phase-Locked Loop (PLL) code and trip only when the frequency 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.

Validation of Equipment Specific IBR Models from OEMs

Typically, IBR plant 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 expected performance requirements. While some of these models are black-boxed models 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 limited insights into specific plant behaviors, one of the major advantages in having them is to be able to replicate real-world behavior as closely as possible. When it comes to validating the EMT model quality of OEM provided IBR plant models, the following considerations are essential.

First, OEMs should be required to provide detailed validation reports of the IBR plant 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 with an equivalent RMS model should also be required. Second, 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, phase jump tests, and subsynchronous tests **Error! Reference source not found.**. Additional test case scenarios considering operating conditions at reduced energy inputs and at minimum system Short Circuit Ratios should also be required **Error! Reference source not found.**.

While a validated OEM provided site-specific, 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, compiler dependencies, etc., hinder the ability for 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 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 IBR model integration

Consistency of black-boxing control and electrical components: Currently, there is 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 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 the one provided such inconsistencies complicate integration and limit model portability across tools. Further, 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 should recommend OEMs to follow standardized, 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, OEM provided black-box models often require specific versions of compilers and operating systems that introduces 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 requirements to ensure support across commonly used platforms.

Support for a range of time-steps: Currently, OEMs define their own time-steps for their controller models, which in some cases are different from the time-step of the system level EMT simulation model. Furthermore, some of the OEM provided models perform well only at specified time-steps and have accuracy or numerical stability issues at other time-steps. TPs and PCs should ensure that OEM provided models not only operate at specified time-steps, 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 of the OEM 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 the intended use case for the IBR plant model. If simulation speed is a bottleneck to adopt large-scale EMT simulation, modeling techniques such as switching function models 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 OEM 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 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 with EMT simulation tools closely.

Initialization of OEM provided black-box controllers: Initialization of black-box controllers is another area that needs attention and could be improved. 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 an average simulation time of 30s, 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 able to initialize OEM black-box controllers, then we can accelerate multi-scenario tests efficiently by reinitializing to a steady-state snapshot every time. TPs and PCs should work together with OEM 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 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, frequency. Care should be taken when a model is expecting a measurement input, and a corresponding meter model was not 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 introduce inaccuracy. Special consideration should be given to frequency measurement as those calculated by some standard library meter models could be susceptible to phase angle shifts producing artificial spikes (see **Figure 6.12** for example). Similar attention should be paid to RMS quantities and parameters that could affect them such as filter time constant or calculation methods.

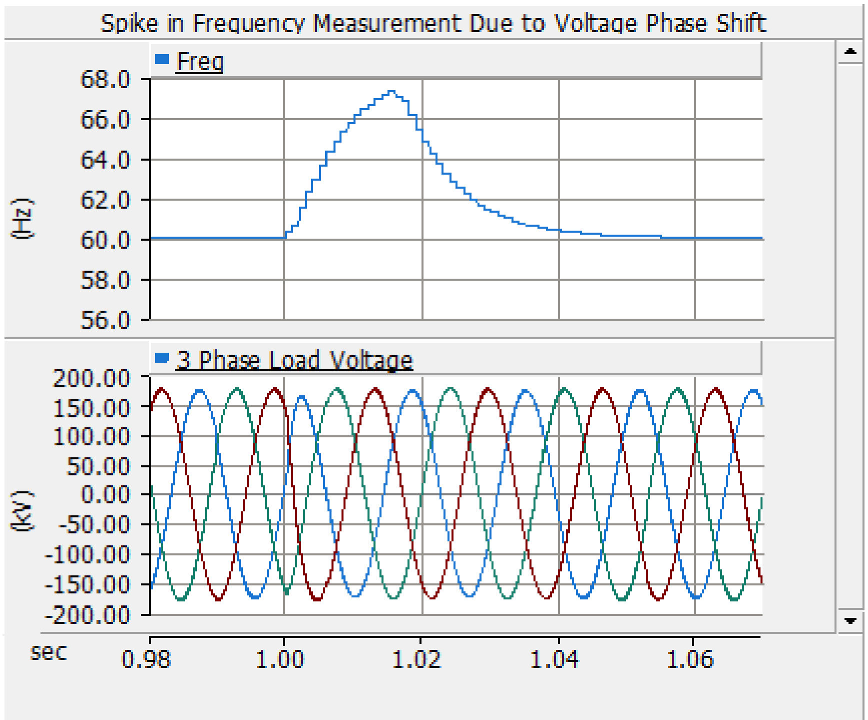

Figure 7.4: Spike in standard library frequency measurement due to voltage phase shift

Chapter 8: Accelerating EMT Simulations

Electromagnetic Transient (EMT) simulation studies were originally utilized for studying fast transients with high frequency content, encompassing switching transients, lightning surges, protection, harmonics, transient over-voltages, 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 localized nature, necessitating the simulation of a specific reduced network section with equivalents for surrounding networks. In some other cases, it is 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 (TSA) requires the simulation of very large-scale grids due to 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 to provide accurate transient simulations. The main reasons for these shortcomings are the model simplifications and/or omissions of certain components, such as the phase-locked loop (PLL), especially under weak system conditions. Therefore, the simulation of large-scale power systems in an EMT environment starts to become 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 does not constitute a slow process anymore.

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, ranging from 1 to 500µs. The time-step selection is constrained by the highest frequency of interest. For transient stability analysis of large power grids, the time-step 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 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 unknowns are found through 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 IGBT models. Such devices modify the coefficient matrix and require repetitive recalculations of LU decomposition for several solution time-points and even several times per time-point 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 (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 simulation and/or networks with multiple power electronics devices modelled in full detail, e.g., a detailed wind farm model. The extent of 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 network tearing into subnetworks solved separately and in parallel. The most popular and simple tearing method is through the application of natural delay-based transmission line (TLM) or cable models. The propagation delay of such distributed-parameters models allows 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. 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 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 requirements that are sometimes lesser than 50 us (typically around 4 – 20 us), therefore, decoupling the system model without introducing modelling 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 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 such as C or FORTRAN, most of the time, implemented plant models are not computationally efficient. As more and more Transmission Planners and Planning Coordinators 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 efforts to investigate the use of Graphics Processing Units (GPUs) 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 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 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

In this method, the power system is divided into subsections which are simulated at different time steps. The detailed subsection can be simulated with a small time-step and the rest of the system can use a larger time-step (faster simulation time). Also, this method allows multiple OEM models requiring different time steps to be simulated in the same system.

The time-step of each portion may be as large as possible, but small enough to simulate the range of frequencies with non-negligeable magnitudes which may appear inside its boundaries. The further away from the origin of the perturbation, the larger the time-step may be.

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

This method is similar to the multi-sampling rate but instead of using different time-steps within the same EMT platform, the EMT platform is interfaced with a positive-sequence RMS platform. The network is divided into two parts, a detailed part that is modelled in the EMT-mode and the rest of the network is modelled using the positive-sequence RMS platform. This method is discussed in detail in Chapter 3.

Aggregation and equivalency

The complexity of simulating over a hundred power electronic devices can be reduced if they can be aggregated into a single device or smaller number of devices. The equivalent system should provide a close matching with the actual system for the required studies.

Using relaxed models for phasor portion

Using high-fidelity IBR models everywhere in EMT area model can be a bottleneck to achieve reasonable simulation speed performance. Similarly, to using phasor-domain modelling 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 allow simulations with large time-steps and are less computationally intensive can help significantly accelerate EMT simulations. For example, inverter-based resources may be modelled 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 time-step up to 150µs.

Synchronous generators may also be simulated in the EMT domain with a very large time-step, up to 150 µs or 1000 µs, if the machine equations are solved with network equations.

Additional Considerations on Solution Time Step and Its Impact on Accuracy

Using larger time step when the EMT model includes non-linearities can introduce errors which may accumulate over time. There are solution techniques available that help address this e.g. iterative solution, interpolation techniques, dynamic phasors, etc. See the following figure of a transformer inrush current with and without iteration at 100µs.

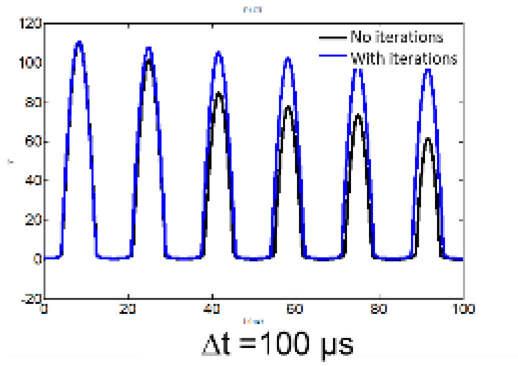

Figure 8.1: Inrush current with and without iteration

Caution: Attention must be paid for the accuracy of the solution technique use (e.g., convergence tolerance and whether the solution is converged or not if iterative solution is used; errors due to time step ratio if interpolation or dynamic phasor techniques are used.)

If artificial time-step 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 may remain below 20us. The figure below demonstrates the error introduced by a current scaling device with a 50us time-step delay in the active power (left) and the reactive power (right). Current scaling devices are used for generation aggregation. It 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 introduces an artificial delay to allow decoupling equations.

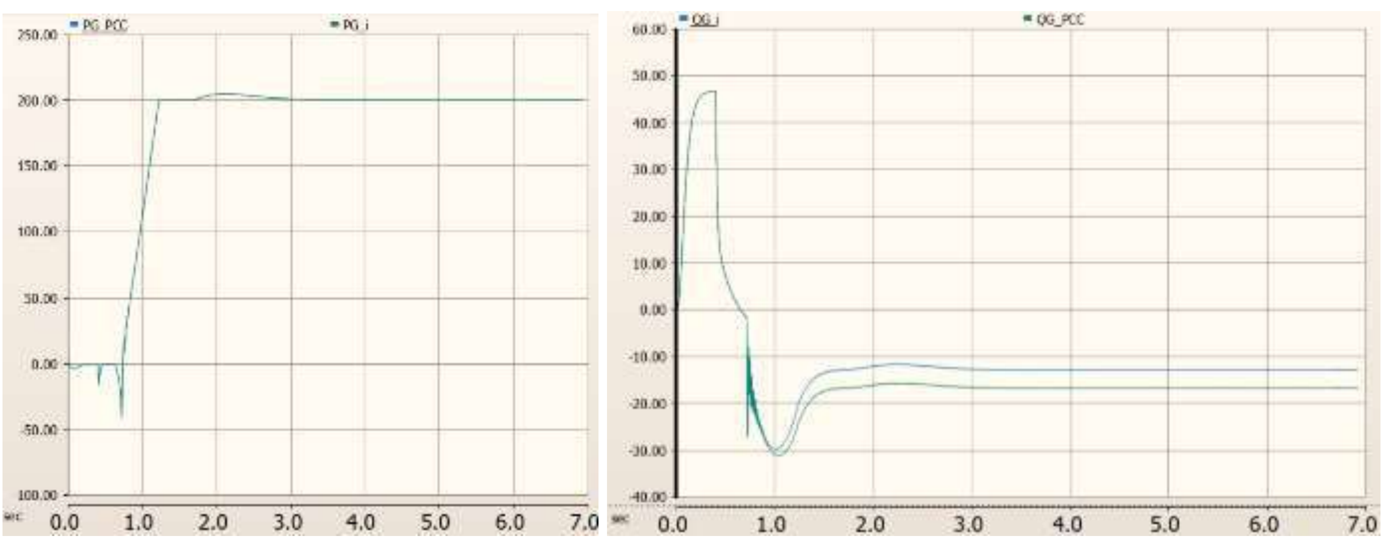

Figure 8.2: Error introduced by a current scaling device

Best Practices for Developing Large EMT Models

As more and more IBRs are integrated into the power grid across the US, the need for extensively studying grid behaviors during a range of operating conditions and fault scenarios would be more than compelling. Large-scale EMT studies would need to be performed repeatedly as a routine part of planning and operational studies. Current practice involves performing EMT studies on targeted, regional system models with the wide-area system being equivalenced appropriately to limit scale. Further, the starting point in a lot of cases involves porting phasor-domain models. To develop high-fidelity and large-scale validated EMT models, there are certain best practices that could be followed by TPs and PCs.

Ensuring 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 should be approached as a multi-step 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 validated with steady-state comparisons followed by specific types of step changes and fault scenarios.

Another aspect to pay 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.

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, 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 situations where 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 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 system studied in the above sections is in the order of 1000s of buses, which is sufficient for most systems that is or will be studied in near future. As the penetration of power electronics increases in the power grid, the size of the system that needs to be studied is expected to grow in EMT simulations. For example, with simplified distribution grid models in today's phasor-domain transient stability (TS) simulators, the power grid in United States has in the range of 100,000 buses. If more detailed distribution grid models and/or IBRs are modelled in detail, the number of buses can easily reach millions. In such cases, it may not be simple to perform splitting of the model only based on transmission lines to introduce parallelism and speed-up. Hence, 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.[44,45,46] Additionally, parallelism in solvers within multi-core CPUs are being explored for further speed-up in simulations.[47,48,49,50]

Hardware: In addition to multi-core CPUs, there have been recent research trends in using graphics processing unit (GPU) for scalable simulations. It may assist with speed-up of certain types of power grids and/or IBRs[51,52]. This is not guaranteed for all types of systems.

Automation: Automatic parallelization of models and solvers is ongoing research and will assist in future with scalability. There is limited published work at this time.

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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 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 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

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

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 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:

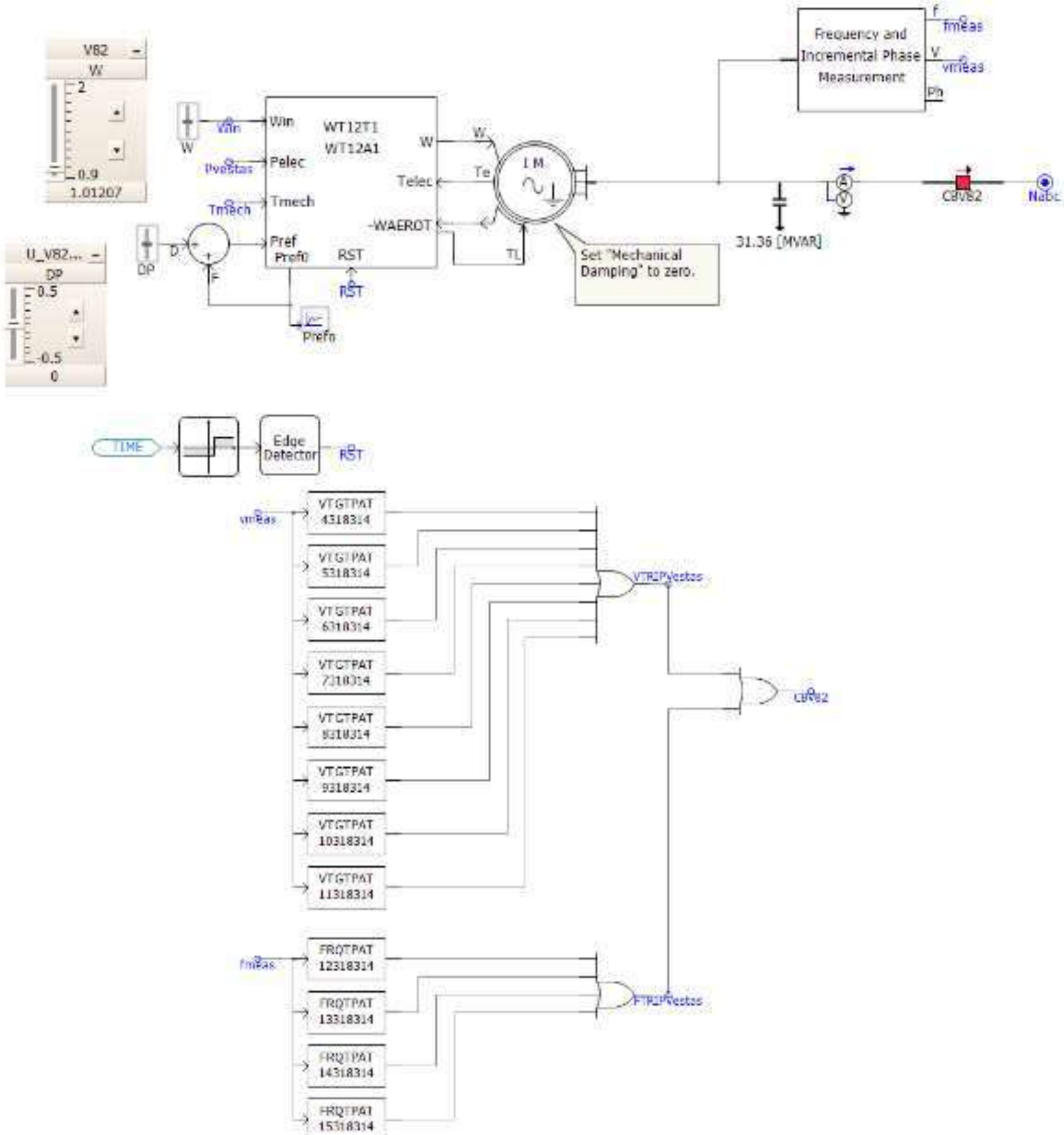

Figure A.1: Details of the EMT model

Model Initialization

Initialization of an EMT simulation differs from software to software. The steps described here are for one of the EMT software and maybe 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 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 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 the machine is released at a user-specified time instant. **Error! Reference source not found.** shows the locations in the model where the user n eeds to enter the data for initialization.

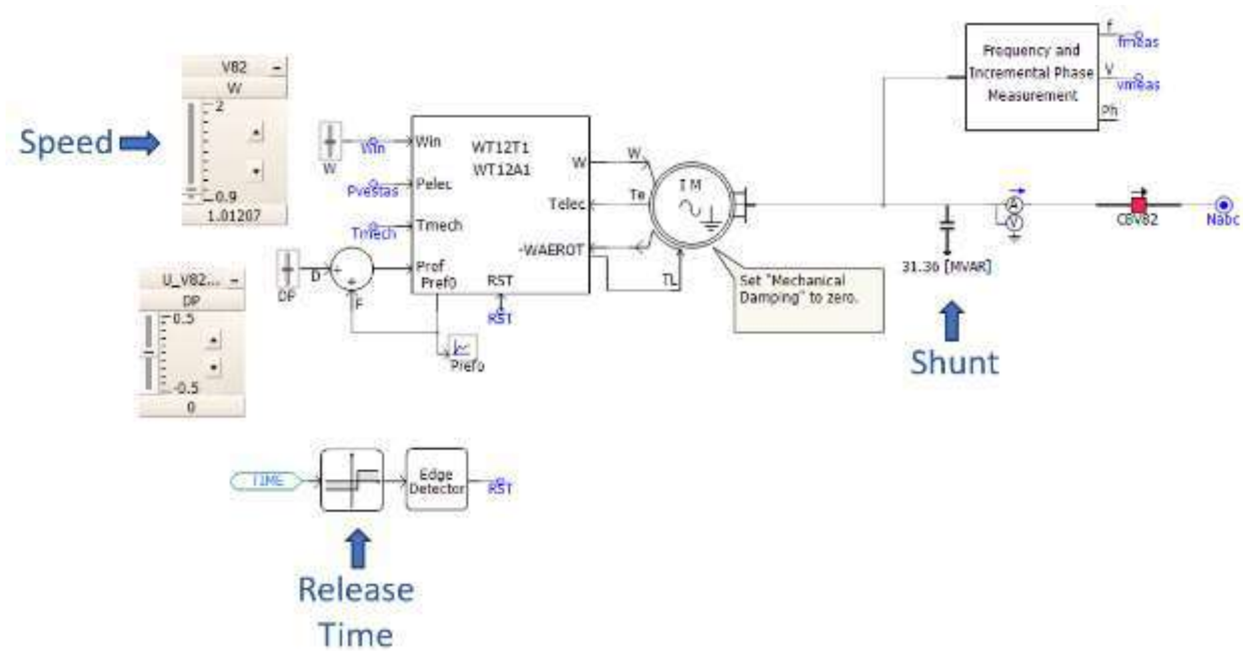

Figure A.2: Initialization of the EMT model

Benchmarking the EMT model against 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.

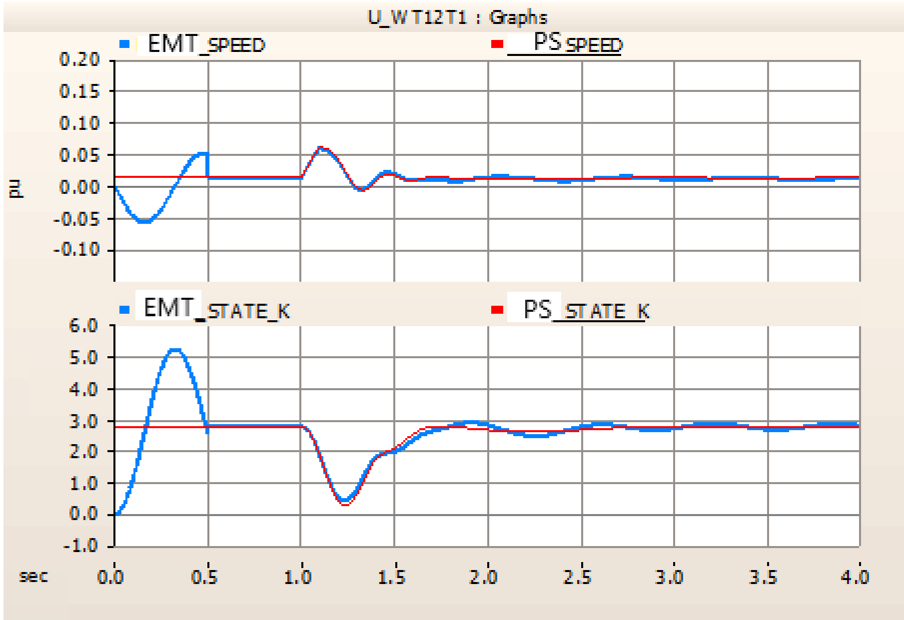

Figure A.3: Comparison of WT12T1 responses between EMT and Positive Sequence simulation

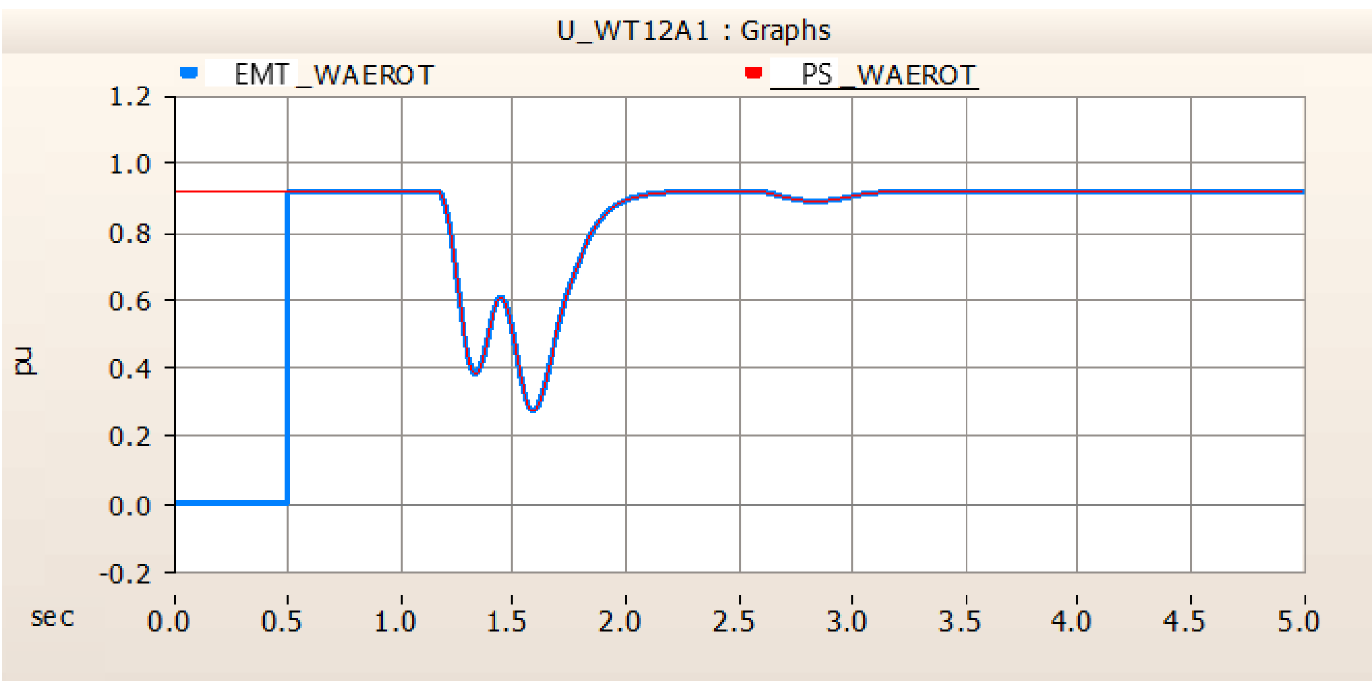

Figure A.4: Comparison of WT12A1 responses between EMT and Positive Sequence simulation

The following figures 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.

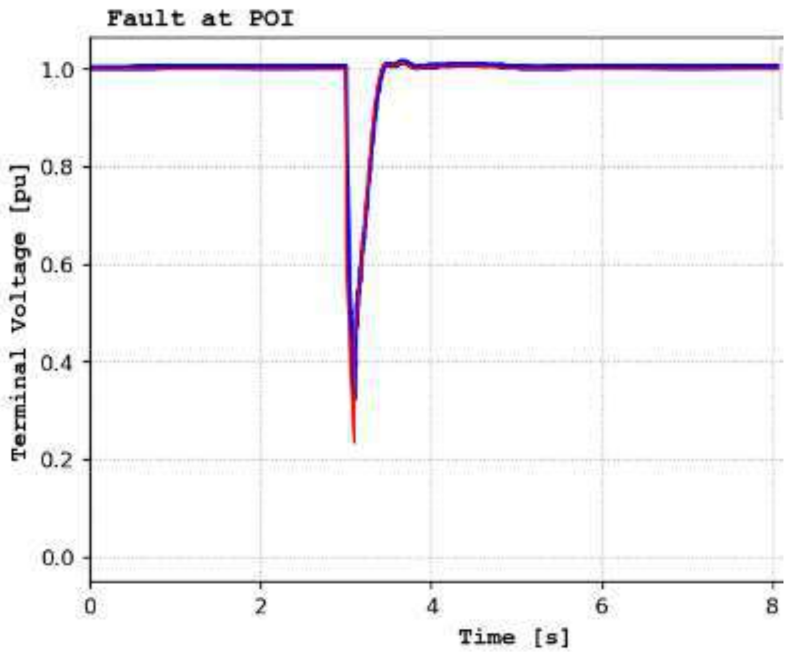

Figure A.5: Comparison of terminal voltages between EMT (blue) and positive sequence (red) models

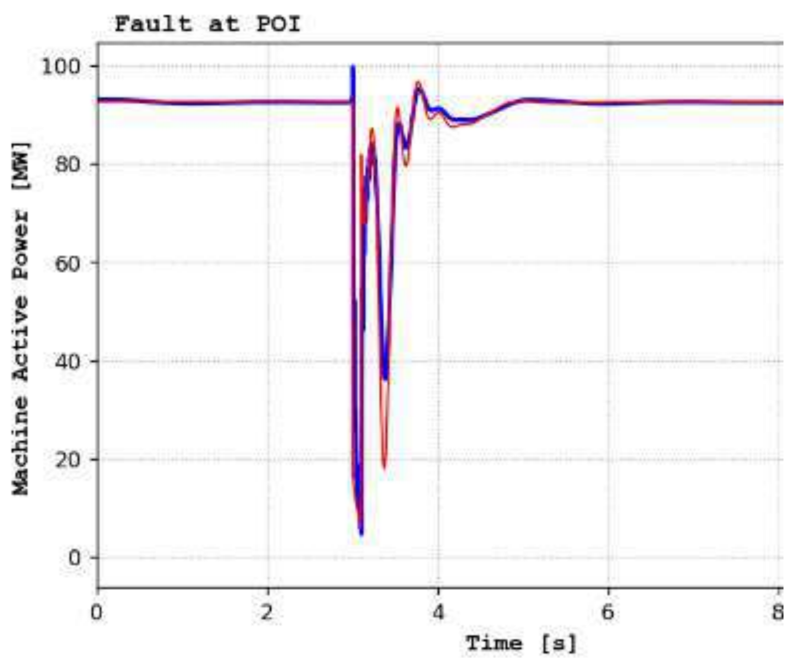

Figure A.6: Comparison of active powers between EMT (blue) and positive sequence (red) models

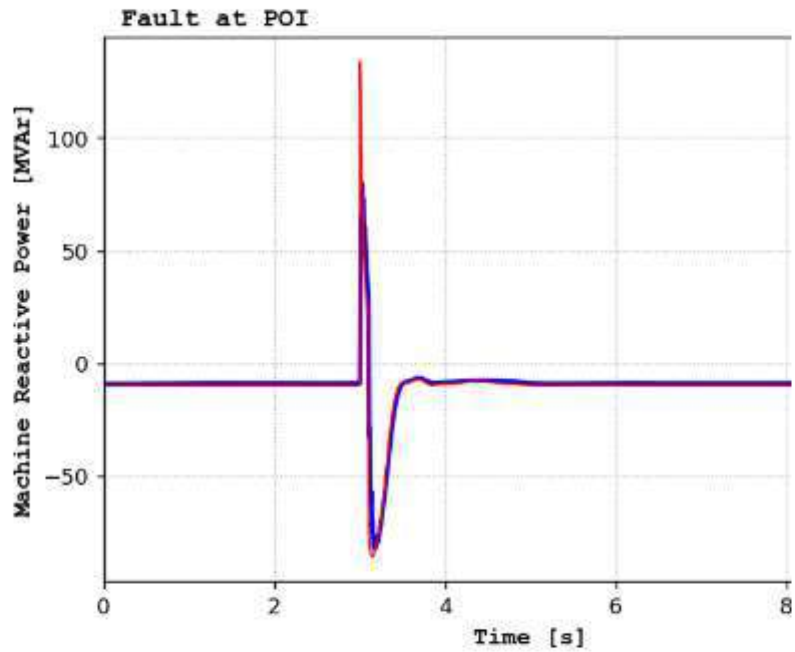

Figure A.7: Comparison of reactive powers between EMT (blue) and positive sequence (red) models

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 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 exists 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 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[53]. 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 model 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 and 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 parameters and controllers instead of OEM-specific data. The results could improve if there were OEM-specific data available.

[53] 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.

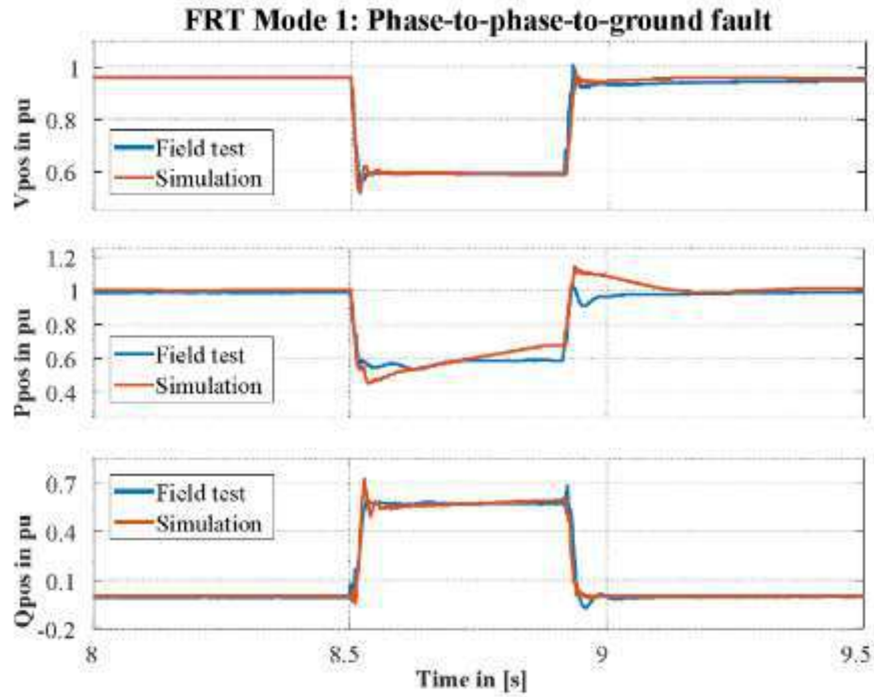

Figure A.7: Simulations and field test validation for an unsymmetrical fault

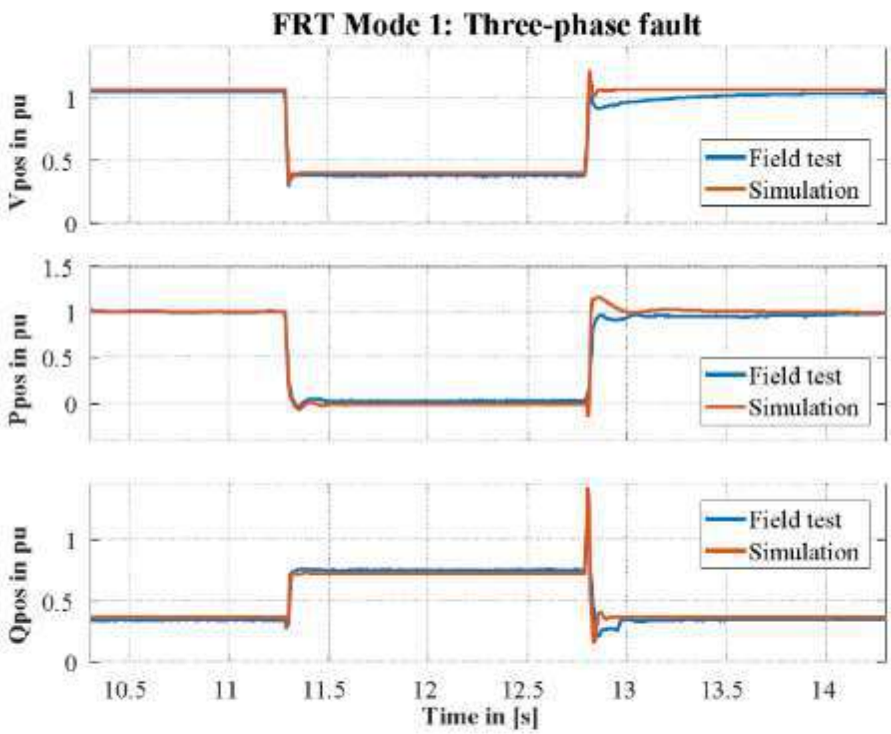

Figure A.8: Simulations and field test validation for a symmetrical fault

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 Inverter and specific PV plants[54]. It implements the control architecture developed by WECC. The model features both a detailed (switching model) representation of a PV inverter as a

[54] https://www.esig.energy/wiki-main-page/user-guide-for-pv-dynamic-model-simulation-written-on-pscad-platform/

current source inverter (CSI) and the average model where the controlled IGBT switching was replaced by an infinite switching frequency leading to a pure sinusoidal output from the CSI, which also allowed use of large solution time step 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.

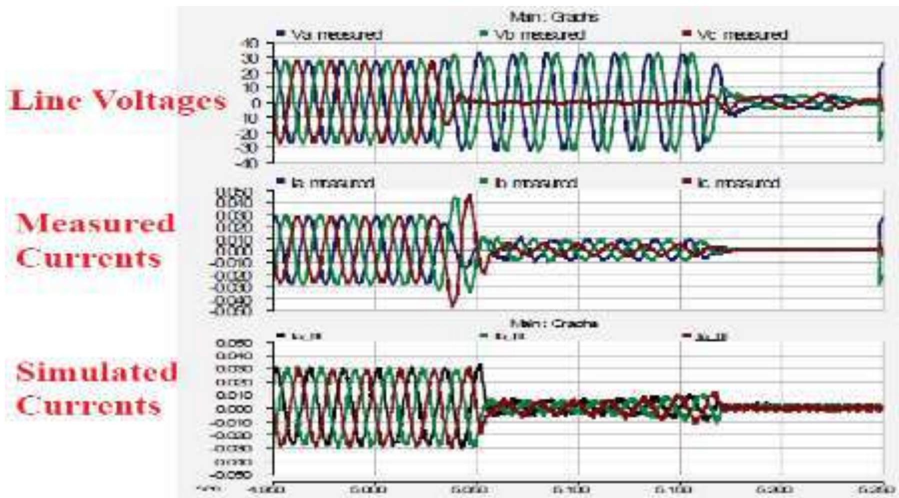

Figure A.9: Comparisons between calculated and measured parameters using a detailed, switching model [3]

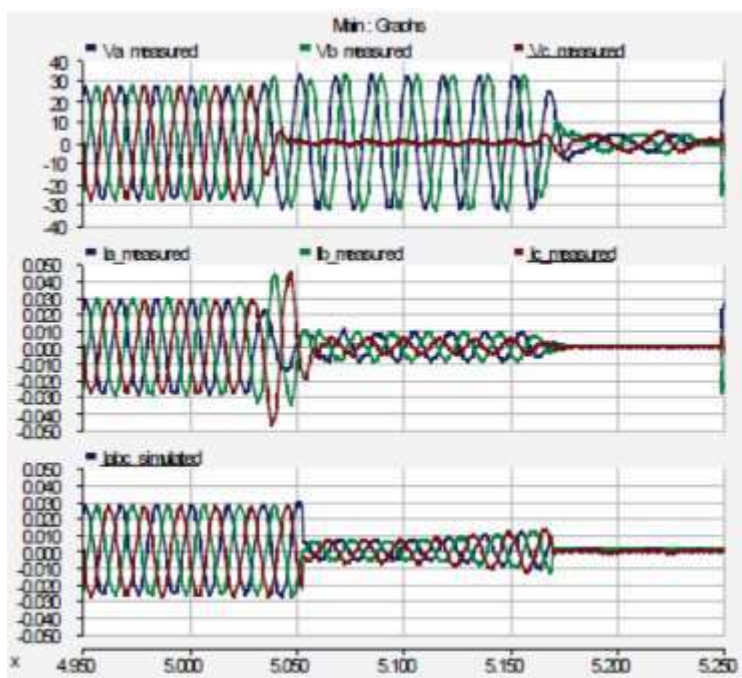

Figure A.10: Comparisons between calculated and measured parameters using an average converter model

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: Example

More Details on Aggregated and Non-aggregated 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 adherence to power-frequency standards, but it cannot be utilized 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. While a typical plant consists of several hundreds of individual units be it 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, 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.[55,56,57,58]

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 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[59]. 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, optimization methods. Similarly, for the equivalent collector network model, there are four main approaches: voltage deviation method, current injection method, power loss method, circuit transformation method. 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 had been developed several years ago[60]. Similar to the criteria described above for PV plants, several methods to grouping wind turbines exist as follows: based on the diversity of the wind speeds, turbine types, impedances, control algorithms, transformer sizes, and based on the short circuit capacity.

[55] WECC REMTF Generic solar photovoltaic system dynamic simulation model specification, September 2012.

[56] 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.

[57] 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.

[58] 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.

[59] 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.

[60] 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, it is to be noted that any type of aggregated IBR plant models need to be appropriately validated for the use cases that they are used as there are some specific use cases like protection and fault ride-through studies where 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, variation of collector cable impedances. These factors could result in variation of power produced by the various units as well as 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 or imbalances[61,62].

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 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 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 is a power plant controller (PPC) present in the PV plant.

[61] WECC, 2014. WECC solar plant dynamic modeling guidelines, WECC Renewable Energy Modeling Task Force. [Online].

[62] 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.

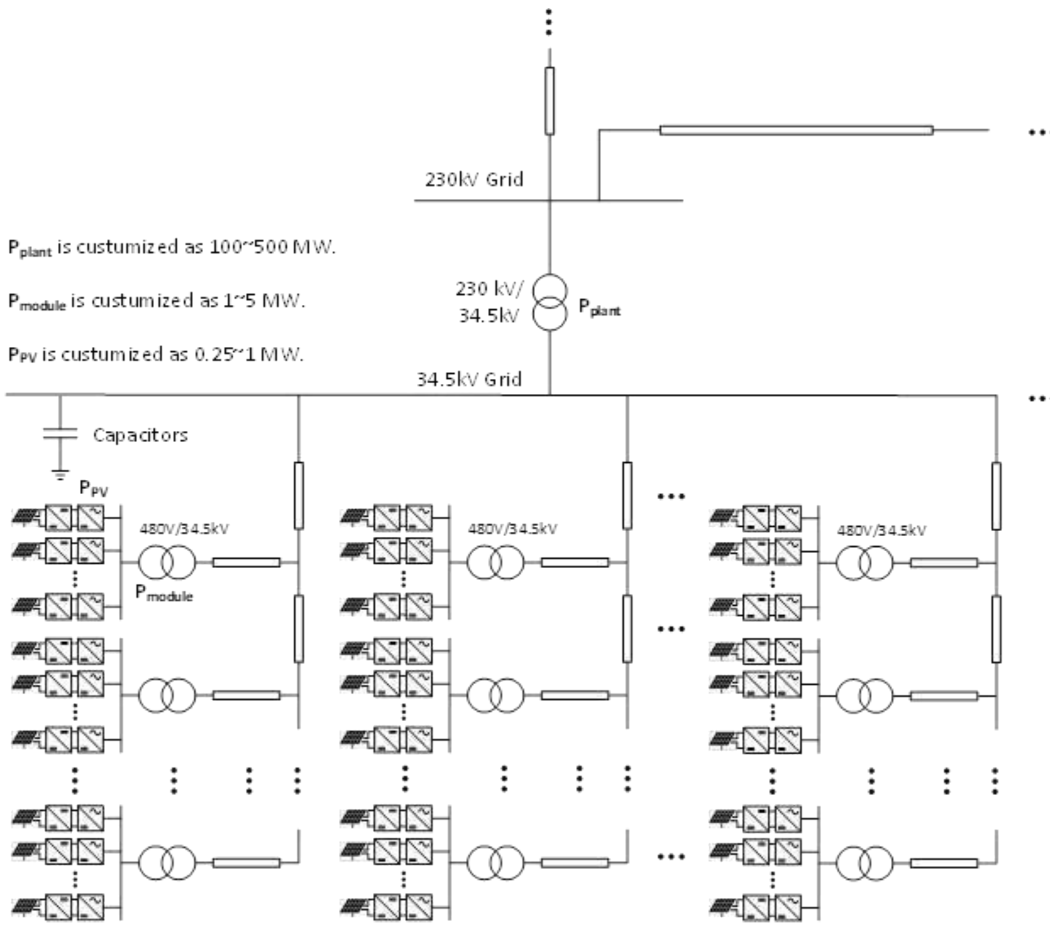

Figure B.1: Configuration of a large PV plant in medium-voltage (e.g., 34.5 kV) distribution system connected to high-voltage (e.g., 230 kV) transmission system.

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 a LCL filter. The PV inverter module is illustrated in Figure B.2. Additionally, different types of inverters have been considered in the models (that is typically 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 implemented in a multi-rate implementation, similar to the field implementation where the controller is implemented in 50-100 µs.

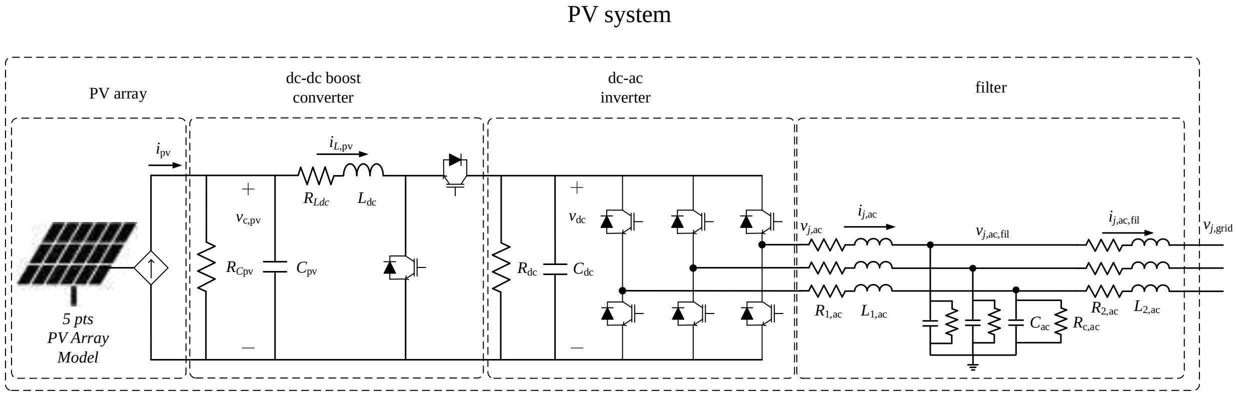

Figure B.2: Configuration of PV inverter module.

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 5 inverter modules may be connected. The PV system is shown in **Figure B.3**.

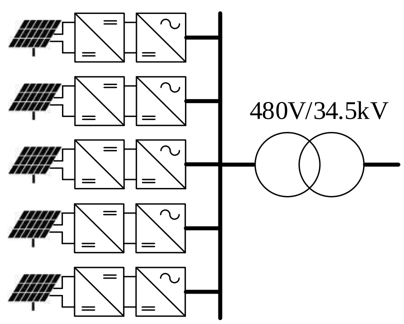

Figure B.3: Configuration of multiple PV inverter modules through a distribution transformer (PV system)

Collector System Model

The collector system[63] within the PV plant is modeled considering the lines, cables, shunts, and transformers that may be present. The lines and cables are modeled using pi-section model and the transformers are modeled using T-type model. A detailed model of the PV plant models includes the collector system with all the PV systems present[64].

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 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 analysis should be extended to the region 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

[63] Sometimes referred to as *plant distribution grid*

[64] 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 integrated model are shown in **Figure B.4**. These results are very similar to the results observed in the NERC report of the event.

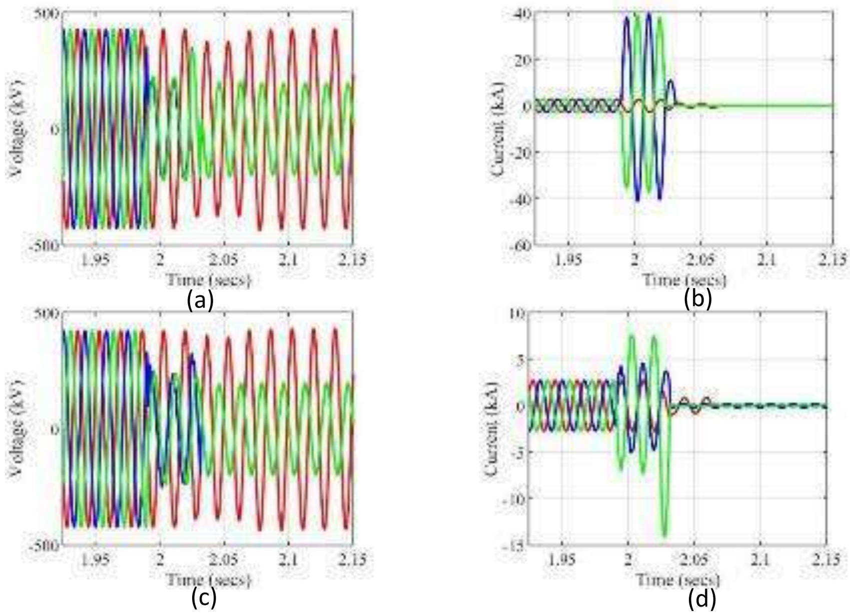

Figure B.4: Simulation results from the integrated EMT high-fidelity model (grid-plant) during line-to-line fault: (a) voltages at the near end of the faulted line; (b) currents at the near end of the faulted line; (c) voltages at the remote end of the faulted line; and (d) currents at the remote end of the faulted line.

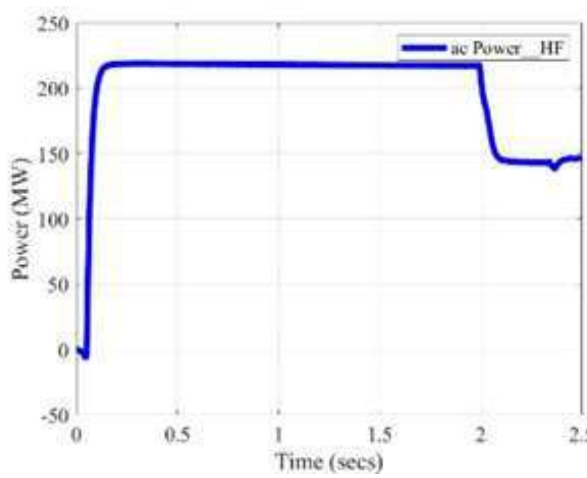

Figure B.5: Active power (in megawatts) from simulation of a high-fidelity switched model of a PV plant with all the inverters represented in electromagnetic transient simulations.

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 reduction observed in the power arises 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 using EMT simulations to replicate field event with trips in IBRs recurrently being observed in the field[65]. 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.

[65] 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 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 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) switching model of each wind turbine converter, 3) 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 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.

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 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 shows a comparison between the simulation time of a full wind farm of more than one hundred 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	-

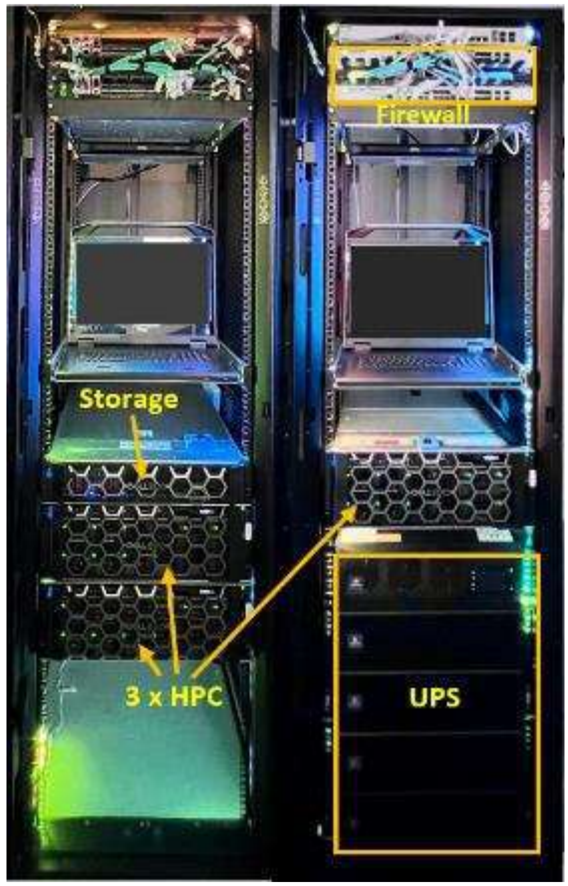

Figure C.1: HPC setup in IBME lab [Source: IBME]

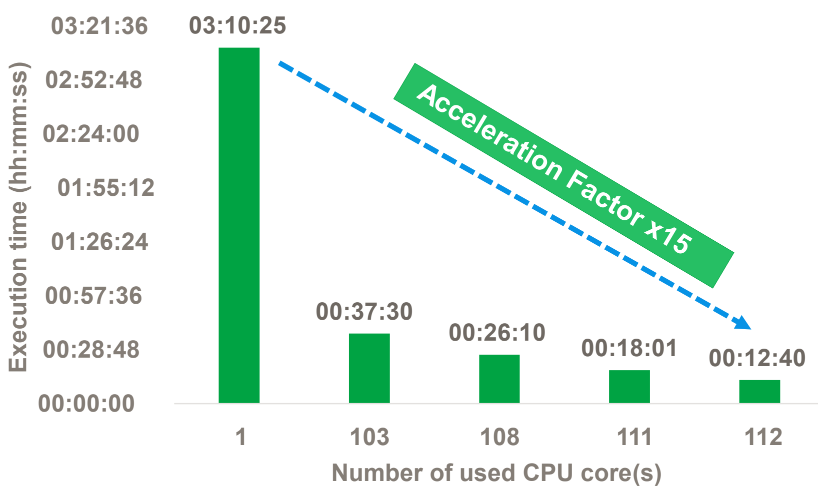

Figure C.2: The simulation time using different numbers of cores [Source: IBME]

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 modelled 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 components. The computing time with a time-step of 50 µs for 1s of simulation on a single core is 275 s. It reduces to 55 s 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

Method 1: Accelerating EMT Simulation using Offline EMT Tool

The following example presents the simulation of the very large Hydro-Quebec grid. A top-level view is presented below.

Figure C.3: Hydro-Québec Power System Example in EMT (Offline)

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 transformers, 23181 RLC branches
- 860 PI-line models, 398 CP-line models
- 3675 ideal switches (e.g. circuit breakers)
- 174 arresters, 99 nonlinear inductances
- 349 synchronous machines with magnetization, exciter, and governor controls
- 2701 PQ loads
- 10 static var compensators
- 56202 control diagram blocks (e.g. each gain is considered as a block)
- Total number of electric nodes: 29803

The computing time for 1 s with a time-step 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 on accuracy. Discontinuity treatment is enabled for switching devices.

It is remarkable that this simulation does not require any user intervention. What is drawn in the schematic diagram is what is simulated. It starts with an integrated load-flow solution that initializes immediately the time-domain computations. Perfectly flat frequency is achieved. A fully iterative solver is used for nonlinear models. The control block diagrams are solved directly with an algebraic loop solver. 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. 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 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 us	
Components	**Quantity**
Three-phase buses	1666
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 15s 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 grid model clearly demonstrate the scalability of parallel EMT simulations. 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 simulation capacity.

Example 3: Modeling 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 battery energy storage systems (BESS), known as Grid Booster (GB), has been proposed to increase the capacity of the main 500kV 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, Center South is shown below. This system has been studied using a wide-area EMT model.

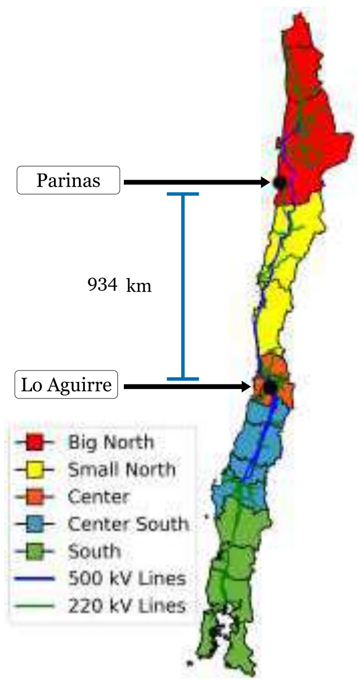

Figure C.4: Chilean Power System Example in EMT

Due to large numbers of IBRs 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. This TLM-based approach allowed to achieve a performance of 13 s for 1 s of simulation with a time-step 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.

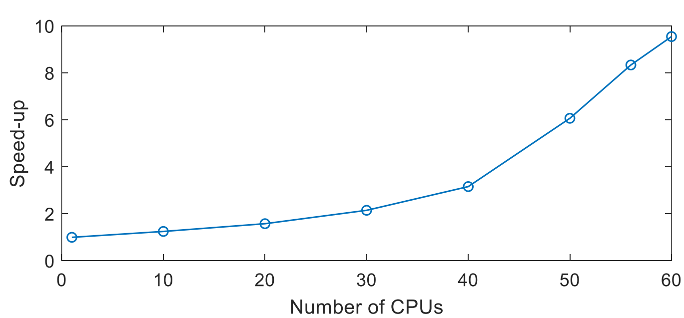

Figure C.5: 1.15 Scalability with increasing # of CPUs

The complete network includes:

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. 57708 control diagram blocks
6. Total number of electric nodes: 6785

Example 4: Modeling Very Large 4000-Bus Australian System

A recent case study of a 4000-bus EMT benchmark that was developed based on a synthetic model of the Australian electricity network[1]. 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 (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 particular, a High-Performance 128-core Windows computer interconnected to 22 high-performance 18-core computers. 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**.

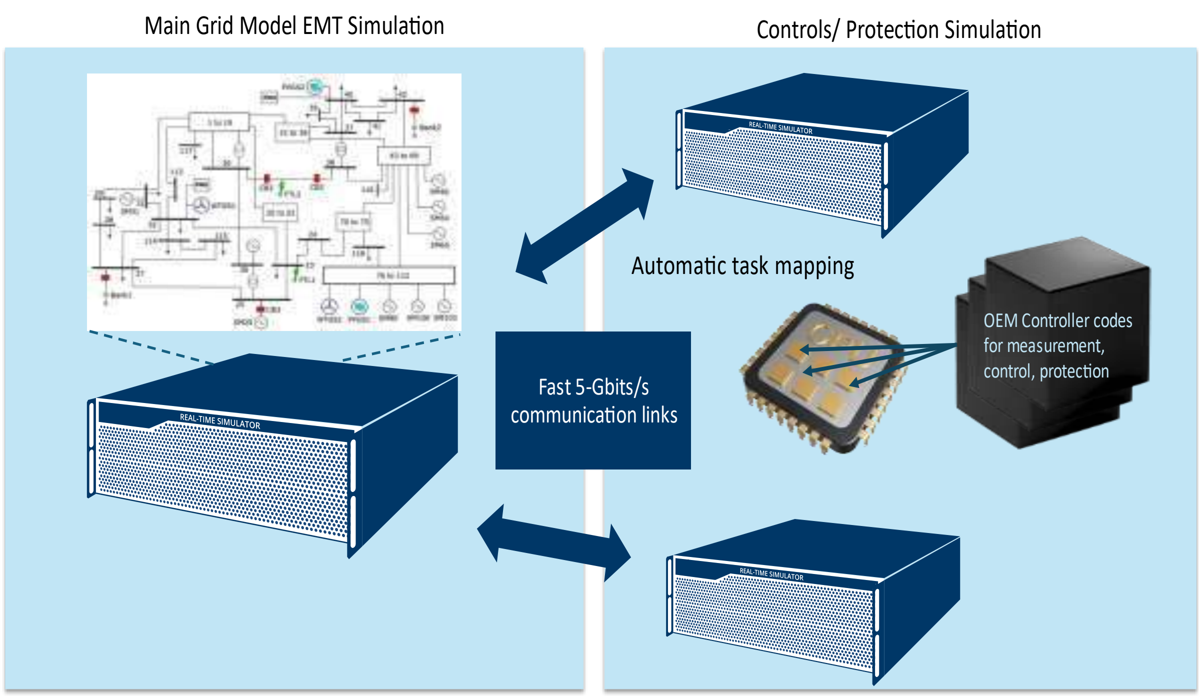

Figure C.6: Multiple Simulator, Multi-Core CPU Real-Time Simulation Architecture for Accelerating EMT Simulation

It is to be noted in 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 the potential for reaching real-time performance. Regardless, this setup showed a significant performance improvement (30 s of simulation in 90 s 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 exceeding, 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 EMT benchmark components list

Component	Approximate # of components
Buses (3-phase)	4000
Lines, loads, switched shunt reactors	6700
Transformers and synchronous machines	2000
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) 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 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 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 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 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 EMT models from potentially disparate sources, or extract them from prior studies.
    - Verify 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 down model documentation
    - 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 (IROL) impact which may expand the study area model making it challenging for EMT tools.

Establishing mature processes to support EMT analysis in operations space has knock-on benefits that extend to any point in the life cycle of an inverter-based resource that requires EMT analysis. For example, an actively managed EMT model repository can benefit the generation interconnection process by reducing time and effort required to collect, process, and validate EMT models of resources near a future project under study.

Additional References

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[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

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[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: Performing EMT Studies – When, How, and What
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, FERC accepted the NERC proposed approach for evaluating Reliability Guidelines. This evaluation process takes place under the leadership of the RSTC and includes:

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

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

Guideline Effectiveness Survey [insert hyperlink to survey]

Errata

Date: Example text here. Example text here. Example text here. Example text here. Example text here.

NERC
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Reliability Guideline: Recommended Practices for Performing EMT System Studies for IBRs

EMTTF Work Item #2

Aung Thant, Senior Engineer, EMTTF Coordinator
RSTC June Meeting
June 11-12, 2024

NERC IBR Strategy

Risk Analysis	Interconnection Process Improvements	Best Practices and Education	Regulatory Enhancements
Event Analysis	Improvements to GIAs and GIP	Reliability Guidelines	NERC Standards Projects
Disturbance Reports	Enhanced Interconnection Requirements	Webinars and Workshops	BES Definition Review
Alerts	Modeling and Study Improvements	Outreach and Engagement	Inverter-Specific Requirements and Standards
Lessons Learned	IEEE 2800-2022	Emerging Reliability Risk Issues	Risk-Based Compliance

EMT Modeling Adoption

Odessa disturbances,
San Fernando disturbance,
2021 CA disturbances

EMT SAR
Project 2022-04

Stage 1
Establishing EMT Model Requirements

Stage 2
EMT Model Quality Verification

Stage 3
EMT Model-based Plant Performance Assessment

Stage 4
Screening and Integration in Interconnection Process

Stage 5
Conducting Interconnection & Planning Studies
(where necessary)

Reliability Guideline: EMT Modeling for BPS-connected IBRs: Recommended Model Requirements and Model Quality Verification March 2023

Draft Reliability Guideline: Recommended Practices for Performing EMT System Studies for IBRs

Purpose

- Equip transmission planning engineers and other industry engineers with the necessary knowledge to know when and how to study the impact of IBRs on the BPS with detailed equipment specific EMT models within the EMT simulation domain.
- 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, etc.

Overview of the Guideline

- Chapter 1: When to Perform EMT Studies
  - Low System Strength
  - Stability Criteria
  - System Topology or Conditions Conducive to Instability
  - Post System Events
- Chapter 2: How to Select Study Area to Be Modeled
  - Study Area Selection
  - Determining Which Dynamic Devices to Include in the Study Area
- Chapter 3: How to Model Study Area and Surrounding External System
  - Modeling of Study Area
  - Modeling of External System
  - Static and dynamic voltage sources
- Chapter 4: System Base Case Model Validation
  - System Model Validation – power flow, fault current, dynamic response, field events
- Chapter 5: Study Scenarios
  - Considering the most critical contingencies and the worst-case operating conditions in which less grid stabilizing characteristics are available, such as system strength, inertia, and damping

Overview of the Guideline

- Chapter 6: Three Types of EMT Studies
  - Dynamic System Impact Assessment Study
    - EMT Analysis: Stability, Ride-Through and Post-Disturbance Performance, Harmonic Distortion / Flicker, Transient overvoltage and overcurrent
    - Simulation quantities to monitor
    - Processing Results
    - Comparison to Phasor-Domain Transient Stability
  - Subsynchronous Oscillation Studies
    - Full Power Converter Systems (FSCS) Turbines
    - Doubly-Fed Induction Generator (DFIG) Turbines
    - Subsynchronous Control Interaction
    - Subsynchronous Ferroresonance
    - Real-World SSO Event Study Framework
    - Case Study of Kauaʻi Island Power System 18-20 Hz Oscillations
  - Transmission System Protection Validation
    - Objective
    - Methodology
    - Examples
    - Summary

Overview of the Guideline

- Chapter 7: Additional Guidance on Modeling of IBR Plants
  - Modeling of Legacy Wind Power Plant
  - Hardware in the Loop (HIL) Validation of Existing IBR Plant Models with Field Measurements
  - HIL Validation of new IBR Models
  - A Spectrum of Model Fidelity for Different Study Use Cases
    - Inverter Control Models
    - Inverter Electrical Models
    - Overall Plant Models
  - Modeling and Testing of Protection System Elements of an IBR Plant
  - Validation of Equipment Specific IBR Models from OEMs
    - Guidelines on OEM IBR model integration
  - Importance of Measurement Models
- Chapter 8: Accelerating EMT Simulations
  - Techniques Used for Accelerating EMT Simulations
    - Multi-sampling rate or multi-time-step simulation
    - Co-simulation with hybrid simulation
    - Aggregation and equivalency
    - Using relaxed models for phasor portion
  - Best Practices for Developing Large EMT Models
  - Looking Forward – Challenges with Speed and Scalability of EMT Simulations

Overview of the Guideline

- Appendix A: Additional Materials on Legacy Plant Modeling
  - Development of a Generic EMT Model from Existing Positive Sequence Model
  - Tuning and Validating Generic EMT Models using Field Disturbance Data
- Appendix B: More Details on Aggregated and Non-aggregated Model Use Cases
- Appendix C: Real-World Case Studies for Leveraging Parallel Computing to Accelerate EMT Simulations
  - Example 1: Modeling A Full Wind Farm: An Example with Large Number of IBRs
  - Example 2: Modeling Hydro-Québec High-Voltage Transmission Network
  - Example 3: Modeling Chilean Grid
  - Example 4: Modeling Very Large 4000-Bus Australian System

Drafting and Review Process

- Multiple touch-points with IRPS from scoping
- Diverse drafting team

Timeline	Event
July 2023	Initial scoping
August 2023	IRPS review of scope
February 2024	1st draft
March 2024	IRPS review of 1st draft
May 2024	2nd draft
May 2024	IRPS consensus to post for public comment 13 “Yes”, 0 “No”

Project Schedule

Task	Target Date	Comment
IRPS Consensus	May 2024	Presented **Draft v2** at May IRPS meeting and get consensus to post for industry public comment period Send copy to RSTC coordinator
RSTC Review and Acceptance to Post for Industry comment	June 2024	Present and obtain acceptance at June RSTC meeting.
Post for industry comment	+ 45 days	Collect, review and incorporate comments as they arrive, especially 2-3 weeks before the comment period closes
3rd Draft	End of September 2024	Incorporate industry feedback. Drafting team may need to meet more frequently around this time. Send redline to IRPS 1-2 weeks before IRPS Oct meeting
Present Final Draft to IRPS	October 2024	Present final draft at October IRPS meeting and get consensus to move to RSTC approval
Materials for RSTC Meeting Due	November 2024	Materials due one month before RSTC meeting.
RSTC Review and Approval of Final Draft for release	December 2024	Present and obtain approval at December RSTC meeting.

Action

- EMTTF seeks RSTC acceptance to the draft guideline for public comment.

Questions and Answers

ERAWG Technical Reference Document: Considerations for Performing an Energy Reliability Assessment: Volume 2

Action
Approve to post for 45-day comment period.

Summary
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.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Technical Reference Document: Considerations for Performing an Energy Reliability Assessment

Volume 2

May 2024

RELIABILITY | RESILIENCE | SECURITY




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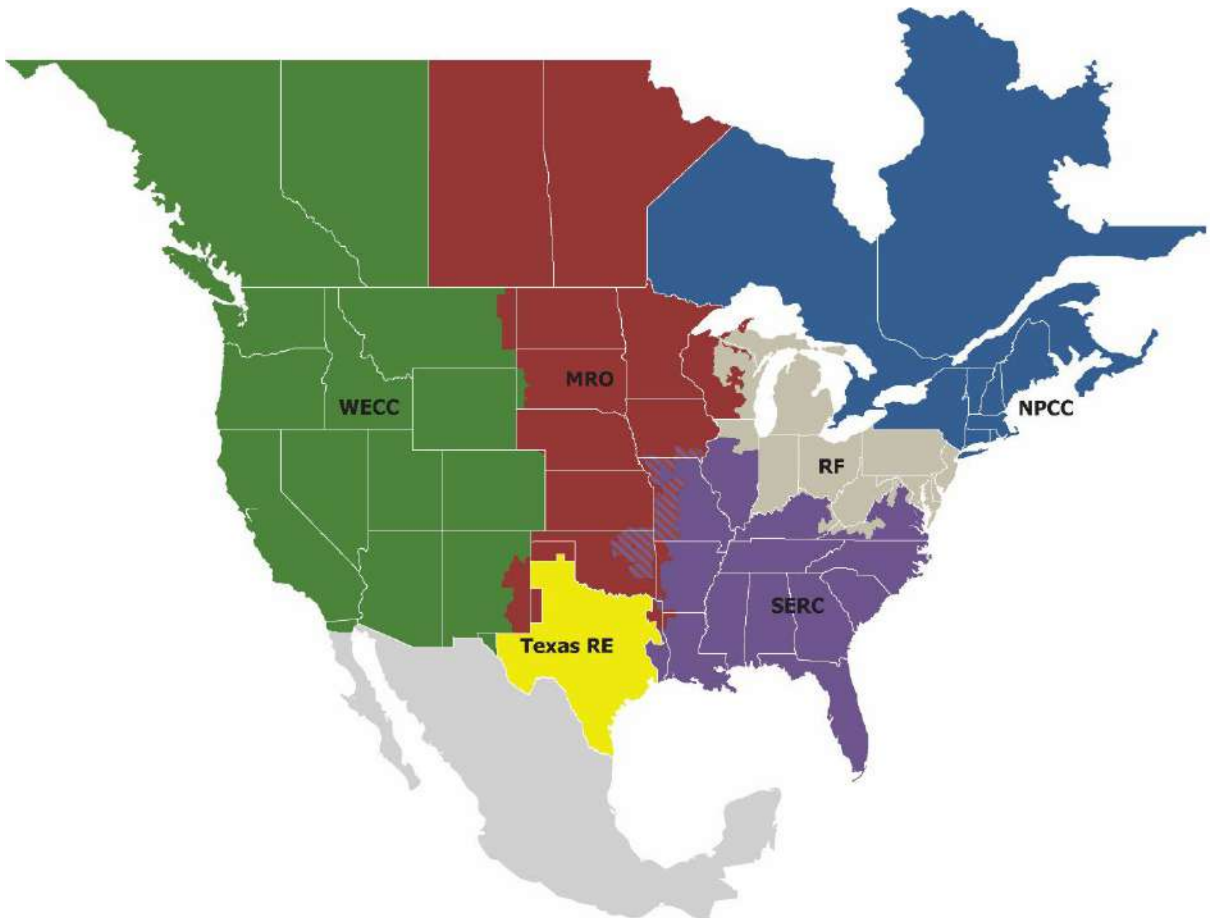
Table of Contents

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") was published in March 2023. It provided an overview of the basic elements of an Energy Reliability Assessment (ERA) and general considerations for performing an ERA. In this volume, details of how to perform an ERA are introduced and discussed, including different methods that can be used to build 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 not to dictate how an ERA is to be performed but to highlight inputs that should be considered when performing an ERA.

There are 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 the Reliability Guideline, 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 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, 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 first, then the applicable chapter for the time horizon being assessed. Following Chapters 1 through 4, there are separate discussions on methods (Chapter 5), case development and scenario modeling (Chapter 6), and metrics (Chapter 7). The discussion on methods will help in the development and design of tools. Case development and scenario modeling discusses a recommended approach for Base Case and 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.

It is acknowledged that, throughout this technical reference document, there are significant differences across North America in terms of available factors that may play a role in promoting energy reliability. To that point, an array of suggested solutions is 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:

- Generating capacity and density (e.g., how much and where) of wind and solar resources are a primary driver for the high degree of diversity among regions, including the performance characteristics for each (e.g., certain areas, such as southwestern United States, are more amenable to highly productive solar resources than those in the north).
- Fuel storage capabilities and capacities of fuel oil, coal, liquefied natural gas (LNG), and nuclear fuels differ across regions, but also within regions depending on their geographic size. By having limited reliance on stored fuels, a region 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.

[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

- Fuel replenishment delay times and diversity of options impact specific factors of an ERA. Longer time delays between arranging and receiving fuel deliveries would drive a need for a longer period of time to be studied, and vice versa, so that reaction to the results can be meaningful.
- Capacity and diversity of the available supply from pipeline natural gas to generation can impact the input assumptions to an ERA. These differences would factor into scenario selection. With a high degree of diversity in supply, 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 to the next may play a role not only in the options available for correcting energy deficiencies but would 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 applies across different systems.

The appropriate actions resulting from identified deficiencies found in ERAs may also differ, based on the items discussed above. Longer lead times may be required for energy deficiencies than capacity deficiencies. 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. Storage optimization over periods of time become part of the solution as VERs fluctuate outputs throughout a day, week, or a longer period.

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 is used to perform 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 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. Accurately modelling 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 as either stored fuels or just-in-time fuels. Stored fuels have tangible inventory and replenishment strategies to consider. Just-in-time fuels require considerations for transportation capacity and the immediate impact of disruptions. Further, just-in-time fuels include weather-dependent fuel sources such as solar irradiance and wind that introduce significant volatility for an analyst to account for.

Power generation is not the only consumer of fuel. Specific fuels (e.g., fuel oil and natural gas) are 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 American Community Survey[6], which includes information on the type 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 an analyst guide the building of future profiles of demand for input into an ERA.

For a more detailed introduction to fuel assurance that is specific to a variety of fuel types, refer to *Reliability Guideline: Fuel Assurance and Fuel-Related Reliability Risk Analysis for the Bulk Power System*[7]

Stored Fuels

Power generators with stored fuels are those where inventory of fuel is on-site or reasonably close to the generator such that risks to the transportation of that fuel to the generator are minimal. Fuels are stored in tanks or piles and have a measurable inventory. Examples are nuclear, fuel oil, coal, hydro facilities with pondage, and LNG.

Once inventory information is gathered and/or assumed, 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

[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] https://data.census.gov/table/ACSDT1Y2019.B25040?q=heat
[7] https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Fuel_Assurance_and_Fuel-Related_Reliability_Risk_Analysis_for_the_Bulk_Power_System.pdf

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 walks through a conversion from gallons of oil to MWh of electrical energy and the amount of time that it would continue to operate at a specific power output.

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 Electrical Energy

Multiple generators at a single site often share fuel inventory where more than one generator could deplete fuel during operations. This is further complicated when there are different generator technologies with different efficiencies 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 fuel supplies at sites provides for a more accurate solution than generalizing that relationship.

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 generator stations that are adjacent to larger storage facilities have fewer obstacles to replenishment that 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 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. 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 generator owner/operators, the specific fuel information can be obtained and properly accounted for through routine surveys.

The following information 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[8] 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, DO limitations, etc. Stored fuels may be used for unit start-up with a portion embargoed for black start service provision
Minimum consumption requirements of fuels that have shelf-life limitations	Surveys of generator owners or operators Assumptions based on Historic 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

[8] 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**
Global shipping constraints	Industry news reports	Stored energy supply is often impacted by world events that cause supply chain disruptions. This includes port congestion, international conflict, shipping embargoes, and confiscation
Localized shipping constraints	Weather forecasts or assumptions, direct communication with local transportation providers, emergency declarations[9]	Considerations for local trailer transportation of fuels over wet/snow-covered roads as well as seaport weather when docking ships.

Fuel Oil Specific Considerations

Fuel oil for generators, diesel fuel for transportation, and home heating oil all share supply chain logistics. There are subtle differences between each type, but at the supply side, they are nearly identical. Since they are the same, stresses on supply from one mechanism can lead to deficiencies in supply to a seemingly unrelated mechanism. The most likely scenario is that cold weather requires higher demand on home heating oil, creating 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.

Fuel oil that is delivered by truck can face a number of obstacles. Truck drivers are limited to the number of hours that they are legally allowed to drive[10]. 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 rules with specific conditions have been requested and granted by state and federal agencies[11].

Delivery by ship or barge may be available to resources with access to waterways. Waterborne cargoes are typically larger 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 nearly 4 million gallons. The largest oil tankers can transport over 50 million gallons of fuel[12]. Challenges in delivering by water include rough seas and waterway freezing.

Representing 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 example sets the initial tank level equal to the actual (or assumed) starting inventory plus all

[9] https://www.fmcsa.dot.gov/emergency-declarations
[10] https://www.ecfr.gov/current/title-49/subtitle-B/chapter-III/subchapter-B/part-395/subpart-A/section-395.3
[11] https://www.fmcsa.dot.gov/emergency-declarations
[12] 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

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. The more complex method accounts 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 depending on the time horizon of the study. Both methods can coexist in the same study. Analysts should consider the appropriate levels of constraints on replenishment capabilities of various oil tanks depending on the attributes of a system under consideration.

Dual Fuel Generator Specific Considerations

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. Consideration should be given to formulate operational models that include the decisions that lead to operations on 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 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 generators that are required to shut down before swapping fuel. 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 be accomplished and the information provided via survey is dependable or vetted for accuracy. Generator owner/operators are the expert in the logistics of fuel swapping and should be consulted when performing an ERA.

Coal Generator Specific Considerations

Coal storage is usually larger than the storage capacity of fuel oil and comes with its own unique challenges. When stored outdoors and exposed to the elements, coal can have different outage mechanisms than 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 be taken to ensure that this assumption is prudent and won't result in unexpected conditions when the fuel supply is depleted or unable to be replenished.

Nuclear Specific Considerations

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 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 advancements in proposed reactor technologies that could change how a nuclear generator would be modeled in an ERA, however most of the operating plants in North America are 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

Pondage hydroelectric "fuel" availability 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 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 which must be well understood while building an energy model and performing an ERA. Just-in-time fuels are delivered immediately prior, or within moments of conversion to electrical 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 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. 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 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 NAESB[13] to be 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 relies on a daily allotment of fuel to be profiled over that 24-hour period. An ERA must consider the limitations that could be imposed by that inconsistency.

Depending on the constraints that are in place on the gas pipeline network for a given region, 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 information concerning the natural gas supply chain, chapter 2 of the NERC Reliability Guideline: Fuel Assurance and Fuel-Related Reliability Risk Analysis for the Bulk Power System, is a valuable reference.

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 that gas demand for heat and industry has a higher level of transportation service (e.g., primary firm) than generation, the equation can be rearranged to solve for gas available for generation, the equivalent of 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 for every region. The simplest form of modeling gas demand would be a linear function of average temperature, or heating degree days[14]. In its most complex form, gas demand modeling can require artificial neural network forecasting models with inputs that include temperatures, wind speeds, day of week, time of year, and any other pertinent inputs that would drive gas demand. A simple example of calculating available natural gas is shown in Example 2.

[13] https://www.naesb.org//pdf/idaywk3.pdf
[14] 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 1,000,000 MMBtu/day, has no additional supply within the area, a fixed quantity of industrial demand of 100,000 MMBtu/day, and heating demand is a linear function of heating degree days from 0 MMBtu/day at 0 HDD and 600,000 MMBtu/day at 75 HDD.

Calculate the quantity of natural gas that would be assumed to be available for power generation at 40 heating degree days.

$$Gas\ Available_{\ Generation} = Gas\ Supply - Gas\ Demand_{Heat} - Gas\ Demand_{\ Industrial}$$

$$\begin{aligned} Gas\ Available_{\ Generation} \\ &= 1{,}000{,}000\ \frac{MMBtu}{day} - \left(600{,}000 * \frac{40\ HDD}{75\ HDD}\right)\frac{MMBtu}{day} \\ &- 100{,}000\ \frac{MMBtu}{day} \end{aligned}$$

$$Gas\ Available_{\ Generation} = (1{,}000{,}000\ - 320{,}000 - 100{,}000)\ \frac{MMBtu}{day}$$

$$Gas\ Available_{\ Generation} = 580{,}000\ \frac{MMBtu}{day}$$

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.

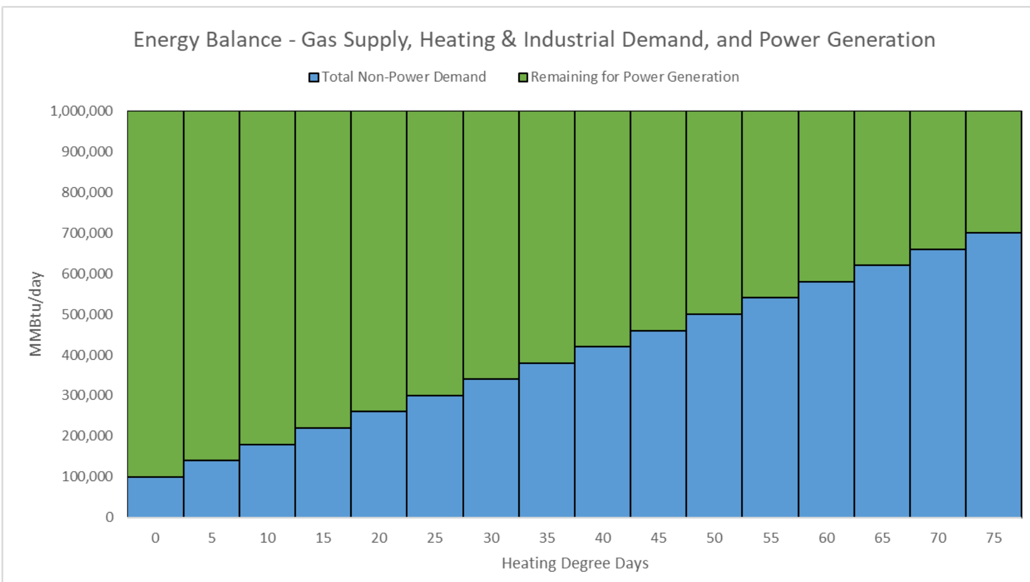
$$Generation\ (MWh) = Gas\ Available /\ Heat\ Rate\ (MMBtu/MWh)$$

$$Generation\ (MWh) = \frac{580{,}000\ MMBtu}{8.0\ MMBtu/MWh} = 72{,}500\ MWh$$

Convert 72,500 MWh to hourly MW, evenly distributed across all hours

$$\frac{72{,}500\ MWh}{24\ hours} = 3{,}020\ MW$$

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 on a network of pipelines will have the potential to impact a number of delivery points, caused by the same event or set of conditions. However, because of the compressibility of natural gas, the downstream effects of interruptions are not necessarily immediate. Studies[15] have shown that there may be significant time between 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 times and ramping capability of generators from offline to high utilization. After the first few hours, once generation is replaced, ERAs should tend to focus on the long term effects of major disruptions and the impact that will have on a generation fleet

[15] https://www.nerc.com/pa/RAPA/Lists/RAPA/Attachments/310/2018_NERC_Technical_Workshop_Presentations.pdf

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 mapping of generators to pipelines. This information can be gathered from pipeline maps, generator surveys, and registration data. Research is required to place the generators on pipelines in the correct location in reference to interconnects, compressor stations, and other pipeline demand. An ERA can then use this information for scenario development and analysis.

The following information is 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	Historic scheduled gas to citygates 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	Some information can be obtained via the EBB Index of Customers, however there is nuanced data that would be needed 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 generate electricity when the fuel is available, and conditions permit. There is no certainty to the amount of energy produced by these resources at any given time and operators cannot require that the generators produce more power when limited fuel will 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, which would 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 output of VERs. For regions 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.

Energy Supply Variability

Several components of energy supply variability have been mentioned already in this technical reference document, stressing the need for ramping capability. Just-in-time fuels are subject to large- and small-scale fuel supply interruptions (including clouds over solar panels, calm winds, and gas network outages). Variability of one fuel supply creates a stress on other fuel supplies or 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. 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 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 near-term ERA to best evaluate the energy reliability risk. Using probabilistic methods can enable the assessment to ensure 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 design basis which stress the system to determine if sufficient energy is available in the time horizon being studied. To support near-term ERAs, 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.

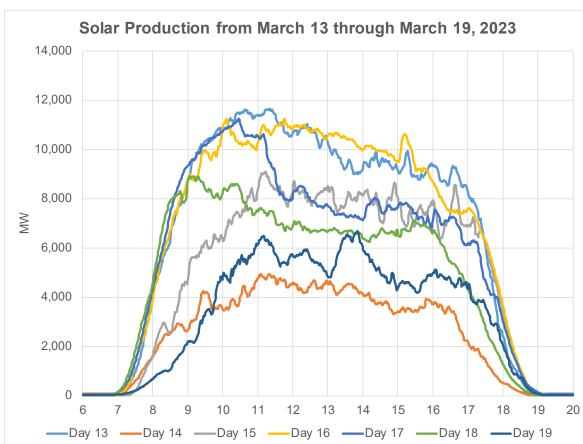


Figure 1.3: Actual solar production for seven consecutive days

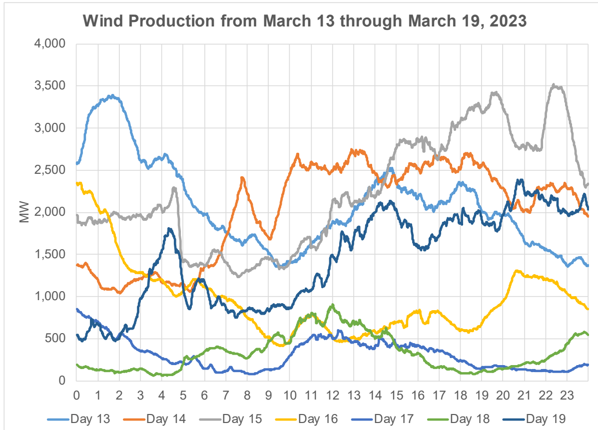


Figure 1.4: Actual wind production for seven consecutive days

Evaluating that capability requires knowledge of fuel supply constraints and specific generator capabilities. For example, in a situation 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 ramps up to replace solar power. Consideration should be made to determine if gas pipeline pressure would remain in tolerance 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 pressures. Pipeline pressure will be maintained by pipeline operators by limiting the rate at which their demand is allowed to fluctuate. This constraint may limit flexibility of natural gas resources beyond what is expected. If fuel systems are unable to keep up with ramping generation, the ramping generation should be discounted at that point. 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 generally can ramp their output down faster than it can ramp up, and some variable resources can be curtailed if a system reliability risk emerges. However, the considerations for pipeline pressures and electric 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, the solar over generation results in the need to back down other supply resources. Additionally, generation problems can arise if gas pipeline pressures are already high, and storage is full, resulting in pipeline constraints. 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 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 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 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 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 from all industries, including power generation, which can limit generator capability completely or concentrated at specific times. 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 points and require evaluations prior to binding on the constraint. Also, 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 analyst performing the ERA (e.g., MWh remaining until emissions constrained rather than tons of CO_2 remaining without a conversion from emissions to electrical 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 have multiple components to them (e.g., NOx, SOx, and CO2), all of which must 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 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 limitations such as required minimum 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.

The following information 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 analysis performing the ERA would be the centralized collection point of the information required to accurately model the limit.

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 conditions. It should be noted, however, that even probabilistic approaches to outage modeling can exhibit a large amount of 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.[16]

Information on generator outages is available through historical data analysis, either through operator logs, operational data, or the NERC Generation Availability Data System (GADS)[17].

In an ERA, it is important to 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.

[16] https://www.epri.com/research/products/000000003002027832
[17] https://www.nerc.com/pa/RAPA/gads/Pages/GeneratingAvailabilityDataSystem-(GADS).aspx

In reality, forced outages are more complex than typical modeling techniques allow. 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 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 comprised primarily of the same types of resources that were discussed in prior sections (e.g., VERs), but have different considerations associated with them being distributed. 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[18]. 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), receive market revenue for participating in the regions, and are typically governed by an agreement between the participant and the ISO/RTO. The development of an ERA must consider these market rules and understand how participants will behave in certain situations. These resources have an expectation to perform

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

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, and there will be other resources who tend to profit more if they're priced further away from the marginal unit. This profitability may change the way a generator is positioned for dispatch, such as increasing their notification-to-start time to avoid staffing their facilities 24/7. Another example would be if a given region's agreements have severe penalties for generators who are not running during a constraint period. To avoid incurring penalties, non-intermittent 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, both out-of-market and non-power, held by generating units that impose take-or-pay or force majeure penalties. 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 demand has components of actual demand, 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 through 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, price responsive loads etc., which can significantly vary the shape of typical hourly demand. Also, as electrification (e.g., electric vehicles and heating) expands within a specific footprint, the analyst would need to make assumptions of the EV charging patterns and other changes to load profile due to electrification of heat or industry. Charging assumptions would differ by seasons and would be different from assumptions made for air condition units and heating sources, which are season specific. Electric vehicles and charging assumptions would also have an impact on predicting demand.

Demand is more versatile than it once was. Demand response programs have been designed to preempt the buildout of additional, or 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 but may not change the overall energy demand on the system. Loss of load diversity without a longer-duration change to temperature set points 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 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. 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 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, 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 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 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 (SDES) or as Long-Duration Energy Storage (LDES)[19], 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 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 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.

SDES can be used for frequency regulation, energy arbitrage, and peaking capacity. These resources include smaller batteries[20], less than 4 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)[21]. For SDES with duration closer to 4 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-Day LDES includes resources with capability 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 can be called on when renewable resources (solar and wind) are not able to produce power for several hours. For example, Inter-Day LDES 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

[19] https://liftoff.energy.gov/long-duration-energy-storage/

[20] As with all inverter-based resources, it is critical to know if the storage resource functions under Grid-Forming or Grid-Following technology.

[21] ACE is defined by NERC in BAL-001-2 (https://www.nerc.com/pa/Stand/Reliability%20Standards/BAL-001-2.pdf)

lower demand periods and as a fixed discharge/generation at normally higher demand periods. The more standard and 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 comprised 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, for example, wind or solar resources unable to generate energy due to weather systems that reduce wind speeds or solar irradiance for extended periods of time.

Seasonal Shifting LDES is storage that holds energy produced in one period to be used weeks or months later. Currently, Seasonal Shifting LDES is focused on "Power-to-X"[22] 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, co-located, or hybrid/storage resources, which can further complicate 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 to a project or to retrofit. Modeling these resources in 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 being used in many cases to shift available energy from low demand periods to high demand periods, or 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 towards 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 is useful for modeling electric storage in an ERA for any time horizon.

[22] 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 defined the primary characteristics of a storage device.
Usable Capacity	Registration data, operational data	Battery storage may not operate well above and below specific charge percentage. For example, batteries charged above 80% or below 20% may under perform. Therefore, the storage capacity may be less that 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 stand-alone configuration. Charging source – primary and secondary	Registration data	Scenario studies may remove a generation type (i.e., solar) which may eliminate the energy supply source.
Ambient temperature limits	Registration data, operational data	This is 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.

Table 1.5: Information Useful for Modeling Electric Storage in an ERA in Any Time Horizon		
Data	**Potential Sources**	**Notes/Additional Considerations**
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. Transmission constraints place limits on how much power can be transferred. ERAs must 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 diving the region zonally. Calculation of specific transfer limits are required by NAESB Standards and are a well-known quantity. 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, there must 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.[23]

Other considerations for transmission capability include grid enhancing technologies, such as ambient adjusted ratings, dynamic line ratings[24], controllable ties, priority to access, and recallable transactions / cutting assistance. These considerations will change the way that imports, exports, and additional transmission usage is modeled in an ERA. Ambient Adjusted Ratings (AARs) 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 which 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) which create must-run conditions for generators should be incorporated into the ERA. For example, must-run condition of hydroelectric generation (to mitigate thermal overloads or under-voltage 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 for when resources are not available due to energy constraints. Additionally, using limitations on imports and exports would factor into the neighboring area ERAs as well.

The following information is useful for modeling transmission in an ERA for any time horizon.

[23] 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. 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

[24] To draw distinction between Ambient Adjusted Ratings and Dynamic Line Ratings, Ambient Adjusted Ratings are a function of forecasted temperatures which can be used in real-time and near-term operations planning and are defined in FERC Order 881 and Dynamic 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
Planned Outages and Maintenance	TOPs, TPs, or other transmission planning entities	
Import/Export Transport 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 regions
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 GADS	Ideally, weather dependent and unit 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 critical limitation 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 in a model.

Labor availability is also an item that may need to be considered at various points in the performance of 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 trades personnel over a holiday weekend. In longer time horizons, labor availability may drive uncertainty in both maintenance and construction scheduling leading to the potential of 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 is considered to look at a timeframe that starts about 1-2 days out and look 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[25]. 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 and can be included in registration data or gathered through generator surveys. Additionally, forecast information may be necessary for BAs 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 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.

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 is useful for modeling natural gas supply in a near-term ERA.

[25] https://www.nerc.com/pa/Stand/Reliability%20Standards/TOP-002-4.pdf

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. NAESB sets five standard cycles that are to be followed by FERC jurisdictional entities (which generally excludes intrastate pipelines and local distribution networks)
Natural gas commodity pricing and availability	Intercontinental Exchange (ICE)[26], Platts[27]	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.

Variable Energy Resources

Modeling VERs 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 the near-term horizon, the forecast error of VER production can be high. The energy available from VERs are based on the following:

1. VER capacities,
2. geographical location of installed VERs,
3. typical forecast errors of wind, solar, and weather,
4. the capacity, configuration, and transmission capacity of co-located energy storage,
5. outage rates of resources, and
6. 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 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, derived from global models allowing for specific localized weather to be extracted. Model blending and model improvement efforts generally produce higher accuracy and/or precision. It is up to the analyst to interpret the output of weather models coordinated with VER production forecasts and apply the results to generator performance assumptions in an ERA. The following information is useful for modeling VERs in a near-term ERA.

[26] https://www.ice.com/index
[27] 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 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 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 time period being studied. The following information 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 well 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 analysis 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 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 regional 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 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 high degree of uncertainty when DER installation exceeds a certain point (e.g., a few thousand MW, for a small- to medium-demand region; more for larger regions). The point where the amount of DER has significant impact on the power system is not clearly standardized and must be understood and defined by the analyst performing the ERA. A lack of visibility and ability to benchmark 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 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 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 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 DER 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 don't really change overnight, and the recent past should be very indicative of the near future, adjusted for weather.

The following information 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. Additionally, specific storage inputs are needed to perform an ERA.

The following information 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[28]	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.

[28] 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 looks at 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 period of time longer than a few weeks, but not a full year. Seasons, and their associated risks, are regionally unique and don't necessarily fit into the classic definitions. The analyst should have a good idea of what seasons are experienced by the region 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 there may be unexpected risks in off-peak times (including off-peak hours within days) that would be identified by an ERA and shouldn't be overlooked. Considerations for inputs to a seasonal ERA are described below.

Supply

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.
The following information 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.
Regional 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.

Table 3.1: Information Useful for Modeling Stored Fuels in a Seasonal ERA		
Data	**Potential Sources**	**Notes/Additional Considerations**
Shipping constraints	Industry news reports	Seasonal ERAs could be impacted by current world events that cause supply chain disruptions. This includes 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 an 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 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, 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[29] 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

Modeling VERs in a seasonal ERA can be done using the existing fleet with minor adjustments for outages and expected expansions. 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.

[29] 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

The following information is 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), Historical observations, 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. That 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 seasonal horizon, there should be some 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 period being studied. The following information is useful 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 well 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 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 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 may finish early or overrun.

Distributed Energy Resources

Seasonal ERAs would depend more on historic 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 scaling that is needed to account for some rapid new development.

The following information 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 the information needed for a near-term ERA, DERs are likely to coordinate with distribution system operators, giving 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 forecast, or legislative goals.
Historic 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 must be made based on historic demand and projected load growth or contraction, based on factors such as climate change and economic factors.

The following information 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[30])	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 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. 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 information is useful for modeling electric storage in a seasonal ERA.

[30] 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[31]	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.

[31] 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

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.

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 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 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 combustible fuels over time with vast disparity between state goals. That would shift competing demands for fuel into additional electric demand. As a side note, electrification may not necessarily eliminate the need for combustible fuels, it may 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 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 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 of overall fuel storage	EIA reports	The U.S. Energy Information Administration reports weekly inventories for five Petroleum Administration for Defense Districts (PADD). Trending PADD inventories over time may provide insight into how replenishment may occur over longer periods of time.
Intra-annual hydro availability	Historical drought conditions	Drought 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.

Just-in-Time Fuels

Natural Gas

Modeling natural gas availability in a planning ERA potentially requires 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 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, 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 information 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 input

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 retirements and new construction where final decisions have not yet been made.

The following information 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 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 utilities commission 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 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

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

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 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 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 in the coming years than it ever has been. Modern demand has components of actual 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.

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.

Table 4.6: Information Useful for Modeling Demand in a Planning ERA		
Data	**Potential Sources**	**Notes/Additional Considerations**
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 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 consider the expected changes brought about by changes in demand.

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 Seasonal ERAs. In this time horizon, there is an opportunity to buildout or upgrade the transmission systems to relieve constraints or for other purposes.

Chapter 5: Methods

Introduction/Overview

The modeling elements 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 towards 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 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 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 versus deterministic methods are defined in Volume 1. Put 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 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 different modeling tools that can be used to perform energy assessments, however, all fall into a handful of tool families with cross family integration leading to more robust results.

Tool Families Overview

The following section describes the families of tools that are available to an analyst performing an energy reliability assessment. 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 (kinds of questions each family can answer); (3) what each family does well; (4) what each doesn't 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 not find recommendations for or names of any specific tools within the described families, however, the reader should be cognizant of any regulatory requirements that require the provision of filings using a specified file format which may be vendor or program specific, e.g. the Federal Energy Regulatory Commission requires Form 715 power flow cases be filed in one of six specific formats.[32]

[32] 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

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 judgement 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 that are utilized to perform an ERA[33]. 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 resource adequacy 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 the intertemporal nature of power systems operations is ignored.

Most resource adequacy 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 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 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 framework. Indeed, highly detailed dispatch-based Monte Carlo approaches closely resemble PCM tools.

RA models can answer or provide guidance to answer the following question:

- Does the system meet the required reliability level considering outage probabilities, reserve margins, and load and weather uncertainty?

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 may not be possible in all RA tools, and that such an analysis comes at a computational cost which must be balanced against other modeling decisions within the probabilistic framework.

[33] 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**
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 resource adequacy metrics such as loss of load expectation and expected unserved energy.
Electric Vehicles (EVs)	RA models should include representations of electric vehicles 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 its 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 resource adequacy 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 PCM 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's 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 (PCMs), 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 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 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:

- 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' underlying capabilities include but are not limited to:

- 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, 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, depending on the level of detail required. The time horizon of analysis can span from short-term operational planning to long-term investment decisions[34]. Unlike CEM which uses 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

[34] 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.

market transactions, transmission flows and congestion, and loss prices. In non-market based regions, these can be used to understand future operations, provision of ancillary services and transmission congestion as well as other factors impacting reliability and economics.

Electricity PCMs are built on robust data structures. This includes 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, 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, PCM 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 cost, and ease of use.

The boundary between PCM and RA tools is blurring, given the increased need for resource adequacy 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 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.

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 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 (EVs)	PCMs should include representations of electric vehicles 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 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	Explained in the text above.
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

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 CEM wouldn't provide information on the nature of these energy constraints: this would need to be implemented by the analysist using their knowledge of the system. Many different CEM options are available to an analyst, including both open source and commercial options. 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 cost, 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 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:

- 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 future resource buildout? (Note that many CEM models don't yet have this capability)

CEMs' family of tools typically include 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 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 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 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 is itself very uncertain. Additionally, these tools may have limitations in 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 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 regions 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. Since CEMs sometimes consider transmission solutions as an investment choice, it can be intimated that they are quasi-transmission constrained, however, 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 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 which incorporates energy constraints where computationally feasible will allow for a recommended resource buildout which is more likely to be energy adequate than if these constraints weren't 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 types of models can be used to guide a choice of simplified pseudo-constraints which 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 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.

Table 5.3: Considerations for Applying Capacity Expansion Models to ERAs	
Consideration	**Description**
Variable Energy Resources	Capacity expansion models 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 a number of 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 assess the impact of compliance costs, emissions trading schemes, and regulatory changes on investment decisions. Additionally, 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 are informed by a previous PCM analysis. Note that emissions constraints in particular may sometimes be overridden during high-risk load shed periods, so it is important to be aware of the specific region's regulations when modeling this process.
Energy Supply Adequacy	Capacity expansion model buildouts should be evaluated using resource adequacy 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 (EVs)	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 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.

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 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 black start 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 are power system physical simulation tools. This family of tools is used to study very short-term periods, typically only a few cycles 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 during a period of question 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:

- Does the system have the ability to 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?
- Does 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 Modeling tools excel in 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 included are:

- 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 timeframes, 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): utilize real-time measurement data from synchronized phasor measurement units (PMUs) 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 which 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 representation of DERs effectively. They may also not be able to capture impacts of certain issues, such as control interactions between inverter-based resources, whereby electromagnetic transient (EMT) tools would be necessary. These issues are well covered in other NERC activities related to modeling for IBR, including the Inverter-based Resource Planning Subcommittee (IRPS). Additionally, these tools can only analyze one operational condition at a time, and as such aren't 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 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 representation 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.

At present, this is 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. Many different 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 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 & higher CT capability with cold air input). The choice to use these tools is often narrowed by need to supplement experience-based judgements.

Interdependence tools

The family of models in this section are those that simulate items that intersect or impinge on electricity system planning and operation which 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 models can vary in complexity, cost, and availability to the analyst or entity performing an ERA, so it is advisable that performers closely consider the needs and benefits for including these types of models in an ERA over the use of engineering judgement. 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 electricity 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-electricity 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 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 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 process, including some of the tools detailed above.

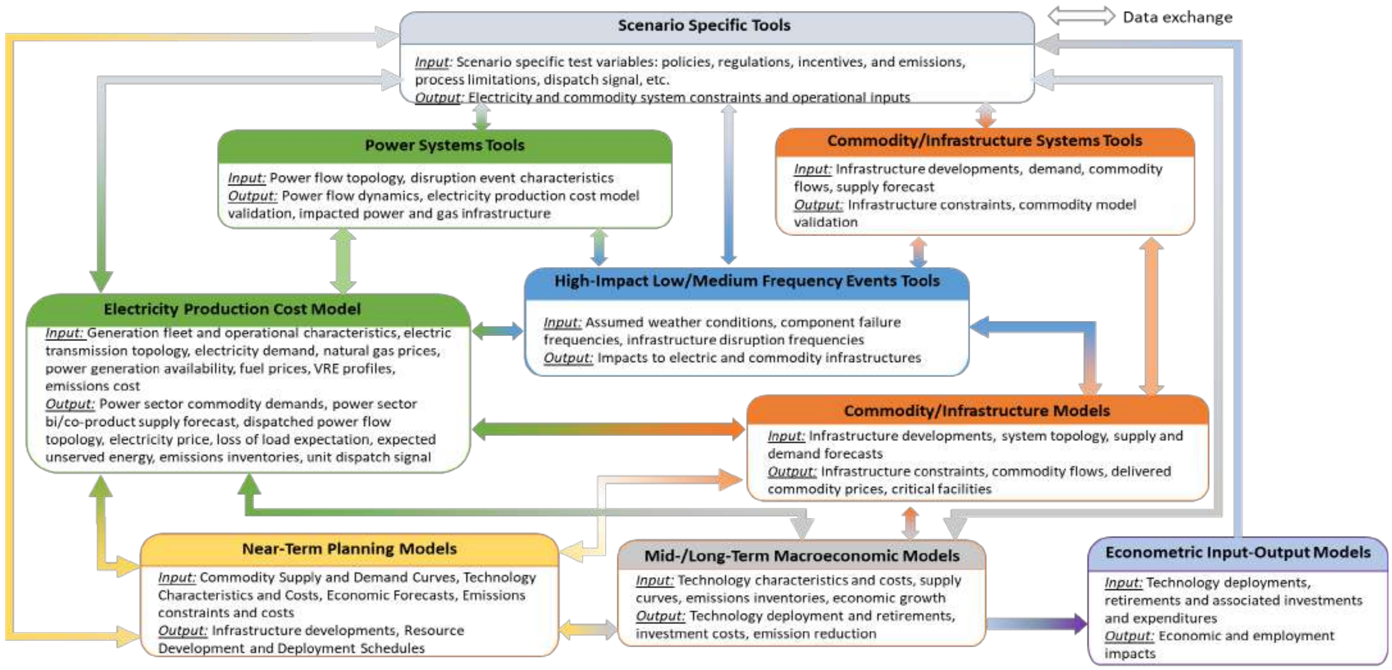


Figure 5.1: Illustrations of the interdependence of tools as they relate to the ERA process

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. An ERA is a look at a certain time period. Therefore, a Base Case would include the most likely to occur series of conditions over the defined period.

There are several input considerations to include in an ERA. Ultimately, the 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 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 which 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 likely will 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 must be established in order 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 must 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's still 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's also helpful when applying scenarios to have a Base Case to compare results. This 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, 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 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,
- and their associated impact.

Choosing the scenarios or method of generating scenarios appropriately is critical to a robust risk assessment 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 an easy to define and objective standard, 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 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 concept to industry planners. However, they are being looked at from a different angle in an ERA.

An excerpt from the NERC Probabilistic Assessment Technical Guideline Document, page 13[35]:

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 in order to isolate the potential impact of each input. Ideally, the change in each input should be accompanied by an associated probability.

[35] https://nerc.com/comm/pc/pawg%20dl/proba%20technical%20guideline%20document_08082014.pdf

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 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 analyst to understand what the appropriate probability is and what it means for the 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 conditions. A sensitivity or scenario analysis would be particularly useful to analyze 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 shouldn't result in outcomes with unacceptable consequences (e.g., a scenario similar to the Base Case with probably should not result in a relatively large-magnitude energy shortfall). Conversely, it may be appropriate to find results with large-magnitude energy shortfall when the worst-case scenario for all inputs is selected. The analyst would need to determine the level of variance that would be needed in order to create that stress, and approach shortfall. It's likely that multiple iterations would be required when initially setting up scenarios (e.g., if the first attempt adds no stress, more variance 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 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 have some risk of occurring and their system should be designed to operate reliability through that occurrence.

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 judgement of subject matter experts, and statistical evaluations. Taking into account conditions that have happened before, locally or in other similar locations, lends credibility in terms of historical events. Note that just because an event has happened in the past, doesn't necessarily mean that it will happen again. Similarly, just because an event has not happened in the recorded past doesn't mean that it can't happen.

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, variable supply (e.g., solar and wind), outage assumptions, and fuel availability are all examples of inputs to an ERA that are 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 criteria 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 certain severe events 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, as well as 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 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 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 assessment can be limited by long-range forecasts (e.g., NOAA outlooks, El Nino 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 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 give 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 not completely uncertain. A variety of factors need to be considered. 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 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 of the system, and criteria are a set standard to determine if the level of a metric is acceptable. In the case of ERAs, a criteria for a metric might be set such that if the criteria are not met, some mitigation activities need to be performed.

Using metrics and criteria is useful for four purposes: quantifying the risk, setting a risk tolerance or 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 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 quantity 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 within 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 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 regions can accept. However, the names of some of the metrics are not different whether used in capacity- or energy-based assessments but reflect the 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 to examine a specific forecasted scenario or set of scenarios that the analyst expects to occur, including in certain situations, tail risk events that can provide a system design basis for planning purposes. Using deterministic scenarios is especially helpful if the analyst wants to stress test a system to understand if the electrical system can reliability meet certain minimum thresholds with respect to criteria including, but not limited to, 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 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 (FEEA)

Energy Emergency Alerts (EEAs) are defined in NERC Standard EOP-011-1[36], 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 for setting criteria for increasingly less probable but impactful events.

For example, ISO New England uses Forecasted EEAs[37] (FEEAs) 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 metrics have been used consistently for a number of years in ERAs.

Reserve Margins

Reserve margins 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 could be based on a fixed value, a set percent of energy demand or related to ancillary service requirements or uncertainty on 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 design around specific scenario's results defined. However, individually the metrics do not as clearly reflect the frequency, durations, and magnitude of expected events. [38]

All of the following metrics can potentially be calculated based on the same set of ERA simulations so do 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 which the available generation is insufficient to serve demand. The calculation is based on whether or not 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

[36] https://www.nerc.com/pa/Stand/Reliability%20Standards/EOP-011-1.pdf
[37] https://www.iso-ne.com/static-assets/documents/rules_proceds/operating/isone/op21/op21_rto_final.pdf
[38] See: Probabilistic Adequacy and Measures Report - 2018

least the number of days with loss of load event 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 shortfall. Used in combination with the expected unserved energy 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 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).

Loss of Load Events (LOLEv)

Loss of 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 accounts 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)

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. 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 appropriate for this reason.

Expected Unserved Energy (EUE)

EUE[39] 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; 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 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)

LOLP is the probability of system daily peak or hourly demand exceeding the available electrical energy during a given period.

[39] 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 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 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 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. These metrics differ from the other probabilistic methods discussed in this document because they are based on a percentile or confidence level of results in the case of VaR and 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 used examples of these metrics are LOLE95 or LOLH95[40].

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 assessment expects 95% of scenarios will have 236.6 MWh or less of load will be lost.

99% CVaR of energy deficiency is 485.3 MWh loss would mean that the average load loss for the worst 1% of scenarios is 485.3 MWh.

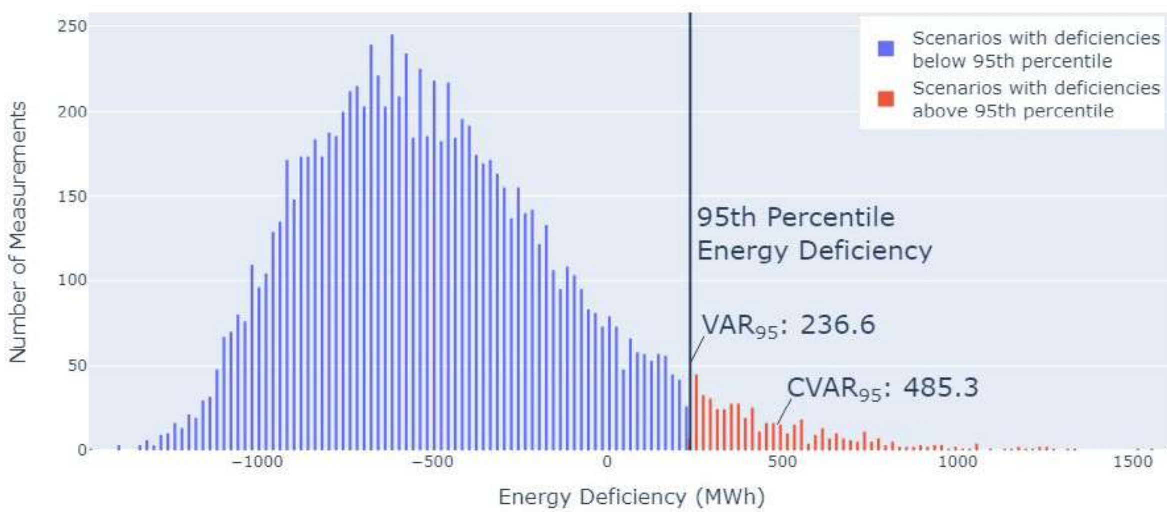


Figure 7.1: Example of VAR and CVAR for the 95 percentile of energy deficiency. VAR is 236.67 since it is the 95th percentile of the measurements and CVAR is the mean of the values greater tha 95th percentile (shown in red).

Selecting the Right Metrics and Criteria

The methods used to perform an ERA are a decision to be made in the early stages of development, as these 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

[40] "Adequacy Standards & Criteria" EPRI.

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 taking 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 easier to inspect and determine what mitigation activities would lower the risk of specific scenarios. This aspect makes communication of the choice of mitigation activities and problems that were identified easier.

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 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 vs 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*

[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 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

Chapter 8: Considerations for Corrective Actions

After performing an ERA and comparing the results to a set of defined criteria, the following actions could delay, reduce, or eliminate energy shortfalls or conditions exceeding the pass/fail criteria. Likely, the pass/fail criteria will be more conservative than 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 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 to conserve fuel that can be used when system conditions are at their worst) and depend on the time horizon of the ERA. Near-term ERAs provide fewer options for mitigation than planning ERAs. Actions should be commensurate with the risk. Care should be taken to maintain reliability and minimize the impact on the BPS and 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 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 for possible actions 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 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 governments (i.e., legislatures and agencies/regulators), state and/or provincial governments (i.e., legislatures and regulators), and registered entities (i.e., resource owners, independent system operators, etc.). 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 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)

[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 of the necessary corrective actions. Communicating early with parties who 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 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 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 are maintained indefinitely, the energy requirement will remain relatively unchanged. Lowering the temperature set-point on a cold day will draw less power over time but restoring the set-point 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.

[44] 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. Replenishment of fuel is a key to extending 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.
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 requires the analyst to 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.

Table 8.1: Considerations for Recommended Corrective Actions in Response to Energy Shortfalls		
Corrective Action	**Time Horizon(s)** [44]	**Considerations**
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 a loss of stored fuels where conservation actions are not enough to prolong the availability of that fuel, controlled power outages may serve to conserve the fuel. This doesn't seem different; however, it does offer the option to shift when the power outages occur, such that fuel is available when it's 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.
Operational strategies for electric storage	NT S P	No storage is 100% efficient. Therefore, energy storage devices (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 Expansion	P	While likely not permissible 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 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

Energy reliability assessments are becoming a necessary component in the suite of tools used by power system planners and operators as more variable energy resources 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. 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 technical reference document, the reader has been provided with a framework that can be used to perform energy reliability assessments. 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. 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 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 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 inventory of each generation station	Generation survey 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, DO limitations, etc. Stored fuels may be used for unit start-up with a portion embargoed for black start 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 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

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 energy supply is often impacted by world events that cause supply chain disruptions. This includes 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[45]	Considerations for local trailer transportation of fuels over wet/snow-covered roads as well as seaport weather when docking ships.
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, historical weather data, weather assumptions based on historical 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

45 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	Some information can be obtained via the EBB Index of Customers, however there is nuanced data that would be needed 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 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 or historical 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	EC GO	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	X	X	ES O	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, operational data	These two parameters combined defined 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 specific charge percentage. For example, batteries charged above 80% or below 20% may under perform. Therefore, the storage capacity may be less that 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 stand-alone configuration. Charging source, primary and secondary	Registration data	Scenario studies may remove a generation type (i.e., solar) which may eliminate the energy supply source.
X	X	X	ES	Ambient temperature limits	Registration data, operational data	This is 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	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 Outages and Maintenance	TOPs, TOs, or other transmission planning entities	Should be included in the BA and/or TOP Data Specifications

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 Transport Limits	Topology and ATC or similar calculations, engineering studies	
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 regions
X	X	X	T	Transmission Topology and Characteristics	BAs and TOPs	Potentially, you may use a simplified or DC equivalent circuit for probabilistic or similar analysis
X	X	X	T	Transmission Outage Rates	NERC GADS	Ideally, weather dependent and unit 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 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.
X			NG	Natural gas scheduling timelines	Pipeline tariffs, NAESB	Timelines may differ between pipelines. NAESB sets five standard cycles that are to be followed by FERC jurisdictional entities (which generally excludes intrastate pipelines and local distribution networks)

Table A.2: Summary of Potential Information Sources in All ERAs						
Near Term	Seasonal	Planning	Topic	Data	Potential Sources	Notes / Additional Considerations
X			NG	Natural gas commodity pricing and availability	Intercontinental Exchange (ICE)[46], Platts[47]	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.
X			VER	Weather forecasts	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 this analysis.
X			VER	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

46 https://www.ice.com/index
47 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			EC GO	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 well aware of what their limits would be and the plans to abide by those limits.
X			EC GO	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			ES O	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			DE R	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 sort of renewable energy credit program will likely need to register with and provide production information to a program administrator.

Table A.2: Summary of Potential Information Sources in All ERAs

Near Term	Seasonal	Planning	Topic	Data	Potential Sources	Notes / Additional Considerations
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
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 DER 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	

Table A.2: Summary of Potential Information Sources in All ERAs						
Near Term	**Seasonal**	**Planning**	**Topic**	**Data**	**Potential Sources**	**Notes / Additional Considerations**
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
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[48]	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.

[48] 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	Regional 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 world events that cause supply chain disruptions. This includes port congestion, international conflict, shipping embargoes, and confiscation

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, 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, 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)	Interstate natural gas pipelines are required[49] 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), Historical observations, 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. That 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 seasonal horizon, there should be some more certainty on what will be commissioned or not.

[49] 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		EC GO	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 well aware of what their limits would be and the plans to abide by those limits.
	X		EC GO	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		ES O	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		ES O	Outage mechanisms	NERC GADS, operator logs	Outage mechanisms can be used to determine outage duration and impact
	X		ES O	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 may finish early or overrun.

Table A.2: Summary of Potential Information Sources in All ERAs						
Near Term	**Seasonal**	**Planning**	**Topic**	**Data**	**Potential Sources**	**Notes / Additional Considerations**
	X		DER	Installation data coupled with expansion assumptions	Electric utility companies (i.e., Distribution Providers, or DPs), production incentive administrators	Similar to the information needed for a near-term ERA, DERs are likely to coordinate with distribution system operators, giving 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 forecast, or legislative goals.
	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)[50]	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.

[50] 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	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.
	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[51]	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.

[51] 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	Regional availability of overall fuel storage	EIA reports	The U.S. Energy Information Administration reports weekly inventories for five Petroleum Administration for Defense Districts (PADD). 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 conditions	Drought 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, 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 input

Table A.2: Summary of Potential Information Sources in All ERAs						
Near Term	**Seasonal**	**Planning**	**Topic**	**Data**	**Potential Sources**	**Notes / Additional Considerations**
		X	EC GO	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 well aware of what their limits would be and the plans to abide by those limits.
		X	EC GO	Trends in individual state carbon emissions goals	State government or public utilities commission 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	ES O	Planned Outage Cycles	Historical planned outrages	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.
		X	ES O	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

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

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 Response capabilities	Electric utilities or other organizations (e.g., demand response aggregation service providers) that manage participation in demand response programs.	

Appendix B: Lists of Examples and Figures

Appendix C: Contributors

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Reliability Guideline: DER Forecasting Practices and Relationship to DER Modeling for BPS Planning Studies

Action
Authorize to post for 45-day comment period.

Summary
Interconnection-wide planning cases contain detailed information on transmission level elements as well as the reflection of aggregate load, DERs, and other distribution equipment on the transmission system. Studies on these planning cases evaluate the reliability impact of future year combinations of generation, transmission, and distribution equipment. These studies for future conditions rely on the high quality of the forecasted data that is submitted to analyze. This reliability guideline contains relevant information, key points, and recommendations to improve the quality of future year projections and base case creation procedures.

To help provide guidance to entities, the System Planning Impacts from Distributed Energy Resources Working Group (SPIDERWG) has identified key high-level recommendations when entering in values for future long-term planning studies.

This guideline has been acted on by the Planning Committee and Reliability and Security Technical Committee previously and is brought for this meeting per the triennial process. The guideline was not part of the original tranche reviews and requires authorization to post.

NERC

NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Reliability Guideline

DER Forecasting Practices and Relationship to DER Modeling for BPS Planning Studies

June 2024

RELIABILITY | RESILIENCE | SECURITY




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Preface

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

Interconnection-wide planning cases contain detailed information on transmission level elements as well as the reflection of aggregate load, distributed energy resources (DERs), and other distribution equipment on the transmission system. Studies on these planning cases evaluate the reliability impact of future year combinations of generation, transmission, and distribution equipment. These studies for future conditions rely on the high quality of the forecasted data that is submitted to analyze. This reliability guideline contains relevant information, key points, and recommendations to improve the quality of future year projections and base case creation procedures.

DER forecasts historically started with a company's interconnection queue and usually used augmenting assumptions like the relative certainty of resource delivery[1] to finalize the forecast.[2] Once a projection was considered to be the most reasonable projection out of a multitude of others, it became the forecast, and decisions were made on those values. Now, many utilities perform integrated resource plans (IRPs) that contain many data sources and feed into multiple outputs at both the transmission and distribution level. Each Transmission Planner (TP), Planning Coordinator (PC), or Resource Planner (RP) has varying procedures to produce a load or DER forecast used within these plans. Because of the complexity of projecting DER growth, there is not an objective way to determine what projection is more "correct" in its capability to predict the future until such future occurs. This reliability guideline provides specific forecasting methods for an entity to choose when building DER forecast and relevant examples where these methods are implemented. This reliability guideline identifies the two large categories of forecasting strategies used in forecasting: top down and bottom up. When using a top-down approach, there are many disaggregation techniques that can be used, two of which are mentioned in this reliability guideline. The guideline also discusses the mechanisms of data collection, the relationship to MOD-031 and MOD-032, and the resulting impact to bulk system planning such that the projections used by the TP or PC are aligned with their base case study assumptions.

It should be the goal of a TP or PC to ensure the data and projections used in their forecasts are useful in their studies[3] performed under TPL-001 or otherwise. To help provide guidance to those entities, the System Planning Impacts from Distributed Energy Resources Working Group (SPIDERWG) has identified key high-level recommendations when entering in values for future long-term planning studies. TPs and PCs should:

1. Attend and contribute to current forums where DER forecasting is discussed. Furthermore, TPs and PCs should coordinate with their RPs to discuss forecasting of DER in their region.
2. Coordinate with RPs in their service territory to ensure resources, inclusive of DER, are not being double counted. RPs should also coordinate with other adjacent RPs to ensure no double counting for DER forecasts.
3. Coordinate between their load forecasting and planning departments to ensure forecasts meet the TP/PC requirements, primarily for development of base cases.
4. Obtain accurate data in their set of future year Interconnection-wide base cases, inclusive of DER values. TPs and PCs are encouraged to coordinate with various sources, including the DP and other forecasting entities, to ensure accurate data is used in future year Interconnection-wide base cases.
5. Develop checklists and use the checklist to validate forecasted data for use in their planning studies.

[1] As an example, the NERC Reliability Assessment Subcommittee defines different tiers for future interconnection to distinguish resources that are near certain to be constructed from those that are uncertain.

[2] In this document, the term "forecast" typically refers to the path expected to be taken for the future based on reasonable assumptions and actions. It should also be noted that the term "projection" refers to a possible future path and useful for "what-if" scenarios.

[3] Or, for TPs and PCs that use external forecasts, that the forecast chosen is useful for their study's objective. Some studies may require lower likelihood projections opposed to those chosen for a DER forecast.

6. Review a variety of DER projections to see which projection is best suited and aligned with their set of study assumptions. This may mean the TP and PC use DER forecasted values for a portion of their studies a different DER projection for others.

Chapter 1: History of Forecasting for the Electric Industry

As transmission planning studies require the use of future data, the method to estimate and produce numbers to fill model parameters is important to the quality of future year studies. These estimations for future year values are the "projections" of the data from known information or assumptions and then collectively refined and agreed upon to be the "forecast" for the utility. This chapter covers the purpose, potential applicable entities, and the historic context for forecasting in the electric industry related to generation, load, and distributed energy resources.

Purpose

The purpose of this guideline is to informTPs and PCs of the available methods to forecast DER information and the methods to ensure the forecast value aligns with future year reliability assessments. The guideline serves to provide planners checks to validate assumptions, values, and methods on projected DER capacity and capability.

Applicability

This reliability guideline is applicable toTPs and PCs. RPs may also find the information here helpful.

Related Standards

This guideline has relevance to NERC Reliability Standards MOD-032 and MOD-033 requirements; however, the procedures contained could be used for other local reliability assessments not covered by MOD-032 or MOD-033.

Background

Many utilities perform IRPs that account for the growing consumer demands, load shapes, and the resource acquisitions in the long-term planning horizon. Utilities typically separate these IRPs based on capacities of coal, natural gas, solar, etc. for specific policy initiatives or resource acquisition targets. In this process, the system electricity demand is projected across the wide area with the generation and transmission projects evaluated for their impact on the ability to serve that system demand. In areas that do not explicitly call their process an IRP, this process can be housed in a variety of different business units that culminate in the same goal: the assessment to serve end-use customer demand.

Integrated Resource Plan Process

The IRP process highlights some of the functions performed by RPs, namely those related to the need to forecast the ability to serve demand into future years. This indicates that if the demand does not have adequate consideration for the resources "behind the meter," the transmission level resource acquisition may not be fully sufficient to meet demand. This is true for areas with high DER penetrations as well as those with little to no data on DERs. Most RPs qualify this inability to serve load with statistical means.[4]

Some entities have enhanced their IRP process into a multi-use, detailed forecasting procedure (see **Figure 1.1**). As indicated in the figure, the uses of the "traditional" forecast were direct and singular. The move to a multi-use forecast at the transmission and distribution level for resource and transmission planning demonstrates the growing importance a DER forecast plays for future year BPS studies. DER forecasts have higher sensitivity in distribution planning as small, local changes can dramatically change a distribution level forecast. For the same impact at a transmission level forecast, a larger amount of widespread DERs would be needed. For both the transmission and distribution systems, inclusion of accurate DER values into transmission planning cases[5] is important as such cases are used to assess the reliability of the BPS; therefore, validated data should feed the DER forecasting process. This guideline covers both the forecasting practice assumptions and data quality checks in order to provide high quality BPS transmission studies.

[4] Loss of load statistics typically include the Loss of Load Probability, Loss of Load Hours, Loss of Load Expectation, and Expected Unserved Energy. The *Probabilistic Assessment Technical Guideline Document* contains a good example to derive these statistics.
[5] Accuracy for any variable in the transmission planning cases is desired, not just DER values.

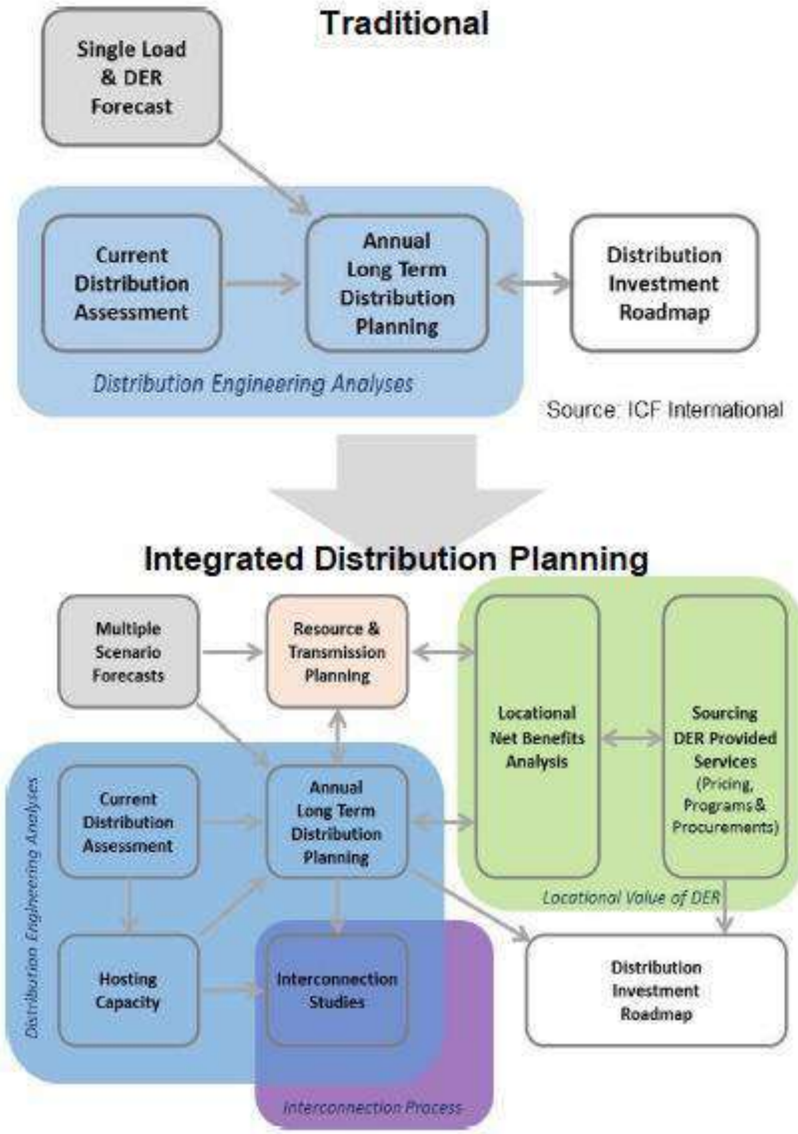

Figure 1.1: Move to Integrated Distribution Planning [Source: Minnesota Public Utilities Commission]

Clarification of Terms

In this document, the terms "projection" and "forecast" have similar meaning in most cases. However, the term projection typically refers to a possible future path and useful for "what-if" scenarios and the term "forecast" typically refers to the path expected to be taken for the future based on reasonable assumptions and actions. **Figure 1.2** illustrates this difference. In evaluating the contribution of DERs to serve end-use demand, these terms are nearly interchangeable. However, this distinction becomes noticeable when determining the capacity of aggregate DERs in a given study.

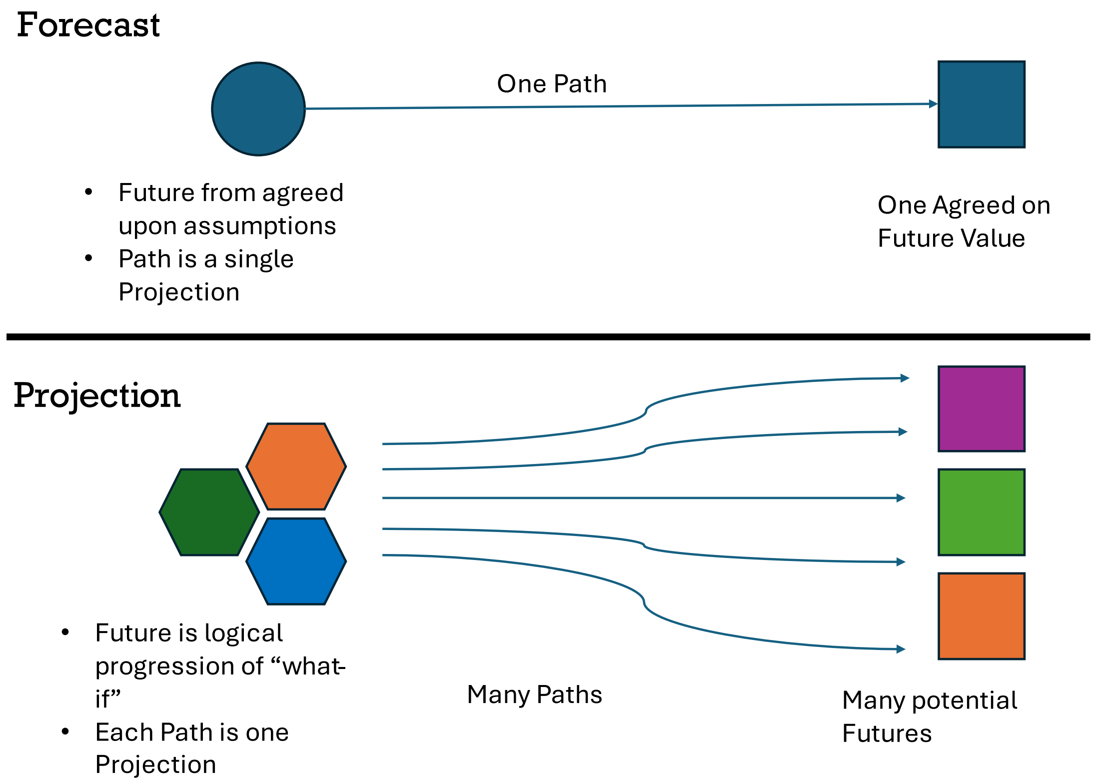

Figure 1.2: Forecast versus Projection Example

For example, if the TP or PC determines that it is highly likely that their DER growth will triple by the end of the decade due to strong economic incentive, then the DER forecast should reflect this tripling and be entered into the base case reflective of those conditions. However, if that same tripling was determined to be very unlikely to occur, the TP and PC would want to know the impacts of the increased DER growth but will not use the value as a base case. Rather, it can be one of many scenarios to compare against the base case to identify "what if" the tripling did occur. The former decision is indicative of a forecast, while the latter, a projection.

Additionally, there are other terms used in this reliability guideline that SPIDERWG has defined in a separate document.[6] Notably, the SPIDERWG defines DER as "any Source of Electric Power located on the Distribution System." There are other definitions of DERs that are valid in their context; yet SPIDERWG's text shows the intent for this reliability guideline. DERs compose of generation resources and are not lumped in with the response of controllable loads.

Growing Emphasis on Scenario Based Planning

Both transmission and distribution entities in some areas are incorporating more variation of scenarios (i.e., energy forecasts of solar photovoltaic (PV), load growth, energy efficiencies) and placing it into a dual, long-term distribution and transmission planning scenarios. The incorporation of extra scenarios transforms the typical resource procurement process into a new forecasting method that can incorporate the end-uses better than looking at a net peak load. In doing so, entities are moving past the limitations of using a single data point for all transmission and distribution requirements. These changes allow for a given DER forecast to provide use in both transmission and distribution system planning, operation, and risk assessment.

[6] See the SPIDERWG Terms and Definitions Working Document available here: https://www.nerc.com/comm/RSTC/SPIDERWG/SPIDERWG%20Terms%20and%20Definitions%20Working%20Document.pdf

There are limitations for multiple scenario projections, such as when separating a solar PV DER forecast from other DER forecasts. Primarily, the additional data burden. Adding in multiple scenarios will require the process take in a larger amount of data, and while such additional refinements will provide the PC or TP added “trust” to use the number in studying their system’s future conditions the data burden increases proportional to the added scenarios. Regardless of these computational limitations, the need for a trustworthy DER forecast becomes important especially when PCs and TPs are looking for guidance on modeling and study procedures for their system. In the case of DERs, it is important for TPs and PCs to track the capacity, vintage, and location of DERs as these assumptions can often have as large of an impact on future scenario study results as gross load forecasts can. SPIDERWG has already provided other reliability guidelines for the modeling, studying, and verification of the DER models in BPS transmission studies; however, many of the SPIDERWG documents emphasize engineering judgement as a method for projecting the changing landscape of DERs. This reliability guideline provides some validation checks to assist the TP and PC in finding a good forecast to base their long-term planning studies on and to ensure alignment between the study assumptions and forecast assumptions.

Chapter 2: Long-Term DER Forecasting Practices

TPs, PCs, and RPs rely on accurate values of existing and projected Load (including DERs) to perform resource planning and transmission planning. Generally, a resource adequacy assessment requires information on future firm capacity increases in order to determine any deliverability upgrades necessary to meet generation and load needs under a variety of future conditions. These studies generally contain a base case and accompanying sensitivities. Including a trustworthy projection of DERs in Interconnection-wide planning cases is important, as the lack of a trustworthy DER capacity will create concern on the validity of decisions supported by studies on those cases. Distribution entities need information from load and DER forecasts in order to plan future projects to meet net load on their systems at times when DERs are not able to supply local load. Similarly, transmission entities need accurate information on future load and DER projections to plan their system, especially given the long lead times for such projects.

Load forecasts for areas with known or expected DER growth that do not account for DERs as separate from gross load will impact the results of simulations. Furthermore, any correlations or changes to normalize load may not be correct[7] for that area as the rates for gross load growth and DER growth can occur at different rates. More challenges arise when considering historic and forecasted DER growth in areas where DER data is not gathered or accounted for in forecast assumptions.

Key Considerations DER Forecast Use in BPS Planning

Load and DER forecasts are used in more than just stability planning. Therefore, prior to developing and using DER forecasts, it is important to consider the key dependencies and relationships between DER forecasting practices and the use of resulting DER projections in BPS planning. These dependencies are important because they can affect how the entity chooses an acceptable DER forecast. Key considerations and dependencies between DER forecasts and BPS planning are highlighted below.

Transmission Planning Model and Study Inputs: Even with a hypothetically perfect forecast, it is necessary to understand how the forecast will be used as an input to the planning model. These inputs can be as simple as a MW rating in the load record that represents a single T-D interface, or as complex as a separate data object that allows planners to specify a multitude of DER parameters in a powerflow case. When forecasting for this equipment, the DER forecast should consider what TP model inputs are needed. An example of this is the "Dgen" value in GE's Postiive Sequence Load Flow's (PSLF) load record or "Distributed Generation" value in Siemen's Power System Simulator for Engineers' (PSS®E) load record. These modeled values affect any post-processing or method selection depending on the desired model input.

The type of study is also an important factor that impacts the applicability of a particular forecast method, acceptable level of uncertainty, or even if a projection should be used in lieu of a forecast. For instance, a resource adequacy study[8] in the planning realm assesses the deliverability of DERs and other resources to the load. In power system stability studies, the TP evaluates how DERs affect the stability of the base case and can alter the "dispatch" of the system to perform scenario analysis. In the resource adequacy study, the DER magnitude and location are important while the latter stability study analysis requires additional system information and data to determine the credibility of the scenario analysis.

[7] For instance in producing a load duration curve for use in reliability studies. The NERC Probabilistic Analysis Working Group has published a technical reference document that discusses these limitations. Available here: https://www.nerc.com/comm/RSTC/PAWG/TRD-Data_Collections_Report.pdf

[8] Resource adequacy studies have historically been performed with Monte-Carlo or Convolution-deconvolution methods in packages separate from the positive sequence power flow software. Some entities perform a composite study that takes information from both the positive sequence software and the resource adequacy software.

Additionally, the modeled composition of the DERs must be understood to ensure accuracy of the forecasts. If the forecast is expecting more utility-scale DERs (U-DERs)[9], the forecast methods should emphasize growth for larger projects. As larger projects, forecasting U-DERs as smaller end-use customers does not capture their characteristics in the forecast correctly. Similarly, if the forecast expects many smaller retail-scale DERs (R-DERs), the forecast should use methods that model individual customer behavior. As such, the DER modeling practices may affect the way the forecast is performed.

Data Gathering: Many of the inputs of a projection will either need to be synthesized or obtained through various data gathering mechanisms. Some of the data gathering mechanisms include surveys, monitoring, and telemetry infrastructure. Each method has a relative accuracy in the way the data is collected, which can result in specific types of forecasting methods being unavailable. For instance, if there isn't a high level of confidence in the results of a customer survey, the forecasting entity might not want to choose a method that focuses on individual behavior but rather on "generic" customers. Furthermore, some mechanisms are embodied in NERC's Reliability Standards to allow transmission entities to gather information related to forecasting or modeling. A more detailed discussion is in **Chapter 3:**; however, the key consideration is having entities responsible for obtaining high quality, accurate information for use in forecasts (inclusive of DER forecasts) to develop future year models. Where data gathering proves insufficient, engineering-judgement based projections can be used in a forecast despite being typically regarded as inexact.

Level of load: Forecasters at various industry and regulatory entities are experienced at projecting seasonal peak load values, but higher variances can be at play due to the nature of how the low load is attained with seasonal off-peak load values.[10] In these seasonal off-peak load forecasts, care must be taken to fully understand if that load is gross or net. Many forecasting agencies will provide values to use directly in planning studies; however, this does not mean that their data is utilizing gross load as DERs can mask load growth in the historic data. This is especially true if the entity utilizes a baseline measurement of load today as opposed to many years ago. Today's load mix can include large amounts of DERs in certain areas, so a baseline measurement today would need to differentiate DERs from gross load for an accurate baseline. There are two key concerns related to DERs masking load. First, given the probabilistic capacity value (e.g., weather variability) the TP or PC needs to characterize the probability or likelihood of DER availability during peak load. This is compounded as the planning criteria may be very different than what is seen in historical data. Secondly, the time of the net peak load shifts as PV penetrations increase.[11] This complicates what the most stressed condition is for future years.

Uncertainty in data: Uncertainty exists with any future long-term projection. In a load forecast, this is the load forecast uncertainty that quantifies the potential span of year-over-year deviations. In any forecasting procedure, a level of certainty is prescribed to the load value. This is typically called a "50/50" or "90/10" load level and assigns a level of certainty that the level will not be higher than the listed amount, mimicking a cumulative distribution function of the load. Uncertainties in load data are prescribed in this manner due to the nature of how aggregate load behavior is tracked. As of today, most DER forecasting practices do not use probabilistic modeling[12] to perform scenarios or predictions as historic data is not widely available to support such methods; however, it is anticipated that DER forecasting will likely have the same data dependency as the load forecast for historical data when the data becomes available.

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[9] To understand the modeling of DER as U-DER and R-DER, see previous modeling guidance for DERs at the RSTC webpage on reliability guidelines. Available: https://www.nerc.com/comm/Pages/Reliability-and-Security-Guidelines.aspx

[10] There are a variety of important factors (e.g., the power factor) in a load forecast and how load is attained for study; however, the full extent is out of scope for guidance related to DER forecasts.

[11] For Example, at high enough penetration levels, even with little cloud cover, the net peak load will eventually shift towards night-time hours. This is a well-known phenomena that the capacity value of solar diminishes as penetrations increase

[12] Weather-based probabilistic models, or probabilistic models in general, require a significant amount of data and computational burden to provide an accurate result.

Resource Profiles: In some forecasting methods, production data for a specific resource type (namely solar PV) is useful for adding confidence in a forecast. This is largely important with solar PV production data as it contains a temporal correlation with the associated resource profile. Resource profiles provide installation-specific or aggregate data to indicate how the total DER output changes in time. In some transmission planning studies (e.g., the Near-Term portion of an Annual Planning Assessment), the accuracy of the study heavily relies upon knowledge of the operational profile of the resources, including DERs. In operations planning (e.g., OPAs and RTAs), such profiles are valuable to determine the total expected power produced by installed capacity. Long-term planners may also desire to know how the profile interacts with shifting base case assumptions in their long-term planning studies. Resource profiles provide a way to convert capacity-based projections into power production at a given time, allowing TPs to enter DER generation into their future cases. Many of the common long-term resource profiles are "synthetic profiles" that convert weather data into a power conversion model for weather-dependent resources. Such methods are a key consideration available to planners to convert forecasted quantities (i.e., long-term weather conditions) into changes in power.

DER Forecasting Approaches

Considering DER forecasts are developed for a variety of uses other than BPS planning, it is important to understand the various approaches and methods in order to adequately use the forecasts within a particular BPS planning study. There are several different approaches and methods that can be used for producing DER forecasts. For example, many states provide DER forecasts to utilities while others provide supplemental information that can be used to enhance a given forecast. A few approaches and methods in use today are detailed in this section. Note that these approaches and methods are not mutually exclusive, and a single forecast can use a combination of multiple approaches and methods. As always, engineering judgement is needed to assign forecasted quantities to values for aggregate DERs in the recommended model framework. The available methods are classified into two broad categories: Top-Down and Bottom-Up. See the section on **DER Forecasting Methods** to determine which specific approach to apply in these broader classifications would be the best fit for the projection or forecast.

Top-Down Approaches

Top-Down approaches forecast DERs at a high level (typically regional, state, balancing area, or utility service territory) and allocate portions of the forecast to smaller areas. The Top-Down approach is characterized by formulating a widespread characteristic to determine the DER capacity, location, or other quantity tracked. To be useful to individual TPs, this high-level approach needs to be broken down by some disaggregation technique, some of which are described below:

Geographic Distribution: This technique allocates future DER projects near the current installed capacity (MW) in each geographic region. Any capacity projection can be allocated based off the geographic distribution formulated in past years. This method works best in similar sized geographic areas with a fixed border. However, certain methods can mitigate against changing geographic boundaries in the forecast. After each of the geographic areas has allocated its final capacity (MW) for the case, these capacities are further allocated across all the substation buses in the planning model that represent that region via some allocation method.[13] An example of some of those areas using a direct proportionality are included for ISO-NE in **Table 1.1**.

Table 2.1: Sample Geographic Distribution by ISO-NE			
State	Load Zone	Dispatch Zone	% of State
CT	CT	EasternCT	18.7
	CT	NorthernCT	18.6
	CT	Norwalk_Stamford	7.3

[13] Commonly this is a direct proportion, and if so, is combined with the proportional allocation method; however, these allocations do not have to be directly proportional but can be some other allocation method.

Table 2.1: Sample Geographic Distribution by ISO-NE			
State	**Load Zone**	**Dispatch Zone**	**% of State**
	CT	WesternCT	55.4
ME	ME	BangorHydro	14.6
	ME	Maine	49.9
	ME	PortlandMaine	35.5
MA	NEMA	Boston	11.9
	NEMA	NorthShore	5.8
	SEMA	LowerSEMA	15.1
	SEMA	SEMA	21.2
	WCMA	CentralMA	14.0
	WCMA	SpringfieldMA	7.1
	WCMA	WesternMA	24.9
NH	NH	NewHampshire	90.6
	NH	Seacoast	9.4
RI	RI	RhodeIsland	100
VT	VT	NorthwestVermont	62.3
	VT	Vermont	37.7

Proportional Allocation: This method allocates DER forecasts by using a ratio based on a metric or measurement at each circuit or substation, irrespective of geographic distribution. See the sample diagram found in **Figure 2.1** that describes one mathematical composition and calculations to perform this method. Example measures that can be used for proportional allocation include number of customers, customer propensity scores used for modeling end-use customer behavior, energy, peak demand, and other system level measurements. For example, a DER projection by county can be allocated to each circuit or substation based on the proportion of the number of customers on each circuit or substation to the number of customers in that county. This method, however, does not consider geographic diversity, which plays a part in capturing solar irradiation for solar PV devices and can limit the effectiveness of a direct proportional allocation.

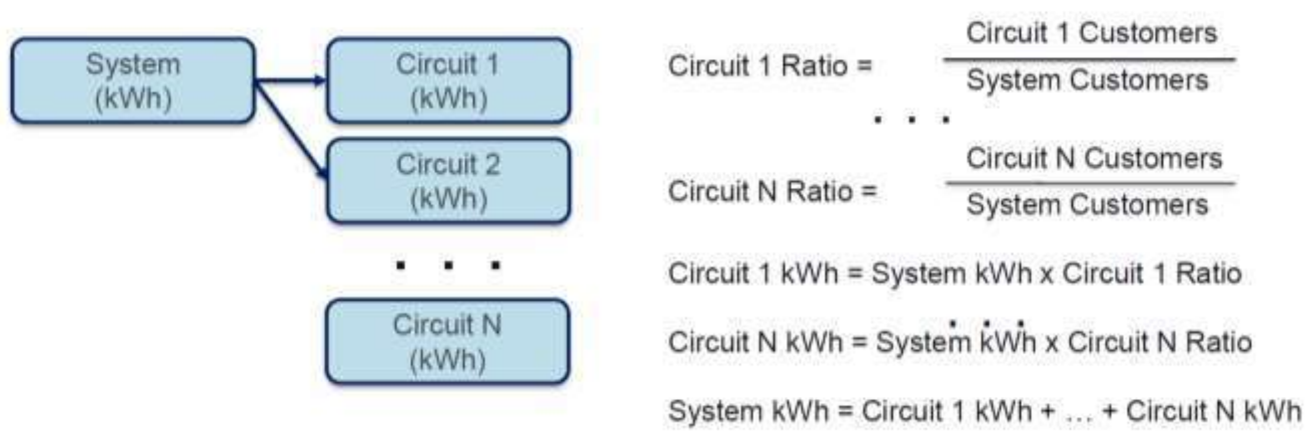

Figure 2.1: Proportional Allocation Flowchart

Bottom-Up Approaches

Companies that have access to appropriate data can use certain approaches to aggregate forecasts up to a specific point (i.e., at each substation, or geographic area). These strategies are typically called “bottom-up” as they use specific information and aggregate the projections to a desired broader footprint. Bottom-Up modeling in this guideline refers to the buildup of forecasts and projections by electrical boundary areas (e.g., substations, distribution circuits, customer meters, etc.) as opposed to other types of "bottom up" approaches (e.g., by end-use devices or by customer classes).

Traditional Load Peak forecasting method: This method is relatively simple and involves utilizing operational data to track the feeder or Transmission and Distribution (T&D) load bank peak active power in the year and then adding these values up to gather a full system peak. Adjustments are typically made to aggregate any non-coincident peak values from each substation to yield the coincident peak for a whole system. See **Figure 2.2** for how this method can produce a projection. The aggregation of these values represents the system peak with forecasts performed on each load record[14] to demonstrate expected growth in each area. The disadvantage of this method is the possibility of load growth masking DER growth and vice versa. For all resources (including DERs) this method assumes that the peak historical output is the maximum capable capacity, which is not necessarily correct. The maximum capable capacity for DERs would require all DERs to be producing at the inverter nameplate rating for all inverters connected to the feeder. For a variety of reasons, that assumption may not hold. Furthermore, projections or forecasts that are based on a measured peak load are susceptible to measurement errors, communication drop-outs, and other measurement concerns. Without visibility into the production of DERs during a measured peak load condition, planners lack the ability to measure the native load and account for the explicit impacts of DERs for projecting to their future cases.

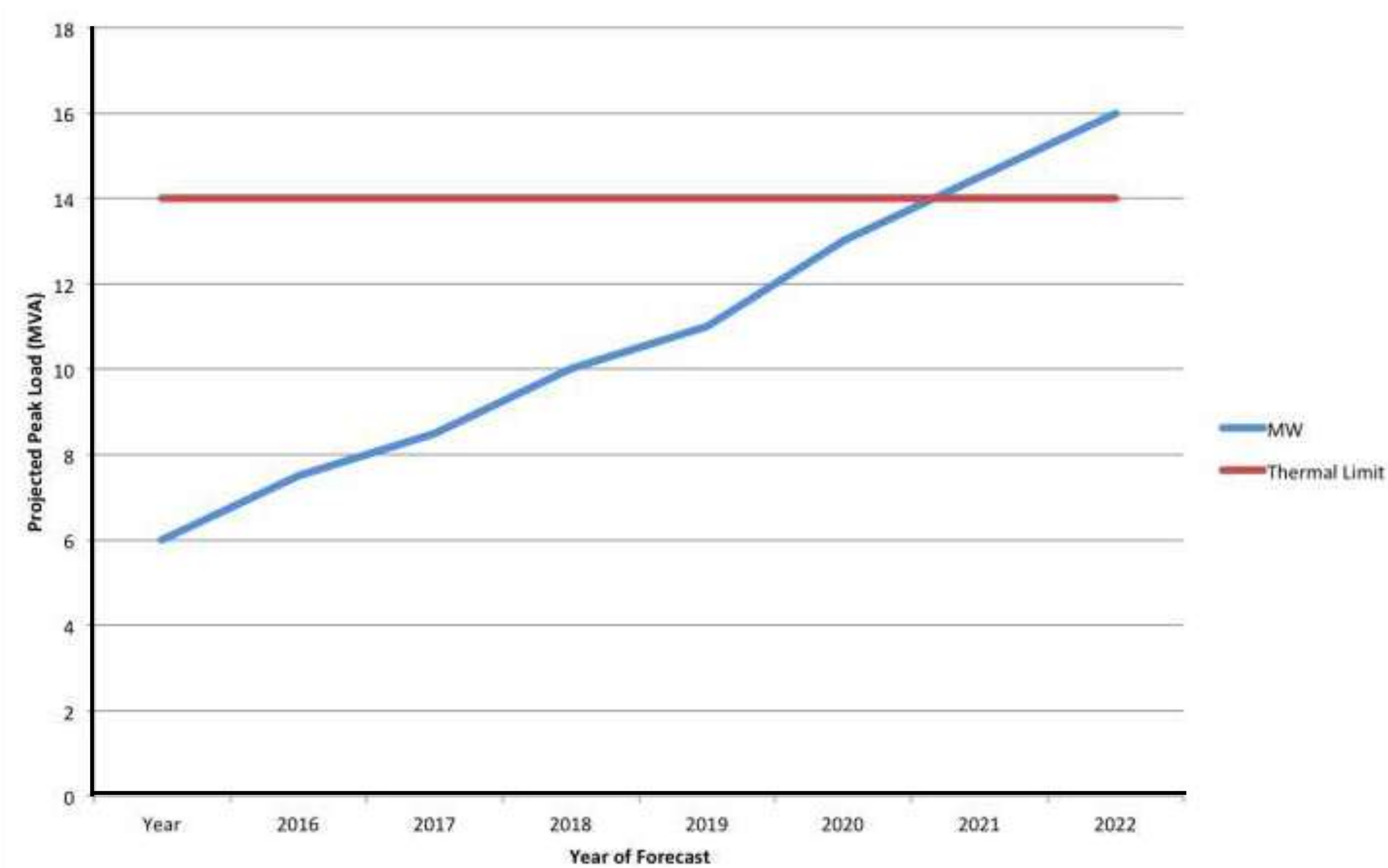

Figure 2.2: An Example of Peak Load Forecasting [Source: NREL]

Net Load simulation method: To align the high-level forecast with the planning models, future net load scenarios can be based on disaggregating the net load into component parts. As such, the native load is separated from the DERs,

[14] This can represent one T-D interface. Some of these records are a single feeder, many feeders, or a large area served by a distribution company.

and the DER resource profile is developed from coincident, historical hourly load and production data. Rather than using the peak data and projecting based on expectations, this method performs a simulation on the resource profiles to provide a final expected DER capacity for the projection. A variety of assumptions regarding the types of loads, DERs (if accounted for), and expected conditions typically accompany the simulation. If historical measured production data is used to create forecasted production DER profiles, an underlying assumption is that the system design and technology trends are not anticipated to change significantly over the forecast period. If significant changes are anticipated, a simulation explicitly accounting for impacts can be performed.

DER Forecasting Methods

Regardless of whether the forecast uses a top down or bottom up approach, a variety of methods can be used to develop a DER projection. Entities producing a DER forecast should choose an appropriate forecast method[15] such that the method matches the available input data and desired outcome. A few different types of methods are described below[16], which include time series extrapolation, policy-based approaches, macroeconomic simulation, Bass diffusion models, and adoption models. It is recommended that these methods be carefully reviewed for the goal, timing, and desired confidence level in the analysis being performed and that TPs or PCs chose a DER forecast that matches their recurring study needs.

Time Series Extrapolation: This approach uses historical adoption rates from years past and extrapolates that growth rate into the future. Some methods fit the data to linear, exponential, or other mathematical expression to build the future growth curve. While this method is easy to develop and communicate, it does not account for potential adjustments based on changing economic conditions or other drivers.

Policy-Based Approaches: This method leverages known or stated policy targets or other established goals and assumes an adoption forecast will successfully achieve some percentage of the stated target by a given date. While this method is straightforward and easy to implement, it requires a stated policy and assumes measures are in place to reach the policy goal.

Macroeconomic Simulation: With adequate data, these methods simulate economic activity at the macro level by considering supply cost curves, supply chain availability, population growth, and policy impacts in the form of tax incentive or capacity limits. Some simulations are even co-optimized with capacity expansion models to determine optimal resource portfolios. These approaches, however, typically generalize the decision-making capabilities of the DER owners and assumes that all the expected changes in the market structure are included in the simulation and may represent unexpected changes as an uncertainty. Additionally, this method assumes that the optimized macroeconomic solution is predictive of the changes to DER; however, some willingness-to-pay charts may not be indicative of changes in mindset for the end-use customers.

Bass Diffusion Models: This method has several variants; however, all Bass Diffusion models aggregate diffusion of new technologies into society. While the model is relatively straightforward and simple to solve without advanced software, the diffusion models are limited in the ability to project dynamic changes in adoption overtime due to

[15] Entities can use these methods to forecast for on-peak or off-peak conditions for DER. To do so, entities need to ensure that the data used in the forecast method is in alignment with the desired outcome. That is, if forecasting for off-peak conditions the data used in the method chosen should be in alignment with an off-peak study.

[16] A comparison of these forecasting methods, and some guidance related to gathering data in support of a forecasting method can be found at various industry reports. Two such EPRI reports are Guidance on Solar PV Adoption Forecasting Methods for Distribution Planning. EPRI. Palo Alto, CA: 2018. 3002014724 Available here: https://www.epri.com/research/products/000000003002014724 and Data Sources and Considerations for Solar PV Adoption Forecasting: Guidance for Data Scientists and GIS Analysis. EPRI. Palo Alto, CA: 2018. 3002014725. Available here: https://www.epri.com/research/products/000000003002014725. Furthermore, Table 2 of NREL's *An Overview of Distributed Energy Resource (DER) Interconnection: Current Practices and Emerging Solutions* compares some of these methods. Available here: https://www.nrel.gov/docs/fy19osti/72102.pdf

changing policy and market conditions. Furthermore, they often require additional information from other sources to assume or predict the level of full market saturation.

Adoption Models: Adoption models attempt to model customer adoption behavior based on number of influencing factors including electricity rates, DER technology costs, or customer demographics (e.g., income level). These models use many different inputs, such as policy impacts, economic impacts, and other socio-economic trends to determine the adoption rate. Adoption models can make granular forecasts at the premise or circuit level where they can be aggregated up to each substation bus. Alternatively, they can create forecasts at a higher zip code or county level where additional disaggregation techniques may be needed. Figure 2.3 illustrates how adoption models can be done at a circuit level and then altered depending on the needs of the study[17].

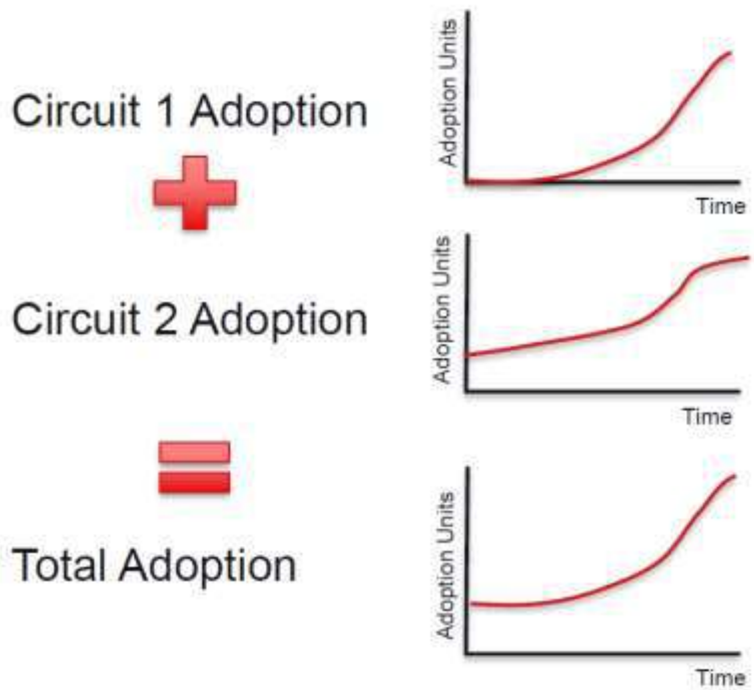

Figure 2.3: Adoption Model High Level Summary [Source: Itron]

Agent Based Models (ABMs): A variant of granular adoption models, ABMs model decision making of each customer as a set of specific preferences based on demographics, geographic locations, behavioral attributions, social networks, and other socioeconomic parameters. ABMs attempt to bridge the cultural attributes of DER adoption to the market data on DER and depend on the specific attributes assigned to individual agents. ABMs assume that their list of attributes can quantify the customer perspective of DER. Granular ABMs require large amounts of data at the premise level or circuit level in order to provide a wide area forecast; however, it does allow the planner flexibility in modeling each circuit explicitly, which can transfer over to the load bank representation in their planning model used in their studies.

Customer Behavior Modeling: As each DER installation represents an owner's decision to purchase the equipment, future installations can be modeled by estimating future customer purchase decisions. In aggregate, these look like a total customer behavior in a geographic region. As each electrical end-user can choose between distribution providers in some markets and self-generation in areas of regional monopolies, the choice can be simulated in a market like structure. By using market or survey data, the modeler characterizes the preferences of these owners to

[17] For TPs and PCs, this circuit level is not an anticipated need. However, if done at a T-D interface, this may be of use to TPs and PCs.

each of the technology attributes. In relationship to DER, key attributes could be the local price of electricity, emissions, provider reputation, geographic location, and appearance of the installation. As purchase decisions vary and markets shift with time, these models must be updated accordingly. The total number of customers purchasing DER then can relate to the inputs to the powerflow programs depending on how specific the geographic data is. There are two primary methods for modeling customer behavior:

- **Econometrics:** this customer behavior model approach uses a regression model to quantify the impact of key drivers on customer adoption behavior using historical purchase data and actual choices made by customers in the market. While it is good to validate key drivers of actual purchases, for ancient technologies with little historical adoption, preferences or demographic characteristics of future adoption populations may differ from historical data sets.
- **Stated Preferences:** This approach estimates customer preferences using surveys with questions about hypothetical purchase decisions among a set of alternative choices. While this method is useful for gathering information on emerging technologies and enables the creation of scenario-based outcomes, the lack of validation from actual purchase decisions can cloud results.

Current Forecasting Entities

Most of the current forecasting is done at the state-level using a variety of methods. National Labs have also helped to perform load forecasting for some entities. These current forecasting entities can be useful to identify the procedures and adapt for entity-specific DER forecasting. Multiple examples are available and the utility to garner more information on specific enhancements to enhance their forecasting practices; however, only some utilities will have the capabilities[18] to produce detailed forecast scenario analysis. Some examples of utility originated forecasting practices are summarized below. The utilities below have a large penetration of DER, and as such, have had some years to refine their method of forecasting.

NVEnergy

Currently, NVEnergy[19] does not get a forecasted capacity or spread of DER from their state or Public Utilities Commission. Their forecasting practices are generated internally for many different DER types, including rooftop solar, wind, and battery technologies. Additional inputs are gathered from their departments that look at net-metering, renewable energy incentive programs, and local, state, or federal policy to adjust this DER forecast. When performing their DER forecast, NVEnergy assumes that the driving factor is the federal incentives that drive growth of historical applications for both rooftop solar and batteries. Because their method is not only based on customer class level (residential versus non-residential) but also on a system level, NVEnergy is able to use those classes to determine the placement of DER into their models.

Imperial Irrigation District (IID)

IID has its own internal process that determines their DER MWs rather than relying upon a state commission or other state body. Their general method for forecasting either load or DER breaks apart differing sets of assumptions and attempts to relate everything to either market incentives or weather. Then, they take a model and apply it against historical projections and the model that has the lowest Mean Absolute Percentage Error (MAPE) is chosen to forecast both load and DER. By doing so, they can model very complex relationships in their region and vary their own incentives for rooftop PV (both U-DER and R-DER). IID estimates that their saturation point[20] if they do not incentivize DER to be 110.5 MW, and if they do incentivize the technology, 184.5MW in 2033. Every time they perform these predictions and forecasts, they revise their projections and ensure the process is accurately capturing the growth of many different technologies. For instance, the IID forecast breaks out lighting; electric vehicle, PV, and other load

[18] To supplement capabilities, contractors and other state regulators have provided energy forecasts to the utilities.

[19] NVEnergy's latest filings can be found online. Their Integrated Resource Plans are available here: https://www.nvenergy.com/about-nvenergy/rates-regulatory/recent-regulatory-filings

[20] These saturation points are limitations of capacity and are assumed values going into the forecast.

technologies and ensures that each is tracked in aggregate, much like the adoption model strategy. In their 2018 report[21], they have changed their Bass Diffusion Method from linear to non-linear when projecting Solar PV as the growth no longer follows a linear pattern. The results of their DER projection can be found in **Figure 2.4.** The figure demonstrates that between the two projections, the Base Case annual installations do not go higher than the ~19 MW per year historic annual installations. However, the High Case that has the market saturation point at 184.5 MW in 2033 projects the annual rooftop PF capacity additions to reach just over 20 MW per year.

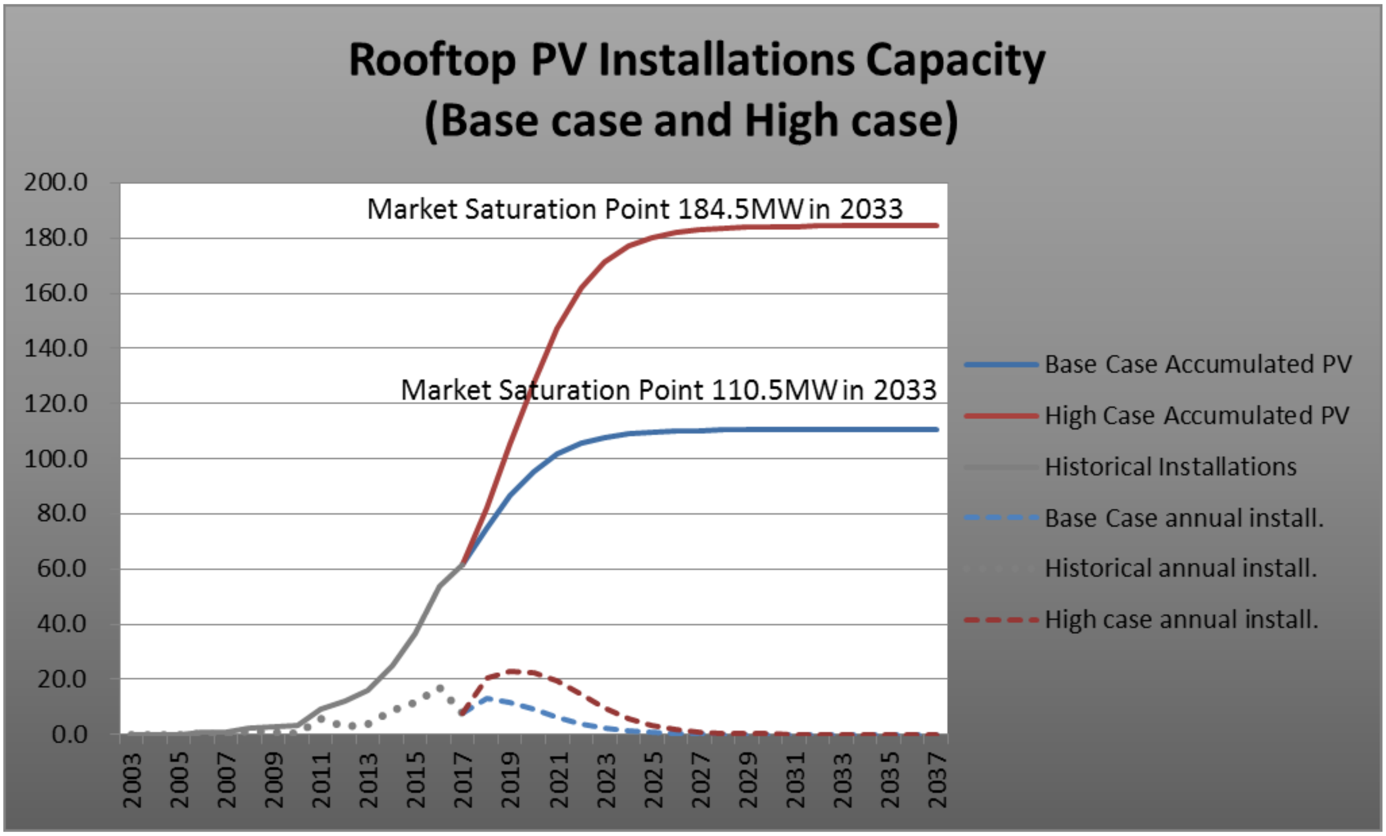

Figure 2.4: IID Projected PV forecast from 2018 Load Forecast

Public Service Company of New Mexico (PNM)

Like NVEnergy and IID, PNM does not receive state input for their forecasts, but rather completes their DER forecast internally[22]. For their method, they do not explicitly track the total DER MW capacity for each year but rather track the incremental changes and plots against energy consumption for future year cases (**Figure 2.5**). In their 2023 integrated resource plan,[23] NWM forecasts their energy consumption in a range of low, medium, or high adoption of residential solar PV installations as part of their reflection for customer interest in these devices. Due to a lack of locational information, PNM distributes their DER additions across all their loads rather than targeting a specific bus for their additional incremental DER; however, they do reflect their capacity as part of their net internal demand and have begun to track the shift increasing DERs have on their peak load.

[21] IID's load forecasting page is reachable at the following link: https://www.iid.com/energy/renewable-energy/integrated-resource-plan. The numbers in this document come from their latest resource plan, the 2018 IRP, available here: https://www.iid.com/home/showpublisheddocument/9280/636927586520070000

[22] PNM provides their full IRP reports, that include their internal DER forecast results, here: https://www.pnmforwardtogether.com/irp

[23] PNM's 2023 integrated resource plan is available here: PNM-2023-IRP-Report-corrected-2023-12-18.pdf (pnmforwardtogether.com)

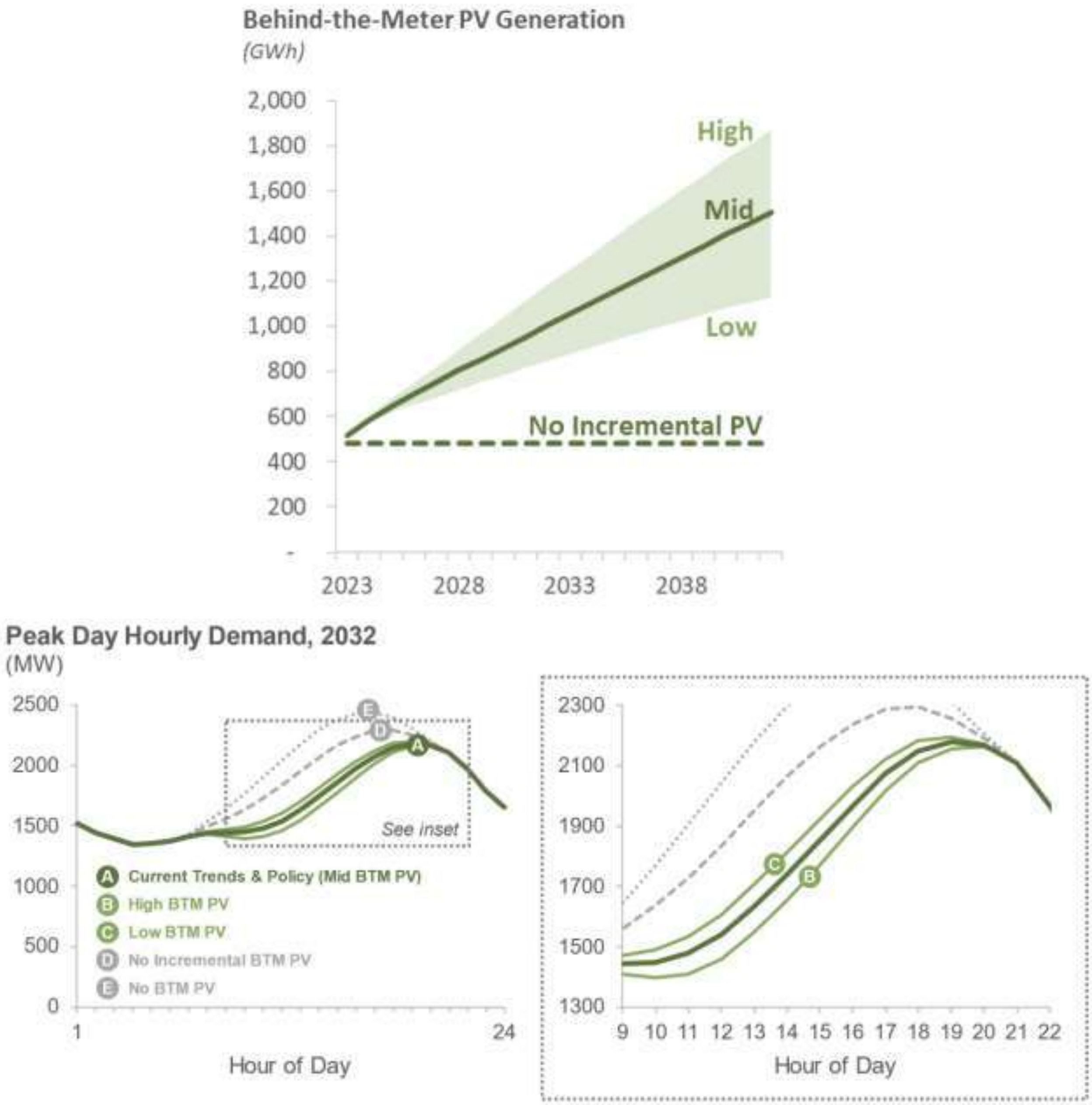

Figure 2.5: NWM Behind the Meter PV Forecast [Source: PNM]

DER Forecast and Modeling at the California ISO

California ISO (CAISO) considers and explicitly models DER in the transmission planning studies, since DER constitute a large portion of the CAISO power supply. The CAISO load forecast utilizes the latest Energy Demand Forecast[24] developed by the California Energy Commission (CEC). This forecast includes applicable Additional Achievable Energy Efficiency (AAEE) and Additional Achievable Photovoltaic (AAPV) scenarios from CEC. It also includes 8760-hourly demand forecasts for the three major Investor-Owned Utility (IOU) areas (Pacific Gas and Electric, Southern California Edison and San Diego Gas and Electric).

[24] The forecasts by the CEC are available for download here: https://www.energy.ca.gov/data-reports/planning-and-forecasting

Since load forecasts from the CEC are generally provided for a larger area, a disaggregation technique to move to bus-level values is necessary for reliability assessments. Consequently, the augmented local area load forecasts that are needed for reliability assessments are developed by the Participating Transmission Owners (PTOs). Allocation methods in use by the PTOs are integrative of the CEC forecast to extract, adjust and modify the information from the transmission and distribution systems and municipal utility forecasts, and include the methods for modeling distributed generation (DG).

Behind-the-meter solar PV are modeled as a component of the load model. In the power flow load table, using the DG field on the PSLF load model, the total nameplate capacity of the DG is represented under PDGmax field. Actual output of the DG is based on the scenario. The total nameplate capacity is specified by the CEC, the allocation and location for projected DG is derived from the latest Distribution Resource Plan (DRP) filed with the California Public Utilities Commission (CPUC) provided by the distribution planning departments of the PTOs. Further, California Public Utilities Code 769 requires the electrical corporations to file distributed resources plan proposals, making this type of data highly visible. According to the Code 769, these plan proposals will “identify optimal locations for the deployment of distributed resources” and defines “distributed energy resources” as “distributed renewable generation resources, energy efficiency, energy storage, electric vehicles, and demand response technologies.” Therefore, it makes it a bit difficult to separate load from generation using just that one data source.

The Code also requires the CPUC to “review each distribution resources plan proposal submitted by an electrical corporation and approve, or modify and approve, a distribution resources plan for the corporation. The commission may modify any plan as appropriate to minimize overall system costs and maximize ratepayer benefit from investments in distributed resources.” CAISO includes distributed resources in its power flow and dynamic stability models according with this CPUC ruling and with the Distribution Resource Plans provided by the participating utilities. Throughout the modeling process, there are several different sources and methods used for various DER forecasts as shown in **Table 2.2** below.

Table 2.2: CAISO Data Sources for DER

Distributed Energy Resource	Source/Method
Behind the meter PV and non-PV generation	CEC demand forecast
Supply-side DG in front of the customer meter	PTO Wholesale Distribution Access Tariff (WDAT)and CPUC Renewable Portfolios Standard (RPS) portfolio
Energy Efficiency[25]	CEC demand forecast using a load modifier
Demand Response	CEC demand forecast for load modifying DR
Energy Storage	Procured storage from Load Serving Entities informed by CPUC targets

San Diego Gas and Electric (SDG&E) Further Modification

SDG&E’s load growth forecast begins with the most recent approved CEC SDG&E Load Modifier Mid Baseline-Low AAEE-AAPV CED forecast. Known new loads, e.g., specific requests for new electrical service, are deducted from the CEC system load growth forecast. The resultant system-level growth is allocated by customer class (residential, industrial, and commercial), proportional to the customer class’s forecasted annual energy consumption. The system-level customer class distribution is then allocated to SDG&E’s distribution circuits using geospatial analysis using satellite imagery and vendor specific proprietary data analytics to score each acre in SDG&E’s territory for the likelihood of increased load by customer. The output of the geo-spatial program is an annual SDG&E peak MW growth by circuit, by customer class for the forecast period. This growth is then uploaded into a vendor supplied forecasting program which uses customer-class load shapes to turn the allocated customer class growth amount into a 576-hour load shape that can then be applied to the circuit or bank load shape. This profile is then weather normalized to an

[25] While this is not included in the SPIDERWG definition of DER, as CPUC Code 769 identifies this as a required item to study and forecast.

adverse 1-in-10-year (90th percentile of high loading) weather event forecast as the basis for making decisions regarding planned capital upgrades and permanent load transfers. As shown, the interaction between multiple data sources, alterations, and adjustments for individual PC or TP use is important when producing a final DER forecast value in transmission planning. Any one of the entities is a successful example of producing a high confidence DER forecast value and can be used as examples to learn from.

Chapter 3: Forecasting Practices and MOD-031

NERC standard MOD-031[26] serves as the primary NERC Reliability Standard associated with forecasting of future quantities for use in reliability assessments. It exists to "provide authority for applicable entities to collect Demand, energy and related data to support reliability studies and assessments and to enumerate the responsibilities and obligations of requestors and respondents of that data." In the standard, it calls out that a PC or Balancing Authority (BA) that identified a need to collect data can do so pursuant to the requirement language as system planners and operators require access to complete and accurate load forecasts such that these planners and operators can perform their assessments. This chapter explores the mechanisms for data flow from different regional entities to the TP and PC and provides recommended practices to coordinate between data gathering mechanisms to increase confidence in forecasts.

Data Requests and Data Transfers in MOD-031

MOD-031 covers gathering of demand side information for future and prior years such that reliability assessments can have sufficient data for their analysis. These assessments are generally wide area looks at future year system reliability, and some common reliability assessments are the Long-Term Reliability Assessment, Winter Reliability Assessment, and other Regional Entity assessments[27] like the WECC Probabilistic Assessment. As demonstrated in **Figure 3.1**, MOD-031 contains a cyclical process in which the PC or BA can request certain data[28] from other NERC registered entities. The data granularity ranges from an hourly demand profile (for the one year prior) to an annual number (for future year projections). As future year steady-state and stability analysis don't necessarily need hourly profiles, these future year values are important to validate Interconnection-wide base case building and model parameterization.

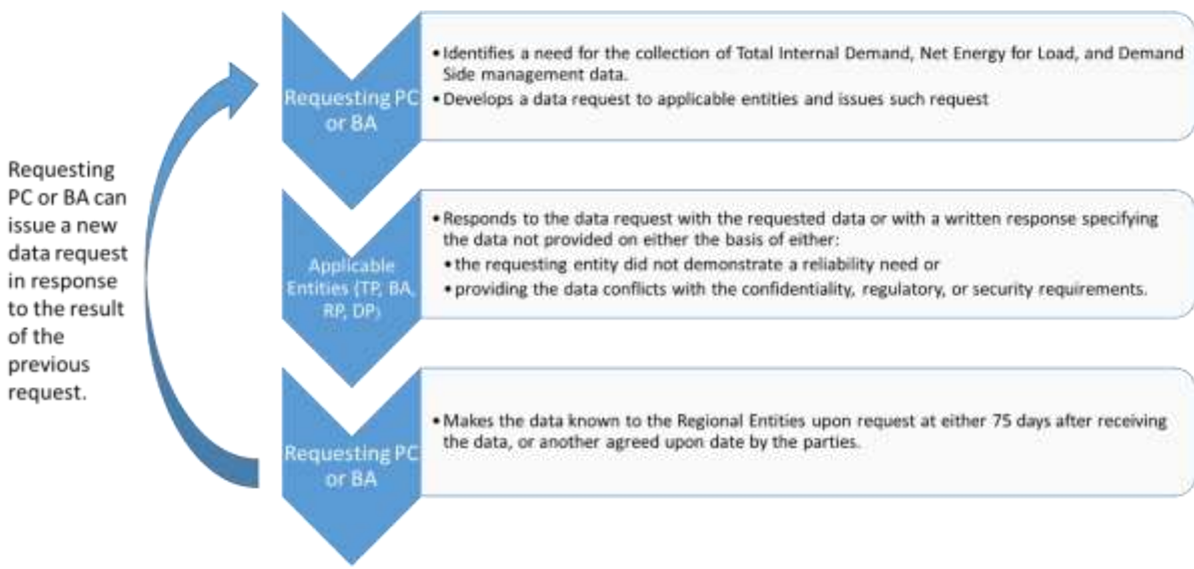

Figure 3.1: MOD-031 Logic Flowchart

As demonstrated in the graph, this data flow is only possible if the applicable entities can transfer the data to the requesting PC or BA. The standard identifies that certain considerations, like confidentiality, regulatory, or security requirements, may make this data not available. However, procedures exist to alleviate or negate many of these data

[26] MOD-031-3 available here: https://www.nerc.com/pa/Stand/Reliability%20Standards/MOD-031-3.pdf

[27] One example is the WECC's annual *Western Assessment of Resource Adequacy*. Information available here: https://www.wecc.org/ReliabilityAssessments/Pages/default.aspx

[28] Specifically, Total Internal Demand, Net Energy for Load, and Demand Side Management data in the timeframe of one year prior to ten years in the future.

concerns. Additionally, if the reliability need is not well demonstrated or articulated, applicable entities can send notice to the PC or BA to continue through the cyclical data procedure. While this method of collection of forecasted values does not generally identify base case creation as a necessary output, the collection of this data clearly can be used to help validate confidence in Interconnection-wide base case, a process found in MOD-032.

MOD-031 and Interconnection-wide Base Case Creation

While the Interconnection-wide Base Case Creation procedures are handled by MOD-032, the information gathered as part of MOD-031 allow for the PC to either forecast or use a forecasted value in developing future base cases, scenarios, or other studies by the PC. As Demand Side Management is defined as "all activities or programs undertaken by any applicable entity to achieve a reduction in Demand," there is a potential to include DERs as part of those activities as the generation by DER offsets a distribution system's Demand at a given time. Thus, Interconnection-wide case builders, generally referred to as "MOD-032 Designees,"[29] should ensure that information gathered by MOD-031, specifically Demand Side Management data, is vetted against the MOD-032 Interconnection-wide Base Cases to increase the confidence in the representation of those cases. Certain exemptions exist where the assumptions for the future year Interconnection-wide base case are not the same as the forecasted value in MOD-031. When creating any base case, certain assumptions are placed based on the composition of the models to produce a starting point. Interconnection-wide base cases follow the same concept. Assumptions decided on for each base case can be validated by the forecasted values with the data under MOD-031 given that the MOD-031 forecast and base case conditions align. This is an important distinction for entities building future year cases as the values received under MOD-031 and MOD-032 should match assuming all things equal[30]. If using MOD-031 to ask for DER information, a clear description of the item should be placed in the data request to ensure the desired data is understood and identified as distribution-connected generation to ensure clarity of the request.

As a hypothetical example, if DER is not explicitly represented in the forecast, a PC might find that, in aggregate, their data request under MOD-031 resulted in a load value higher than the base case value used for the next year. The PC then must adjust the load and DER values to account for the missing DER impact. In a similar manner, a PC may determine that their previous base case assumptions contained too much DER capacity on the system for future year four from a previous request, and then also must refine their system model to become more in line with the submitted data. PCs should also consider using data from trusted outside sources instead of their MOD-031 data requests. As an example of supplemental data, **Figure 3.2** shows the CEC providing an expected solar PV rooftop forecast for public use. Such data can be used to help refine the base case assumptions used for future case setups assuming the outside data set's assumptions are in alignment with the base case assumptions. TPs or PCs may require additional analysis before incorporating wholesale (See **Example Checklist to Verify Forecasted DER Values**)

[29] These designees arise from MOD-032 R4's standard language where the PC submits models to the "ERO or its designee to support creation of the Interconnection-wide case(s) that includes the Planning Coordinator's planning area." See MOD-032 here: https://www.nerc.com/pa/Stand/Reliability%20Standards/MOD-032-1.pdf

[30] To clarify, if the assumptions driving the future year base case creation are also those chosen for the forecasted method, the two results of the quantity (i.e. a wide-spread MW value of Load) should be the same as represented in both the base case used in transmission planning and in the forecast used in resource planning. Furthermore, resource adequacy has different levels of "firmness" of resource commitment for future years for transmission level interconnection. This could introduce step change differences in resources between the transmission planning and resource planning cases and is indicative of an assumption difference in the cases. This further proves the point that "all things equal" the values should match, but there are instances where assumptions are not equal.

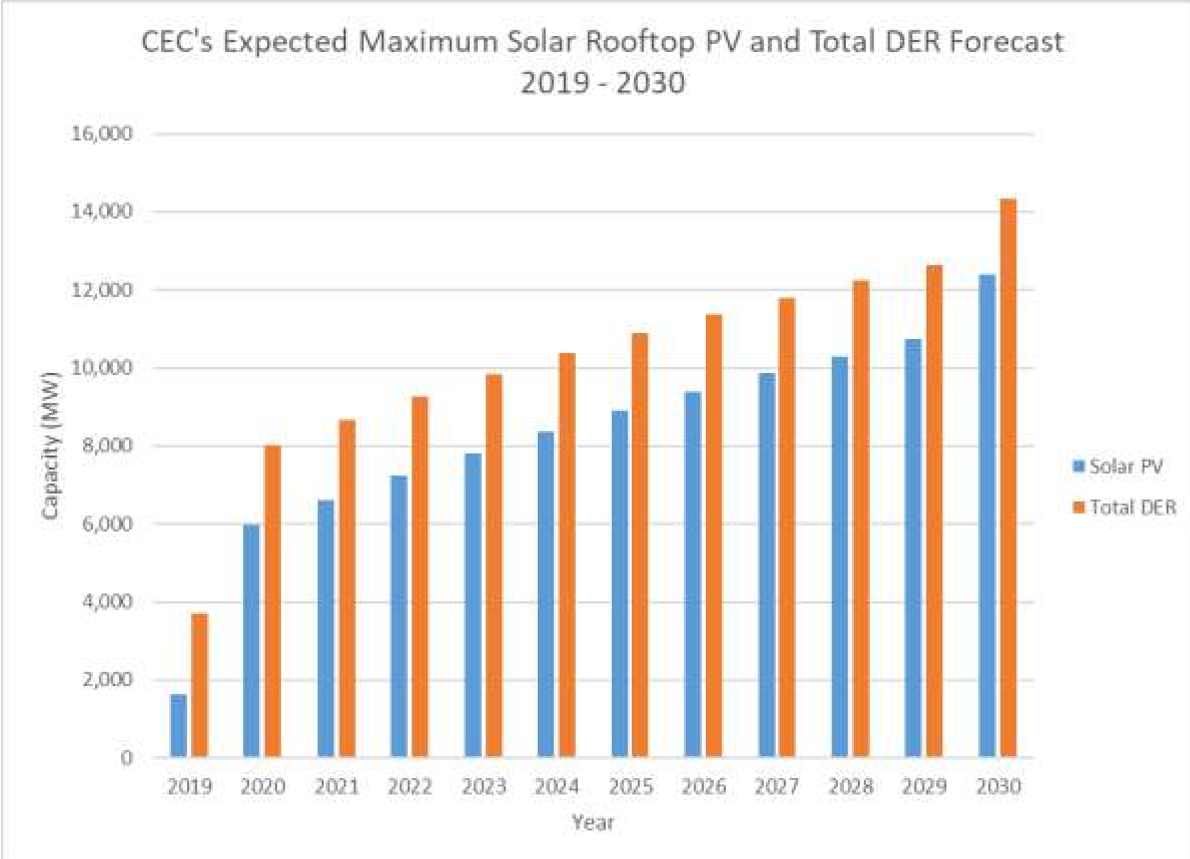

Figure 3.2 Example of Values to Build Base Cases

Key Points of a DER Forecast with Relationship to Planning Studies

Future studies should be of high quality as well as being representative of the study conditions. Some DER forecast information is more important for long term transmission planning studies. In particular, MOD-031 already has a list of minimum values associated with the data request in its first requirement; however, an additional set of points, in **Table 3.1**, should be explicit or identified in DER forecasts.

Table 3.1: Key Values to Consider in MOD-031 Data Requests and their Importance in Planning Studies		
Item Requested	**Information in Planning Study**	**Key Points**
DER Capacity and Type (MW)	In order to fill out the steady state modeling tables, the total DER capacity would need to be accounted, as well as what amount of DER is expected to be contributing for the base case assumptions. Additionally, knowing which type of the DER was built during the historic years and projected future years will provide TPs a way to view the operational profiles of their local T-D interface and how	When building an Interconnection-wide base case, capacity information, dispatch patterns, and other assumptions are used to provide the starting cases. The DER capacity, type, and dispatch provides these BPS level studies a starting point for the expected future conditions. For other future assessments, distributing a larger region (i.e. state level) forecasted capacity with a type based on historical

Table 3.1: Key Values to Consider in MOD-031 Data Requests and their Importance in Planning Studies		
Item Requested	**Information in Planning Study**	**Key Points**
	such changes impact the way they study their area.	adoption can provide TPs a higher sense of trust for the expected future operational profile.
DER Location (Load Bus)	TPs and PCs want to know the geographic spread of the DER penetration and the electrical bus in their model represents that geographic region. At both a coarse and fine regional level, the TP/PC would want to know the proximity of DER to other load buses and any reconfiguration schemes that may change the DER location.	Knowing the existing locations of DER, combined with forecasted locations from a larger geographic level allows the TP to compare to a smaller geographic level[31] and to gain more trust in their placement of DER in their planning models. In instances where the T-D interface depends on feeder configuration for DER, this can also impact the power flow of the associated Load Bus in the forecast.
T-D Operational Profile	TPs/PCs would want to know the expected type profile to determine their more risky hours. To do so, they would want to know the expected outputs for the aggregate DER modeled at the T-D interface between current conditions and future conditions. This is above and beyond simple capacity values and types.	DER forecasting entities have some level of assumptions tied to how the operational profile changes due to how much extra DER of specific types are deployed. TPs and PCs are looking at optimizing the case creation process based on many targets; however, the adjustments from T-D operational profiles may require the TP/PC to review how they expect the dispatch pattern or other characteristics of the DER in future base cases.[32]

Best Practices and Forecasting Procedures

This section highlights best practices for disaggregating DER into appropriate values for building future-year base cases. As today's load mix can include a large amount of DER in a specific region, a TP or PC using forecasted values in aggregate should take care on how the disaggregation of the value in their region is applied. This is specifically concerning the disaggregation of DER from load; DER in a region from an aggregate, study-level DER value; and DER types from the total amount of DER represented at the specific region. Figure 3.3 shows how disaggregation of a forecasted value may occur. Assumptions and methods surrounding these separations should be based on latest available engineering judgement and documented in the base case building assumptions. As shown in the figure, the disaggregation to the model level input is the result for each individual load record in the planning case. As TP and PC modelling practices differ, the disaggregated value could be the active power generated from an explicit generation record to a value entered the "distributed generation" component of the load record. Both are considered an explicit representation of DER in the transmission model. The delivery point in the figure is the Transmission to Distribution Interface (T-D Interface) where multiple feeders or phases of distribution banks may occur. Sometimes,

[31] i.e. from a state down to a specific Transmission Owner or utility

[32] For example, DER forecasts that identify an increase of BESS DER in a region historically dominated by Solar PV would have the output of the aggregated DER at the T-D interface not be limited by irradiance in this future case.

the DER model value is the same as the T-D Interface DER value depending on the TP or PC modeling practice. In all instances however, disaggregation from the wide area DER (sound in MOD-031) to the load record in a individual planning area occurs from the Forecasted DER to the value at the T-D Interface.

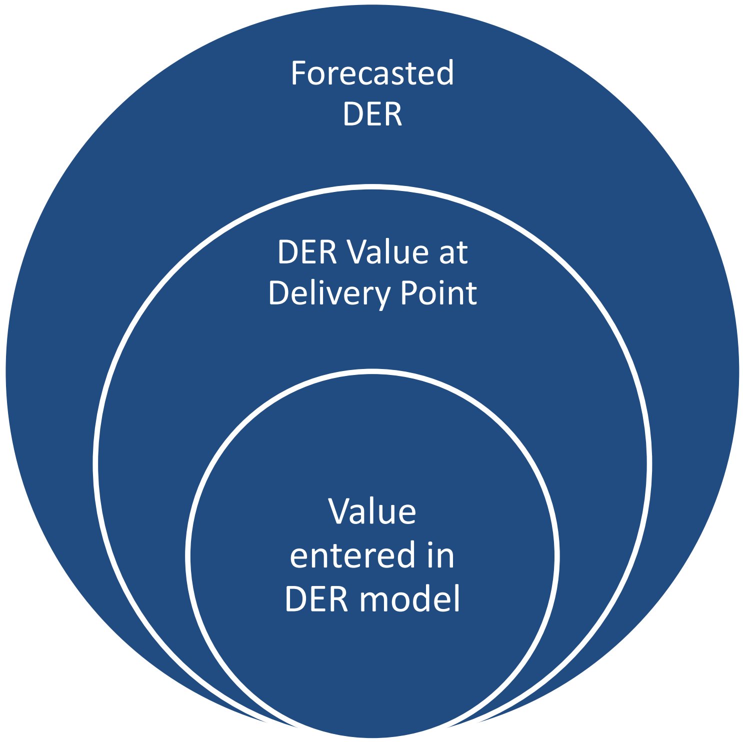

Figure 3.3: Disaggregation of DER into a Useful Study Value.

In the current list of NERC Registered Entities, the DP is the best fit for a functional entity that may maintain a relationship with the DER associated with the distribution system they oversee. While some DPs may not have information from all DER owners at this time, this lack of data does not detract from the importance of providing accurate future aggregate DER values to be used in transmission level studies.[33] It is important that entities chose a method from **DER Forecasting Methods** and ensure that future year forecast information is available to validate future year base cases. TPs and PCs should perform DER (and load) forecasting to the limits of their data availability or request forecasts from other entities (including other trusted vendors) to ensure their future year base case assumptions match.

Data from Reputable Sources

When unable to forecast from a certain data set, TPs and PCs may look for information from trusted sources. The specificity of the region (e.g., substation specific versus region specific) under forecast, expected DER growth from the TP/PC, and previous ability to track and predict useful information are a few important factors when integrating DER forecasts from a trusted source. As forecast approaches and methods are not mutually exclusive, a single forecast can use a combination of approaches and methods to also assist in verifying base case quantities. As such, a TP or PC should fully understand the methods and approaches when provided with a forecasted value and take the most suitable one for their base case creation procedures.

An example of this can be seen when Arizona Public Service (APS) began implementing a different rate structure (**Figure 3.4**) based on the net load of their service area. This created a differing adoption rate (and thus forecast) of

[33] See *Data Collection: Approaches for Probabilistic Assessments Technical Reference Document* for more information. Available here: https://www.nerc.com/comm/RSTC/PAWG/TRD-Data_Collections_Report.pdf

DER growth. APS worked with an entity to assess the potential solar adoption of rooftop solar in their service territory and forecasted their adoption using an S curve Bass diffusion model. The model added constraints by both customer segments as well as physical characteristics like shading, structural adequacy, and rooftop orientation. Such a model allowed the forecast to project hourly values when coupled with historic production and the forecast Global Horizontal Irradiance (GHI) from a typical meteorological year[34] in their area. The results of the simulation included annual production, capacity, and number of installations. Here APS was able to provide WECC their forecast values at specific substations in the base case creation process[35]. As their procedure forecasted the T-D operational profile, the location, capacity, and expected production from that capacity, APS was able to send to WECC the major values needed when adding DER into a future planning base case.

Figure 3.4: APS's Change in Annual Rooftop Solar Growth

Example Checklist to Verify Forecasted DER Values

Forecasts do not necessarily align between the distribution and transmission side of a T-D Interface. A DP may want to emphasize local factors that contribute to more DER capacity projections when performing distribution planning studies; however, a TP/PC may want to emphasize growth across a larger geographic area for use in their studies even if the growth simplifies local factors. These forecasts may align in terms of DER capacity and location; however, this may not always be the case. Further, forecasts for a broader geographic area require more error to label values as "suspect". For instance, in CAISO the TPs submit their powerflow data with the forecasted DER and Net Load values in the steady state models. For CAISO, it would take more difference to label the data received as "suspect" than for the TP forecasting their own set of DER penetrations to establish the values, as the TP's planning region is smaller

[34] This method of forecasting the GHI to produce an expected production profile allows for a forecasted capacity value to also produce an expected operational profile.

[35] To be clear, a forecast that does use exponential growth using the same data may have a different purpose and may still be useful in other instances than base case creation such as the development of a scenario case. However, for the submittals, this value was used in the forecast.

than its PC or BA. As such, the above questions do not have a size limitation or threshold associated with them, as they are applicable for entities that have a large or small penetration of DER.

Each of the points above indicate that some quality control should be performed for future year projections. Generally, TPs and PCs are encouraged to:

1. Understand DER forecast assumptions and their base case assumptions.
2. Determine if the forecast values come from a wide area perspective or a local perspective compared to the T-D Interface.
3. Compare the forecast value to their base case assumptions.
4. Identify specific technical rationale for differences between the forecast and base case or alter base case values to match.

Currently, some entities look at forecasts developed four to five years ago and compared the information to today's system to see if the forecast from years past accurately predicted today's electric system. Seeing a difference between historic forecasts and today's quantities provides entities information for possible improvements in their process; however, TPs and PCs should implement a more proactive approach when producing, obtaining, or altering forecasted penetrations. An example checklist of questions a TP, PC, or other entity can ask regarding the DER quantities found in **Table 3.1** is in Error! Reference source not found. below**.** Answering these questions allows a TP, PC, or other entity a method to qualify their level of confidence in the future studies and base cases. Depending upon the relative size of the area being forecasted, the questions may have a differing role, or level of severity, and other questions may also be added. TPs, PCs, and DPs should coordinate on the questions to help improve the transmission system models and case development practices to ensure the information gathered in MOD-031 and from other forecast entities can validate their planning models and practices.

Did you find a reputable source?

- Was the data filled out completely?
- Are there any suspicious values?
- Is this an aggregate level forecast?

Are you tracking DER location in the forecast?

- DER Capacity
- DER dispatch and assumptions depending on base case
- Is there a link to base case inputs?

Are you taking into account expected operational profiles?

- Did you assume one profile?
- What are the profiles based on?

Do you understand the method, inputs, and outputs of the forecast?

- Did you need weather data?
- Did the forecast use more than one method?
- Did the forecast use sensitivities?

Does the forecast "make sense" from a high level and T-D perspective?

- Is the forecast coordinated with neighboors?
- Does the output of the DER match with assumptions?
- Did the forecast sensitivities include policy/market/economic changes?
- How sensitive was the forecast?

Figure 3.5: Example Checklist Questions for MOD-031

Chapter 4: Long-Term DER Forecast Impacts to BPS Level Studies

In addition to the items listed in **Table 3.1**, the policy and market trends at the state and federal level should be considered when developing the assumptions for and deciding on the forecast capacity (i.e., MW) for DER in future-year base cases. These policy and market trends should inform both the sensitivity cases and long-term future projection cases for policy targets. For example, policies that may promote specific DER development in certain areas should be studied and projected into cases to determine the effects of that policy on reliability. In recent years, varying policies have been adopted regarding Battery Energy Storage Systems (BESSs) and should inform long-term study assumptions and drive the data in portions of **Table 3.1**.

Likelihood of Different Projections

As discussed in **Chapter 1**, the differences between the DER projections and forecasts are highlighted when looking at how differing projections impact the end forecast. Since each projection is a "what-if" scenario used to show the logical outcome of a particular assumption, the forecast can be altered depending on the projection chosen. Projections have a likelihood of occurring which can be expressed as a probability.[36] These probabilities are difficult to obtain quantitatively but are more easily expressed qualitatively or in relation to the probability of other projections. For projections based on non-policy inputs, a mathematical expression may be able to provide a likelihood for that projection; however, energy policies may not have a mathematical expression for its impact on the projection. Renewable policies in each state that require (or strive to achieve) a specific percentage of renewable generation by a given date should be evaluated to determine DER growth projections, and the TP should identify the forecast (most likely) for these projections as a base case. The TP can then choose a different projection to perform a sensitivity on the impact energy policy may have on the capacity of DERs in a planning model.

Since some energy policy targets are more likely and certain non-policy projections will have a higher likelihood of occurrence, a projection that focuses solely on the higher likelihood policies is well suited to use in a forecast. Since a TP or PC will also need to study the lower likelihood, high impact situations, the TP or PC will need to find a projection that focuses on these lower probability impacts. These lower probability scenarios will be used in their future studies to determine the impact that differing projections have on their areas. To illustrate this, consider the following steps a hypothetical TP took to analyze the impact of low likelihood, high impact DER projections.

1. A TP uses a state-level forecast and disaggregates the forecast into their models. After verifying the forecast with a checklist like the content in **Example Checklist to Verify Forecasted DER Values**, the TP determines that this forecast captured the high and medium likelihood projections on adoption of DER in their area.
2. The TP also determined that this forecast was developed prior to a pledge by the state that the resource mix would contain 20% more DER by a future date.
3. To analyze the scenario in which the state meets that DER goal, the TP produces a separate projection for rapid deployment of DER. After careful analysis, the TP determines that the increased DER scenario would have a lower likelihood of occurrence than the forecast received from the state due to supply chain bottlenecks.
4. The TP studies determined that the impact to their system under this lower likelihood projection requires upgrades to station service in a location that when using the forecast results did not occur. As a result, the TP produces a plan to upgrade that station, even though the issue presented itself in a lower likelihood projection.

[36] Some items, such as an expected or future policy, are non-quantifiable as a probability or likelihood of occurrence. These are captured in a forecast by projection or scenario studies. Extreme weather scenarios, on the other hand, are an example of a probabilistically quantifiable projection.

Long-Term Dispatch Considerations

Dispatch patterns vary according to the various kinds of resources that are a part of the dispatch interface studied. For instance, a T-D interface dominated by Solar PV DER will have different dispatch assumptions than one that contains Solar PV and BESS. Because of the many different operational characteristics of differing types of DER, it is recommended that consistent labeling of the data is included at all stages so all information is clearly understood by the entities. That is, DER information from the distribution side of the T-D interface to the transmission side should contain adequate labels and descriptions. For instance, the label of "DER" is less useful than "Quantity of Solar PV DER confirming to IEEE 1547-2018." This will allow a TP to predict changes in dispatch patterns in the long-term horizon.

Since types of DER can behave differently, forecasting just one DER value for study will require some engineering judgement or considerations of expected output at the future modeled conditions. An example of these changing conditions can be found in **Table 4.1**, where the historic DER installation has been estimated and then anticipated changes have been forecasted for future BPS-level studies. A determination on the expected flow or impact to the T-D interface cannot be reached without also looking at the changes the modified resource mix has on the dispatch profile. An example, using hypothetical data, of how this dispatch pattern may be altered is shown in **Figure 4.1.** This example takes the expected capacity changes and, assuming the changes operate similar to current resources, visibly alters the aggregate DER output. As demonstrated in the figure, both the maximum MW produced and the times where those maximums are likely to occur shift depending on the expected resource changes. As such, long-term dispatch assumptions should be examined when differing resources make up the aggregate DER.

Table 4.1: Example Dispatch Changes Affecting Future T-D Flows

Item	Historical Output	Future Conditions
Resource Profiles	Obtained a historic output profile from SCADA system sampling near or at the T-D interface	Assumed same historic resource profiles
BESS MW Value	A 5 MW total of BESS were found to be on the feeder.	It is anticipated three new 4 MW BESSs are installed on this feeder, bringing the total to 17 MW
Solar PV MW Value	15 MW of U-DER DER is associated with historic T-D penetrations	5 MW additional U-DER is planned to be added for this future case. Total of 20 MW
Microturbine Value	A 1 MW microturbine was added before the large expansion of Solar PV and BESS in this feeder. It runs between 0700 and 1800 hours	Assumed same 1 MW turbine exists in the future case.
Other	A residual amount of data was not directly metered or associated with the BESS or Solar PV quantities. Its value can rapidly change and was associated with non-metered U-DER or R-DER	Same values applied in future case.

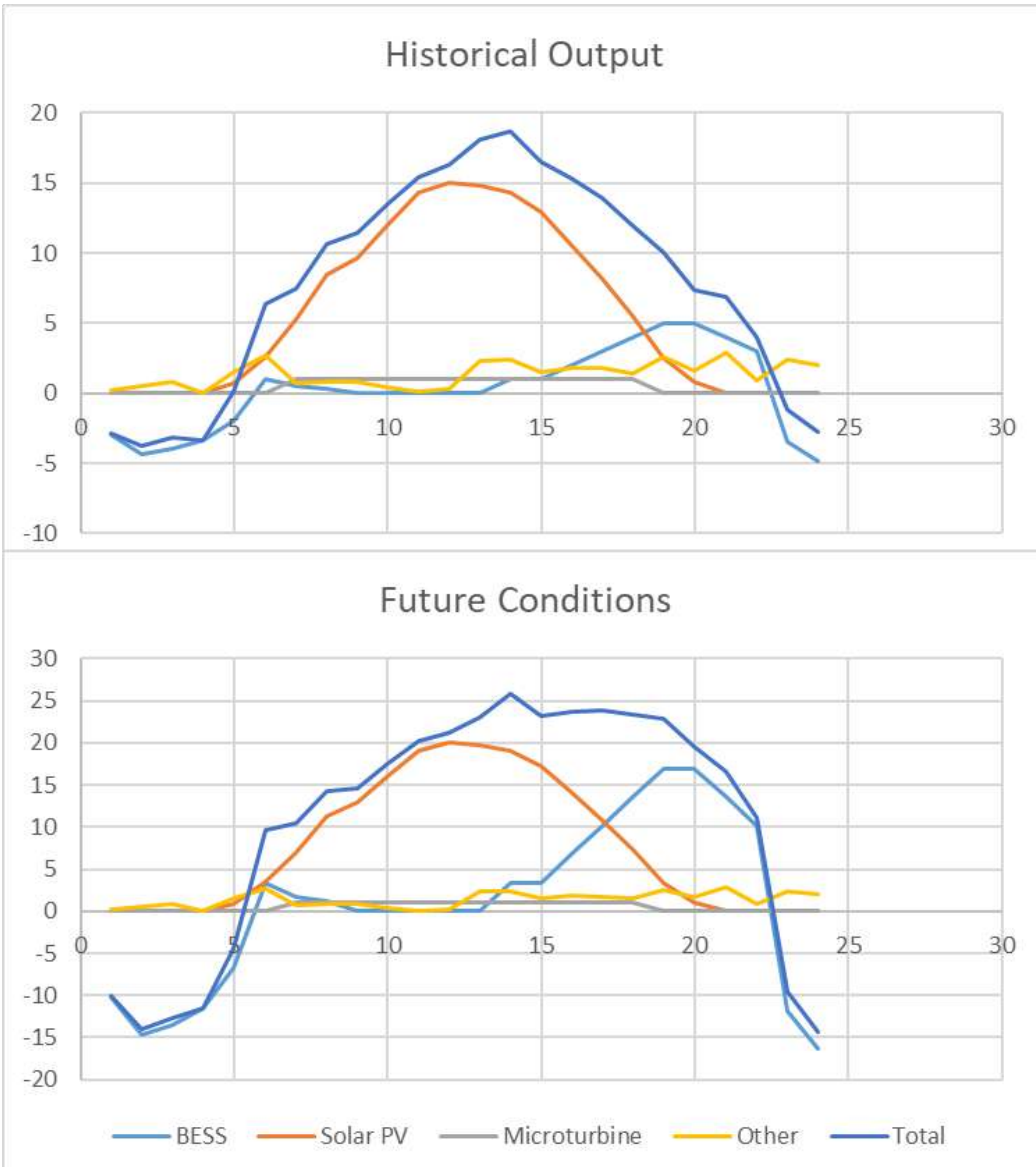

Figure 4.1: Example Long-Term Dispatch Forecast at a T-D Interface

The example in **Figure 4.1** demonstrates just one of the differing types of profiles the future output profiles predicted for this T-D interface. This future operational profile may change depending on the types of services and interconnection agreements the installations may have. The point of this example, however, is that a TP or PC can use their engineering judgement to determine the risk hours for a T-D interface based on the forecast value, historic operating profiles, and anticipated changes to the aggregate behavior of the T-D interface.

Example DER Forecast to BPS Study Dispatch Changes

ISO-NE provided an example that highlights the approaches and recommendations from the previous chapters. ISO-NE's load forecast department uses a top-down forecasting approach for each state. This way, they are able to capture the various state incentives for load and DER. Based on previous studies, they altered their percentages to those found in **Table 2.1** in order to distribute into their study case. This provides a way to geographically distribute the DER forecast into the geographic zones in their study. They further disaggregate their forecast by proportionally distributing the growth already spread by geographic proportions into each load record according to how much it makes up the total load in that dispatch zone. The left figure in **Figure 4.22** provides a visual indication of the DER percentages found in **Table 2.1**. The right figure in **Figure 4.2** shows how those percentages can be allocated to predefined dispatch zones.

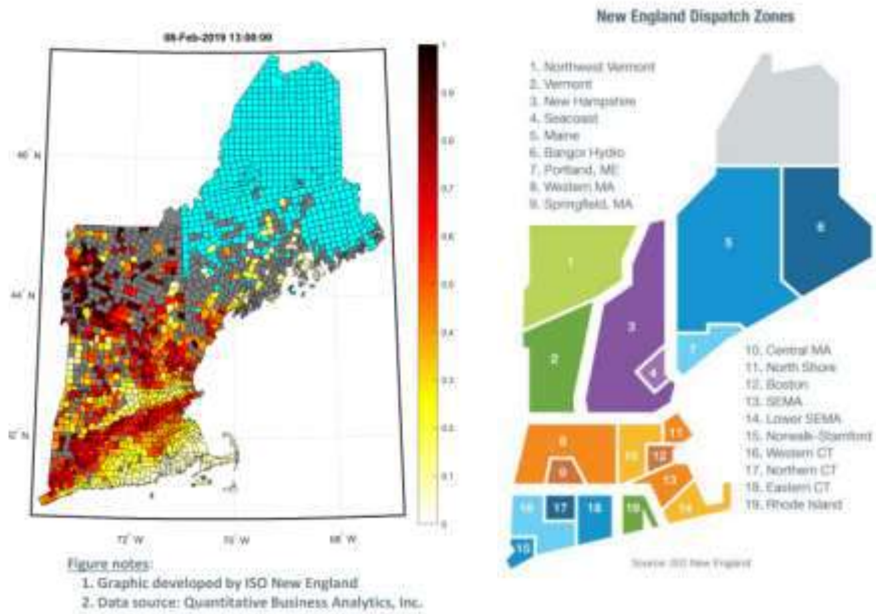

Figure 4.2: ISO-NE Geographic Distribution Breakdown

After ISO-NE developed expected dispatch zones, they were then able to adjust study dispatch values based on their DER forecast. Their expected DER growth is captured in **Figure 4.3**. Figure 3.3 also contains the prior year forecasts and the historical growth to demonstrate how ISO-NE kept refining their process after previous forecasts proved to differ significantly from actual growth.

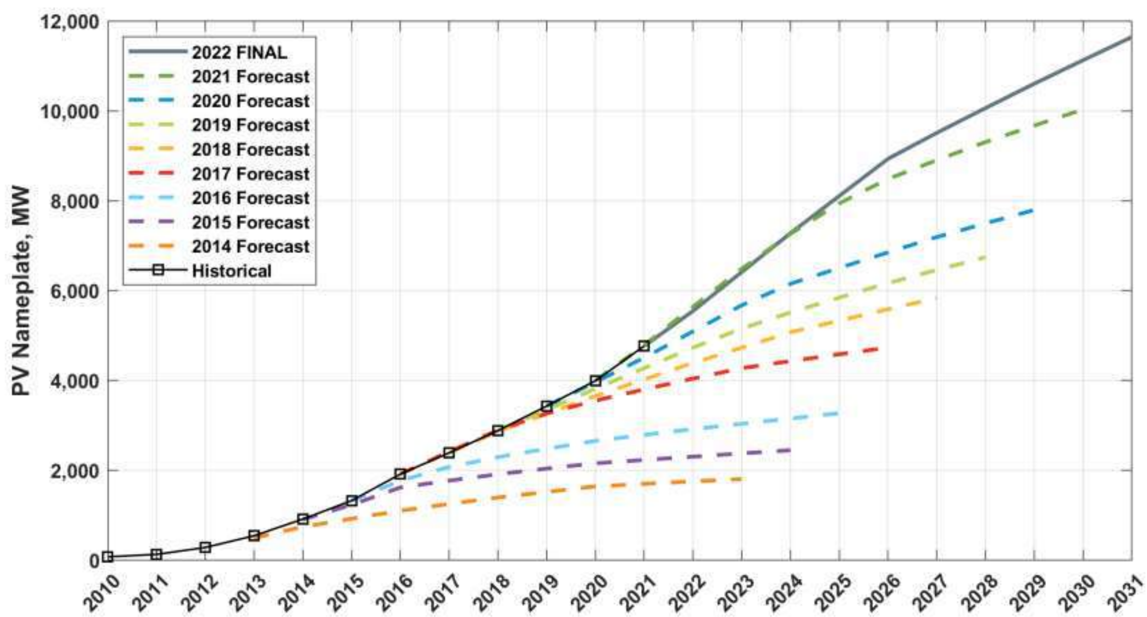

Figure 4.3: ISO-NE DER Forecast from Historic Growth

As seen from the figures above, the geographic distribution method done through ISO-NE allows for future studies can allocate differing DER generation for various areas of their system. While a local area or bus may only see 1 MW or so of difference, the studies performed at ISO-NE are able to account for large differences in projections. For the projection graphs found in **Figure 4.33** and the geographic distribution in **Figure 4.22**, it can readily be seen that a significant amount of DERs are coming online in multiple different regions and that the initial forecasts were lacking. In this ISO-NE example, the difference between the2014 forecast and the 2016 forecast for the 2020 year is almost 1 GW. On a system-level perspective, 1 GW of load served locally displaces large BPS-level generation facilities for future BPS-level reliability studies. Spread throughout the many busses, the impact of this large amount of DER may be reduced; however, depending upon state and local programs, DER may be concentrated in small pockets. Both the system and local areas can experience reliability concerns from that new system dispatch.

TPs and PCs should use DER forecasts that contain a high level of confidence in their accuracy and that the studies conducted by the TP/PC are able to use these high confidence forecasts. In ISO-NE's example, they were able to find a reputable source that tracked DER information that produced reliable forecasts for use in studies. ISO-NE understood the limitations and assumptions of the forecast which resulted in a successful refinement to future forecasting procedures. This type of approach provides a higher confidence in the DER forecast values and helps to proactively identify risk posed by long-term dispatch changes.

Procedure Refinements and High-Level Recommendations

SPIDERWG has performed an analysis of its membership's forecasting practices and a few of the TPs performed some sort of procedural refinement for their forecasting practices. From the SPIDERWG analysis of their own membership's practices, SPIDERWG identified the following:

1. Some entities manually checked actuals against previous years' forecasts. Entities that manually checked their forecasts generally took their current year DER queue and compared it with the previous years' forecast to make changes to the forecasting procedures.
2. Some entities perform automated checking of forecasts via playback into their procedure. Entities that performed automatic checking generally used a playback of a model to match their forecasts with other types of projections to see how their forecast aligned with their past and current projections. This is typically done as part of a larger effort to refine the forecasting procedures.
3. Some entities do not perform any refinement to their forecasting strategy or projection.

Based the above points, TP and PCs should:

4. Attend and contribute to current forums where DER forecasting is discussed. Furthermore, TPs and PCs should coordinate with their RPs to discuss forecasting of DER in their region.
5. Coordinate with RPs in their service territory to ensure resources, inclusive of DER, are not being double counted. RPs should also coordinate with other adjacent RPs to ensure no double counting for DER forecasts.
6. Coordinate between their load forecasting and planning departments to ensure forecasts meet the TP/PC requirements, primarily for development of base cases.
7. Obtain accurate data in their set of future year Interconnection-wide base cases, inclusive of DER values. TPs and PCs are encouraged to coordinate with various sources, including the DP and other forecasting entities, to ensure accurate data is used in future year Interconnection-wide base cases.
8. Develop checklists as in **Error! Reference source not found.**5, altered to fit their needs, and use the list when incorporating forecasted data in their planning studies.
9. Review a variety of DER projections to see which projection is best suited and aligned with their set of study assumptions. This may mean the TP and PC use DER forecasted values for a portion of their studies a different DER projection for others.

Additionally, if entities other than the TPs and PCs desire to perform a forecast for DER, those entities are encouraged to coordinate with DER developers and other distribution entities to obtain important capacity, location, and operational profiles.

Contributors

NERC gratefully acknowledges the contributions and assistance of the following industry experts in the preparation of this guideline. NERC also would like to acknowledge all the contributions of the NERC SPIDERWG.

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Guideline Information and Revision History

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

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

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:

- Count of self-attesting TPs and PCs that have implemented a checklist akin to **Figure 2.5**
- Count of entities that have identified specific changes to forecast information, including changes to data collection, forecasting practices in industry, Load Forecast Uncertainty, expected forecast error, planning assessment inputs.
- Comparison of realized DER values from previous year forecasts as reported by a TP or PC.
- Percentage of DER modeled in a transmission base case[37] compared to the total capacity[38] of DER reported in the NERC Long-Term Reliability Assessments for a given year, adjusted for resource categorization shifts.

Effectiveness Survey

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

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

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

Guideline Effectiveness Survey [insert hyperlink to survey]

[37] This includes both explicitly modeled DER as generators or DER modeled using the dg fields in the load model.

[38] Calculated using best available capacity factors and engineering judgment to align the generation in the base case to nameplate capacity.

White Paper: Reducing Impacts on Bulk Power System Variability and Uncertainty - DER Data Collection, Storage, and Sharing with DER Aggregators

Action

Requesting RSTC Reviewers

Summary

Large penetrations of Distributed Energy Resources (DERs) are significantly increasing variability and uncertainty within planning and operations of the bulk electric system. 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. 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 Distributed Energy Resources (DERs) to participate in wholesale markets. The 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.

This paper's purpose is to convey the needs of collecting information for DERs in a manner that is supportive of grid reliability.

[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

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 received from over 100 sent), however, the SPIDERWG could not generalize the results as a limited number of members responded to this voluntary survey.

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 as the current 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.

[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

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, key entities may not be able to plan and model the system appropriately. With lower penetrations, the variability and uncertainty may not impact an entity 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 needed to provide this critical information for planning and modeling.

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 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

[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.

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

[15] SPIDERWG has published a paper describing the available coordination and communication strategies related to DERs. This is available here: [INSERT LINK WHEN PUBLISHED]

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 reduction translate to more accurate studies and therefore clearer identification of potential reliability risk in the planning horizon. 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, transmission service providers, and market operators presents a unique challenge due to both

[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.

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). 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, 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 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 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 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 because data elements are not only defined in a single object model, but 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 behind those exchanges. 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.

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 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 is it 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, 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.

Modeling DERs in CIM

DER Data covers four distinct functions in the energy industry, which will be defined in this section.

- Capability Data,
- Configuration Data,
- Aggregation Data, and
- Condition & Control Data

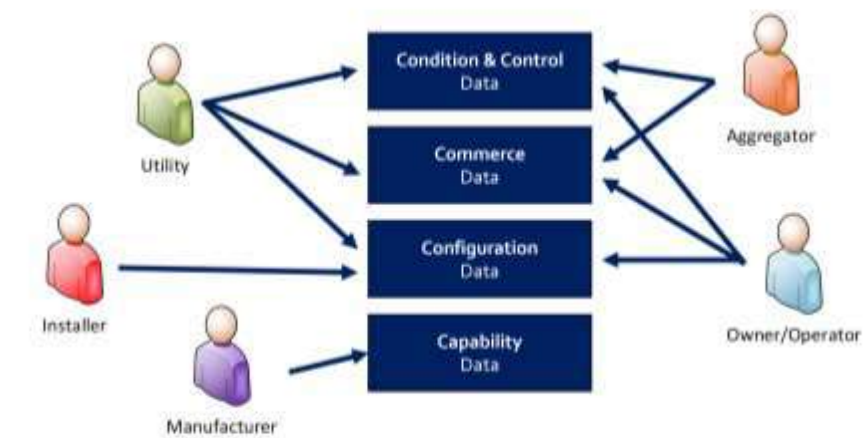

Figure 1: DER Data Set Sources

This data can be provided by multiple entities across the energy industry, including the manufacturer, owner, aggregator, and utility operator (see Figure 1). Typically, each of these stakeholders all use their own set of custom data formats, which are difficult to share and interpret. 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[18]. Examples of DER Capability Data include the

- Make & model identifier
- Rated voltage
- Rated current
- Maximum apparent power output
- Maximum reactive power injection

[18] https://www.energy.ca.gov/programs-and-topics/programs/solar-equipment-lists

- 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.

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[19]. 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 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 describe 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

[19] https://standards.ieee.org/ieee/1547/5915/

- 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 ConnectivityNode
  - 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 poletop 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 Data

Aggregation 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. Examples of DER Aggregation 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. 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.

DER Conditions & Controls Data

Another significant challenge is the exchange of real-time measurements and net aggregate data from both SCADA and AMI across the Transmission-Distribution boundary. 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 multiple distribution feeders backfeeding 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[20] 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[21] 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.

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.

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[20] The concept of separating the OT data bus from the IT enterprise message bus is introduced in https://www.osti.gov/servlets/purl/1813936

[21] 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.

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,[22] EPRI,[23] Vermont Electric Power Company[24], and Collaborative Utility Solutions.[25] 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, 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.

The breadth of industry stakeholders that require access to DER data (**Figure 2**) is significantly broader than historical industry interactions with single set of data. A single system of record a y likely path to allow both transmission and distribution utilities the ability to ensure 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.

[22] 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/
[23] Available here: https://www.epri.com/research/products/000000003002006001
[24] Initial architecture available here: https://www.vermontspc.com/sites/default/files/2024-01/VSPC_VXPlatformpresentation.pdf
[25] The library of resources for Collaborative Utility Solutions is available here: https://www.cusln.org/resources/Public%20Library

Figure 2: 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 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.

Appendix A: Detailed Survey Process with Questions

SPIDERWG followed up its original modeling survey[26] 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)

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

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?

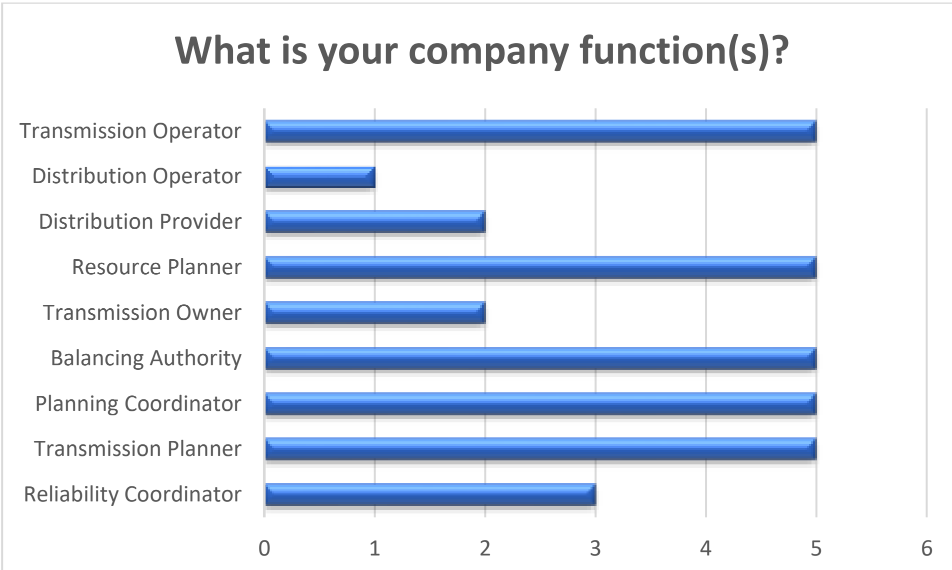
26. For information provided by the DER Aggregator, what telemetry granularity are they able to provide? (e.g., SCADA scans, Advanced Distribution Management System (ADMS), other time frame or framework)

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.

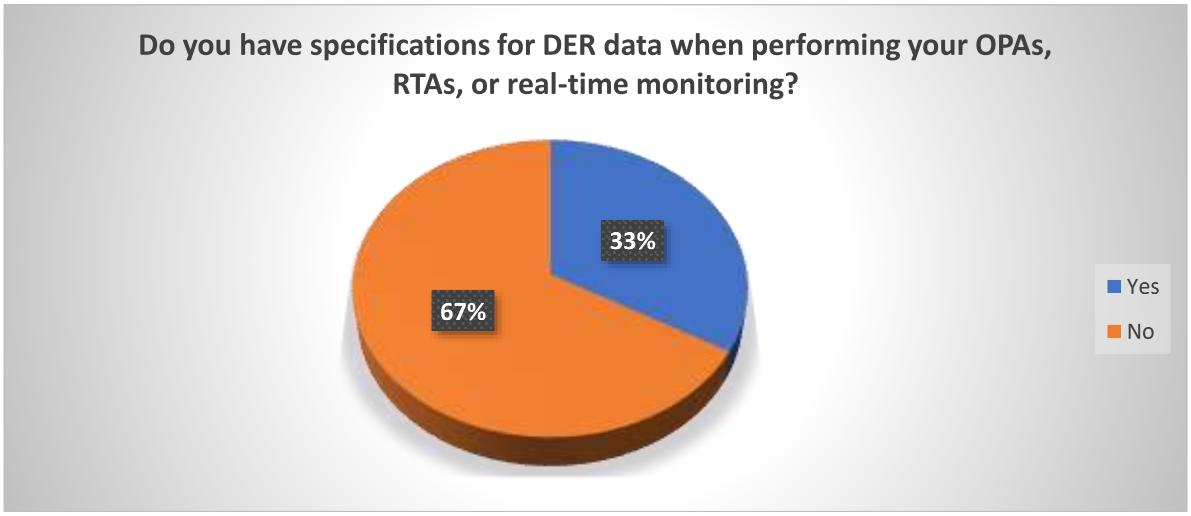
1. What is your company function(s)? (Select all that apply)



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.

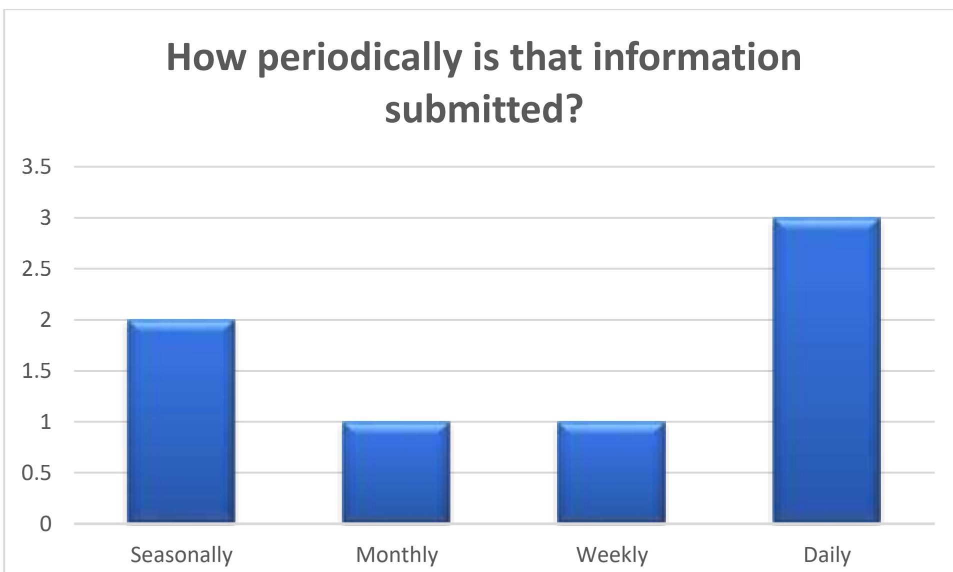
2. If you are a Reliability Coordinator (RC), do you have specifications for DER data when performing your Operating Planning Analysis (OPAs), Real-time assessment (RTAs), or real-time monitoring?



Key takeaway: question 2

Only one surveyed memberSurveyed members with DER aggregators in their region hasve specifications 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?



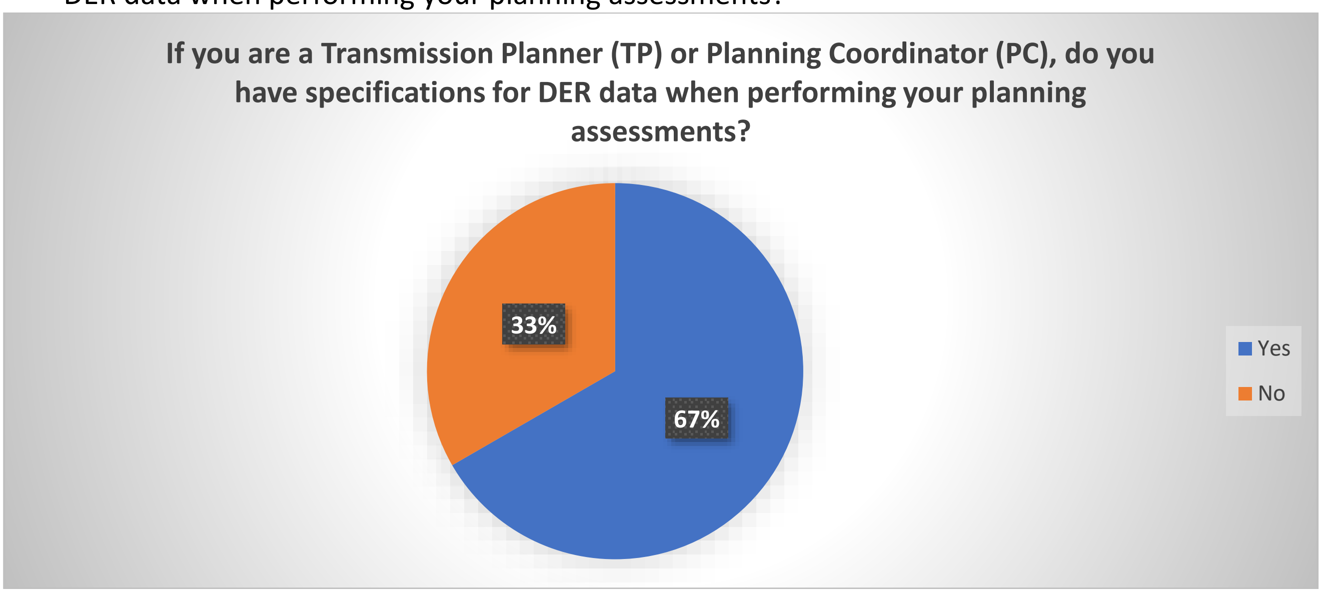
Key takeaway: question 3

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 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.

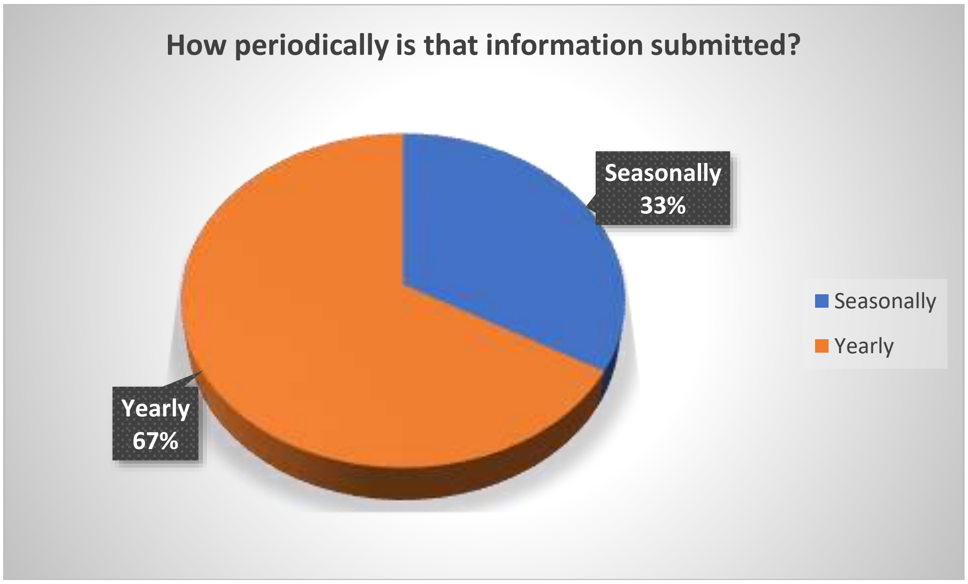
4. If you are a Transmission Planner (TP) or Planning Coordinator (PC), do you have specifications for DER data when performing your planning assessments?



Key takeaway: question 4

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?



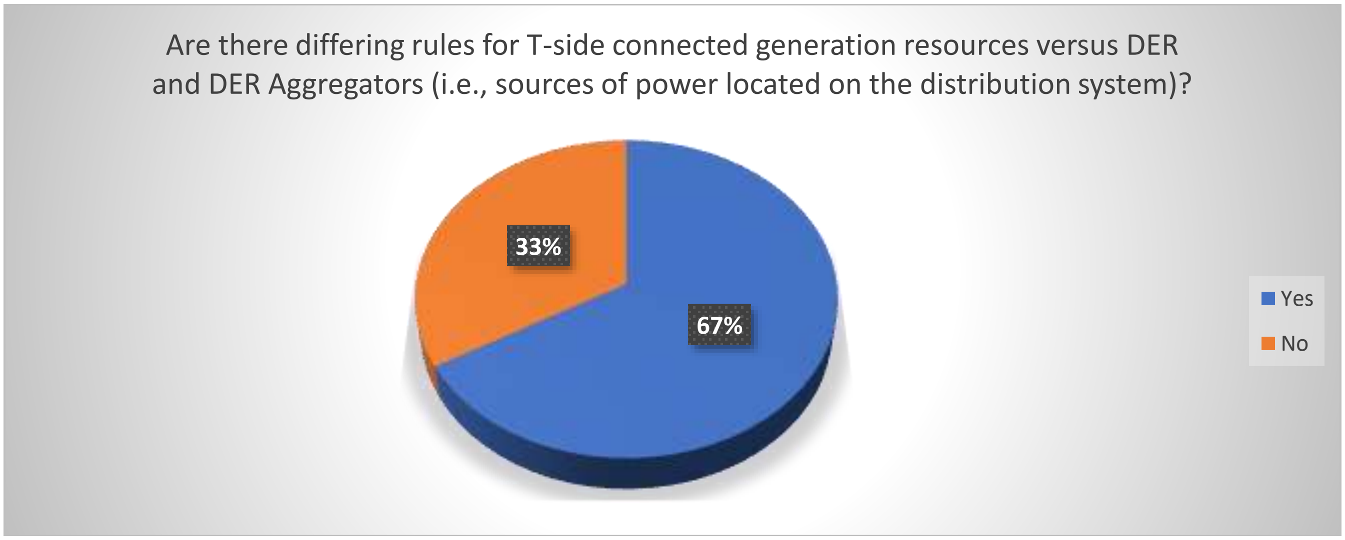
Key takeaway: question 5

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.

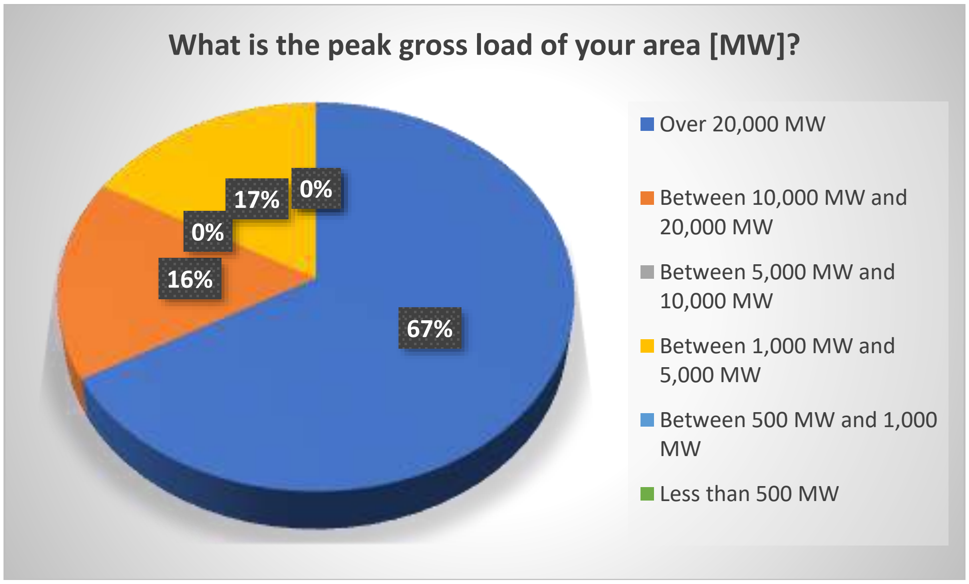
Key takeaway: question 6

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 to transmission 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.

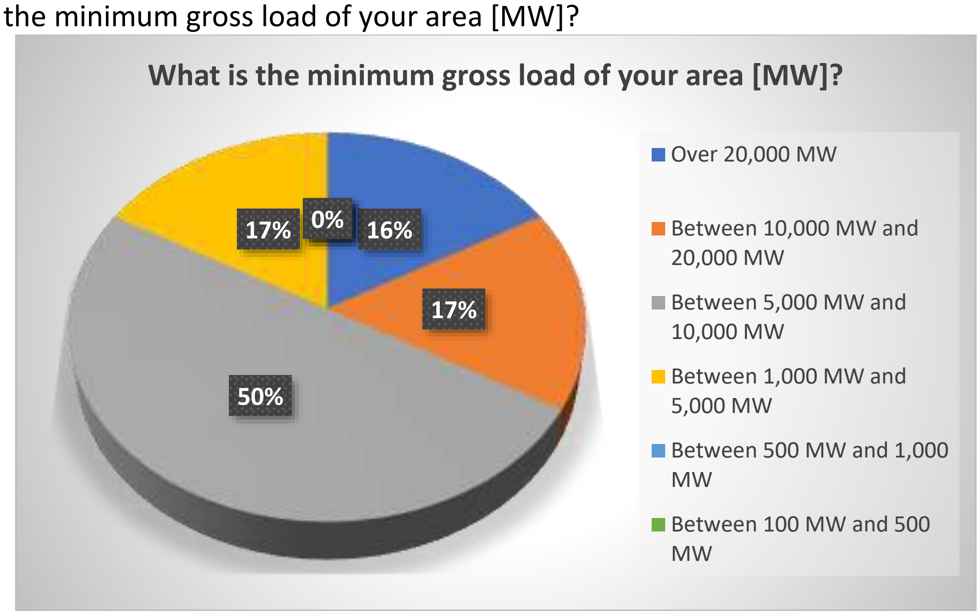
7. What is the peak gross load of your area [MW]?



Key takeaway: question 7

Majority of surveyed members (6775%) have over 20,000 MW gross peak load. One entityRemaining 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.

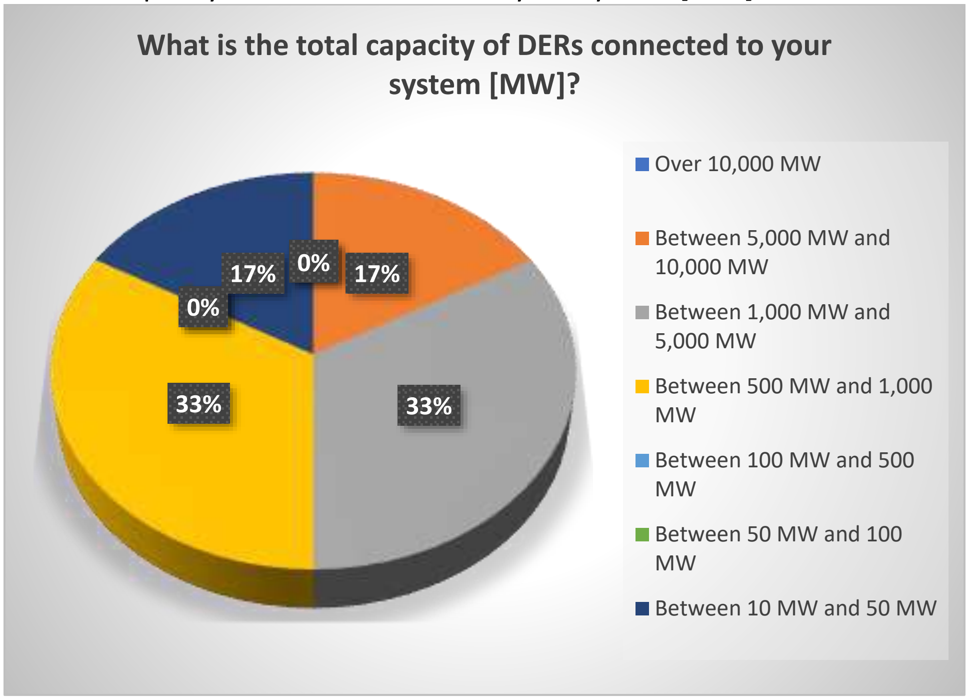
8. What is the minimum gross load of your area [MW]?



Key takeaway: question 8

Minimum gross load among members range between 1,000 MW to over 20,000 MW

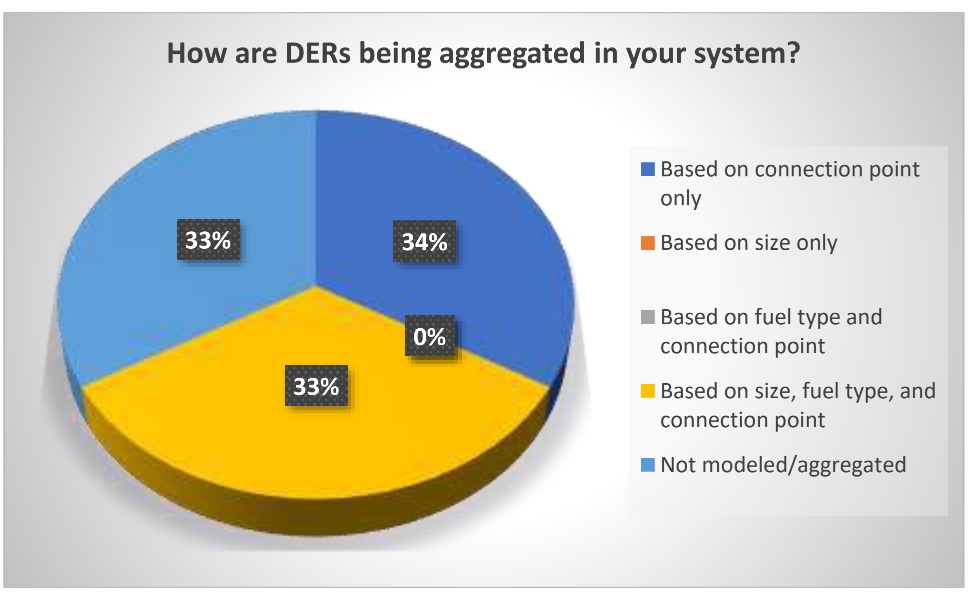
9. What is the total capacity of DERs connected to your system [MW]?



Key takeaway: question 9

7583% 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.

10. How are DERs being aggregated in your system?



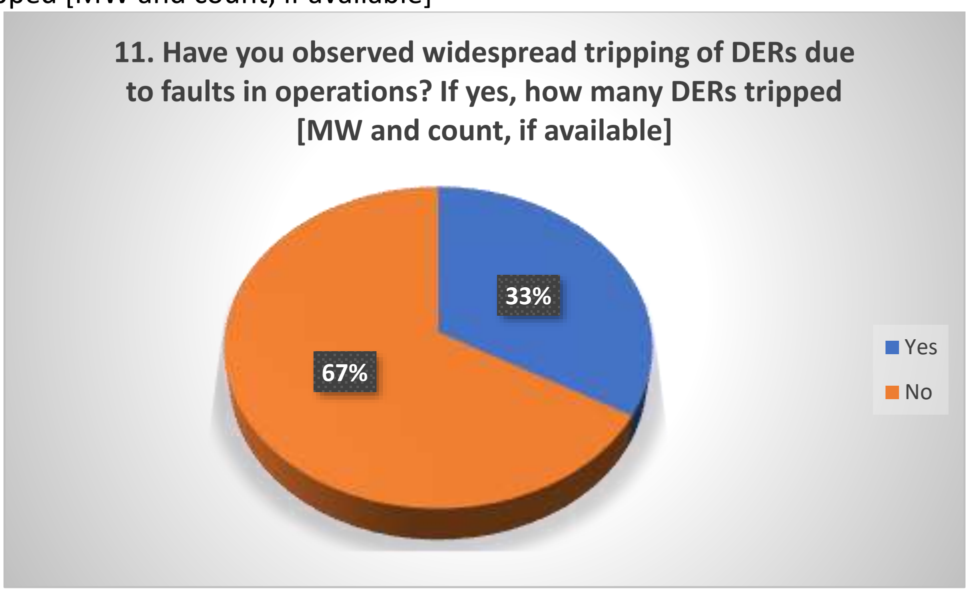
Key takeaway: question 10

Half of surveyedOne-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 entityTwo 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.

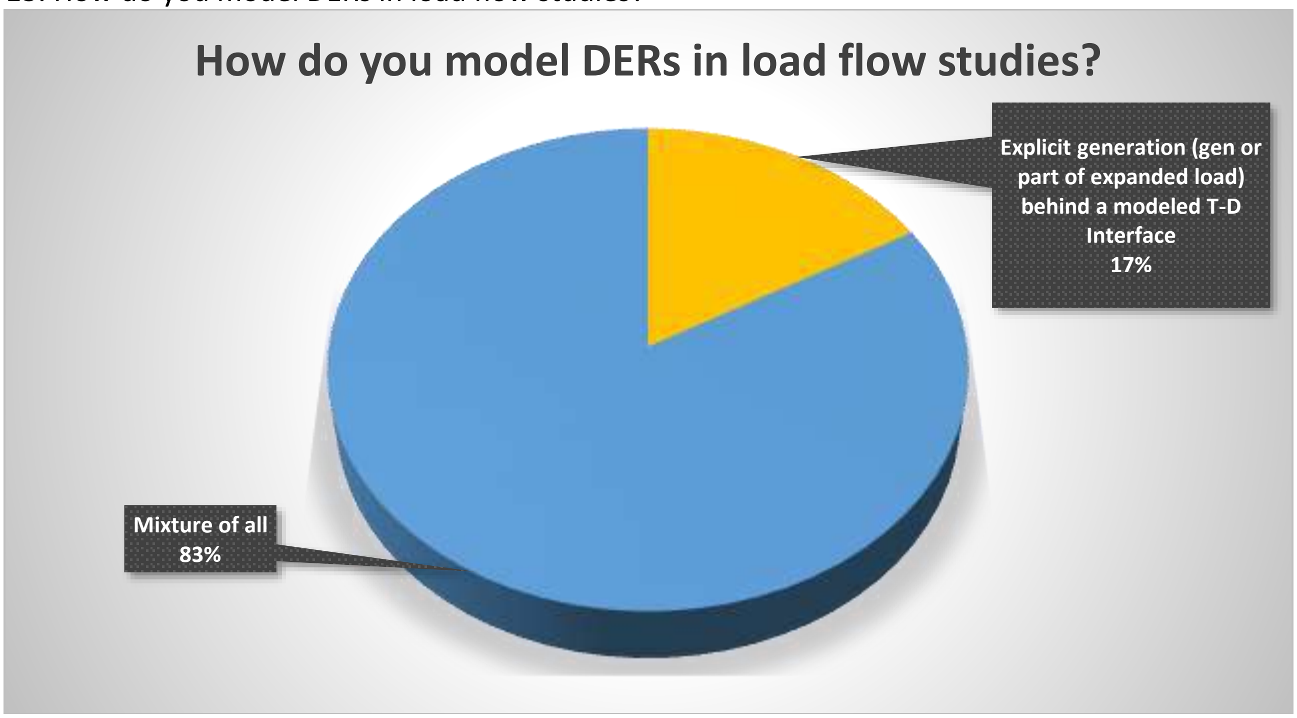
12. Do you receive any DER operational data (e.g., active power output of DER or DER status)

Key takeaway: question 12 (open ended)

Most 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?



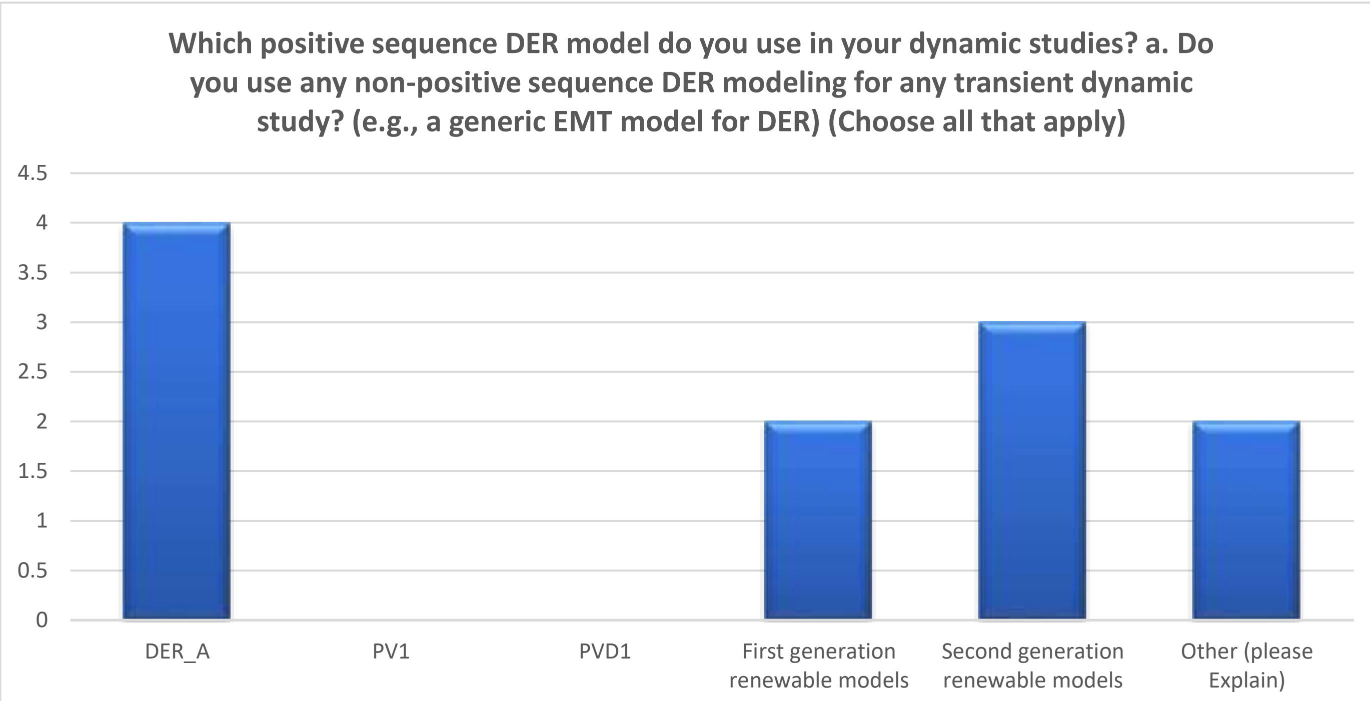
Key takeaway: question 13

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.

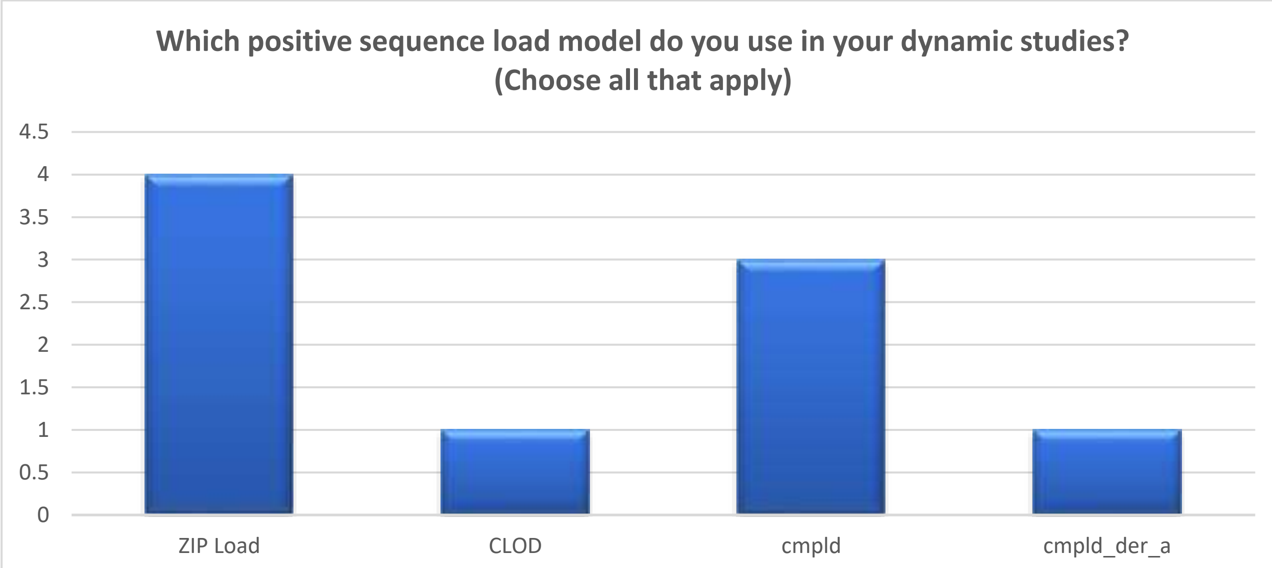
One entity with the smallest amount of DER connected (10 MW to 50 MW) uses a explicit generation behind a modeled T-D Interface as a DER model.

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, Exciter, and Governor 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)

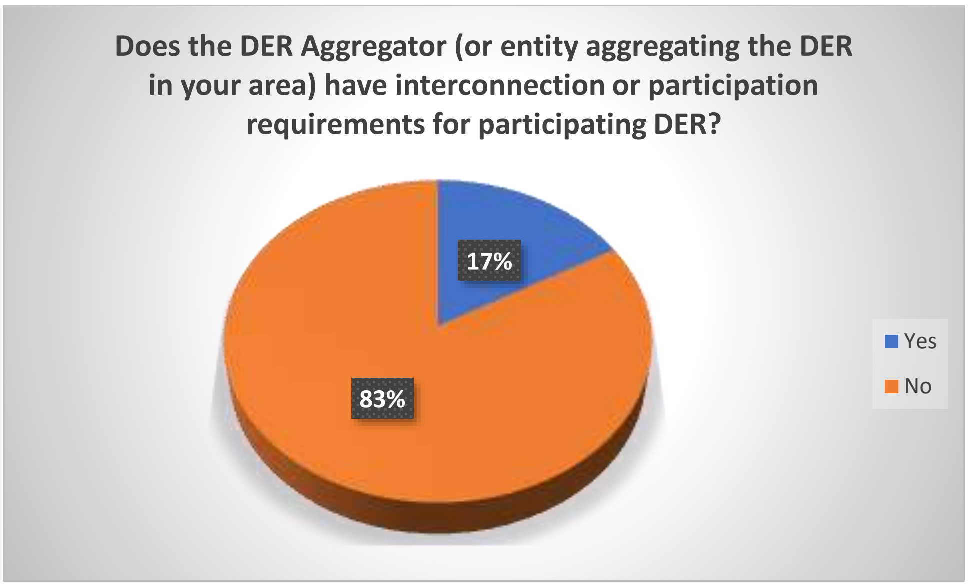
One entity allows DER aggregations to participate in their wholesale electric market. In general, the entity that represent a registered aggregator should also represent the load. Under the pilot for DER aggregations, they will be controlled through base point instruction produced using security-constrained 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)

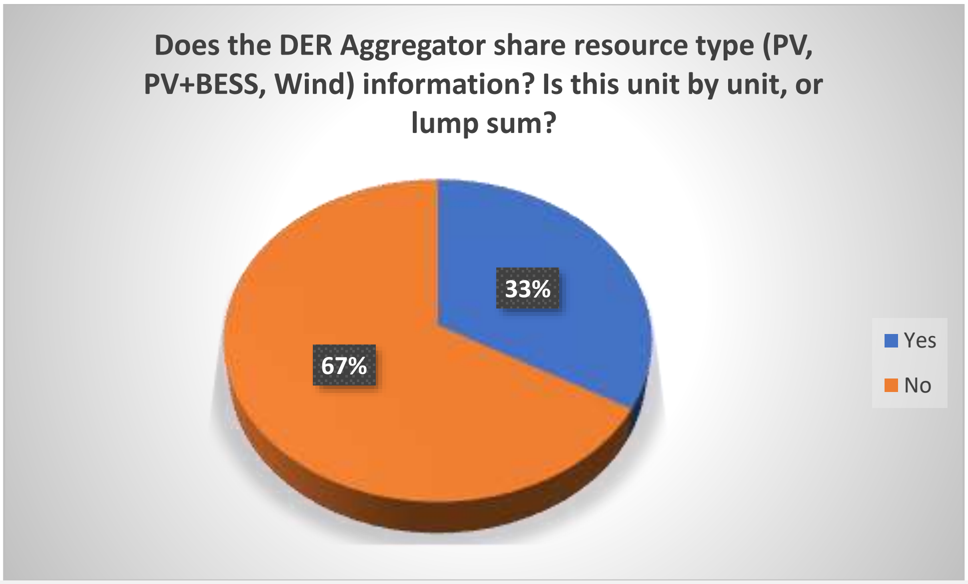
One entity shared that prior to allowing a premise or device to become part of an aggregation, the distribution service providers review the list of all proposed premises and devices and can either approve or reject each individual line item. This is their first opportunity to head off potential concerns. 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.

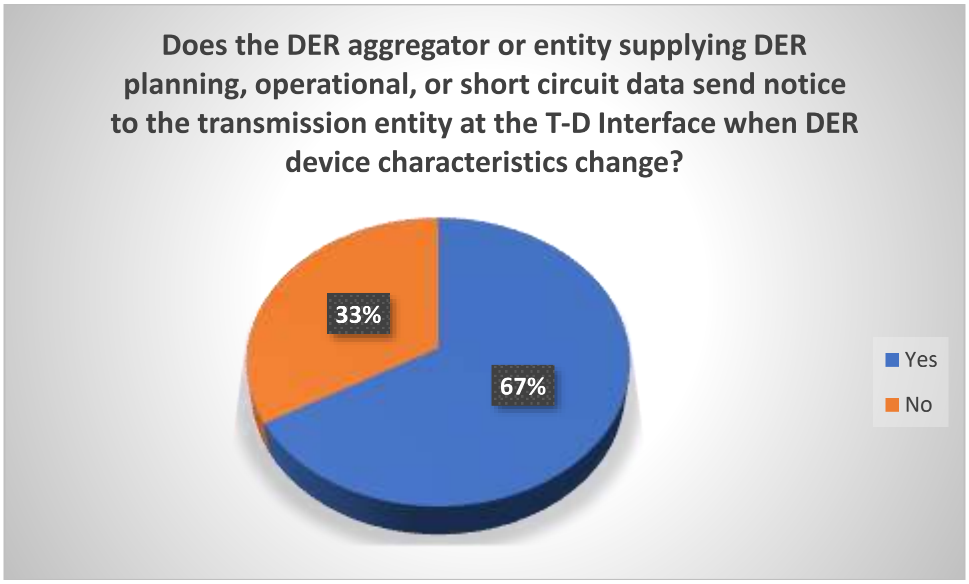
21. Does the DER Aggregator share resource type (PV, PV+BESS, Wind) information? Is this unit by unit, or lump sum?



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.

Effective Facility Ratings Programs
Incorporating Sampling into Facility Ratings Assurance

Action
Request RSTC Comments

Background
The reliability of the BPS depends upon registered entities having strong and sustainable Facility Ratings methodologies. Facility Ratings are data intensive and require substantive oversight and validation activities. This whitepaper details how using sampling as an internal control or quality assurance activity as part of the Facility Ratings methodology can help registered entities enhance the validation process and minimize issues and ensure oversight for adherence to the entity's Facility Rating Methodology.

Summary
The Facility Ratings Task Force requests that the RSTC solicit volunteers to provide feedback on this document in anticipation of submitting the finalized document to the RSTC for approval at its September meeting.

Assessing the Effectiveness of Facility Ratings Methodologies

Incorporating Sampling into Facility Ratings Assurance / May 2024

Executive Summary

Facility Ratings are one of the most data intensive regulations in the NERC suite of Reliability Standards and one of the most important for oversight and validation activities. Using internal controls, such as sampling in this case, for process validation can be a solution that strengthens an entity's methodology and increases success rates for numerous reasons. The following list represents the solution sets proposed in this white paper.

- Accuracy and reliability: Sampling can ensure that the process being validated is accurate and reliable by establishing checks and balances throughout the process. This helps identify any errors or deviations and ensures that the data collected is accurate and trustworthy.
- Compliance: Sampling can help organizations validate their methodologies comply with regulatory requirements, industry standards, and best practices. By implementing internal controls, companies can demonstrate that they have a robust process validation system in place.
- Risk mitigation: Sampling can help identify potential risks associated with the process being validated. By implementing appropriate controls, companies can mitigate these risks and prevent potential issues or failures. This includes both operational risks (such as errors or fraud) and compliance risks (such as violations of laws or regulations).
- Continual improvement: Sampling allows for continuous monitoring and evaluation of the validated process. This helps identify areas of improvement and ensures that the process remains effective and efficient over time. By using internal controls, companies can identify opportunities for optimization and make necessary adjustments to enhance the process.
- Confidence and transparency: Employing sampling as an internal control for process validation instills confidence in stakeholders, including customers, regulators, and investors. When a company has strong internal controls, it demonstrates its commitment to accuracy, reliability, and compliance. This transparency helps build trust and credibility among stakeholders.

In summary, sampling as an internal control as part of the Facility Ratings Methodology can be a helpful tool and may be essential for process validation as it can help to ensure accuracy, compliance, risk mitigation, continual improvement, and transparency. By implementing sampling as a control, companies can enhance the validation process and minimize potential issues or failures.

Introduction

The stated purpose of Standard FAC-008-5 is to: **"To ensure that Facility Ratings used in the reliable planning and operation of the Bulk Electric System (BES) are determined based on technically sound**

principles. A Facility Rating is essential for the determination of System Operating Limits." The word Facility when capitalized and used in this context is meant to refer to a set of equipment that operates as a single BES Element—e.g., a generator, transformer, or transmission line. The individual components which comprise a BES Element may be referenced as facilities.

Determining a Facility Rating for a BES Element seems like a simple enough proposition, but many factors can lead to mis-determination of individual facility ratings and therefore lead to inaccuracies in a company's Facility Ratings. The goal of a Facility Ratings methodology (FRM) should be to accurately represent the capabilities for each BES Element which allows effective and complete utilization of a Facility without jeopardizing any of the underlying facilities. To measure the effectiveness of a registered entity's FRP, it is prudent to:

- consider the completeness of the methodology,
- measure the consistency of application of the FRP, and
- evaluate the accuracy of the results or outputs.

Any discrepancy detected in the process or in the accuracy of the results may indicate the need for focused improvements to the methodology, depending on what the issue was and when it occurred.

With respect to measuring the effectiveness of the FRP, audit principles and practices – such as sampling can be especially useful tools for registered entities as well as the regional entities. In 2015, the ERO published a Sampling Handbook that was created to define sampling for audit practitioners and can be utilized by industry; however, let's dive deeper into the types of tools that may be more useful in an FRP and potential ways those tools can be used. While the Public Company Accounting Oversight Board and the Institute of Internal Auditors both define (audit) sampling and the methods for using this to support an opinion, this paper will discuss data sampling as an internal control or quality inspection metric within an FRP.

Sampling is a method of evaluating a subset of a population by reviewing only a portion of that population to reach conclusions with a pre-defined level of certainty. This type of approach is useful when performing quality checks to validate the accuracy of ratings, the completeness of ratings implementation of the FRP, and the consistency of application of the methodology. There are multiples ways to conduct sampling, but broadly speaking there is statistical sampling and non-statistical sampling.

Sampling is a detective control that may identify defects or inconsistencies in the FRP with some degree of certainty based on a predefined level of desired accuracy. These findings are useful to identify process gaps, inconsistent execution of the organization's FRP, human errors, control failures or control design failures. Correcting the identified issues would improve the processes and FRP. By selecting a small, representative set of Facility Ratings and assessing the accuracy of the inputs, assumptions, calculations, and methodology, the sampling outputs can be used to estimate the overall quality of the FRP execution. Furthermore, sampling when used over time can identify trends and areas of focus to strengthen a registered entity's FRP and drive continuous improvements.

The goal for this whitepaper is to provide a reference resource for registered entities seeking to improve its FRP by adding sampling or enhancing existing sampling. To facilitate this goal, the paper will discuss the assessment of risks inherent to an FRP, the benefits of sampling as part of an FRP, methods for, and examples of sampling in an FRP.

Parameters Which Impact Facility Ratings

Parameters listed in this section should be considered when determining appropriate sampling approaches, as they relate to the likelihood and impact of equipment rating and Facility Rating accuracy issues.

Parameters typically described in a Transmission Owner's (TO) Facility Ratings Methodology (FRM)

Regulations and Industry Guidelines

Various NERC, FERC, NESC, state administrative codes, and other regulations can impact Facility Ratings. Some requirements are noticeably clear, and some are up to interpretation or to define for themselves.

- Note that changing regulations sometimes means system-wide Facility Ratings updates, and some only need to be applied going forward.
- FAC-008 requires underlying assumptions used in establishing the equipment ratings that comprise a facility rating should be consistent with one of the following: manufacturer-provided ratings, industry standards (e.g., IEEE, CIGRE, ANSI), or testing/performance history/engineering analysis.

Definition of "Facility"

Terms that appear in FAC-008 like "Facility", "Element", "component", "Equipment Rating", and "Facility Rating" can be open to interpretation. However, in general, a Facility contains electrical equipment of distinct types. Different TOs may define Facilities differently and one important aspect of Facilities is endpoints. One example of facility definition is by current split point, where a TO may include all equipment in a line Facility up to the bus, then all equipment in a bus Facility up to a transformer facility, etc. Some TOs, however, do not explicitly have bus sections, rather, the bus ratings are accounted for in their line Facility ratings.

Equipment types

There are many common equipment types that TOs use in electric power transmission systems, however, not all TOs own and operate the same types of equipment. FAC-008 lists several types of equipment in scope but does not describe the entire scope of equipment that falls under FAC-008.

Equipment types that are not specifically defined in FAC-008 but that might be part of a TO's FRM include: circuit breakers, disconnect switches, gas-insulated switchgear, circuit switchers, current transformers, line/wave traps, meters, remote terminal units, fault recorders, and solid-state flow control devices (including FACTS). Some of this equipment falls under FAC-008's "terminal equipment" category.

It can be beneficial to list equipment that is not in an FRM (e.g., series connected primary fuses or capacitors) if a TO does not own that equipment.

Equipment material and characteristics

Equipment material and characteristics are some of the most impactful parameters that impact equipment ratings and Facility Ratings because current carrying capacity typically depends on the heating up and cooling down of metal equipment. Examples include:

- Stranded conductor size, type of metal, stranding, and bundling (multiple wires per phase).
- Conductor length (e.g., jumpers are short and are less dependent on conductor strength, and therefore can operate at higher temperatures).
- Conductor sag.
- Environmental variables that impact heating or cooling of metal equipment, such as air temperature, wind (including sheltering), and solar. These are all variables that require estimations and assumptions that contribute to equipment ratings.
- Seasonal assumptions related to environmental variables. A TO might have different assumptions for different equipment (e.g., overhead conductor is typically more exposed and responsive to wind, compared to substation equipment).
- Electrical resistance, airflow convection, and surface radiation.
- Physical temperature limit.
- Impact of higher temperatures (e.g., loss of equipment life, loss of strength), considering magnitude and duration of temperatures.
- Factory-tested rating capabilities of power transformers (unique per equipment).
- Air vs. gas vs. oil insulated equipment properties (e.g., disconnect switches, circuit breakers).
- Gas, fluid, insulation, sheath/jacket, and installation properties (e.g., direct bury vs. duct bank, thermal backfill, and native soil) associated with underground transmission lines. These installations do not lend themselves to field verification activities due to their unique properties.
- Unique properties of submarine (underwater) cables. These installations do not lend themselves to field verification activities due to their unique properties.
- Assumptions related to current transformers.
- Assumptions related to connectors and fittings.
- Other characteristics not related to equipment material include:
  - Relay settings (reach limits) – voltage converted to amps that represent when a relay will trip.
  - Readability for meters.

Definition of Normal and Emergency Ratings

The definitions of "Normal Rating" and "Emergency Rating" can be open to some interpretation. In general, Normal Rating is the level of electrical loading that electrical equipment can withstand without unacceptable loss of equipment life, not restricted to a finite time. Emergency Rating is the level of electrical loading that electrical equipment can withstand with acceptable loss of equipment life for a finite time. Different TOs might specify different emergency rating durations and consider different related parameters (e.g., pre-load conditions).

Jointly owned equipment and Facilities

Facilities might contain some equipment that is owned by one TO and other equipment that is owned by another TO. Alternatively, Facilities might contain equipment that is co-owned between multiple TOs. Each TO's FRM must describe how Facility Ratings for these types of Facilities are managed.

Additional details

An FRM might include additional details such as:

- Reference to detailed Equipment Ratings methodology documents (e.g., separate criteria documents which are part of the FRM).
- Details about legacy FRM, if appropriate
  - Not all updates require equipment ratings and Facility Ratings to be updated. Minor changes over time might or might not be traceable to the rating basis of any given piece of equipment at any given time.
- A description of how temporary alternate ratings are used.
- A statement about establishing Equipment Ratings based on records available at the time the rating was established, and if new or improved equipment records become available, updating the respective Equipment Rating accordingly.
- A statement about limiting the number of emergency events to limit the acceleration of loss of equipment life.
- Reference to various software programs/applications that might not provide identical results, but are within typical metering accuracy (e.g., 1%-3%).

Parameters not described in a TO's FRM

There are many processes and practices that could impact Facility Ratings that are not part of a TO's FRM, including:

- Material specifications, including warranties and contractual agreements with equipment vendors.
- Design practices (e.g., buffers, factors of safety).
- Construction tolerances (e.g., pole setting, sag/tension).
- Quality assurance and quality control practices (e.g., field verification of equipment rating details).
- Current and legacy maintenance and asset renewal practices.
- Current and legacy modeling practices for PLSCADD models for line ratings.

  - Guidance on how to evaluate different rating scenarios (e.g., feature codes of LiDAR point types, code clearances for ground, buildings, etc.)
  - As-built modeling practices
- PLSCADD models are typically not updated with 100% of as built information.
  - Note: These models are based on survey (typically LiDAR), weather data, and operational data (current flow). These are variables that contribute to the inherent accuracy (or inaccuracy) of line ratings.
  - Not all updates require equipment ratings and Facility Ratings to be updated. Minor changes over time might or might not be traceable to the rating basis of any given piece of equipment at any given time.
- Operational history, if available (e.g., magnitude and duration operating equipment in emergency scenarios).
- All use cases for temporary alternate ratings (e.g., in Operations).
- Third party activities near transmission lines (e.g., material stockpiles and other encroachments).

Other Notes

Facility Ratings contribute to System Operating Limits, which also consider system stability and voltage.

Facility Ratings do not consider operating economies.

Assessing Risk

To ensure a reliable and secure bulk power system (BPS), it is of utmost importance that registered entities have strong and sustainable Facility Ratings methodologies. Facility Ratings play a significant role in planning and operating the BPS and errors can pose significant risk to the BPS. System operating limits (SOLs)—essential components in real-time operations of the grid—are based upon Facility Ratings and are vital to supporting and maintaining situational awareness. Incorrect facility ratings can result in operating in an unknown state, uncontrolled widespread service outages, and fires, among other things. In addition, Facility Ratings and System Operating Limits play a key role in modeling the grid as future BPS projects are contemplated to manage load growth and mitigate system constraints. When Facility Ratings are not determined correctly and applied consistently for all applicable Facilities, this can result in equipment being operated beyond its capability, causing equipment damage or line sagging beyond its design, resulting in unplanned outages and safety issues. It is for this reason that Facility Ratings issues were noted as one of the contributing factors to the August 2003 blackout.

A foundational first step in producing a strong and sustainable Facility Ratings methodology is a risk assessment to determine what aspects of the methodology may require additional checks and balances. Certain attributes of the Facility and some basic tenets should be considered when incorporating sampling to ensure the implementation of the methodology has been accomplished as intended. These include the following items, but are not limited to:

1. Voltage level - Higher voltage Facilities indicate power transfer capability which implies larger risk.
2. Interface Limits - Facilities included in IROLs, transfer paths, Flow Gates, Generic Transmission Constraints are in place to mitigate significant risks.
3. Remedial Action Schemes - Facilities involving Remedial Action Schemes and the alternate-flow Facilities that support Remedial Action Schemes provide for reliable operations.
4. Generation interconnects - Facilities supporting current and near-future generation interconnections are emerging as a risk due to grid transformation seen across the bulk power system.
5. Facilities impacted by long duration planned outages - Facilities supporting flows during construction, re-builds, and extended maintenance periods are needed for reliable operations while reliability improvements are underway.
6. Facilities normally involved in congestion - Facilities that are a cause of congestion or are continually supporting flow because of congestion may be worth periodically validating.
7. High profile Facilities - Facilities that support locations considered high profile (e.g., State Capitols, major infrastructure like gas refineries) may warrant a review.
8. Facilities maintained after an event- Facilities that had equipment changes (e.g., storm restoration, fire, flood, sabotage, etc.) warrant a review soon after the change is completed.
9. Residual Facilities- Facilities that did not necessarily meet any other risk evaluation warrant a periodic review specific to the risk posed.

The Foundation of a sustainable Facility Ratings Program should include the following four attributes:

1. **Leadership commitment** for consistent messaging and training
2. **Effective inventory and change management**
3. **Quality assurance reviews** (e.g., methodology, equipment changes, etc.)
4. **Periodic validation** through risk-based sampling

These base attributes of a Facility Ratings methodology provide the basis to ensure entities have a strong and sustainable methodology and program. Each of the bullets represents a great deal of effort depending upon the organization. There may not be a single solution considered as absolute across all organizations and should be based on the organization's view of their own risk. Leadership may be a senior level executive or a department head depending upon the nature of the organization. Tools for inventory and change management should be selected to fit the needs of the organization and with processes to support minimization of errors. The veracity and complexity of the Facility Ratings methodology must be based on risk.

Instituting a sound methodology for FAC-008 can be summarized in the key factors below. The goal of the methodology is to provide clear direction on how the organization's Facility Ratings maintain reliable planning and operation of the system.

1. Document Control
    a. Defining the Approvals and the review cycle for the methodology
2. Defining the Scope of Equipment
    a. List all equipment that applies.
    b. Clearly defined reasoning on how ratings for each equipment type were determined.
    c. Normal and Emergency Ratings for each equipment type
    d. Consideration for ambient adjusted temperature for each equipment type
    e. Considerations for operating limitations (abnormal configurations, protection setting limitations, clearances, etc.)
3. Determination of the most limiting element.
4. Defining how jointly owned Facilities will be addressed.
5. Utilizing Internal Controls to identify gaps in methodology execution and mitigate drift to failure.

Leadership Commitment

The foundation of a sustainable Facility Ratings methodology begins with the "tone at the top." An entity must have high level support and understanding regarding the criticality of Facility Ratings and the business need to maintain Facility Ratings. A sustainable methodology is an investment of time and resources that are balanced against the risks associated with Facility Ratings. Without an executive level or leader champion, success may be limited. The "tone at the top" also supports the consistent message and expectations of accountability across the organization. Each group, department, or employee should be aware of the importance of a Facility Ratings methodology and acts accordingly to support implementation of the methodology with the understanding of how Facility Ratings impact different departments across the organization.

The Facility Ratings methodology is dependent upon a Facility Ratings methodology. The methodology must address all equipment types that impact Facility Ratings and focus on reliability of protecting assets. An organization should maintain an accurate inventory of equipment that comprises a Facility or impacts a Facility Rating. In the most recent SAR focused on FAC-008, the Project 2021-08 Standard Drafting Team discussed an opportunity where a non-electrical component of a Facility may be the most limiting element that defines a Facility Rating. An example of this could be Facility Ratings limited by Protection System settings. That condition has been seen in the field and highlights the need to understand equipment that could affect Facility Ratings which go beyond the historical understanding of a Facility. Keeping in focus the reliability impact of Facility Ratings and how they are used within your methodology should provide reliable operations and awareness.

Effective Inventory and Change Management

In the May 2023 ERO Enterprise webinar on Facility Ratings Themes, the idea of a Facilities baseline was presented and supports this discussion. Knowing what the baseline consists of is key to understanding risk. There are several aspects of a Facility baseline that will be discussed throughout this whitepaper but knowing what you have is a key component to success. As discussed in the ERO Enterprise Themes and Best Practices for Sustaining Accurate Facility Ratings Report, a best practice is to have trained personnel that use inventory management tools to maintain a change management process. The inventory must be documented and managed in a way that supports the attributes necessary to implement the organization's Facility Ratings methodology consistently across all departments.

Simply knowing the equipment may not be enough to maintain reliable operations. Understanding what equipment is more susceptible to overloads (e.g., thermal, voltage) because of the equipment type, equipment loading, or system configuration is important. Knowing what Facility Ratings are for electrically connected Facilities is important to understand from a reliability perspective. A change by one company could impact what may be considered the most and next most limiting element in an electrically connected Facility. This scenario needs to be considered in the Facility Ratings methodology to help ensure reliable operations and awareness. The susceptibility aspects of equipment and configurations of electrically connected equipment could play into sampling techniques employed to verify Facility Ratings (to be discussed later). Project 2021-08 Modifications to FAC-008 is considering the idea of defining responsibilities for owners of electrically connected Facilities to help ensure operators have the most accurate Facility Rating, but implementation of any FAC-008 revisions is years away. Until then, consideration of this issue is a best practice.

One other aspect that needs consideration in a Facility Ratings methodology is how ambient temperature plays a role in determining Facility Ratings. With FERC Order 881 coming into play for the industry it will be important to establish and manage a firm foundation on the static Facility Ratings to effectively apply Ambient Adjusted Ratings. Is the location of the Facility taken into consideration as part of the Facility Ratings methodology? How historical ambient temperatures are determined for the application of the Facility Ratings methodology would be a best practice to document within the methodology itself.

Internal Controls

As with any methodology there is a certain level of internal controls that must be implemented to maintain sustainability. At a minimum, organizations should consider how robust their methodology is in terms of managing, reporting, and validating Facility Ratings information. Detective, preventive, and corrective controls need to be implemented into the workflows to ensure the most accurate information is being utilized. These controls can identify errors and mitigate issues or identify process design flaws to be critically reviewed. The nature of the error is as important as the error itself. An organization should be able to differentiate the difference in impact for an error that simply changes an Equipment Rating versus affecting the overall Facility Rating and act accordingly. The detective control of finding an error may change based on the department or responsibilities of individuals. Communications associated with the finding need to be part of the internal control environment so that anyone affected is aware. In some cases, there may need to be checklists built into processes that help prevent errors but also may be useful in detecting errors when validating information through sampling. Of course, if there are issues found the organization should consider the most effective way to incorporate lessons learned into its methodology to avoid repeat occurrences. Causation of the issue needs reviewed to ensure improvements in the methodology if there was a missing control or process. An organization cannot "human-proof" all aspects of a methodology but building automated controls (like communications based on a finding) is considered a best practice for more sophisticated companies. The ERO Enterprise Themes and Best Practices for Sustaining Accurate Facility Ratings Report, portrays a significant need for enhanced internal controls at every level of a Facility Ratings methodology. The robustness of the controls may be dependent upon the risk associated with the process or methodology broadly, such as number of assets in scope, number of changes to elements, number of ratings changes, etc. The risk factors should be organization specific. A smaller company with minimal risk or limited Facilities representing non-minimal risk (e.g., one 345 kV line) will have a different approach to internal controls than a larger company with more risk. The key point is to ensure that internal controls are in place to help mitigate the risks associated with Facility Ratings.

Sustainability

To sustain a methodology, it is important to establish an accurate starting point or baseline. This is typically done through several steps that start with field verification of the assets. Field verification is typically followed by a review of the drawings and a recalculation of the Facility Ratings while keeping in mind that these Facility Ratings are an aggregate of system Elements as defined in the NERC Glossary of Terms. Entities should consider evaluating the effectiveness of their change and asset management process periodically. This evaluation could reveal specific areas that may benefit from additional attention. It is also vital to ensure appropriate internal team stakeholders, such as key departments and contractors, are being accounted for and involved in the periodic review/assessment process. Once the change and asset management processes are reviewed, the current documentation associated with the processes and procedures should also be reviewed and updated as needed. Clear roles and duties should be assigned and documented. Companies that are successful in establishing sustainable methodologies have a positive cultural environment. This positive cultural environment is established by the "tone from the top." In other words, company executives help ensure that involved personnel and departments are aware that they are key and critical components in assuring overall reliability. Their work is crucial, and accuracy is important. Successful companies usually have an executive sponsor to support this effort. In summary, the following list highlights (in no order) the best practices used by companies that have positioned their Facility Ratings methodologies for long-term sustainability:

- Robust documented change management process.
- Inventory management tools, with required training.
- Checklists for new inventory additions.
- Effective data capture processes.
- Single database for master record keeping.
- Access controls established for facility management tools.
- Built in quality assurance reviews, in concert with internal controls.
- Periodic in-field validation/field walk-downs.
- Facility ratings methodology owner.
- Management oversight.

Lastly, the impact of mergers and acquisitions should also be taken into consideration as the merger of two or more entities will result in more than one set of Facility Ratings methodologies, supporting policies, and procedures. Company executives should reinforce efforts to create and maintain a single detailed and comprehensive Facility Ratings methodology and program. A “pre-merger” effort for Facility Ratings (and other Reliability Standards) would serve to ensure the consistent establishment and management of Facility Ratings (and other Reliability Standards) across the new organization.

Periodic Validation

One thing is certain in the industry, there is not a single solution at this point that considers how Facility Ratings should be validated. Facility Ratings are good for the day they were created, and “drift” may occur after that day. “Drift” could be slow paced like exposure to the elements over time or faster paced like restoration after a storm. In any case “drift” can be approached through a risk-based sampling validation effort. The reliability risk of Facility Ratings should be considered as organizations consider sampling for validation. Again, there should not be a blank prescriptive “X% per year” approach placed upon the industry as that will have different impacts on the many different entities involved. The money spent validating “X%” may not have the desired effect if the risk is not considered.

Risk, in its simplest definition, is a combination of impact times frequency (aka likelihood X consequence). In many cases a risk matrix tool (see visual below) can be developed to help visualize risks to an organization. To create a risk matrix a company must first identify the risks and then evaluate the risks accordingly. Taking the recent ERO Enterprise Themes and Best Practices for Sustaining Accurate Facility Ratings Report, has the organization considered the risk of having some of the themes noted being present and what that may mean to reliable operations? Understanding what Facilities are being rated and how those Facility Ratings impact the bulk power system is critical to recognizing risk.

When preparing to sample, the question to keep in focus is “If I lost this facility what would be the reliability impact to the BPS?” Prioritizing based on this impact question will allow you to start/continue your sampling decisions on the most critical assets first.

Impact

Likelihood

	Negligible	Minor	Moderate	Significant	Severe
Very Likely	Low Med	Medium	Med Hi	High	High
Likely	Low	Low Med	Medium	Med Hi	High
Possible	Low	Low Med	Medium	Med Hi	Med Hi
Unlikely	Low	Low Med	Low Med	Medium	Med Hi
Very Unlikely	Low	Low	Low Med	Medium	Medium

Once the sampling is complete and the validation efforts are finalized, an organization should review the results. Error rates should be factored in and defined as to the trends of the error rates (human error typo, contractor management, emergency restoration, etc.). The reliability risks associated with the errors may impact the sampling, timing of sampling, or other internal triggers (such as an in-depth Root Cause Analysis). Your sampling strategy should adapt to the results you are receiving. Trending of the errors may support more effectively designed internal controls or be the result of a well-defined internal control. If the trend is a result of a well-defined internal control, an organization should evaluate efforts to mitigate the trending error and the timing associated with the inventory. For instance, if all the one-line drawings completed by third party X over a "sample x" period are a source of errors at what point will the third-party organization be reconsidered as a resource? This may require a secondary risk evaluation depending upon the nature of the error.

One aspect of using sampling as periodic validation that must be considered is timing. Both in and when sampling is initiated as well as when sampling results are mitigated, balanced against the maturity of the organization's risk appetite. Should sampling occur every year? Should sampling occur every year for some items and every three years for others? Should sampling results change the periodicity of sampling? As companies perform risk assessments of their inventory there will need to be an understanding of how sampling timing was determined. The timing should be based on the risk to reliability and not the risk of compliance monitoring. A company should strive to implement a Facility Ratings validation process that is supported by a well-documented risk strategy that effectively balances the resource allocation to the reliability of the electric grid. Care should be taken here as seen by some points made during outreach regarding FAC-008. Some companies felt like they were effectively managing Facility Ratings until an external party started reviewing or convinced the organization to dive deeper in a review of all aspects of their methodologies.

Methods for Verifying Facility Ratings

It is helpful to consider (1) existing vs. new or modified facilities and (2) substation vs. transmission line facilities when considering ratings verification, due to their unique differences.

Existing Facilities

Verifying **existing** equipment ratings and Facility Ratings typically involves verifying that field conditions match the ratings system of record (SOR). This type of verification is typically viewed as a "detective" control because it happens after a facility has been installed and a rating is in place. Drawings and other supporting records can help clarify where field conditions are not known or easily determined (e.g., inaccessible or legacy equipment).

Substation methods

- Site visits to verify nameplate information matches the ratings SOR. Lack of visible or any nameplate information might involve outages and other methods to verify equipment attributes and ratings. At times, a conservative assumption must be made when a rating cannot be determined in the field (e.g., legacy equipment with no nameplate or available records). Technology like photo recognition could improve the efficiency and even accuracy of site visit verifications.
  - Technology like photo recognition could improve the efficiency and even accuracy of existing equipment rating verifications.

- Reviewing drawings and supporting records vs. the ratings SOR. This can identify discrepancies that might require field verification to address.
- Post-construction project data verification. This verification method involves a site visit after a substation facility has been constructed and placed in-service, but before the project is closed out, to confirm all records and ratings SOR match field conditions. This method is primarily for substations because verification of transmission line rating attributes cannot be accomplished by a site visit. This is a detective method for existing facilities that have just been installed and therefore can identify gaps in current business practices and preventive controls.
  - Note: depending on timing, this could function as a preventive control for new and modified facilities if executed prior to energization or in-service.

Transmission line methods

- LiDAR survey, PLSCADD model updates, and thermal rating studies to review clearances.
  - Note that this process can result in updated Facility Ratings that do not qualify as errors due to many factors (change in survey technology/accuracy, third party activities near lines, reflecting current methodology and practices vs. legacy, etc.)
- Site visits to confirm conductor type. This typically involves outages to safely evaluate conductor cross-section for material type and stranding.
- Note: Third-party encroachments can impact valid ratings for transmission lines. Controls to help address these impacts include (1) business practices requiring third parties to contact the transmission owner before constructing facilities near transmission lines, (2) business practices to detect third-party encroachments that were not approved, and to evaluate their impacts, (3) the LiDAR method described above.

New or Modified Facilities

Verifying **new or modified** equipment ratings and Facility Ratings typically involves verification during the ratings update process of construction and maintenance. This type of verification can be viewed as a "preventive" control because it happens during the construction or maintenance project process.
Note: business practices that route maintenance replacements through the construction process for ratings updates help ensure ratings data is updated timely and accurately.

Substation methods

- Project process quality control (QC) (Engineering, ratings stewards, field personnel) pre- and post-energization/in-service. Business practices may also allow some quality checks and updates during the as built/closeout phase of construction projects. Note: Engineering can involve multiple functional areas (e.g., Construction for most equipment and System Protection for relays). This type of QC can include contractor checklists and drawing markups.
  - Technology like photo recognition could improve the efficiency and even accuracy of new and modified equipment rating verifications.

- Data integration
    - Smart equipment supplies data to a ratings SOR. This method involves equipment like relays, which are programmed with rating settings, to be integrated with applications like ratings SORs. This helps reduce data handoffs and potential for error but should include quality checks/validations before accepting into the ratings SOR. This can happen before the next method, to enable quality checks/validations.
    - Data fields shared between applications. Specifically, ratings-related equipment attributes from a Computerized Maintenance Management System (CMMS) can feed a ratings SOR. This helps reduce data handoffs and potential for error but should include quality checks/validations before accepting into the ratings SOR.

Transmission line methods

- Project process QC described above for substations. For transmission lines this could also include surveys (e.g., for pole location and wire position). Note that new wire typically creeps or elongates for several years after installation. This is a factor in verification methods for conductor position (as are weather conditions and system flow at the time of LiDAR survey)

Tracking/Metrics

The usefulness of verification methods can be increased using metrics to track the characteristics of facility rating issues that are found. This can help focus future efforts to help companies manage the cost vs. risk associated with facility ratings.

Matrix

Verification Method	For Existing or New/Modified Facilities?	Preventive or Detective	Substation or Transmission Line	Cost/Effort	Notes
Site visits	Existing	Detective	Substation	Scope-dependent	Full system review is costly
Records review	Existing	Detective	Substation	Scope-dependent	Does not include field verification
Post-construction project data verification	Depends on timing	Depends on timing	Substation	Moderate per facility	Can identify gaps in current processes, and cost can potentially be capitalized
LiDAR surveys	Existing	Detective	Transmission Line	Relatively high	Typically includes PLSCADD model development and thermal rating study to verify/update line ratings
Site visits	Existing	Detective	Transmission Line	Relatively low per facility	To confirm conductor type when records are unclear. Can lead to model updates and revised line ratings (previous item) or construction projects to achieve rating needs.
3rd party encroachment prevention/detection	Existing	Detective	Transmission Line	Relatively low for prevention, scope-dependent for detection	Prevention can be difficult with third parties. Detection can be costly depending on method and scope.
Quality control practices during construction projects	New/Modified	Preventive	Both	Relatively low per facility	Part of Construction project process before
Quality control practices during maintenance projects	New/Modified	Preventive	Both	Relatively low per facility	Route ratings updates for maintenance projects through the construction project process
Data integration	New/Modified	Preventive	Substation	Relatively low after initial setup and data cleanup	Automation and limiting duplicate information

Creating a Facility Ratings methodology inclusive of Verification Activities

To ensure a reliable and secure BPS, it is of utmost importance that registered entities have strong and sustainable facility ratings methodologies. Accurate facility ratings are needed for operating, planning, and maintaining the Bulk Electric System (BES). Facility ratings are an essential component of determining SOLs and interconnection reliability operating limits (IROL) and are used for making decisions associated with operating the BPS.

But the question remains within companies when looking at facility ratings methodologies, what types of verification and validation activities should be part of the methodology providing assurance of accuracy? Considering risk and risk tolerance, the entity needs to balance verification and process controls building on the Risk Assessment discussion earlier in this document. A good Facility Ratings methodology takes the methods described in the earlier section of this document dedicated to Methods for Verifying Facility Ratings and incorporates validation activities into each step of the Facility Ratings process to provide additional levels of assurance that processes are working as designed and controls are operating effectively.

Verification at various process stages

There are many stages of a process, procedure or project that may suggest additional verification is necessary or desired for additional layers of assurance. A few examples of this may include project initiation, emergency work, and changes or upgrades to the ratings database or drawing updates. In addition to these, substantive changes to systems that drive grid reliability and stability would be key considerations in validation, verification, testing and control implementation.

- Energy Management systems
  - EMS and Facility Ratings Database auto-comparisons tools should be considered if available to ensure consistency between programs. A similar approach should be considered for an entity's EMS real-time or situational awareness tools.
  - If Auto-Comparison tools are not available, sample manual verification should be considered.
  - Upon completion of a Project or Emergent work and prior to energization, verification of Facility Ratings to EMS Ratings should be made to ensure consistency.
- Planning Database
  - Planning Database and Facility Ratings Database auto-comparisons tools should be developed/considered if available to ensure consistency between programs. A similar approach should be considered for an Entity's Planning Database (TO) and Transmission Planners database.
  - If Auto-Comparison tools are not available, sample manual verification should be considered throughout the year.
  - Upon energization of facility, Post project or emergent activities should include verification of Facility Rating to Planning Database should be made to ensure that all post project and emergent work changes were captured.

Ranges of Reasonableness (Robustness, frequency, risk criteria, sampling size, etc.)

- To sustain a methodology, it is important to establish an accurate starting point or baseline for both equipment and facility ratings. If an appropriate baseline is established, and appropriate change management program is understood, and followed, as appropriate tools to document the ratings are in place, the robustness of the periodic verification can be developed.
  - For example, if a ratings database is utilized where all equipment and their characteristics are captured, an entity could leverage the database as a "checklist" or means during field verification that the equipment exists.
- Frequency – An entity should leverage existing processes and procedures where possible. Field verification frequency could be associated with Capital Project work, Preventative maintenance work, or an appropriate period that provides the entity reasonable assurance.
  - For example, certain entities that are performing full system walkdowns may try to leverage a 5–6-year period which covers approximately 20% of their facilities.
- Risk Criteria – An entity should determine appropriate risk events or risks to be addressed. For example, the entity should have a set of risk considerations or criteria that may drive risk higher and suggest additional testing or controls. Risk considerations of this type may look at mergers and acquisitions, personnel changes, process changes, ownership of equipment unclear or undefined, shared responsibilities, contractor work is performed, undocumented processes exist, etc.

Metrics as validation

Using metrics can be an effective way to serve as a checkpoint or dashboard that controls are working as designed. Balancing metrics with benefit received for tracking is also important. For instance, when performing field verifications of information captured in as-builts or one-line diagrams to equipment in a facility, one metric could be number of variances or percentage variance to the total. The most important aspect of metrics is to ensure the metrics are designed in support of validating controls, validating process effectiveness and efficiency of tracking to benefit from the data produced. For efficiency of industry resource usage, it can be easy to over architect processes, metrics, and controls for ratings accuracy. The appropriate use of process, controls and metrics will be specific for each organization and should make efficient use of resources to assure appropriate resources to achieve accuracy of facility ratings and nimble processes for dynamic changes in approach.

Value proposition

- An important part of the methodology is evaluation of the processes and steps executed by measuring the resources to accomplish with the benefit recognized by expending those resources. Cost-benefit analytics are a systematic process that businesses use to analyze which decisions to make and which to forgo – this applies to evaluation of controls to put in place to provide assurance of the objectives (accurate facility ratings or successful facility ratings methodologies, etc.). The sum of the potential rewards expected from a control or process step subtracting the total costs associated with taking that action represents the cost benefit recognized with the resource outlay.
- However, all the cost benefit analysis should be framed according to the level of risk. As previously discussed, the organization needs to assess the risk with its current execution of its Facility Ratings

methodology, risk of inaccurate ratings or adherence to its methodology, and risk threshold or tolerance to guide the level of validation or verification activities necessary to ensure successful implementation of ratings. These risk analytics should be key considerations in the cost-benefit equation and decision-making process.

Effective Facility Ratings Programs Whitepaper

Facility Ratings Task Force
Request for Review

Jennifer Flandermeyer
Reliability and Security Technical Committee Meeting
June 11, 2024

Sub-team #3 - Members

Team Leads: Jennifer Flandermeyer and John Stephens

Members:

- Curtiss Frazier – Ameren
- Rajesh Geevarghese – Exelon Corp
- Brad Harris – CenterPoint Energy
- Kim Kubrak – Reliability First
- Ryan Mauldin – NERC
- Karen Onaran – Electricity Consumers Resource Council
- Jon Radloff – American Transmission Company
- Jim Uhrin – Reliability First

Whitepaper

- The whitepaper details how using sampling as a quality assurance activity or an internal control as part of the Facility Ratings program can help registered entities enhance the validation process and minimize potential issues or failures.
- Sampling used for quality control or as an internal control:
  - Ensures the registered entity process being validated is accurate and reliable by establishing checks and balances.
  - Helps the registered entity validate its FRP by demonstrating compliance with regulatory requirements and industry standards.
  - Helps identify potential risks associated with the process being validated, allowing risk mitigation to occur in a timely manner.
  - Allows for continual improvement of the validated process through monitoring and evaluation thereby ensuring the process remains effective and efficient over time.
  - Demonstrates a commitment to accuracy, reliability, compliance and transparency which instills confidence among all stakeholders, regulators, customers and investors.

The Ask and the Goal

The Ask

- The Facility Ratings Task Force is requesting that the RSTC solicit volunteers to review and provide feedback on the draft whitepaper "Effective Facility Ratings Programs - Incorporating Sampling into Facility Ratings Assurance".

The Goal

- Incorporate RSTC member suggestions and present the whitepaper to the RSTC for approval at its September meeting.

Questions and Answers

Implementation Guidance for FAC-008-5

Action

Requesting RSTC Review

Summary

The existing Implementation Guidance document was written for Reliability Standard FAC-008-3 by the Midwest Reliability Organization Standards Committee and endorsed by the ERO Enterprise on October 10, 2017. Reliability Standard FAC-008-3 is inactive as Reliability Standard FAC-008-5 became mandatory and effective on October 1, 2021. Sub-team #1 is developing this new guidance to provide the industry with pertinent approaches to being compliant with the requirements of the revised standard.

Sub-team #1 of the Facility Ratings Task Force requests that the RSTC review and provide feedback on this document in anticipation of submitting the finalized document to the RSTC for endorsement at its September meeting.

Note: The Implementation Guidance document is currently being reviewed by NERC Publications. The document will be sent to the RSTC as soon as possible.

FAC-008-5 Implementation Guidance Development

Facility Ratings Task Force Sub-team #1

Request for Review

Robert Reinmuller
Reliability and Security Technical Committee Meeting
June 11, 2024

Sub-team #1 - Members

- Team Lead: Robert Reinmuller
- Members:
  - Curtiss Frazier – Ameren
  - Rajesh Geevarghese – Exelon Corp
  - Mike Guite – BC Hydro
  - David Jacobson – Hydro One
  - Jim Kubrak – Reliability First
  - Ryan Mauldin – NERC
  - Devon Tremont – Utility Services
  - Jim Uhrin – Reliability First

Sub-team #1 - Update

- The team has worked diligently over the past year to draft an Implementation Guidance (IG) document for FAC-008-5 to replace the legacy MRO IG document for FAC-008-3.
- The team shared the draft document with the FRTF membership on March 17, 2024, and received numerous comments throughout April. To be thorough, the team accepted comments received well beyond the deadline knowing this would likely require extending the development period to incorporate relevant ideas.
- The team continues to incorporate the suggestions received, improving the clarity and readability of the document.

The Ask and the Goal

The Ask

- The team is requesting the members of the RSTC to review and submit comments by July 19th on the most current version of the Implementation Guidance which will be provided immediately following the conclusion of this meeting.

The Goal

- Incorporate RSTC member suggestions and present the finalized IG document to the RSTC for endorsement at its September meeting.

Questions and Answers

White Paper: New Tech Enablement and Field Testing

Action

Request for Comment

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.

Summary

To better drive technology adoption and innovation, the paper makes a key recommendation of a formalized 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.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

New Technology Enablement and Field Testing

NERC Security Integration and Technology Enablement Subcommittee (SITES) White Paper

June 2024

RELIABILITY | RESILIENCE | SECURITY

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Preface

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

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

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

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

Statement of Purpose

This white paper uses the term “utilities” to broadly encompass all entities involved in the electric industry’s management and operation of the grid, including those responsible for transmission, generation, and distribution. This definition includes independent power producers (IPP) despite their traditional distinction from utilities. For the purposes of simplicity and coherence, both utilities and IPPs will be collectively referred to as “utilities” in this document.

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

Broadly, the electric industry shows a willingness to seek out and embrace new technology to support the changing grid and supports the development and implementation of new reliability and security standards when appropriate. In fact, the electric industry is seeing a greater workload and pace of standards development than ever before. As the grid continues to evolve and the pace of technological change rapidly accelerates, the electric industry needs mechanisms to enable and support entities willing to invest in testing and deploying new technologies in secure, reliable ways that can be shared with their peers. As a general principle, SITES believes that new technology exploration and adoption, if implemented reliably and securely, should be possible for utilities across the industry.

When the implementation of new technology is challenged by regulatory standards, technology exploration in the form of field trials can be deployed to reduce or remove those challenges. This white paper proposes the Regional Engagement for Technology and Integration Innovation Acceptance (RETINA) program to address barriers through coordinated field trials of emerging technologies that are pre-standard authorization request (SAR) and pre-standards development. 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, artificial intelligence (AI) and machine learning (ML), and real-time decision enhancement with synchrophasor data. By cultivating guidance from trial results, RETINA aims to facilitate faster, compliant adoption of beneficial solutions ahead of standards revisions.

Overcoming obstacles requires commitment from FERC and ERO Enterprise leadership, flexible regulatory enhancements, and close coordination between stakeholders. By modernizing grid operations through secure technology integration, collaborative efforts like RETINA can optimize reliability, resilience, and cyber security for the future.

Introduction

Background

With the aim of supporting the BPS in a secure, reliable, and effective manner, the SITES charter[1] tasks the subcommittee with "identify[ing] potential barriers (e.g., regulatory, technological, complexity) and support[ing] the removal of these barriers to enable industry to adopt emerging technologies." Due to the nature of critical infrastructure and the unbending need for a focus on reliability, the electric industry is recognized as generally lagging on the adoption of newer and innovative technologies broadly available, including those that have been proven to meet the security and reliability needs of other critical infrastructure sectors, including healthcare (specifically pharmaceuticals), financial services, and the defense industrial base. While the security, reliability, and resilience needs 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 address factors that are inhibiting adoption by the electric sector and stifling ongoing innovation of new technology. The paper makes formal recommendations to address what SITES considers the greatest roadblocks for the electric industry.

Among the challenges related to new technology in the electric industry, this white paper gives special attention to assessing the industry's regulatory framework, including the NERC Critical Infrastructure Protection (CIP) standards and the standards development process with an aim to identifying enhancements or complementary processes to better facilitate new technology adoption.

Appendix A offers further discussion and insights into industry struggles with workforce, financing, and internal regulatory compliance approaches, which can hinder adoption of new digital technologies among utilities.

NERC CIP Standards and Standards Development

The NERC CIP standards, consisting of multiple requirements, are designed to protect the Bulk Electric System from cyber-attacks and other threats. One of the many processes outlined in the NERC Standards Process Manual[2] 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. A SAR development team then reviews the SAR, makes necessary revisions based on formal or informal industry comment, and returns the revised SAR to the SC for a standard drafting team[3] to begin, launching a cycle of drafting, quality reviews, comments, balloting,[4] and SAR revisions sometimes. Eventually, the team may end with a successful ballot or ballots and a final adoption ruling. For a given standards project, this process may take anywhere from a year to many years.

The collaborative nature of the standards development process is a success story for industry. SITES acknowledges that it takes time to perfect a standard given the consequences 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 standard. In some cases, taking multiple years is justified. However, in this length of time, technology is likely to advance significantly, potentially rendering the original objective of a SAR out of place or outdated. This merely underlines the challenge faced by industry in achieving the balance of reliability and security along with the flexibility of supporting new technology adoption within the NERC Reliability Standards.

[1] https://www.nerc.com/comm/RSTC/SITES_/SITES%20Scope.pdf

[2] https://www.nerc.com/pa/Stand/Revisions%20to%20the%20NERC%20Standard%20Processes%20Manual%20SP/SPM_Clean_Oct2018.pdf

[3] Historically, the SAR drafting team and the standard drafting team for a project have the same members.

[4] https://www.nerc.com/pa/Stand/Pages/Balloting.aspx

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 factors including 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, and meet evolving regulatory and environmental standards. This process is also key to addressing current challenges and leveraging opportunities presented by advancements like 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, so barriers to adoption negatively impact the drive to innovate as well.

Highway Metaphor

Navigating through the lanes of technology adoption and innovation is akin to driving a vehicle on a highway subject to speed limits. Here, compliance with regulatory standards (speed limits) potentially restricts the vehicle's own (technology's) capabilities to ensure safety and order. Optimal management is akin to drivers voluntarily adhering to the speed limit, recognizing its merit in ensuring smooth traffic flow, safety, fuel economy, operational efficiency, and overall public good. Conversely, positioning a police officer (audit and enforcement) on the highway fosters compliance but does not inherently validate or assess the appropriateness or effectiveness of the established speed limit (standard) as traffic patterns evolve and adapt. Upkeep means analyzing and adapting the speed limit (standard) based on evolving vehicle capabilities (security improvements), advancements in road-safety technologies (safe-by-design architecture), and evolving traffic conditions (progressive utilities and emerging markets). This mirrors the challenge in technology regulation of ensuring that standards evolve with technological advancements and threat landscapes. This metaphor underlines the necessity for a regulatory framework and supporting mechanisms that not only ensure compliance but also facilitate a responsive and adaptive environment for technological progress.

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 is required to bolster 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 (IBR), distributed energy resources (DER) and DER aggregators, and 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, are at the forefront of digital technologies that may offer reliability, resilience, and security benefits to the BPS that may be inhibited by the challenges discussed in this white paper.

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. For 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 that 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 that 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.

Compliance as a Driver

In a perfect world, compliance with regulatory standards, internal control frameworks, and metrics should facilitate and drive maturation and modernization while safeguarding operations. Rather than approaching compliance as a mere regulatory checkbox, entities could see compliance as a guide to embedding an ever-improving risk management framework—enabled through ongoing secure and effective adoption of technological innovations—within their operational systems and processes. This speaks to a mature strategy in which 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 enable rather than stifle change in their organizations.

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 the electric industry is subject to many of the roadblocks identified in this white paper. Some use cases are widely viewed as simply disallowed, even if indirectly, under current regulatory standards, such as the broad scope of the NERC CIP applicable systems used in cloud service provider environments. Other use cases may see limited adoption but still suffer challenges that inhibit 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 that promise potential benefits to grid reliability, resilience, or security while not currently enjoying wide adoption 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 and virtualization in the utility sector offers numerous benefits, including enhanced scalability and flexibility of computing infrastructure. It facilitates advanced data analytics, improves operational efficiency, and reduces IT infrastructure costs. Cloud technology allows 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, such as managed security service providers (MSSP) 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 cyber security measures with controls and architectures that surpass NERC CIP as a baseline for a comprehensive cyber security program. 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 allow 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 by facilitating 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:** By 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, allowing 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 the 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 (PMU) 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 regulatory standards may not coincide in a timely fashion 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 toward 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, cyber security 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 add 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 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.

Because registered entities own 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 toward a nuanced yet impactful limitation on technological enablement. MSSPs and 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, 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 the 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 cyber security 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, new technologies, and cyber security paradigms, such as "zero trust,"[5] the electric industry should endeavor to evaluate the 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, SITES also recognizes that it is appropriate to retire and relax outdated requirements.[6] Ultimately, striving for compliance should

[5] https://www.nerc.com/comm/RSTC_Reliability_Guidelines/White_Paper_Zero_Trust_For_Electric_OT.pdf
[6] https://www.nerc.com/pa/Stand/Project%20200812%20Coordinate%20Interchange%20Standards%20DL/Paragraph_81_Criteria.pdf

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 support technology innovation and adoption, the electric industry must be able to perform proof-of-concept deployments beyond alternative or simulated test environments. The industry must be allowed to pilot and trial new technology in production or live operation environments across regions to explore use cases, evaluate reliability and security impacts, and understand regulatory standards challenges. For this to occur, however, there must be an understood "safe" space, in cooperation with regulatory bodies, to allow for beneficial experimentation and learning.

Under the NERC Rules of Procedure, a precedent exists in the way of field tests that offer potential opportunities for compliance waivers to establish the aforementioned "safe" regulatory space for the testing as needed—however, there are limitations. The current standards development procedure 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 that this field test process offers to industry because new technologies often fall into 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 results tend to vary between a drastically slowed process to the outright stifling of adoption, such as with cloud technology and real-time decision use of PMUs. In other cases, in which an applied technology is out of scope, limitedly or non-applicable, or non-jurisdictional, we see outright proliferation, such as in IBRs, DERs, and electric-vehicle charging. It should be noted that the proliferating technologies are also predominantly integrated with cloud technology, underscoring regulatory requirements as the primary barrier for cloud technology adoption for in-scope NERC CIP systems.

[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 to explore new technology emerges, industry readiness often follows, prompting a willingness to test the technology in real-world settings. SITES believes that, through carefully managed field trials, we can cultivate awareness, align interests, endorse good practices, and ultimately establish a precedent 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 allow 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 function more effectively as a leading—rather than a lagging—indicator of reliability and security risk mitigation. Above all, such trials may empower industry to achieve swifter adoption of secure and reliable technologies by utilities, even in cases where standards development work is identified as potentially being needed.

Consider the NERC CIP V3 to V5 transition pilot project in which volunteer utilities updated their systems ahead of the V5 standards becoming mandatory and underwent specialized V5 audits during this time. This initiative allowed standards developers to refine the standards based on real-world applications and challenges encountered during the transitions that these utilities experienced during the pilot. Drawing on this model, a given technology field trial may, where appropriate, employ compliance waivers or specialized audits for volunteer entities. This could occur at a given trial's onset or after a re-evaluation at predefined milestone events. With implementation reviews, security and reliability guidelines, and potentially even Compliance Monitoring and Enforcement Program (CMEP) guidance developed as a result of a given field trial, industry may pave a path to enable broadening adoption after a trial, even before potential standards development follow-up may begin.

SITES envisions Regional Entities as the vanguard of conducting and coordinating these 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 Department of Energy (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 and facilitated by NERC in collaboration with industry stakeholders through committees and working groups under the RSTC (e.g., 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 like 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 when the added regional diversity may offer valuable additional insights to the trial.

These field trials represent an opportunity for the electric industry to proactively walk hand in hand with regulators to ethically seek secure and reliable implementations of emerging technology on which our increasingly diverse and complex grid will become dependent—whether or not we are proactive in guiding its implementations. By taking a proactive and collaborative approach to the exploration of new technologies with field trials, we can discourage and thereby mitigate grid-reliability risk from edge-case experimentation while safeguarding the grid's operational integrity and increasing industry's agility and efficacy in ensuring that 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 organizational 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 duration, goals, minimum or maximum number of volunteers, and volunteer requirements.
- Regulatory Approvals, Waivers, and Audits: Alongside developing initial scope, secure necessary ERO Enterprise approvals for trials that might impact current 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 inhibit widespread technology innovation and adoption across the industry. Workforce challenges, financial limitations, rigid compliance approaches, and a 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 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 test new technologies through proof-of-concept installations, sometimes at low cost or even for 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.

Nonetheless, all of these share the same challenge in that these alternate environments face 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 ensuring the desired outcome.

Roadblocks for Technology Innovation and Adoption

To better enable technology advancement for the industry with the aim of furthering grid reliability, resilience, and security, we must first explore the 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 that are slowing or impeding innovation and the widespread adoption of these advancements, including internal compliance strategies, workforce constraints, financing, and regulatory framework challenges, are explored.

Workforce Acquisition and Retention

The acquisition and retention of a skilled workforce is a challenge in the electric utility sector, crucially influencing the rate and scope of technology adoption. Rather than being isolated, these incidents are common across the industry. An awareness of these challenges often leads organizations, intentionally or not, to adopt conservative approaches toward technological advancement, ranging 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 not only be 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 pace with technological progress. These scenarios may lead to outsourcing, resulting in increased remote access and other consequences that may further aggravate financial, compliance, and risk concerns. Compounded by the attractiveness of new industries, the evolving nature of required skill sets, 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 toward 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, as follows:

- **Lack of Expertise:** Smaller utilities often struggle to attract the necessary expertise, especially in specialized areas like operational technology (OT), combined security and engineering skill sets, 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 at which 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 the industry for more appealing jobs. Forward-thinking utilities that have begun adopting new technologies offer contrasting messaging, marketing themselves as "technology companies that deliver electricity" coupled 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 technological advancement, thus also playing a crucial role in retaining talent.
- **Pay and Benefits:** Offering competitive pay and having available budget resources 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 like 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, and Remote Work:** Factors like 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 can consider the following 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 travel and flexible working options, can significantly boost both acquisition and retention of talent.
- **Prioritize a Positive Organizational Culture:** Ensure that 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 and 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. Discussed below are some key financial considerations that utilities should manage in order to innovate more effectively:

- **CapEx vs. OpEx:** Utilities earn a return on capital expenditures (CapEx) (physical assets) but not on operating expenses (OpEx) (like fuel and maintenance), thereby impacting much of the decision-making around implementing technology in the industry. Some utilities may find success in classifying on-premises IT infrastructure (like servers and telecommunications equipment) and even software (like EMS and supervisory control and data acquisition (SCADA)) as CapEx, highly dependent on state public utility commissions (PUC) and other oversight policies. Technology that fails to be designed-in and added to larger capitalized projects is often relegated to OpEx, as is often the case with software and hardware dedicated to cyber security, in addition to new technology initiatives. Additionally, cloud services such as 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 CapEx. 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 Research and Development Funding:** Exploring new technologies often requires upfront investment in research and development (R&D). 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.

Stifling Innovation from Vendors

The relationship between innovation and regulation presents a significant challenge in the electric sector, particularly regarding vendor-produced technologies. This challenge is rooted in the inherent lag between technological advancement and regulatory response, which often burdens vendor innovation. Explored below are the various ways in which this challenge manifests for vendors:

- **Compliance as a Prerequisite for Adoption:** Vendors developing products for a compliance-focused environment face a unique dilemma. Without clear compliance precedents, utilities, especially those sensitive to compliance risk, hesitate to adopt innovative solutions. The common question from vendors' customers — "How will it meet compliance?" — underscores the need for compliance assurance to precede widespread adoption. This scenario puts vendors in a challenging position, as they must innovate within the confines of existing standards, often limiting the scope of their creativity and technological advancement.

- **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 since they have the support staff to manage these complexities, a luxury that smaller organizations often lack. This disparity influences the risk appetite of utilities, as larger entities are 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 use their vendor relationships to drive innovation in directions that suit their needs.

- **The Innovation-Regulation Gap:** Innovation almost always precedes regulation, making it challenging for regulators to define 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. This dynamic can lead to shifting definitions and potentially alter the original intent of regulations. Vendors often lack direct access to compliance decision-makers and their opinions before deploying technology at client sites, further complicating the landscape.

- **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 standards even when new technologies might offer enhanced security, performance, and scalability.

- **Hardware Lifecycle:** OT 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 in which 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 Regional Entities. This is explored in finer detail below:

- **New Technology and Prescriptive 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 vs. 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, with 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 re-evaluation of compliance approaches to accommodate these advancements, especially where cloud technology plays a role. The transition between ignorance and understanding, whether a standard is truly restrictive of a new technology or not, happens at different timescales for individual entities and the electric industry as a whole. Traditional networking transitioning to software-defined networking is another example, challenging traditional static documentation evidence measures in the presence of policy-driven ephemeral configurations and baselines. Standards project 2016-02 is an example of an industry-wide effort that leads the way for these transitions and even paves 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 10 to 1, suffer this burden on their staffing resources and compliance programs disproportionately. More staff means being able to divide and conquer and thus have an easier time staying up to date with regulatory changes and guidance.

- **Compliance as an Enabler, Not an End Goal:** Compliance should not be the ultimate goal but part of the overall security program. It should enable operations rather than dictate them. Active participation in standard development teams, committees, and industry working groups like SITES is crucial for utilities to ensure that proposed standards support, rather than hinder, 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 that utilities are equipped to be appropriately nimble in the adoption of new technology toward securing the grid. Utilities should strive for overarching security in which compliance is a component, not the entirety. This involves viewing compliance as a facilitator of operational flexibility and innovation. In other words, 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 or a replacement for registered entities performing independent security risk assessments.

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 standards that support technological advancements while maintaining grid reliability, resilience, and security. Additional recommendations to promote a more mature and flexible culture of compliance are listed below:

- Aim to be risk-averse rather than change-averse.

- When evaluating new technology without existing available guidance, consider engaging regulatory bodies and auditors up front.

- Improve awareness of available regulatory guidance papers. More knowledge creates more options.

- With the aim of cultivating a culture of compliance internally within an organization, create a safe and mutually beneficial space for internal disclosure on compliance risks.

- Seek mock audits from outside consultants or regional entities after initially implementing new technology.

Lessons From Alternative Regulatory Frameworks

In gauging the effectiveness and impact of regulatory standards like NERC CIP, a comparative lens aimed at alternative frameworks and industries could be enlightening as the other standards could offer insight into the symbiosis between technology enablement and regulatory landscapes. The PCI DSS and standards applied in diverse sectors like insurance and safety present a spectrum of methodologies and outcomes concerning technology adoption and security governance. Various 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 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 cyber security 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 of 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 toward compliance. The prescriptive nature and clear delineations within the PCI DSS serve to eliminate ambiguity regarding compliant technologies and practices, which can be especially advantageous for entities with limited cyber security expertise or resources. This approach to validation also fosters a degree of uniformity in security postures across entities, ensuring that baseline cyber security 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, a bureaucratic element 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 that 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 cyber security posture of the healthcare sector. However, without a centralized and standardized validation mechanism or clear-cut technological guidelines, entities with limited cyber security expertise might inadvertently integrate technologies that inadequately safeguard PHI, thereby increasing 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 cyber security efficacy and resilience across different entities, pivoting the risk landscape toward a scenario in which 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 in which technological innovation and adoption must be meticulously balanced with rigorous internal risk assessments and cyber security expertise to safeguard against the unintended elevation of cyber security threats within the healthcare sector.

Assessment of SOX (Sarbanes–Oxley Act)

SOX, centered around financial integrity, delivers guidelines without delving into technical cyber security specifications. This regulatory framework, while emphasizing financial accuracy, does not stipulate a detailed technological roadmap, potentially allowing entities to explore innovative financial or cyber security technologies freely. However, this general approach may also induce challenges in which organizations, in ensuring compliance, could opt for established, proven technologies, potentially circumventing innovative but unvetted solutions. The resulting cyber security strategy, while adhering 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, as the risk of 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 (CJI), 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 can 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 enabling and inhibiting 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 cyber security expertise. Consequently, while CJIS provides a robust and flexible framework for safeguarding CJI, its inherent complexity and the requisite resources for ensuring compliance could curtail rapid technology adoption and innovation to a certain extent.

Appendix B: Contributors

SITES would like to thank the following individuals, for their contributions to the development of this white paper and its recommendations:

- Dan Goodlett
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Proposed RSTC Charter Revisions

Action

Review initial proposed changes to the RSTC Charter and solicit RSTC feedback.

Background

In November 2019, the NERC Board of Trustees (Board) approved creation of the Reliability and Security Technical Committee (RSTC) to replace the former Operating, Planning and Critical Infrastructure Protection Committees and approved the initial RSTC Charter. The RSTC Charter provides for two voting sector seats for each of Sectors 1-10 and 12, with ten voting at-large seats, in addition to the Chair and Vice-Chair voting members. There are also non-voting members delineated in the Charter.

This structure is designed to meet NERC's responsibility to ensure a balanced stakeholder process in its standing committees. As the Electric Reliability Organization, NERC's rules must "assure its independence of the users and owners and operators of the bulk-power system, while assuring fair stakeholder representation in the selection of its directors and balanced decision making in any ERO committee or subordinate organizational structure." Section 215(c)(2)(A) of the Federal Power Act. *See also*, NERC Bylaws, Article VII, Section 1; *and* NERC Rules of Procedure, at Section 1302.

Under the RSTC Charter, at-large members are selected to allow for better balancing of representation of geographic diversity, subject matter expertise, organizational types, and North American countries. To support such goals and a full RSTC membership ready to tackle reliability risks facing the electric industry, the Charter states that if a sector receives no nominations during the election process, the seat will be converted to at-large membership for the remainder of term.

While there are benefits to this approach, lessons learned after conversions of sector seats without a nominee between 2020-2023 indicates that modifications would be appropriate to support operation as intended. In particular, the conversion process has led the at-large member group to grow from ten to fifteen members with four sectors under-represented.

NERC staff has therefore developed targeted draft revisions to the RSTC Charter to address concerns with respect to balanced sector membership based on such lessons learned.

Summary

The proposed revisions would modify Section 3 Membership – Member Selection as follows:

- (2) Election of Sector Members:

NERC members in each sector will annually elect members for expiring terms or open seats using a nomination and election process that is open, inclusive, and fair. If a sector has no nominations for any open sector ~~one or both sector~~ seats ~~at the annual election~~during the sector election period, the RSTC will convert those empty sector seats to at-large seats until the end of the term unless a valid sector nomination is received prior to the end of the at-large nomination period. NERC Staff shall provide any existing sector representative written notice approximately one week before the end of the sector election period if there have been no nominees for an open sector seat.

These proposed revisions to the RSTC Charter would enhance the sector election process to provide a longer grace period prior to conversion of an open sector seat to an at-large seat and allow for notifications to underrepresented sectors prior to an unfilled seat being converted.

- (4) Selection of At-Large Members

  The RSTC NS solicits and reviews nominations from the full RSTC and industry to fill at-large representative seats. After reaching consensus, the RSTC NS submits a recommended slate of at-large candidates to the Board ~~at its annual February meeting for approval.~~. During its selection process the RSTC NS will prioritize its consideration of candidates that would help ensure balanced sector representation on the RSTC. To the extent practicable, the RSTC NS will balance the following criteria to select at-large members: (a) geographic diversity from all Interconnections and ERO Enterprise Regional Entities; (b) high-level understanding and perspective on reliability risks based on experience at an organization in a sector; and, (c) experience and expertise from an organization in the sector relevant to the RSTC. The RSTC NS selection process shall also ensure that at-large members include no more than two individuals that would be eligible for the same particular sector, except where it would ensure equitable representation from the United States and Canada in proportion to each country's percentage of total Net Energy for Load.

  ~~The Board votes to appoint the at-large members.~~

  These proposed revisions would provide additional clarity that the Nominating Subcommittee should prioritize consideration of candidates that would help support balanced sector representation as it evaluates a recommended slate of at-large candidates for presentation to the Board.

These draft tailored revisions would help ensure sector balance, while maintaining geographic diversity, high-level understanding and perspective on reliability risks, and experience and expertise.

Next Steps

NERC staff will distribute draft Charter revisions after the meeting for RSTC comment from June 12-July 19, 2024.

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Reliability and Security Technical Committee Charter

February 2025

Approved by the NERC Board of Trustees: February __, 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 boundaries as shown in the map and 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

Section 1: Purpose

The Reliability and Security Technical Committee (RSTC) is a standing committee that strives to advance the reliability and security of the interconnected BPS of North America by:

- Creating a forum for aggregating ideas and interests, drawing from diverse industry stakeholder expertise, to support the ERO Enterprise's mission;
- Leveraging such expertise to identify solutions to study, mitigate, and/or eliminate emerging risks to the BPS for the benefit of industry stakeholders, the NERC Board of Trustees (Board) and ERO Enterprise staff and leadership; and,
- Overseeing the implementation of subgroup work plans that drive risk-mitigating technical solutions.

Section 2: RSTC Functions

Create a forum for industry stakeholders to support NERC programs in the development of key ERO Enterprise deliverables.

- Facilitate and advocate information sharing among relevant industry stakeholders;
- Review and provide guidance in developing deliverables critical to ERO functions, such as Reliability Standards, reliability assessments, requests for data (pursuant to Section 1600 of the NERC Rules of Procedure Section (ROP)), Implementation Guidance, and other analyses, guidelines, and reports;
- Solicit and coordinate technical direction, oversight activities, and feedback from industry stakeholders;
- Disseminate ERO deliverables to industry to enhance reliability;
- Develop internal and review external requests for industry actions and informational responses;
- Develop appropriate materials, as directed by ERO functions or the NERC Board, to support ERO Enterprise functions; and,
- Coordinate with ERO staff and liaise with government agencies and trade associations.
- Provide technical input and analyses on operating and planned BPS reliability and security, emerging issues and risks, and other general industry concerns at the request of the NERC Board or NERC staff.

Develop a two-year Strategic Plan to guide the deliverables of the RSTC and ensure appropriate prioritization of activities.

- Ensure alignment of the Strategic Plan with NERC priorities, 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;
- Coordinate the objectives in the Strategic Plan with the Standing Committees Coordinating Group; and,
- Obtain annual NERC Board approval. The RSTC will target presenting the Strategic Plan to the Board at its February meeting, at the same time that the RSTC presents the full RSTC membership list in accordance with Section III below.

Coordinate and oversee implementation of RSTC subgroup work plans.

- Assign an RSTC member sponsor, as necessary, to subgroups to ensure alignment with RSTC schedules, processes, and strategic goals.
- Create and disband subcommittees, working groups and task forces to support ERO Enterprise functions;
- Harmonize and approve the work plans of subcommittees, working groups, and task forces with the Strategic Plan; and,
- Track the progress of the subcommittees, working groups, and task forces to ensure that they complete assigned activities as outlined in their work plans and in alignment with the RSTC Strategic Plan.

Advise the NERC Board of Trustees.

- Update the NERC Board semi-annually on progress in executing the Strategic Plan; and,
- Present appropriate deliverables to the NERC Board.

Section 3: Membership

Representation Model

The RSTC has a hybrid representation model consisting of the following types of memberships:

- Sector members;
- At-large members; and,
- Non-voting members.

Two members shall be elected to each of the following membership sectors:

- Sector 1 - Investor-owned Utility;
- Sector 2 – State or Municipal Utility;
- Sector 3 - Cooperative Utility;
- Sector 4 - Federal or Provincial Utility/Power Marketing Administration;
- Sector 5 - Transmission-Dependent Utility;
- Sector 6 - Merchant Electricity Generator;
- Sector 7 - Electricity Marketer;
- Sector 8 - Large End Use Electricity Customer;
- Sector 9 - Small End Use Electricity Customer;
- Sector 10 - ISO/RTO; and,
- Sector 12 - Government Representatives.

Selection of at-large members will allow for better balancing of representation on the RSTC of the following:[1]

- Regional Entity and Interconnection diversity (i.e., goal of having at least one representative from each Interconnection and Regional Entity footprint);
- Subject matter expertise (Planning, Operating, or Security);
- Organizational types (Cooperatives, Investor-Owned Utilities, Public Power, Power Marketing Agencies, etc.); and,
- North American countries, consistent with the NERC bylaws (Canada, Mexico, and U.S.) to support diversity of views on issues facing reliability of the North American BPS.

Upon expiration of his or her term as chair, the outgoing chair may remain a non-voting member of the RSTC for one year, in the interest of continuity.[2]

Below is a breakdown of voting and non-voting membership on the RSTC:

[1] *See,* NERC Sector 13 in the NERC Bylaws (2021).

[2] Provided that, if the outgoing chair is elected to represent a voting sector that individual would hold a voting membership position for the relevant term.

Voting Membership	
Name	**Voting Members**
Sectors 1-10 and 12	22
At-Large	10
Chair and Vice-Chair	2
Total	**34**

Non-Voting Membership[3]	
Non-Voting Member	**Number of Members**
NERC Secretary	1
United States Federal Government	2
Canadian Federal Government	1
Provincial Government	1
Former Chair	1
Total	**6**

Member Selection

RSTC members are not required to be from organizations who are NERC members.

Members are appointed to the RSTC upon approval of the NERC Board and serve on the RSTC at the pleasure of the NERC Board.

1. **Affiliates**

   A company, including its affiliates, may not have more than one member on the RSTC. Any RSTC member who is aware of a membership conflict of this nature is obligated to notify the RSTC secretary within 10 business days. The RSTC secretary will in turn report the conflict to the RSTC chair.

   Members impacted by such a conflict, such as through a merger of organizations, must confer among themselves to determine which member should resign from the RSTC and notify the secretary and chair; however, if they cannot reach an amicable solution to determine who will remain, the Nominating Subcommittee will review the qualifications of each member and make a recommendation to the NERC Board for final approval.

2. **Election of Sector Members**

   NERC members in each sector will annually elect members for expiring terms or open seats using a nomination and election process that is open, inclusive, and fair. If a sector has no nominations for one or both sector seats during the sector election period, the RSTC will convert those empty sector seats to at-large seats until the end of the term unless a valid sector nomination is received prior to the end of the at-large nomination period. NERC Staff shall provide any existing sector representative written notice approximately one week before the end of the sector election period if there have been no nominees for an open sector seat.

   Sector elections will be completed in time for the Nominating Subcommittee to identify and nominate at-large representatives as well as for the secretary to send the full RSTC membership list to the NERC Board for approval at its annual February meeting.

[3] Upon recognition of NERC as the ERO, Mexican Government representation will be equitable and based approximately on proportionate Net Energy for Load.

If an interim vacancy is created in a sector, a special election will be held unless it coincides with the annual election process. If a sector cannot fill an interim vacancy, then that sector seat will remain vacant until the next annual election. Interim sector vacancies will not be filled with an at-large representative.

3. **Nominating Subcommittee**

   The Nominating Subcommittee (RSTC NS) will consist of seven (7) members (the RSTC vice-chair and six (6) members drawing from different sectors and at-large representatives). Apart from the vice-chair, members of the RSTC Executive Committee (RSTC EC) shall not serve on the RSTC NS.

   The NS members are nominated by the RSTC chair and voted on by the full RSTC membership.

   The term for members of the NS is one (1) year.

   The RSTC NS is responsible for (a) recommending individuals for at-large representative seats, and, (b) managing the process to select the chair and/or vice-chair of the RSTC. The RSTC vice-chair shall recuse him or herself from this process (a) unless he or she is not seeking re-election, or (b) until the RSTC NS has concluded a vote to recommend the vice-chair for subsequent RSTC election to the chair position. At-large members on the RSTC NS shall recuse themselves from recommendations for at-large representative seats if they are seeking reappointment.

4. **Selection of At-Large Members**

   The RSTC NS solicits and reviews nominations from the full RSTC and industry to fill at-large representative seats. After reaching consensus, the RSTC NS submits a recommended slate of at-large candidates to the Board. During its selection process the RSTC NS will prioritize its consideration of candidates that would help ensure balanced sector representation on the RSTC. To the extent practicable, the RSTC NS will balance the following criteria to select at-large members: (a) geographic diversity from all Interconnections and ERO Enterprise Regional Entities; (b) high-level understanding and perspective on reliability risks based on experience at an organization in a sector; and, (c) experience and expertise from an organization in the sector relevant to the RSTC. The RSTC NS selection process shall also ensure that at-large members include no more than two individuals that would be eligible for the same particular sector, except where it would ensure equitable representation from the United States and Canada in proportion to each country's percentage of total Net Energy for Load.

5. **Non-Voting Members**

   Non-voting members shall serve a term of two (2) years, just as voting members. At the start of the annual RSTC nomination process the RSTC secretary will coordinate with entities entitled to non-voting membership to identify representatives for any open non-voting seats. The RSTC secretary shall do this by reaching out to the relevant Governmental Authorities to solicit interest for non-voting member seats and forwarding those names to the RSTC NS for inclusion in the slate of candidates presented to the Board at its annual February meeting. Where more than one candidate is proposed, the RSTC secretary will work with the relevant Governmental Authorities to reach a decision.

6. **International Representation**

   International representation on the RSTC shall be consistent with Article VIII Section 4 of the NERC Bylaws.

Member Expectations

RSTC members and the RSTC's subordinate groups are expected to act in accordance with this charter, as well as to accomplish the following:

- Adhere to NERC Antitrust Guidelines[4] and Participant Conduct Policy[5];
- Demonstrate and provide knowledge and expertise in support of RSTC activities;
- Where applicable, solicit comments and opinions from constituents and groups of constituents or trade organizations represented by the member and convey them to the RSTC;
- Respond promptly to all RSTC requests, including requests for reviews, comments, and votes on issues before the RSTC; and,
- During meetings, comply with the procedures outlined for that meeting and identified in this Charter. .

Sponsor Expectations

Sponsors are expected to act in accordance with this charter, as well as to accomplish the following:

- Understand and advance the expectations of the RSTC, not those of their sector or other interest group;
- Assure that recommendations and action plans are designed for implementation;
- Support the subgroup Chair and Vice-Chair in seeing the big picture without directing the activities of the subgroup; and,
- Liaise with the RSTC.

Member Term

Members shall serve a term of two years.

An RSTC member may serve a term shorter than two (2) years if:

- Two (2) members are simultaneously selected to a sector that did not have any existing members, in order to stagger their terms, one member will be assigned a one-year term and the second member will be assigned a two-year term.
- A member is selected to fill a vacant member seat between elections, the term will end when the term for that vacant seat ends.

There are no limits on the number of terms that members can serve.

Vacancies and Proxies

Membership vacancies may be filled between annual elections using the aforementioned selection process.

1. **Vacancies Created by the Member**

   In the event a member can no longer serve on the RSTC, that member will submit a written resignation to the RSTC chair or the secretary. A change in employment does not automatically require a member's resignation and will be evaluated on a case-by-case basis.

2. **Vacancies Requested by the Chair**

   The chair may request any RSTC member who ceases to participate in the RSTC consistent with member expectations (above) and to the satisfaction of the chair, to submit a resignation or to request continuation of membership with an explanation of extenuating circumstances. If a written response is not received within

[4] https://www.nerc.com/pa/Stand/Resources/Documents/NERC_Antitrust_Compliances_Guidelines.pdf
[5] https://www.nerc.com/gov/Annual%20Reports/NERC_Participant_Conduct_Policy.pdf

30 days of the chair's request, the lack of response will be considered a resignation. If the chair is not satisfied with a written response, the RSTC chair will refer the matter to the NERC Board.

3. Vacancies Requested by the Board

RSTC members serve at the pleasure of the NERC Board. The NERC Board may initiate a request for resignation, removal, or replacement of a member from the RSTC, as it deems appropriate or at the request of the RSTC chair.

4. Proxies

A voting member may select a proxy who attends and votes during all or a portion of a committee meeting in lieu of a voting member, provided that the absent voting representatives notifies the RSTC chair, vice chair, or secretary of the proxy. A proxy may not be given to another RSTC member. A proxy must meet the RSTC's membership eligibility requirements, including affiliate restrictions.

To permit time to determine a proxy's eligibility, all proxies must be submitted to the secretary in writing at least one week prior to the meeting (electronic transmittal is acceptable) for approval by the chair. Any proxy submitted after that time will be accepted at the chair's discretion.

Section 4: Meetings

Open meetings will be conducted in accordance with this Charter. The Chair may consult Robert's Rules of Order for additional guidance.

Quorum

The quorum necessary for transacting business at meetings of the RSTC is two-thirds of the voting members currently on the RSTC's roster and is determined once at each meeting.

If a quorum is not determined, the RSTC may not take any actions requiring a vote; however, the chair may allow discussion of the agenda items.

Voting

Actions by the RSTC will be approved upon receipt of the affirmative vote of two-thirds of the votes cast at any meeting at which a quorum is present. An abstention ("present" vote) does not count as a vote cast.

Voting may take place during regularly scheduled in-person meetings, via electronic mail, or via conference call/virtual meeting.

Refer to Section 7 for voting procedures.

Executive, Open and Closed Sessions

The RSTC and its subordinate groups hold meetings open to the public, except as noted herein. Although meetings are open, only voting members may offer and act on motions.

All meetings of the Executive Committee and the RSTC NS shall be conducted in closed session.

The chair may also hold closed sessions in advance of the open meeting with limited attendance based on the confidentiality of the information to be disclosed at the meeting. Such limitations should be applied sparingly and on a non-discriminatory basis. Any discussion of confidential information in a closed session shall be consistent with Section 1500 of the NERC ROP.[6]

Majority and Minority Views

All members of a committee will be given the opportunity to provide alternative views on an issue. The results of committee actions, including recorded minutes, will reflect the majority as well as any minority views of the committee members.

Action without a Meeting

Any action required or permitted at a meeting of the committee may be taken without a meeting at the request of the chair.

Such action without a meeting will be performed by electronic ballot (e.g., telephone, email, or Internet survey) and considered a roll call ballot. The secretary will announce the action required at least five business days before the date on which voting commences. As time permits, members should be allowed a window of ten (10) business days to vote. The secretary will document the results of such an action within ten (10) business days of the close of the voting period. Such action must meet the regular meeting quorum and voting requirements above.

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[6] Section 1500 of the NERC ROP - https://www.nerc.com/FilingsOrders/us/RuleOfProcedureDL/NERC%20ROP%20(With%20Appendicies).pdf

Section 5: Officers and Executive Committee

Officers

The RSTC will have two officers – one chair and one vice-chair.

Officers shall be selected as follows:

- The RSTC NS solicits nominations for chair and vice-chair through an open nomination process. Self-nominations are permitted during the open nomination period.
- At the close of the nomination period, the RSTC NS will propose a chair and a vice-chair candidate. The full RSTC will elect the chair and vice chair.
- The chair and vice chair must be a committee member and shall not be from the same sector.
- The elected chair and vice-chair are appointed by the NERC Board.
- No individual may serve more than one term as vice chair and one term as chair unless an exception is approved by the Board. A term lasts two years.

Upon expiration of his or her term as chair, the outgoing chair may remain a non-voting member of the RSTC for one year, in the interest of continuity.[7]

Secretary

NERC will appoint the RSTC secretary.

A member of the NERC staff will serve as the secretary of the RSTC. The secretary will do the following:

- Manage the day-to-day operations and business of the RSTC;
- Prepare and distribute notices of the RSTC meetings, prepare the meeting agenda, and prepare and distribute the minutes of the RSTC meetings;
- Facilitate the election/selection process for RSTC members; and,
- Act as the RSTC's parliamentarian.

Chair

The chair will direct and provide general supervision of RSTC activities, including the following:

- Coordinate the scheduling of all meetings, including approval of meeting duration and location;
- Develop agendas and rule on any deviation, addition, or deletion from a published agenda;
- Preside at and manage meetings, including the nature and length of discussion, recognition of speakers and proxies, motions, and voting;
- Act as spokesperson for the RSTC at forums inside and outside of NERC; and,
- Attend meetings of the NERC Board when necessary to report on RSTC activities.

Vice Chair

The vice chair will assume the responsibilities of the chair under the following conditions:

[7] Provided that, if the outgoing chair is elected to represent a voting sector that individual would hold a voting membership position for the relevant term

- At the discretion of the chair (for brief periods of time);
- When the chair is absent or temporarily unable to perform the chair's duties; or,
- When the chair is permanently unavailable or unable to perform the chair's duties. In the case of a permanent change, the vice chair will continue to serve until a new chair is nominated and appointed by the NERC Board.

Executive Committee

The RSTC EC shall consist of six (6) members:

- Chair;
- Vice-chair;
- Four (4) RSTC voting members selected by the RSTC chair and vice-chair with a reasonable balance of subject matter expertise in Operations, Planning, and/or Security and with consideration for diversity in representation (i.e., sectors, Regional Entities, Interconnections, etc.).
  - The RSTC chair and vice-chair shall evaluate composition of the RSTC EC within six months of their election as officers for the appropriate balance of technical expertise, geographical representation, and tenure.

The RSTC EC of the RSTC is authorized by the RSTC to act on its behalf between regular meetings on matters where urgent actions are crucial and full RSTC discussions are not practical. The RSTC shall be notified of such urgent actions taken by the RSTC EC within a week of such actions. These actions shall also be included in the minutes of the next open meeting.

Ultimate RSTC responsibility resides with its full membership whose decisions cannot be overturned by the EC. The RSTC retains the authority to ratify, modify, or annul RSTC EC actions.

After general solicitation from RSTC membership, the RSTC EC will appoint any sponsors of subgroups.

Section 6: RSTC Subordinate Groups

The RSTC organizational structure will be aligned as described by the NERC Bylaws to support a superior-subordinate hierarchy.

The RSTC may establish subcommittees, working groups, and task forces as necessary. The RSTC will be the responsible sponsor of all subordinate subcommittees, working groups, or task forces that it creates, or that its subordinate subcommittees and working groups may establish.

Officers of subordinate groups will be appointed by the chair of the RSTC. Where feasible, officers shall be selected from individuals employed at entities within NERC membership sectors 1 through 12 to support sufficient expertise and diversity in execution of the subordinate group's responsibilities.

Subcommittees, working groups, and taskforces will conduct business in a manner consistent with all applicable sections of this Charter, including the NERC Antitrust Guidelines[8] and Participant Conduct Policy[9].

Subcommittees

The RSTC may establish subcommittees to which the RSTC may delegate some of RSTC's functions. The RSTC will approve the scope of each subcommittee it forms. The RSTC chair will appoint the subcommittee officers (typically a chair and a vice chair) for a specific term (generally two years). The subcommittee officers may be reappointed for up to two additional terms. The subcommittee will work within its assigned scope and be accountable for the responsibilities assigned to it by the committee. The formation of a subcommittee, due to the permanency of the subcommittee, will be approved by the NERC Board.

Working Groups

The RSTC may delegate specific continuing functions to a working group. The RSTC will approve the scope of each working group that it forms. The RSTC chair will appoint the working group officers (typically a chair and a vice chair) for a specific term (generally two (2) years). The working group officers may be reappointed for one (1) additional term. 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 transitioning to a subcommittee any working group that is required to work longer than two terms.

Task Forces

The RSTC may assign specific work to a task force. The RSTC will approve the scope of each task force it forms. The RSTC chair will appoint the task force officers (typically a chair and a vice chair). 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 review the task force's execution of its work plan 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 transitioning to a working group any task force that is required to work longer than two years.

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[8] https://www.nerc.com/pa/Stand/Resources/Documents/NERC_Antitrust_Compliances_Guidelines.pdf

[9] https://www.nerc.com/gov/Annual%20Reports/NERC_Participant_Conduct_Policy.pdf

Section 7: Meeting Procedures

Voting Procedures for Motions

In-Person

- The default procedure is a voice vote.
- If the chair believes the voice vote is not conclusive, the chair may call for a show of hands.
- The chair will not specifically ask those who are abstaining to identify themselves when voting by voice or a show of hands. If the chair desires a roll call, the secretary will call each member's name.

  Members answer "yes," "no," or "present" if they wish to abstain from voting. As provided above, an abstention does not count as a vote cast.

Conference Call / Virtual[10]

- All voting shall default to being conducted through use of a poll.
- Where a need to record each member's vote is requested or identified, the RSTC may conduct voting via a roll call vote.

Minutes

- Meeting minutes are a record of what the committee did, not what its members said.
- Minutes should list discussion points where appropriate but should usually not attribute comments to individuals. It is acceptable to cite the chair's directions, summaries, and assignments.
- All Committee members are afforded the opportunity to provide alternative views on an issue. The meeting minutes will provide an exhibit to record minority positions.

[10] Virtual meetings include those where virtual attendance is possible, such as a fully or partially virtual meeting.

Section 8: RSTC Deliverables and Approval Processes

The RSTC will abide by the following to approve, endorse, or accept committee deliverables.

Reliability Guidelines, Security Guidelines and Technical Reference Documents

Reliability Guidelines, Security Guidelines, and Technical Reference Documents suggest approaches or behavior in a given technical area for the purpose of improving reliability.

Reliability and Security Guidelines

Reliability Guidelines and Security Guidelines are not binding norms or mandatory requirements. Reliability Guidelines and Security Guidelines may be adopted by a responsible entity in accordance with its own facts and circumstances.

1. **New/updated draft Guideline approved for industry posting.**

   The RSTC accepts for posting for industry comment (i) the release of a new or updated draft Guideline developed by one of its subgroups or the committee as a whole; or (ii) the retirement of an existing Guideline.

   The draft Guideline or retirement is posted as “for industry-wide comment” for 45 days. If the draft Guideline is an update, a redline version against the previous version must also be posted.

   After the public comment period, the RSTC will post the comments received as well as its responses to the comments. The RSTC may delegate the preparation of responses to a committee subgroup.

   A new or updated Guideline which considers the comments received, is approved by the RSTC and posted as “Approved” on the NERC website. Updates must include a revision history and a redline version against the previous version. Retirements are also subject to RSTC approval.

   After posting a new or updated Guideline, the RSTC will continue to accept comments from the industry via a web-based forum where commenters may post their comments.

   a. Each quarter, the RSTC will review the comments received.

   b. At any time, the RSTC may decide to update the Guideline based on the comments received or on changes in the industry that necessitate an update.

   c. Updating an existing Guideline will require that a draft updated Guideline be posted and approved by the RSTC in the above steps.

2. **Review of Approved Reliability Guidelines, Security Guidelines and Technical Reference Documents**

   Approved Reliability Guidelines or Technical Reference Document shall be reviewed for continued applicability by the RSTC at a minimum of every third year since the last revision.

3. **Communication of New/Revised Reliability Guidelines, Security Guidelines and Technical Reference Documents**

   In an effort to ensure that industry remains informed of revisions to a Reliability Guideline or Technical Reference Document or the creation of a new Reliability Guideline or Technical Reference Document, the RSTC subcommittee responsible for the Reliability Guideline will follow an agreed upon process. Reliability Guidelines, Security Guidelines, and Technical Reference Documents (including white papers as discussed below) shall be posted on the RSTC website.

4. **Coordination with Standards Committee**

Standards Committee authorization is required for a Reliability Guideline or Security Guidelines to become a supporting document that is posted with or referenced from a NERC Reliability Standard. See Appendix 3A in the NERC's ROP under "Supporting Document."

Section 1600 Data or Information Requests[11]

A report requested by the RSTC that accompanies or recommends a Rules of Procedure (ROP) Section 1600 - Data or Information Request will follow the process outlined below:

1. This Section 1600 request, with draft supporting documentation, will be provided to the RSTC at a regular meeting.
2. The draft Section 1600 data request and supporting documentation will be considered for authorization to post for comments at the RSTC regular meeting.
3. A committee subgroup will review and develop responses to comments on the draft Section 1600 data request and will provide a final draft report, including all required documentation for the final data request, to the RSTC at a regular meeting for endorsement.
4. The final draft of the 1600 data request – with responses to all comments and any modifications made to the request based on these comments – will be provided to the NERC Board.

Other Types of Deliverables

1. **Policy Outreach**

   On an ongoing basis, the RSTC will coordinate with the forums, policymakers, and other entities to encourage those organizations to share Reliability Guidelines, technical reference documents and lessons learned to benefit the industry.

   Reports required under the NERC ROP or as directed by an Applicable Governmental Authority or the NERC Board: documents include NERC's long-term reliability assessment, special assessments, and probabilistic assessments. These reports may also be used as the technical basis for standards actions and can be part of informational filings to FERC or other government agencies.

2. **White Papers**

   Documents that explore technical facets of topics, making recommendations for further action. They may be written by subcommittees, working groups, or task forces of their own volition, or at the request of the RSTC. Where feasible, a white paper recommending potential development of a standard authorization request (SAR) shall be posted for comment on the RSTC website. White papers will be posted on the RSTC webpage, after RSTC approval.

3. **Technical Reference Documents and Technical Reports**

   Documents that serve as a reference for the electric utility industry and/or NERC stakeholders regarding a specific topic of interest. These deliverables are intended to document industry practices or technical concepts at the time of publication and may be updated as deemed necessary, per a recommendation by the RSTC or its subgroups to reflect current industry practices. Technical reference documents and reports will be posted on the RSTC webpage, after RSTC approval.

[11] Section 1600 of the NERC ROP - https://www.nerc.com/FilingsOrders/us/RuleOfProcedureDL/NERC%20ROP%20(With%20Appendicies).pdf. This process only applies to Section 1600 requests developed by the RSTC and its subordinate groups.

4. **Implementation Guidance**

   Documents providing examples or approaches for registered entities to comply with standard requirements. The RSTC is designated by the ERO Enterprise as a pre-qualified organization for vetting Implementation Guidance in accordance with NERC Board -approved Compliance Guidance Policy. Implementation Guidance that is endorsed by the RSTC can be submitted to the ERO Enterprise for endorsement, allowing for its use in Compliance Monitoring and Enforcement Program (CMEP) activities.

5. **Standard Authorization Requests (SAR)**

   A form used to document the scope and reliability benefit of a proposed project for one or more new or modified Reliability Standards or definitions or the benefit of retiring one or more approved Reliability Standards.

   Any entity or individual, including NERC Committees or subgroups and NERC Staff, may propose the development of a new or modified Reliability Standard. A SAR prepared by a subordinate group of the RSTC must be endorsed by the RSTC prior to presentation to the Standards Committee. Each SAR should be accompanied by a technical justification that includes, at a minimum, a discussion of the reliability-related benefits and costs of developing the new Reliability Standard or definition, and a technical foundation document (e.g., research paper) to guide the development of the Reliability Standard or definition. The technical foundation document should address the engineering, planning and operational basis for the proposed Reliability Standard or definition, as well as any alternative approaches considered to SAR development.

   RSTC endorsement of a SAR supports: (a) initial vetting of the technical material prior to the formal Standards Development Process, and, (b) that sound technical justification has been developed, and the SAR will not be remanded back to the RSTC to provide such justification per the Standard Processes Manual.

Review Process for other Deliverables

Deliverables with a deadline established by NERC management or the NERC Board will be developed based on a timeline reviewed by the RSTC to allow for an adequate review period, without compromising the desired report release dates. Due to the need for flexibility in the review and approval process, timelines are provided as guidelines to be followed by the committee and its subgroups.

A default review period of no less than 10 business days will be provided for all committee deliverables. Requests for exceptions may be brought to the RSTC at its regular meetings or to the RSTC EC if the exception cannot wait for an RSTC meeting.

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

Actions for Deliverables

1. **Approve:**

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

2. **Accept:**

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

3. **Remand:**

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

4. **Endorse:**

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

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Reliability and Security Technical Committee Charter

February 2025~~4~~

Approved by the NERC Board of Trustees: February __~~5~~, 2025~~4~~

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 boundaries as shown in the map and 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

Section 1: Purpose

The Reliability and Security Technical Committee (RSTC) is a standing committee that strives to advance the reliability and security of the interconnected BPS of North America by:

- Creating a forum for aggregating ideas and interests, drawing from diverse industry stakeholder expertise, to support the ERO Enterprise's mission;
- Leveraging such expertise to identify solutions to study, mitigate, and/or eliminate emerging risks to the BPS for the benefit of industry stakeholders, the NERC Board of Trustees (Board) and ERO Enterprise staff and leadership; and,
- Overseeing the implementation of subgroup work plans that drive risk-mitigating technical solutions.

Section 2: RSTC Functions

Create a forum for industry stakeholders to support NERC programs in the development of key ERO Enterprise deliverables.

- Facilitate and advocate information sharing among relevant industry stakeholders;
- Review and provide guidance in developing deliverables critical to ERO functions, such as Reliability Standards, reliability assessments, requests for data (pursuant to Section 1600 of the NERC Rules of Procedure Section (ROP)), Implementation Guidance, and other analyses, guidelines, and reports;
- Solicit and coordinate technical direction, oversight activities, and feedback from industry stakeholders;
- Disseminate ERO deliverables to industry to enhance reliability;
- Develop internal and review external requests for industry actions and informational responses;
- Develop appropriate materials, as directed by ERO functions or the NERC Board, to support ERO Enterprise functions; and,
- Coordinate with ERO staff and liaise with government agencies and trade associations.
- Provide technical input and analyses on operating and planned BPS reliability and security, emerging issues and risks, and other general industry concerns at the request of the NERC Board or NERC staff.

Develop a two-year Strategic Plan to guide the deliverables of the RSTC and ensure appropriate prioritization of activities.

- Ensure alignment of the Strategic Plan with NERC priorities, 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;
- Coordinate the objectives in the Strategic Plan with the Standing Committees Coordinating Group; and,
- Obtain annual NERC Board approval. The RSTC will target presenting the Strategic Plan to the Board at its February meeting, at the same time that the RSTC presents the full RSTC membership list in accordance with Section III below.

Coordinate and oversee implementation of RSTC subgroup work plans.

- Assign an RSTC member sponsor, as necessary, to subgroups to ensure alignment with RSTC schedules, processes, and strategic goals.
- Create and disband subcommittees, working groups and task forces to support ERO Enterprise functions;
- Harmonize and approve the work plans of subcommittees, working groups, and task forces with the Strategic Plan; and,
- Track the progress of the subcommittees, working groups, and task forces to ensure that they complete assigned activities as outlined in their work plans and in alignment with the RSTC Strategic Plan.

Advise the NERC Board of Trustees.

- Update the NERC Board semi-annually on progress in executing the Strategic Plan; and,
- Present appropriate deliverables to the NERC Board.

Section 3: Membership

Representation Model

The RSTC has a hybrid representation model consisting of the following types of memberships:

- Sector members;
- At-large members; and,
- Non-voting members.

Two members shall be elected to each of the following membership sectors:

- Sector 1 - Investor-owned Utility;
- Sector 2 – State or Municipal Utility;
- Sector 3 - Cooperative Utility;
- Sector 4 - Federal or Provincial Utility/Power Marketing Administration;
- Sector 5 - Transmission-Dependent Utility;
- Sector 6 - Merchant Electricity Generator;
- Sector 7 - Electricity Marketer;
- Sector 8 - Large End Use Electricity Customer;
- Sector 9 - Small End Use Electricity Customer;
- Sector 10 - ISO/RTO; and,
- Sector 12 - Government Representatives.

Selection of at-large members will allow for better balancing of representation on the RSTC of the following:[1]

- Regional Entity and Interconnection diversity (i.e., goal of having at least one representative from each Interconnection and Regional Entity footprint);
- Subject matter expertise (Planning, Operating, or Security);
- Organizational types (Cooperatives, Investor-Owned Utilities, Public Power, Power Marketing Agencies, etc.); and,
- North American countries, consistent with the NERC bylaws (Canada, Mexico, and U.S.) to support diversity of views on issues facing reliability of the North American BPS.

Upon expiration of his or her term as chair, the outgoing chair may remain a non-voting member of the RSTC for one year, in the interest of continuity.[2]

Below is a breakdown of voting and non-voting membership on the RSTC:

[1] *See,* NERC Sector 13 in the NERC Bylaws (2021).

[2] Provided that, if the outgoing chair is elected to represent a voting sector that individual would hold a voting membership position for the relevant term.

Voting Membership	
Name	**Voting Members**
Sectors 1-10 and 12	22
At-Large	10
Chair and Vice-Chair	2
Total	**34**

Non-Voting Membership[3]	
Non-Voting Member	**Number of Members**
NERC Secretary	1
United States Federal Government	2
Canadian Federal Government	1
Provincial Government	1
Former Chair	1
Total	**6**

Member Selection

RSTC members are not required to be from organizations who are NERC members.

Members are appointed to the RSTC upon approval of the NERC Board and serve on the RSTC at the pleasure of the NERC Board.

1. **Affiliates**

   A company, including its affiliates, may not have more than one member on the RSTC. Any RSTC member who is aware of a membership conflict of this nature is obligated to notify the RSTC secretary within 10 business days. The RSTC secretary will in turn report the conflict to the RSTC chair.

   Members impacted by such a conflict, such as through a merger of organizations, must confer among themselves to determine which member should resign from the RSTC and notify the secretary and chair; however, if they cannot reach an amicable solution to determine who will remain, the Nominating Subcommittee will review the qualifications of each member and make a recommendation to the NERC Board for final approval.

2. **Election of Sector Members**

   NERC members in each sector will annually elect members for expiring terms or open seats using a nomination and election process that is open, inclusive, and fair. If a sector has no nominations for one or both sector seats ~~at the annual election~~during the sector election period, the RSTC will convert those empty sector seats to at-large seats until the end of the term unless a valid sector nomination is received prior to the end of the at-large nomination period. NERC Staff shall provide any existing sector representative written notice approximately one week before the end of the sector election period if there have been no nominees for an open sector seat.

   Sector elections will be completed in time for the Nominating Subcommittee to identify and nominate at-large representatives as well as for the secretary to send the full RSTC membership list to the NERC Board for approval at its annual February meeting.

[3] Upon recognition of NERC as the ERO, Mexican Government representation will be equitable and based approximately on proportionate Net Energy for Load.

If an interim vacancy is created in a sector, a special election will be held unless it coincides with the annual election process. If a sector cannot fill an interim vacancy, then that sector seat will remain vacant until the next annual election. Interim sector vacancies will not be filled with an at-large representative.

3. Nominating Subcommittee

The Nominating Subcommittee (RSTC NS) will consist of seven (7) members (the RSTC vice-chair and six (6) members drawing from different sectors and at-large representatives). Apart from the vice-chair, members of the RSTC Executive Committee (RSTC EC) shall not serve on the RSTC NS.

The NS members are nominated by the RSTC chair and voted on by the full RSTC membership.

The term for members of the NS is one (1) year.

The RSTC NS is responsible for (a) recommending individuals for at-large representative seats, and, (b) managing the process to select the chair and/or vice-chair of the RSTC. The RSTC vice-chair shall recuse him or herself from this process (a) unless he or she is not seeking re-election, or (b) until the RSTC NS has concluded a vote to recommend the vice-chair for subsequent RSTC election to the chair position. At-large members on the RSTC NS shall recuse themselves from recommendations for at-large representative seats if they are seeking reappointment.

4. Selection of At-Large Members

The RSTC NS solicits and reviews nominations from the full RSTC and industry to fill at-large representative seats. After reaching consensus, the RSTC NS submits a recommended slate of at-large candidates to the Board~~ at its annual February meeting for approval~~. During its selection process the RSTC NS will prioritize its consideration of candidates that would help ensure balanced sector representation on the RSTC. To the extent practicable, the RSTC NS will balance the following criteria to select at-large members: (a) geographic diversity from all Interconnections and ERO Enterprise Regional Entities; (b) high-level understanding and perspective on reliability risks based on experience at an organization in a sector; and, (c) experience and expertise from an organization in the sector relevant to the RSTC. –The RSTC NS selection process shall also ensure that at-large members include no more than two individuals that would be eligible for the same particular sector, except where it would ensure equitable representation from the United States and Canada in proportion to each country's percentage of total Net Energy for Load.

~~The Board votes to appoint the at-large members.~~

5. Non-Voting Members

Non-voting members shall serve a term of two (2) years, just as voting members. At the start of the annual RSTC nomination process the RSTC secretary will coordinate with entities entitled to non-voting membership to identify representatives for any open non-voting seats. The RSTC secretary shall do this by reaching out to the relevant Governmental Authorities to solicit interest for non-voting member seats and forwarding those names to the RSTC NS for inclusion in the slate of candidates presented to the Board at its annual February meeting. Where more than one candidate is proposed, the RSTC secretary will work with the relevant Governmental Authorities to reach a decision.

6. International Representation

International representation on the RSTC shall be consistent with Article VIII Section 4 of the NERC Bylaws.

Member Expectations

RSTC members and the RSTC's subordinate groups are expected to act in accordance with this charter, as well as to accomplish the following:

- Adhere to NERC Antitrust Guidelines[4] and Participant Conduct Policy[5];
- Demonstrate and provide knowledge and expertise in support of RSTC activities;
- Where applicable, solicit comments and opinions from constituents and groups of constituents or trade organizations represented by the member and convey them to the RSTC;
- Respond promptly to all RSTC requests, including requests for reviews, comments, and votes on issues before the RSTC; and,
- During meetings, comply with the procedures outlined for that meeting and identified in this Charter. .

Sponsor Expectations

Sponsors are expected to act in accordance with this charter, as well as to accomplish the following:

- Understand and advance the expectations of the RSTC, not those of their sector or other interest group;
- Assure that recommendations and action plans are designed for implementation;
- Support the subgroup Chair and Vice-Chair in seeing the big picture without directing the activities of the subgroup; and,
- Liaise with the RSTC.

Member Term

Members shall serve a term of two years.

An RSTC member may serve a term shorter than two (2) years if:

- Two (2) members are simultaneously selected to a sector that did not have any existing members, in order to stagger their terms, one member will be assigned a one-year term and the second member will be assigned a two-year term.
- A member is selected to fill a vacant member seat between elections, the term will end when the term for that vacant seat ends.

There are no limits on the number of terms that members can serve.

Vacancies and Proxies

Membership vacancies may be filled between annual elections using the aforementioned selection process.

1. **Vacancies Created by the Member**

   In the event a member can no longer serve on the RSTC, that member will submit a written resignation to the RSTC chair or the secretary. A change in employment does not automatically require a member's resignation and will be evaluated on a case-by-case basis.

2. **Vacancies Requested by the Chair**

   The chair may request any RSTC member who ceases to participate in the RSTC consistent with member expectations (above) and to the satisfaction of the chair, to submit a resignation or to request continuation of membership with an explanation of extenuating circumstances. If a written response is not received within

[4] https://www.nerc.com/pa/Stand/Resources/Documents/NERC_Antitrust_Compliances_Guidelines.pdf
[5] https://www.nerc.com/gov/Annual%20Reports/NERC_Participant_Conduct_Policy.pdf

30 days of the chair's request, the lack of response will be considered a resignation. If the chair is not satisfied with a written response, the RSTC chair will refer the matter to the NERC Board.

3. Vacancies Requested by the Board

RSTC members serve at the pleasure of the NERC Board. The NERC Board may initiate a request for resignation, removal, or replacement of a member from the RSTC, as it deems appropriate or at the request of the RSTC chair.

4. Proxies

A voting member may select a proxy who attends and votes during all or a portion of a committee meeting in lieu of a voting member, provided that the absent voting representatives notifies the RSTC chair, vice chair, or secretary of the proxy. A proxy may not be given to another RSTC member. A proxy must meet the RSTC's membership eligibility requirements, including affiliate restrictions.

To permit time to determine a proxy's eligibility, all proxies must be submitted to the secretary in writing at least one week prior to the meeting (electronic transmittal is acceptable) for approval by the chair. Any proxy submitted after that time will be accepted at the chair's discretion.

Section 4: Meetings

Open meetings will be conducted in accordance with this Charter. The Chair may consult Robert's Rules of Order for additional guidance.

Quorum

The quorum necessary for transacting business at meetings of the RSTC is two-thirds of the voting members currently on the RSTC's roster and is determined once at each meeting.

If a quorum is not determined, the RSTC may not take any actions requiring a vote; however, the chair may allow discussion of the agenda items.

Voting

Actions by the RSTC will be approved upon receipt of the affirmative vote of two-thirds of the votes cast at any meeting at which a quorum is present. An abstention ("present" vote) does not count as a vote cast.

Voting may take place during regularly scheduled in-person meetings, via electronic mail, or via conference call/virtual meeting.

Refer to Section 7 for voting procedures.

Executive, Open and Closed Sessions

The RSTC and its subordinate groups hold meetings open to the public, except as noted herein. Although meetings are open, only voting members may offer and act on motions.

All meetings of the Executive Committee and the RSTC NS shall be conducted in closed session.

The chair may also hold closed sessions in advance of the open meeting with limited attendance based on the confidentiality of the information to be disclosed at the meeting. Such limitations should be applied sparingly and on a non-discriminatory basis. Any discussion of confidential information in a closed session shall be consistent with Section 1500 of the NERC ROP.[6]

Majority and Minority Views

All members of a committee will be given the opportunity to provide alternative views on an issue. The results of committee actions, including recorded minutes, will reflect the majority as well as any minority views of the committee members.

Action without a Meeting

Any action required or permitted at a meeting of the committee may be taken without a meeting at the request of the chair.

Such action without a meeting will be performed by electronic ballot (e.g., telephone, email, or Internet survey) and considered a roll call ballot. The secretary will announce the action required at least five business days before the date on which voting commences. As time permits, members should be allowed a window of ten (10) business days to vote. The secretary will document the results of such an action within ten (10) business days of the close of the voting period. Such action must meet the regular meeting quorum and voting requirements above.

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[6] Section 1500 of the NERC ROP - https://www.nerc.com/FilingsOrders/us/RuleOfProcedureDL/NERC%20ROP%20(With%20Appendicies).pdf

Section 5: Officers and Executive Committee

Officers

The RSTC will have two officers – one chair and one vice-chair.

Officers shall be selected as follows:

- The RSTC NS solicits nominations for chair and vice-chair through an open nomination process. Self-nominations are permitted during the open nomination period.
- At the close of the nomination period, the RSTC NS will propose a chair and a vice-chair candidate. The full RSTC will elect the chair and vice chair.
- The chair and vice chair must be a committee member and shall not be from the same sector.
- The elected chair and vice-chair are appointed by the NERC Board.
- No individual may serve more than one term as vice chair and one term as chair unless an exception is approved by the Board. A term lasts two years.

Upon expiration of his or her term as chair, the outgoing chair may remain a non-voting member of the RSTC for one year, in the interest of continuity.[7]

Secretary

NERC will appoint the RSTC secretary.

A member of the NERC staff will serve as the secretary of the RSTC. The secretary will do the following:

- Manage the day-to-day operations and business of the RSTC;
- Prepare and distribute notices of the RSTC meetings, prepare the meeting agenda, and prepare and distribute the minutes of the RSTC meetings;
- Facilitate the election/selection process for RSTC members; and,
- Act as the RSTC's parliamentarian.

Chair

The chair will direct and provide general supervision of RSTC activities, including the following:

- Coordinate the scheduling of all meetings, including approval of meeting duration and location;
- Develop agendas and rule on any deviation, addition, or deletion from a published agenda;
- Preside at and manage meetings, including the nature and length of discussion, recognition of speakers and proxies, motions, and voting;
- Act as spokesperson for the RSTC at forums inside and outside of NERC; and,
- Attend meetings of the NERC Board when necessary to report on RSTC activities.

Vice Chair

The vice chair will assume the responsibilities of the chair under the following conditions:

[7] Provided that, if the outgoing chair is elected to represent a voting sector that individual would hold a voting membership position for the relevant term

- At the discretion of the chair (for brief periods of time);
- When the chair is absent or temporarily unable to perform the chair's duties; or,
- When the chair is permanently unavailable or unable to perform the chair's duties. In the case of a permanent change, the vice chair will continue to serve until a new chair is nominated and appointed by the NERC Board.

Executive Committee

The RSTC EC shall consist of six (6) members:

- Chair;
- Vice-chair;
- Four (4) RSTC voting members selected by the RSTC chair and vice-chair with a reasonable balance of subject matter expertise in Operations, Planning, and/or Security and with consideration for diversity in representation (i.e., sectors, Regional Entities, Interconnections, etc.).
    - The RSTC chair and vice-chair shall evaluate composition of the RSTC EC within six months of their election as officers for the appropriate balance of technical expertise, geographical representation, and tenure.

The RSTC EC of the RSTC is authorized by the RSTC to act on its behalf between regular meetings on matters where urgent actions are crucial and full RSTC discussions are not practical. The RSTC shall be notified of such urgent actions taken by the RSTC EC within a week of such actions. These actions shall also be included in the minutes of the next open meeting.

Ultimate RSTC responsibility resides with its full membership whose decisions cannot be overturned by the EC. The RSTC retains the authority to ratify, modify, or annul RSTC EC actions.

After general solicitation from RSTC membership, the RSTC EC will appoint any sponsors of subgroups.

Section 6: RSTC Subordinate Groups

The RSTC organizational structure will be aligned as described by the NERC Bylaws to support a superior-subordinate hierarchy.

The RSTC may establish subcommittees, working groups, and task forces as necessary. The RSTC will be the responsible sponsor of all subordinate subcommittees, working groups, or task forces that it creates, or that its subordinate subcommittees and working groups may establish.

Officers of subordinate groups will be appointed by the chair of the RSTC. Where feasible, officers shall be selected from individuals employed at entities within NERC membership sectors 1 through 12 to support sufficient expertise and diversity in execution of the subordinate group's responsibilities.

Subcommittees, working groups, and taskforces will conduct business in a manner consistent with all applicable sections of this Charter, including the NERC Antitrust Guidelines[8] and Participant Conduct Policy[9].

Subcommittees

The RSTC may establish subcommittees to which the RSTC may delegate some of RSTC's functions. The RSTC will approve the scope of each subcommittee it forms. The RSTC chair will appoint the subcommittee officers (typically a chair and a vice chair) for a specific term (generally two years). The subcommittee officers may be reappointed for up to two additional terms. The subcommittee will work within its assigned scope and be accountable for the responsibilities assigned to it by the committee. The formation of a subcommittee, due to the permanency of the subcommittee, will be approved by the NERC Board.

Working Groups

The RSTC may delegate specific continuing functions to a working group. The RSTC will approve the scope of each working group that it forms. The RSTC chair will appoint the working group officers (typically a chair and a vice chair) for a specific term (generally two (2) years). The working group officers may be reappointed for one (1) additional term. 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 transitioning to a subcommittee any working group that is required to work longer than two terms.

Task Forces

The RSTC may assign specific work to a task force. The RSTC will approve the scope of each task force it forms. The RSTC chair will appoint the task force officers (typically a chair and a vice chair). 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 review the task force's execution of its work plan 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 transitioning to a working group any task force that is required to work longer than two years.

[8] https://www.nerc.com/pa/Stand/Resources/Documents/NERC_Antitrust_Compliances_Guidelines.pdf

[9] https://www.nerc.com/gov/Annual%20Reports/NERC_Participant_Conduct_Policy.pdf

Section 7: Meeting Procedures

Voting Procedures for Motions

In-Person

- The default procedure is a voice vote.
- If the chair believes the voice vote is not conclusive, the chair may call for a show of hands.
- The chair will not specifically ask those who are abstaining to identify themselves when voting by voice or a show of hands. If the chair desires a roll call, the secretary will call each member's name.

  Members answer "yes," "no," or "present" if they wish to abstain from voting. As provided above, an abstention does not count as a vote cast.

Conference Call / Virtual[10]

- All voting shall default to being conducted through use of a poll.
- Where a need to record each member's vote is requested or identified, the RSTC may conduct voting via a roll call vote.

Minutes

- Meeting minutes are a record of what the committee did, not what its members said.
- Minutes should list discussion points where appropriate but should usually not attribute comments to individuals. It is acceptable to cite the chair's directions, summaries, and assignments.
- All Committee members are afforded the opportunity to provide alternative views on an issue. The meeting minutes will provide an exhibit to record minority positions.

[10] Virtual meetings include those where virtual attendance is possible, such as a fully or partially virtual meeting.

Section 8: RSTC Deliverables and Approval Processes

The RSTC will abide by the following to approve, endorse, or accept committee deliverables.

Reliability Guidelines, Security Guidelines and Technical Reference Documents

Reliability Guidelines, Security Guidelines, and Technical Reference Documents suggest approaches or behavior in a given technical area for the purpose of improving reliability.

Reliability and Security Guidelines

Reliability Guidelines and Security Guidelines are not binding norms or mandatory requirements. Reliability Guidelines and Security Guidelines may be adopted by a responsible entity in accordance with its own facts and circumstances.

1. **New/updated draft Guideline approved for industry posting.**

   The RSTC accepts for posting for industry comment (i) the release of a new or updated draft Guideline developed by one of its subgroups or the committee as a whole; or (ii) the retirement of an existing Guideline.

   The draft Guideline or retirement is posted as "for industry-wide comment" for 45 days. If the draft Guideline is an update, a redline version against the previous version must also be posted.

   After the public comment period, the RSTC will post the comments received as well as its responses to the comments. The RSTC may delegate the preparation of responses to a committee subgroup.

   A new or updated Guideline which considers the comments received, is approved by the RSTC and posted as "Approved" on the NERC website. Updates must include a revision history and a redline version against the previous version. Retirements are also subject to RSTC approval.

   After posting a new or updated Guideline, the RSTC will continue to accept comments from the industry via a web-based forum where commenters may post their comments.

   a. Each quarter, the RSTC will review the comments received.

   b. At any time, the RSTC may decide to update the Guideline based on the comments received or on changes in the industry that necessitate an update.

   c. Updating an existing Guideline will require that a draft updated Guideline be posted and approved by the RSTC in the above steps.

2. **Review of Approved Reliability Guidelines, Security Guidelines and Technical Reference Documents**

   Approved Reliability Guidelines or Technical Reference Document shall be reviewed for continued applicability by the RSTC at a minimum of every third year since the last revision.

3. **Communication of New/Revised Reliability Guidelines, Security Guidelines and Technical Reference Documents**

   In an effort to ensure that industry remains informed of revisions to a Reliability Guideline or Technical Reference Document or the creation of a new Reliability Guideline or Technical Reference Document, the RSTC subcommittee responsible for the Reliability Guideline will follow an agreed upon process. Reliability Guidelines, Security Guidelines, and Technical Reference Documents (including white papers as discussed below) shall be posted on the RSTC website.

4. **Coordination with Standards Committee**

Standards Committee authorization is required for a Reliability Guideline or Security Guidelines to become a supporting document that is posted with or referenced from a NERC Reliability Standard. See Appendix 3A in the NERC's ROP under "Supporting Document."

Section 1600 Data or Information Requests[11]

A report requested by the RSTC that accompanies or recommends a Rules of Procedure (ROP) Section 1600 - Data or Information Request will follow the process outlined below:

1. This Section 1600 request, with draft supporting documentation, will be provided to the RSTC at a regular meeting.
2. The draft Section 1600 data request and supporting documentation will be considered for authorization to post for comments at the RSTC regular meeting.
3. A committee subgroup will review and develop responses to comments on the draft Section 1600 data request and will provide a final draft report, including all required documentation for the final data request, to the RSTC at a regular meeting for endorsement.
4. The final draft of the 1600 data request – with responses to all comments and any modifications made to the request based on these comments – will be provided to the NERC Board.

Other Types of Deliverables

1. **Policy Outreach**

   On an ongoing basis, the RSTC will coordinate with the forums, policymakers, and other entities to encourage those organizations to share Reliability Guidelines, technical reference documents and lessons learned to benefit the industry.

   Reports required under the NERC ROP or as directed by an Applicable Governmental Authority or the NERC Board: documents include NERC's long-term reliability assessment, special assessments, and probabilistic assessments. These reports may also be used as the technical basis for standards actions and can be part of informational filings to FERC or other government agencies.

2. **White Papers**

   Documents that explore technical facets of topics, making recommendations for further action. They may be written by subcommittees, working groups, or task forces of their own volition, or at the request of the RSTC. Where feasible, a white paper recommending potential development of a standard authorization request (SAR) shall be posted for comment on the RSTC website. White papers will be posted on the RSTC webpage, after RSTC approval.

3. **Technical Reference Documents and Technical Reports**

   Documents that serve as a reference for the electric utility industry and/or NERC stakeholders regarding a specific topic of interest. These deliverables are intended to document industry practices or technical concepts at the time of publication and may be updated as deemed necessary, per a recommendation by the RSTC or its subgroups to reflect current industry practices. Technical reference documents and reports will be posted on the RSTC webpage, after RSTC approval.

[11] Section 1600 of the NERC ROP - https://www.nerc.com/FilingsOrders/us/RuleOfProcedureDL/NERC%20ROP%20(With%20Appendicies).pdf. This process only applies to Section 1600 requests developed by the RSTC and its subordinate groups.

4. **Implementation Guidance**

   Documents providing examples or approaches for registered entities to comply with standard requirements. The RSTC is designated by the ERO Enterprise as a pre-qualified organization for vetting Implementation Guidance in accordance with NERC Board -approved Compliance Guidance Policy. Implementation Guidance that is endorsed by the RSTC can be submitted to the ERO Enterprise for endorsement, allowing for its use in Compliance Monitoring and Enforcement Program (CMEP) activities.

5. **Standard Authorization Requests (SAR)**

   A form used to document the scope and reliability benefit of a proposed project for one or more new or modified Reliability Standards or definitions or the benefit of retiring one or more approved Reliability Standards.

   Any entity or individual, including NERC Committees or subgroups and NERC Staff, may propose the development of a new or modified Reliability Standard. A SAR prepared by a subordinate group of the RSTC must be endorsed by the RSTC prior to presentation to the Standards Committee. Each SAR should be accompanied by a technical justification that includes, at a minimum, a discussion of the reliability-related benefits and costs of developing the new Reliability Standard or definition, and a technical foundation document (e.g., research paper) to guide the development of the Reliability Standard or definition. The technical foundation document should address the engineering, planning and operational basis for the proposed Reliability Standard or definition, as well as any alternative approaches considered to SAR development.

   RSTC endorsement of a SAR supports: (a) initial vetting of the technical material prior to the formal Standards Development Process, and, (b) that sound technical justification has been developed, and the SAR will not be remanded back to the RSTC to provide such justification per the Standard Processes Manual.

Review Process for other Deliverables

Deliverables with a deadline established by NERC management or the NERC Board will be developed based on a timeline reviewed by the RSTC to allow for an adequate review period, without compromising the desired report release dates. Due to the need for flexibility in the review and approval process, timelines are provided as guidelines to be followed by the committee and its subgroups.

A default review period of no less than 10 business days will be provided for all committee deliverables. Requests for exceptions may be brought to the RSTC at its regular meetings or to the RSTC EC if the exception cannot wait for an RSTC meeting.

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

Actions for Deliverables

1. **Approve:**

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

2. **Accept:**

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

3. **Remand:**

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

4. **Endorse:**

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

Potential Bulk Power System (BPS) Impacts Due to Severe Disruptions on the Natural Gas System

Action

- Informational presentation on the results of the NERC-NAERM[1] joint study of the Potential Bulk Power System (BPS) Impacts Due to Severe Disruptions on the Natural Gas System.
- Accept the subsequent draft report for a 45-day review and comment period by the RSTC members.

Background

In August 2022, NERC requested support from the Department of Energy's Office of Electricity (DOE-OE) with a natural gas pipeline outage study to assess interdependencies with the BPS. NERC noted that the 2021 Electric Reliability Organization (ERO) Reliability Risk Priorities Report emphasized the growing interdependencies of the electric and gas sectors, with the potential for common-mode failures that could have widespread reliability impacts. The dependence on natural-gas-fired generation to maintain reliability does not align with the construct and weatherization requirements for natural gas gathering and delivery systems. Hence, the report recommended that NERC should conduct special assessments that address natural gas availability and pipeline common mode failures that are impactful to the BPS.

A similar Special Reliability Assessment was performed in 2017, "Potential Bulk Power System Impacts Due to Severe Disruptions on the Natural Gas System," which included a single-point-of-disruption (SPOD) analysis that modeled impacts from gas pipeline asset disruptions.

Summary

The assessment identifies potential areas by US state which may experience natural gas shortfalls upon the loss of major natural gas infrastructure facilities (e.g., processing plants, storage facilities, compressor stations, key pipeline segments, and liquefied natural gas [LNG] terminals). The assessment was conducted by interconnection and distinguishes impacts between Summer and Winter.

[1] North American Energy Resilience Model (NAERM). Under this project, DOE employed modeling and simulation capabilities developed under the NAERM program to support NERC's reliability assessments.

NERC-NAERM Update

Potential Bulk Power System Impacts Due to Severe Disruptions on the Natural Gas System

Scott Barfield-McGinnis, Principal Technical Advisor

Reliability and Security Technical Committee Meeting

June 11, 2024

Introduction

- NAERM – North American Energy Resilience Model
  - National-scale energy planning and situational awareness capabilities for rigorous and quantitative assessment, prediction, and improvement
  - Advances existing capabilities to model, simulate, and assess the behavior of electric power systems, as well as its associated dependencies on natural gas (NG), telecommunications, and other critical infrastructures.
- NERC-NAERM Joint Project
  - Potential Bulk Power System (BPS) Impacts Due to Severe Disruptions on the Natural Gas System
  - Revisit the 2017 Single Points of Disruption (SPOD)
  - Uses 2021 planning basecases
  - Uses Argonne National Laboratory tool – *NGfast*
  - Numerous data sets
    - Publicly available from Energy Information Administration (EIA)
    - Non-public Critical Energy Infrastructure Information (CEII)

SPOD Study Process

NG Scenarios

- Top 20 scenarios
- 6 Eastern Interconnection
  - 4 Summer
  - 2 Winter
- 14 Western Interconnection
  - 3 Summer
  - 11 Winter

Case Preparation & Study Setup

- Steady-State AC Outage Analysis in sequence
- Power Rebalance excludes any constrained NG plants
- No Area Interchange
- Allow for basic operating functions to alleviate voltage or thermal constraints

Perform BPS Analysis

- Study utilized industry power flow software tools
- Interconnection planning cases were used (Eastern and Western Interconnection, and ERCOT)
- Basic operating actions alleviate most voltage and thermal constraints

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NG Study Parameters

- NG Infrastructure
  - Pipeline segment outages
  - Disruption of LNG transport operations
  - Natural gas underground storage disruptions
  - Interruption of compressor station operations
  - Natural gas processing plant outages
- Linear Model
  - Starts in the upstream state
  - Proceeds to the terminal state(s)
  - Accounts for firm/interruptible
  - NG operator action mitigation

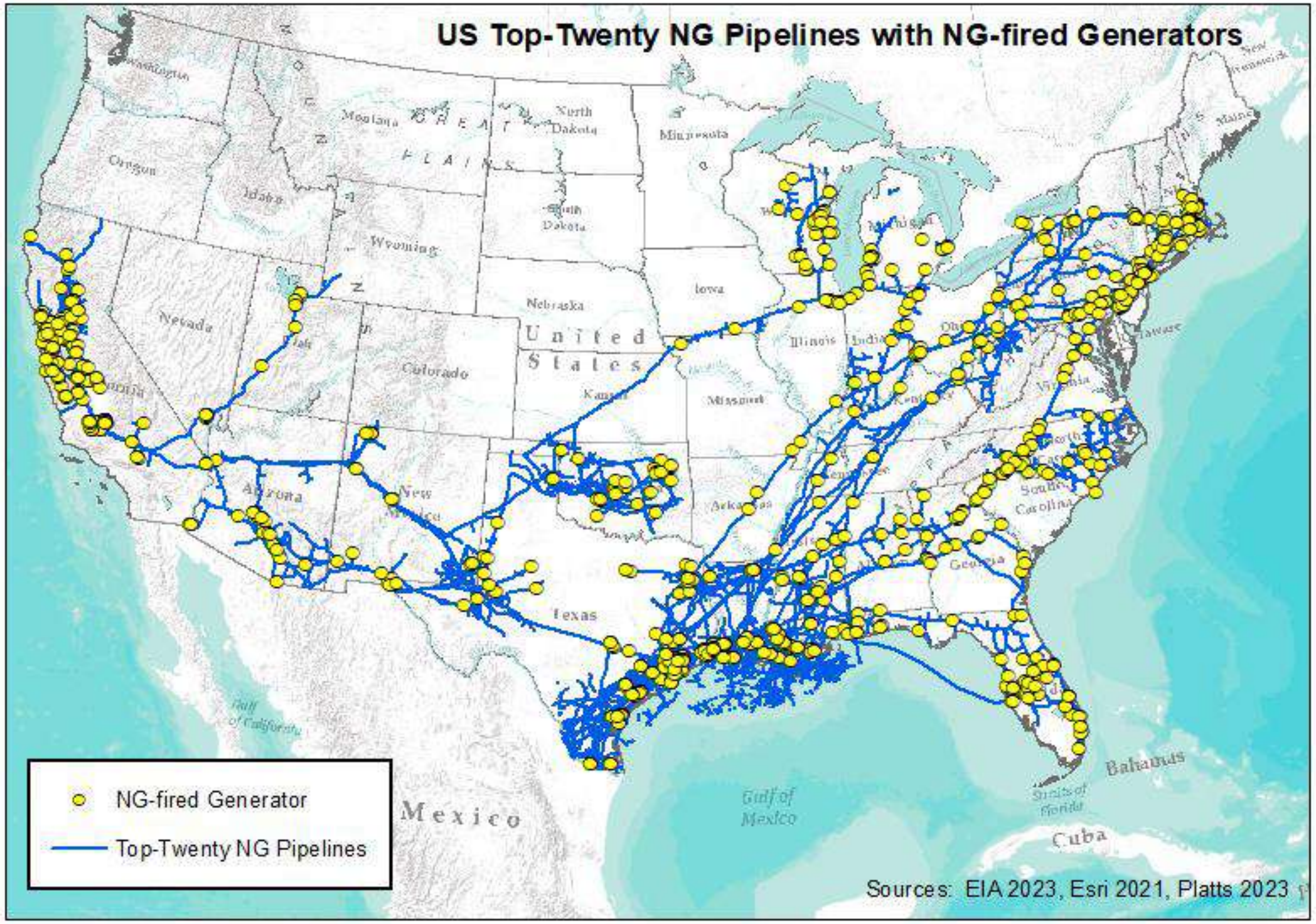
Asset Type	Count	Months	Runs*	Total *NGfast* Runs
State Border Points	996	12	2	23,184
Compressor Stations	1,335	12	2	32,040
LNG Import Terminals	10	12	2	240
Underground Gas Storage Fields	420	12	2	10,080
NG Processing Plants	669	12	2	16,056
Total	**3,400**	**12**	**2**	**81,600**

**Compensated Runs*

BPS Power Flow Parameters

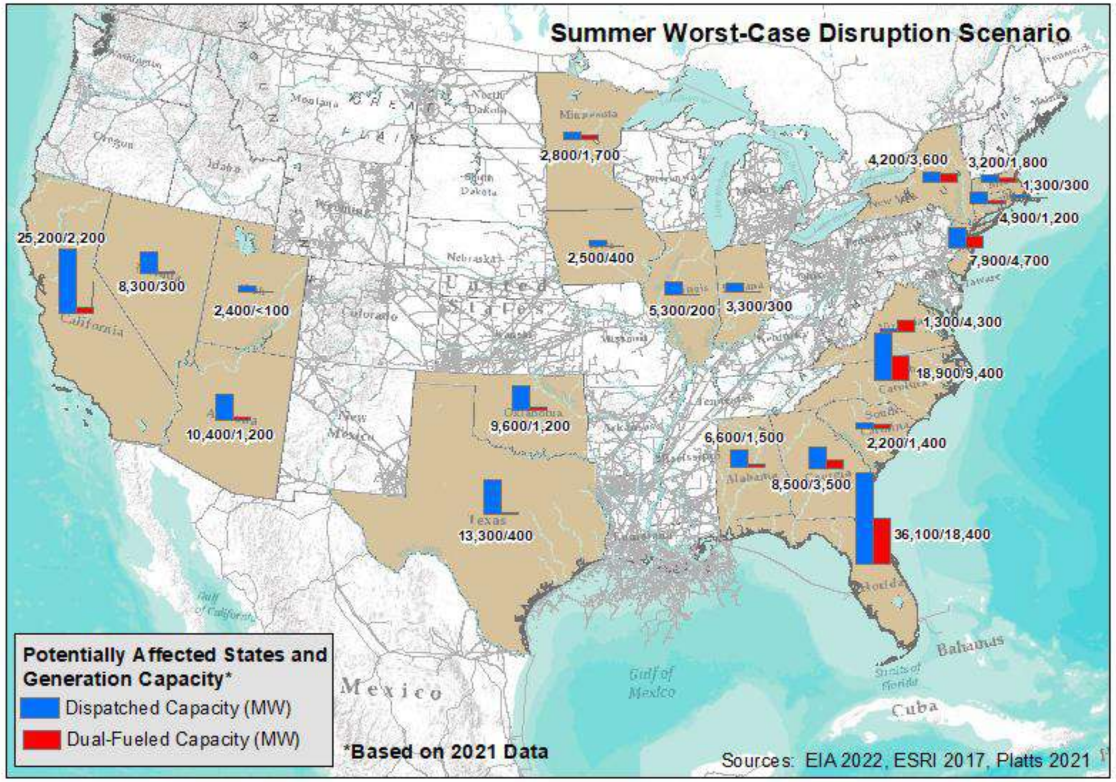
- 2021 basecases (IE, ERCOT, WI)
- Power Flow Application
  - V&R Energy's Physical
  - Operational Margins (POM) 2023 Suite
- Elements
  - Remote regulations enabled
  - Voltage-controlling transformers disabled
  - Switched Shunts enabled
  - Continuous Shunts enabled
  - Phase Shifting transformers disabled
  - Reactive power flow controlling transformers disabled
- Area Interchange disabled

Top-Twenty Pipelines in Terms of Deliveries to Electric Customers (2021)

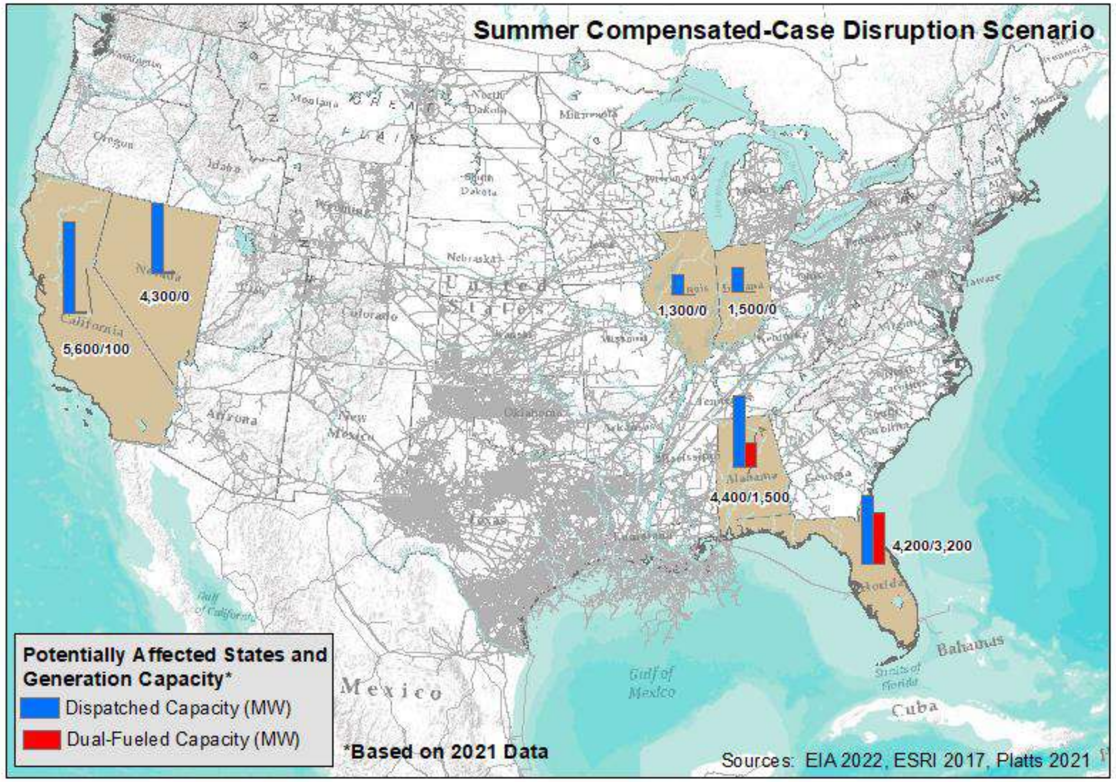


Summer Worst-Case and Compensated Scenario

Worst-Case

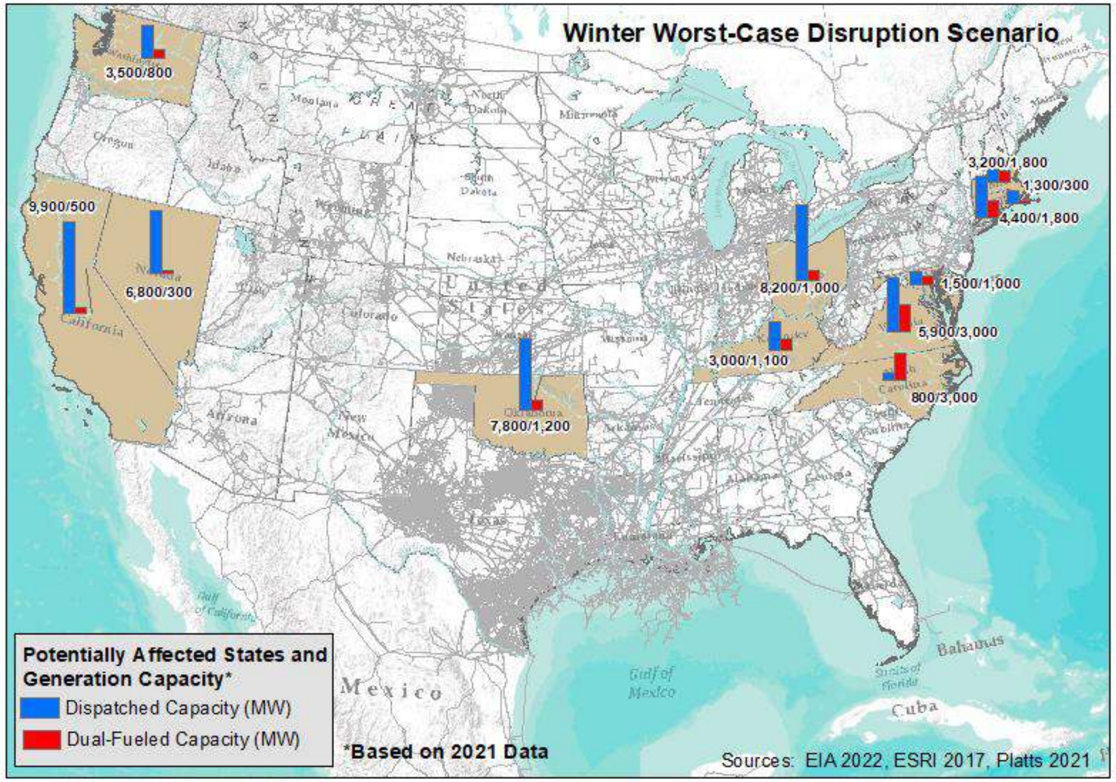


Reasonable Best-Case

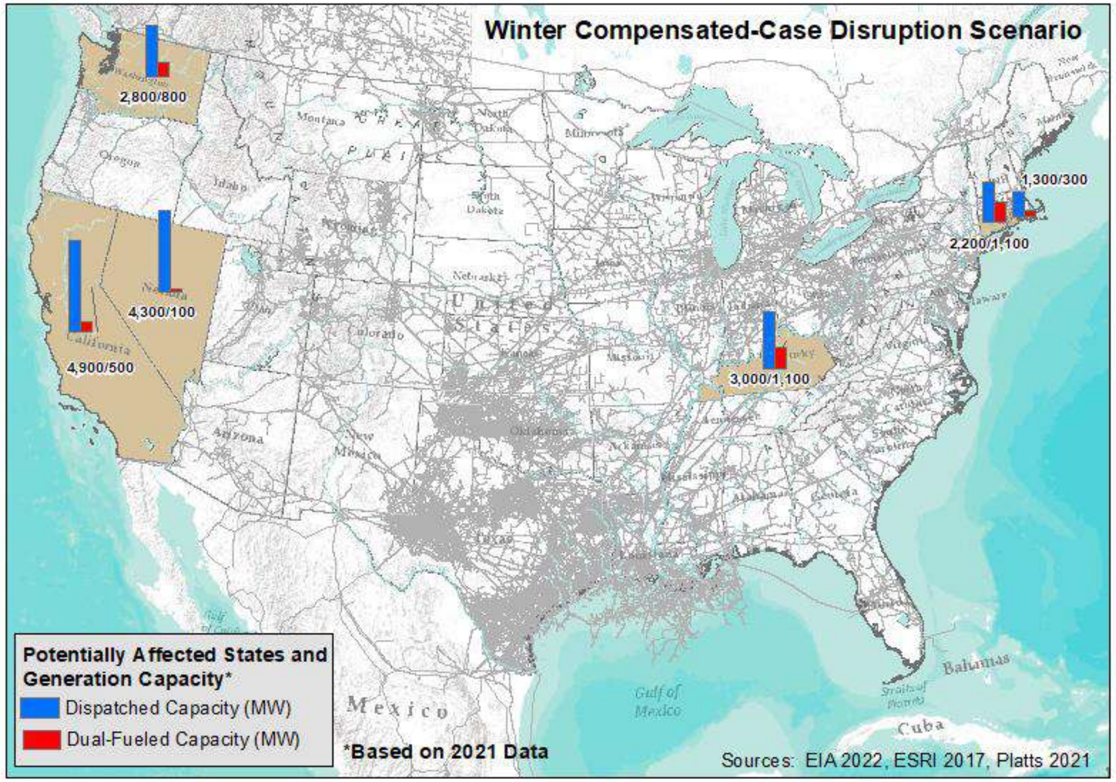


Winter Worst-Case and Compensated Scenario

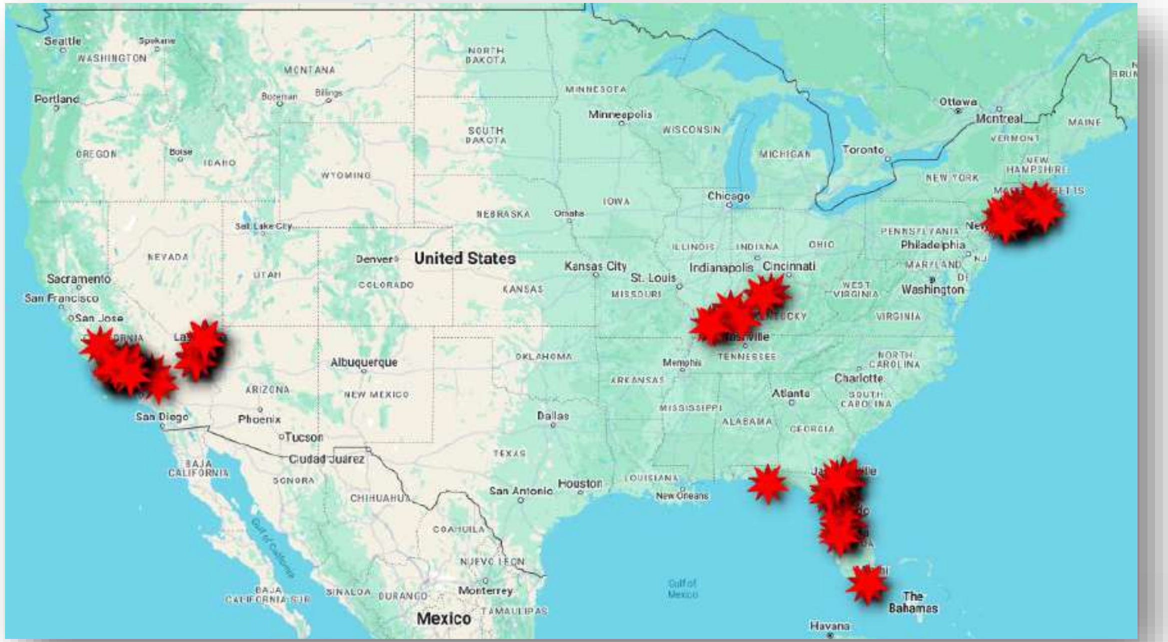
Worst-Case



Reasonable Best-Case



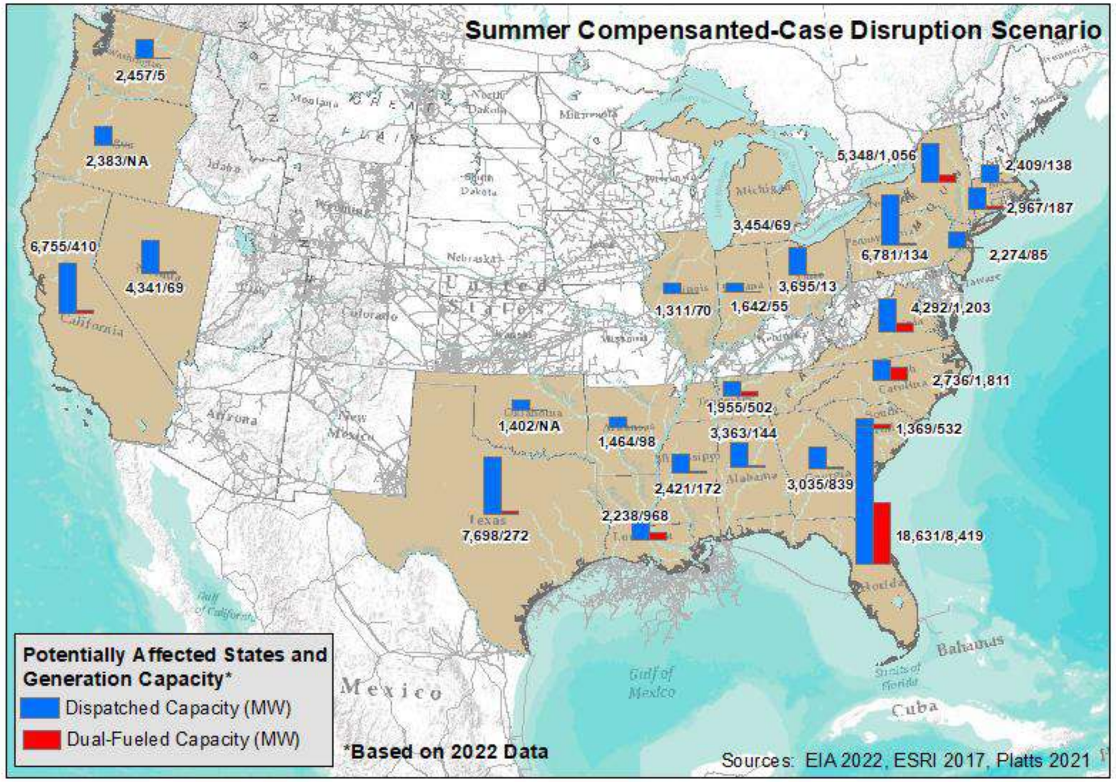
Key Findings



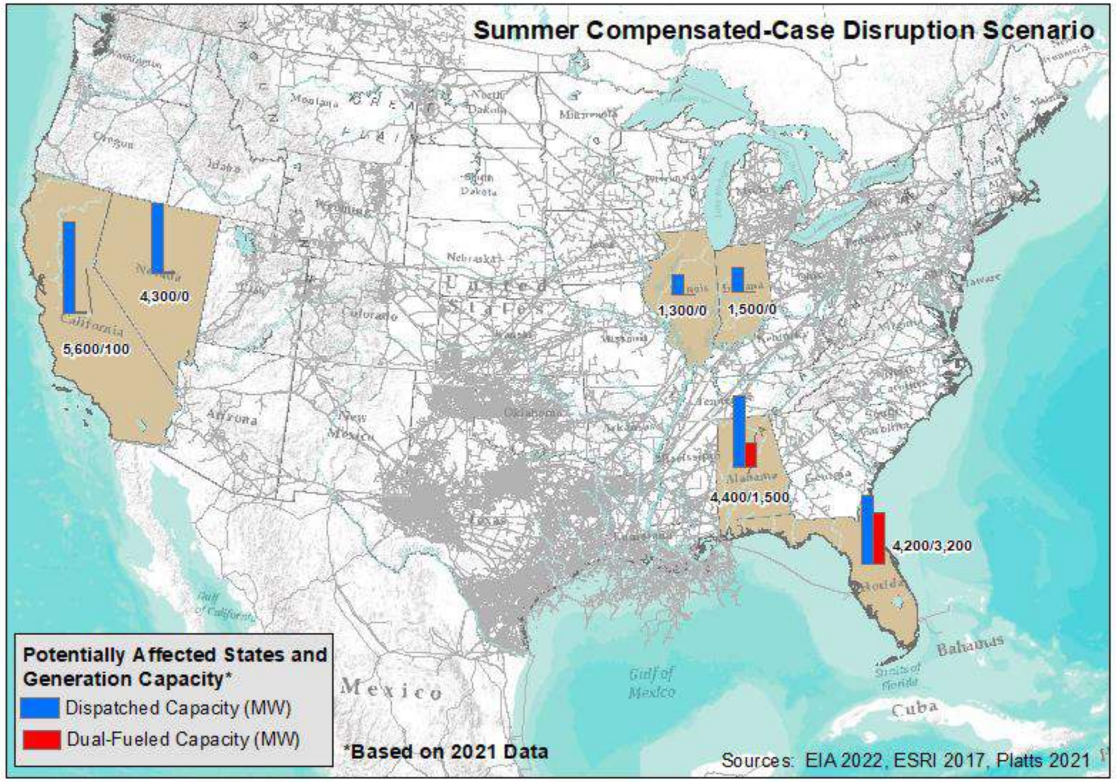
- Top Event Threats
  - EI in summer and WECC in winter
- Some scenarios include generation loss that exceeds the reserves available
  - Increased Inter-Area transfers would be required in those cases.
- ERCOT no SPOD >2 GW (assumes gas compensation measures are taken)
- Steady-state assessment yields positive results in most of the scenarios (no significant operating constraints)
- Flows are not always Gulf-states to NE

Summer Reasonable Best-Case Comparison

Summer 2018

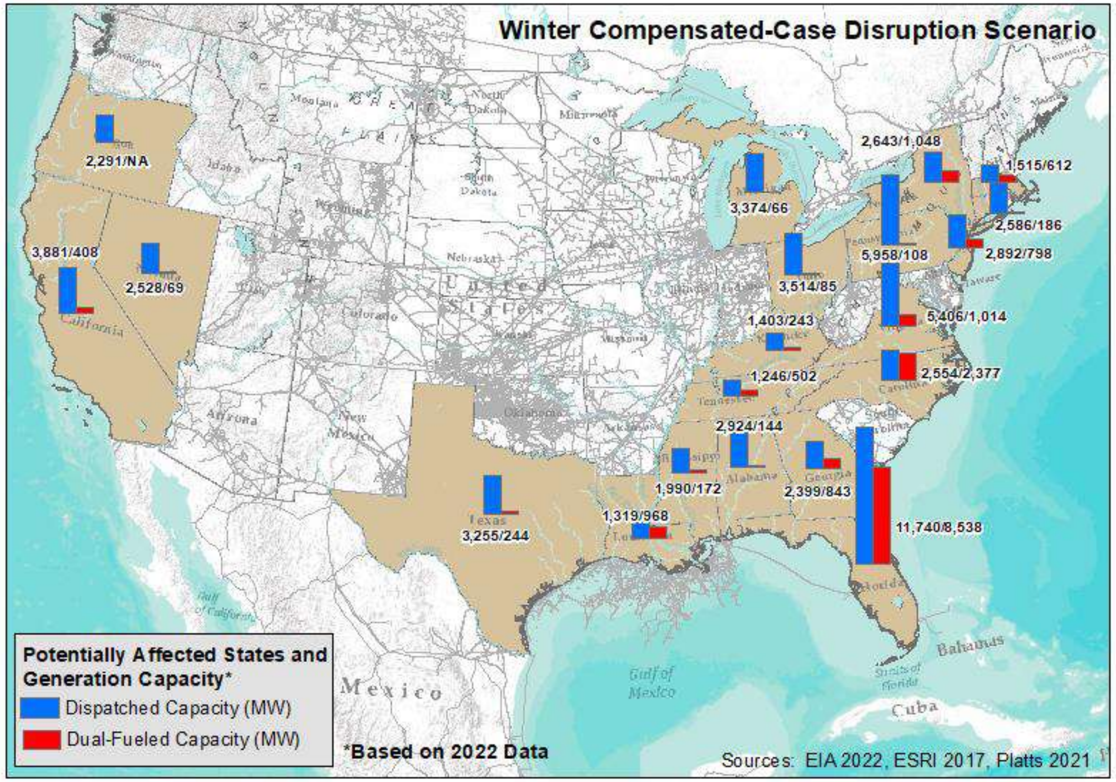


Summer 2024

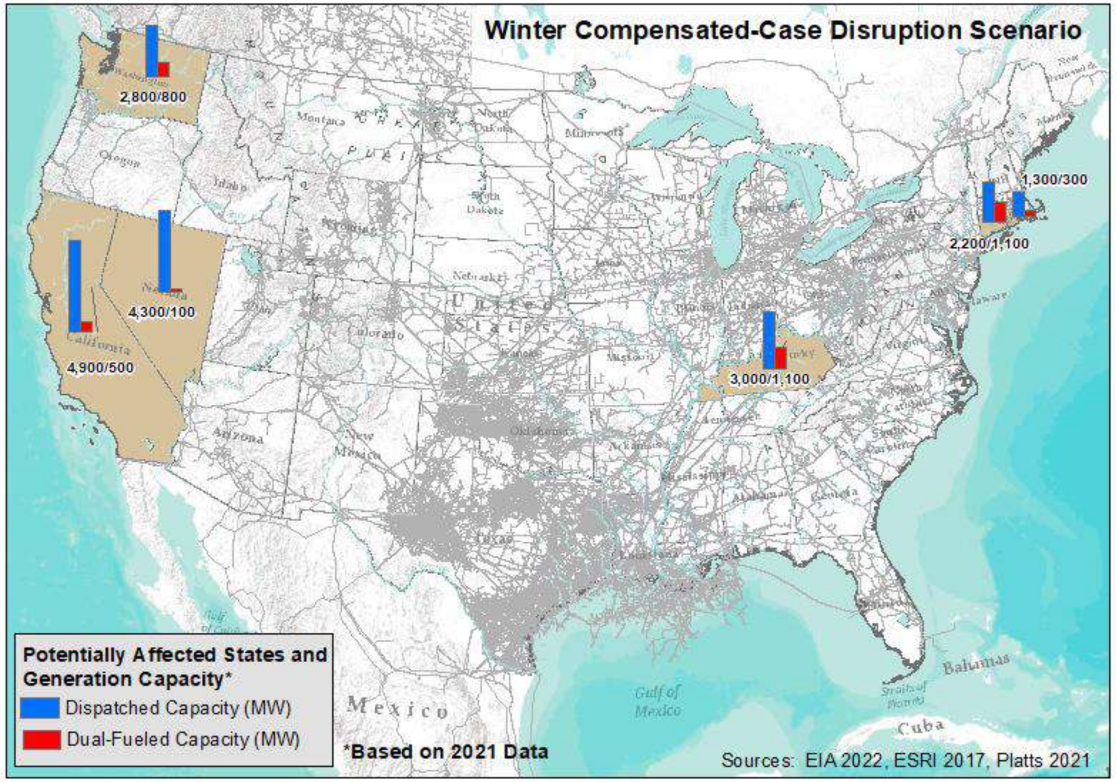


Winter Reasonable Best-Case Comparison

Winter 2018



Winter 2024



Conclusions and Next Steps

- Conclusions
  - Top Threats: EI in summer and WECC in winter
  - Some scenarios losses exceeded available reserves
  - ERCOT had no losses >2 GW (with compensation)
  - One SPOD would require a power transfer into California
    - Insignificant dual-fuel and LNG storage to provide mitigation
  - NG will become more important due to reliance of filling gaps in fuel uncertain resources
- Next Steps
  - Request RSTC members to comment on the draft report
  - 45-day comment period
  - Publish report – late August
  - Phase II gas study for BPS (time domain)

Acknowledgements

- NAERM Staff
  - Argonne National Laboratory
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NERC-NAERM Joint Project:
Potential Bulk Power System Impacts Due to Severe Disruptions on the Natural Gas System

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Questions and Answers

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